VANRY
ASSOCIATES
HIGH PERFORMANCE EXECUTIVE COUNSEL

PO Box 2086, Station Terminal T: 604 732 4010
Vancouver, BC V6B 3T2 Canada www.vanry.com

alectra
utilities

Alectra Utilities
2020 - 2024 Distribution System Plan
Assurance Review Report

23 May 2019

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Executive Summary

Vanry & Associates Inc. (Vanry) was engaged by Alectra Utilities Corporation (Alectra Utilities or Alectra) to undertake an independent, third-party review of the methodologies used to assess asset health, as well as the processes and methodologies used in development of the Distribution System Plan ("DSP") for the 2020 – 2024 planning period. This report documents our assurance review of the draft DSP which encompasses all of the Alectra legacy utilities.

Our work comprised multiple reviews of the DSP documentation, including appendices, and multiple meetings/video conferences with relevant Alectra subject matter experts ("SMEs") and interviews of other relevant Alectra personnel. The review paid particular attention to two areas: Asset Management ("AM") process, and the 5-year System Investment Plan. The AM review assessed the methodologies employed by Alectra and evaluated the asset management process, specifically the links between i) inputs that drive the needs of investment, ii) processes used to prioritize and pace solutions and iii) alignment of investments with intended performance outcomes (customer focus, operational effectiveness, public policy responsiveness, financial performance). In terms of inputs into the AM process, the review included an assessment of the methodologies used in developing an evaluation of the Asset Condition Assessment ("ACA") and provides an opinion of the alignment of this methodology to established industry best practices. Our review team is made up of professionals that are well regarded in the industry and known as experts in this area. Stewart Ramsay and Darin Johnson led the majority of the investigations, and data collection, with support from Neil Reid. Julius Pataky served as our own independent QA/QC lead and framed our internal review methodology.

The System Investment Plan review evaluated the appropriateness of the 5-year system investment decisions and plan developed based on the information derived from the asset management process. The review assessed the relationship between the needs identified from the asset management process and capital investment plan, specifically the appropriateness of prioritization and pacing with a focus on key drivers of change over the 5-year planning period.

Our review was limited to a review of the DSP and its appendices, review of Alectra's process and methodology documentation and business cases provided by Alectra and information gained during interviews with Alectra's subject matter experts and management personnel. We did not undertake verification of other underlying input data, nor did we validate the input data that Alectra received from other sources and stakeholders, such as equipment manufacturers and regional transportation authorities.

Alectra has continued to make improvements in its asset management processes, analytical capabilities, and in its understanding of the system and the assets that make up the system. Alectra continues to improve on its abilities to leverage its investments in tools, such as GIS, and continues to investigate and adopt new tools and technologies. Alectra exhibits sound asset management capabilities and these are used to good effect in bringing together the DSP. Alectra is focused on continuous improvement, including continuing to strengthen its Asset Management process and capabilities.

We note that Alectra has made substantial progress and improvements since our last review of the 2017 Enersource Rate Zone DSP. Since that time Alectra has brought all the legacy utilities together under a common asset management framework and set of processes. It has transitioned the conduct of the ACA in-house, and it has adopted and implemented the C55 optimization process. All of this represents a significant level of effort and Alectra has accomplished this effort quickly and to good effect. The level of standardization of process and methodology is evident throughout the DSP and the underlying analyses and business cases. Alectra continues to make improvements in its AM processes and is demonstrating its commitment to continuous improvement.

In our review of the DSP and our discussions with Alectra personnel, Alectra demonstrates clearly that it understands the value and the limitations of the data and analyses that it has at its disposal and is working systematically to improve the quality of data for the highest value/risk decisions that it is making. Alectra has continued to improve its ability to assess pacing of investments. Alectra not only assesses potential investment portfolios against financial and rate impacts, it assesses them against other realistic constraints such as labour availability, workload throughput, and the probabilities of other regional partners and developers meeting proposed construction timelines. There is a clear understanding among the Alectra staff that pacing is an integral part of the decision process and Alectra appears to be far more tuned to finding opportunities to defer investments within appropriate risk profiles for the sake of limiting the financial impacts on customers. Alectra has taken unprecedented steps to work directly with customers to ensure that it has a detailed understanding of the drivers and concerns of its customers and it has reflected this heightened understanding in the evaluation of needs, projects, investments, risk and costs.

We do wish to register two concerns that we highlight in our conclusions. We applaud Alectra for the time and effort that it has invested in the Customer Engagement activities over the last two years. It is clear that Alectra has spent significant time in listening and understanding customers' needs, desires and concerns, and it has reflected the customer input in the development of the DSP and the underlying investment plans. It is clear that Alectra has worked hard to find and strike the balance between reliability, risk, and cost. We are concerned that while the level of investment in asset renewal and replacement is balanced, it is just at the balance point, and thus maybe too close to the edge of the risk envelope.

The following summarizes our concerns. These do not stem from the process or the methodology. Our concerns lie in a small number of decisions that Alectra has taken that Vanry believes could have potential implications for the customers and Alectra.

1. Alectra like many utilities in North America, is battling a chronic failure of Underground Residential Distribution ("URD") cable, referred to by Alectra in its DSP documentation as XLPE. Alectra, appropriately, is allocating a large percentage of its system investment to the proactive replacement and refurbishment of the failure-prone URD cable and associated assets. The analysis in the DSP, and our experience with other utilities suggests that at the proposed level of investment, which is significant, may not enable Alectra to stay ahead of the deterioration rates in its URD fleet. It is well understood across the North American distribution sector that reactive replacement work is more costly than proactive replacement work by anywhere from 2 to 6 times. Capital investments in

proactive work can reduce the costs of reactive work (both Capital and OMA), often to a better cost impact to customers. This often requires capital investment up front, with the payback to the customer being seen over time.

Conversely, utilities that reduce proactive replacement as a means of reducing investment or rates, most often find themselves being pulled into a vicious cycle of having more of their planned replacement funding being consumed with responding to reactive replacements. This reduces the amount of planned replacements that can be undertaken, which in turn leads to more reactive spending. Once started, the vicious cycle is extremely difficult to exit and can turn into a so called "death spiral" where all of the planned spending is consumed in a fully reactive mode and reliability deteriorates to universally unacceptable levels.

We are concerned that Alectra may not have allocated sufficient funding required to keep up with the cable failure rates. This leaves Alectra and its customers exposed to risk of entering a vicious cycle, if any of the following should occur:

- Alectra is not able to secure the investment levels that it seeks for URD and associated equipment replacements;
- Alectra is not able to execute the work that it has in the plan for URD replacements due to resource limitations (availability of personnel, or as a result of other emergent work such as road widening or storm response) to its current estimated levels; or
- The failure rates for the URD cable increase above the current projections.

While we understand, and greatly respect, that Alectra has selected this level of investment in its efforts to balance rates/costs to customers, we are concerned that the deference to customer concerns regarding rates may have overweighed cost and underweighted risk. We recognize that Alectra has selected the most aggressive investment option that it had proposed to customers and yet we believe that Alectra should consider increasing the level of URD replacements in its plan to put further distance between Alectra and the threshold of the vicious cycle. We believe that doing so would ultimately serve the customers' concerns regarding cost, while also ensuring that there is no deterioration in reliability. Should Alectra not elect to increase the investment in URD replacement above what it has proposed in the DSP, we strongly encourage Alectra to ensure that it secures and deploys all of the investment that it has proposed and that Alectra not allow itself to be distracted from executing on the replacement of the URD cables in its plan.

2. Alectra, in deference to customer concerns about costs, has elected to defer investments related to DER, specifically the Neighborhood DER Pilot ($9.8M). Based on our work with other utilities, around the globe, we believe that it is critical that distribution utilities invest in technologies that will allow them to integrate and coordinate dispatch of DERs and other Grid Edge technologies. The inability on the part of the distributers to have visibility to and to interact with DERs and Grid Edge devices has led to significant negative consequences for customers.

For example, Hawaii Electric has now reached a level of saturation of DER on its system that has resulted in voltage instability island wide on each of the islands and as a result, HECO has placed a moratorium (up to 2 years) on any new residential roof top solar. This comes at a time when the costs of new roof top solar have fallen into the affordable range for middle- and low-income customers. The lack of visibility and coordination capability has resulted in an inequity of costs as more affluent customers are paying less and more of the system cost burdens are falling to middle- and low-income customers.

Similar situations are occurring in California where the lack of visibility and control of DER and Grid Edge devices have threatened the reliability of the system. In the previous fire season in California, the smoke from the fires moved into the Bay Area and the resulting solar obscuration reduced solar panel output by 90% across the region. The result was significant spikes in load for the distribution system as many of the customers with solar had added significant load behind the meters that the utility could not see and had not been required to serve. When the solar output dropped the distribution system was severely stressed and many areas were at the verge of collapse. The impact on generation portfolios was also staggering. It created significant unexpected volatility in the market and resulted in much higher costs than any providers had anticipated and planned for.

Vanry believes that Alectra should endeavor to continue its work on understanding the most effective ways to interface and interact with DERs, EVs and other Grid Edge devices, and to do so before there is significant penetration in its system. Doing so will allow Alectra to make rational and appropriate proposals for investments in technology that will ultimately result in optimal cost for delivered energy for customers, regardless of the source of energy.

Alectra's current thinking about these systems is progressive and consistent with thought leaders in the industry. If Alectra does not progress and test these capabilities we are concerned that it could fall behind and end up working in a reactive approach (Hawaii and California) which will ultimately result in higher costs and risk for customers, especially lower- and middle-income customers, who are most vulnerable. We understand the concerns of Alectra's customers, and why Alectra might defer the pilot investments. In the end, we believe that deferring the investments could lead to higher costs for customers in the near future.

Based on our review of the DSP, the supporting documents and analyses, and our interviews with the Alectra personnel, we believe that the DSP represents a well reasoned, fact-based assessment of the needs of the system and that it reflects the concerns of the relevant stakeholders and the desires of customers, as of the 2018 and 2019 customer engagement activities. It is evident that the customer engagement results have influenced the focus of the DSP as well as the associated investment planning. In our discussions with staff and our review of the plans, we see clear signs that Alectra is actively looking for ways to improve efficiencies of its investment plans and to reduce the overall impact on rates. The staff understand that the customers feel significant rate pressure and we believe this is being reflected in their approach to the planning and the DSP. We believe that the proposed investment plans align with what we see as being needed by the system to deliver the required performance levels and to meet the regulatory requirements. The pacing of the investments appears reasonable and reflective of a need to balance between costs and performance obligations and risks. The quality and calibre of the report, and the continually improving work that underpins it, is reflective of sound asset management processes and thinking.

Based on our review of the report and our assessment of the content, as well as the intent of Alectra, we believe that the Alectra DSP, and the underlying methodologies, analyses, and supporting documentation are aligned with the OEB requirements and that, in total, they represent a good-faith effort to produce a high quality, accurate assessment of the investment needs of the system over the planning horizon.

We believe that Alectra is making excellent progress in its efforts to become a leading asset management organization. It has continued to improve its processes and tools, recently adding the Copperleaf C55 investment prioritization/optimization tool. There is significant talent and capability within Alectra that appears to complement what we have seen in the past in the legacy utilities. Alectra has also continued to improve the capabilities of personnel, standardizing approaches through collaboration and training.

Alectra's thinking and approach to grid modernization is progressive and consistent with the global leaders in this area. Alectra shows a forward thinking understanding of the relationship between emerging technologies, new tools and systems (such as DERMs – Distributed Energy Management Systems) and the legacy operational technologies.

Overall Alectra is performing at a high level and the resulting DSP reflects a combination of high caliber people working in an effective and efficient well reasoned process.

Introduction and Approach

Vanry & Associates Inc. (Vanry) was engaged by Alectra Utilities Corporation (Alectra Utilities or Alectra) in February 2019 to provide Capital Investment Plan Third Party Review Consultation Services regarding Alectra's Distribution System Plan (2020-2024). Alectra contracted with Vanry to provide an Independent third-party review of the Asset Management ("AM") process and the 5-year capital investment plan identified in the draft Distribution System Plan ("DSP"); and to provide an opinion as to the strength of the DSP and its compliance with the DSP Chapter 5 filing requirements.

This report is a review of the draft DSP prepared by Alectra Utilities to be filed as part of Alectra's rate application to the Ontario Energy Board ("OEB") in 2019.

Alectra Utilities was formed in February 2017 through the consolidation of PowerStream Inc., Enersource Hydro Mississauga and Horizon Utilities Corporation and a subsequent acquisition of Brampton Hydro Inc. In addition, in January 2019, Guelph Hydro Electric Systems Inc. was consolidated into Alectra Utilities. In the past, capital investment plans were established on an individual basis for each of its five rate zones, corresponding to each of the predecessor utility service territories. To support the effective and efficient planning of capital investments and its efforts to operate as a single entity, Alectra Utilities has developed this Distribution System Plan (DSP) for its entire system.

This Distribution System Plan Review examines the methodologies and processes used to assess the asset management inputs, decisions and establishment of the subsequent 5-year system investment plan for Alectra Utilities entire service territory.

Our work included an in-depth review of the DSP documentation, including appendices, and multiple meetings/video conferences with relevant Alectra subject matter experts ("SMEs") and interviews of other relevant Alectra personnel. The review paid particular attention to two areas: Asset Management ("AM") process, and the 5-year System Investment Plan. The AM review assessed the methodologies employed by Alectra and evaluated the asset management process, specifically the links between i) inputs that drive the needs of investment, ii) processes used to prioritize and pace solutions and iii) alignment of investments with intended performance outcomes (customer focus, operational effectiveness, public policy responsiveness, financial performance). In terms of inputs into the AM process, our review included an assessment of the methodologies used in developing an evaluation of the Asset Condition Assessment ("ACA") and provides an opinion of the alignment of this methodology to established industry best practices.

The System Investment Plan review evaluated the appropriateness of the 5-year system investment decisions and plan developed based on the information derived from the asset management process. The review assessed the relationship between the needs identified from the asset management process and capital investment plan, specifically the appropriateness of prioritization and pacing with a focus on key drivers of change over the 5-year planning period.

We assigned four highly qualified and experienced resources to undertake this assessment. The team is made up of professionals that are well regarded in the industry and known as experts in this area. Stewart Ramsay and Darin Johnson led the majority of the investigations, and data collection, with support from Neil Reid. Julius Pataky served as our own independent QA/QC lead and framed our internal review methodology.

In undertaking the review, Vanry applied a methodical approach consisting of:

1. Document review
    a. Alectra Utilities Distribution System Plan 2020-2024, including appendices
    b. Other supporting documents provided by Alectra, including, Copperleaf C55 business case optimization back-up and other technical materials
    c. OEB Chapter 5 requirements for Consolidated Distribution System Plan, July 12, 2018

2. Development of lines of inquiry specific to each report/document and various areas of the processes for development of the DSP:
    a. Asset Management Framework and process
    b. Asset Condition Assessment
    c. Customer engagement process and results
    d. Capital investment planning including C55 investment optimization
    e. System planning process
    f. "Utility of the future" initiatives, such as Grid Modernization, DER and EV integration and application of microgrids
    g. Assessment of non-wires alternatives, CDM, and other technologies

3. Application and use of AMI and AMI data
    a. Interviews with the relevant leaders and SMEs to ensure that Vanry has a clear and appropriate understanding of the processes used for each part of the process. The Asset Management Framework and capital investment planning process was investigated in sufficient detail to enable Vanry to make meaningful assessments. Topics discussed in interviews include the following:
    b. Inputs to and use of C55
    c. Process for development of business cases
    d. ACA process, especially integrating the legacy utilities
    e. Underground cable renewal investments
    f. Grid Modernization initiatives
    g. AMI and use of AMI data and grid analytics
    h. System Planning criteria
    i. Reliability performance
    j. Performance Monitoring and metrics
    k. Continuous improvement
    l. Optimization of investment Forecasting (load, EV, PV)
    m. Risk analysis
    n. Customer engagement process and results

4. Review of additional supporting documents provided during, and subsequent to, the interviews, including sample detailed business cases, C55 training materials, and first and second-round customer engagement results.

5. Vanry's scope did not include the assessment of quality or veracity of underlying source data of the processes and methodologies.

Based on the results of our reviews and discussions with Alectra personnel, this report provides observations, assessments, conclusions and recommendations regarding:

1. Customer input regarding needs and priorities
2. The Asset Management Process
3. The capital investment plans
4. The AM processes and resulting DSP

Summary of Approach

Asset Management Process Review

Initiation:

This initial step entailed identifying the key materials used in the Asset Management Process. Specifically, this included DSP and related documents. Alectra also identified key leaders participating in the Asset Management process for assistance and interviews to understand the practical application of the processes and resulting investment decisions. There were approximately 15 individuals involved and responsible for various aspects of the process.

Documentation Review:

This step entailed first the review of the new internally prepared Asset Condition Assessment Report, Appendix D to the DSP, to assess its reasonableness and appropriateness. This assessment reviewed the methodology used to generate the asset health indices used to advise the identification of investment needs. This review included assessment against the stated assumptions, input and weighting factors, as well as comparison to industry leading practices.

The documentation review continued with materials which documented the process used by Alectra to prioritize and pace the proposed investment plans. This included a review of documents describing the process and the review of work products of the process (e.g., category-specific asset strategy, used in the development of business cases for inclusion in the Copperleaf C55 optimization process, investment summaries), as well as tools and documents which described the project selection/prioritization criteria.

Interviews:

The next step in the review entailed conducting interviews to clarify our understanding of the documentation reviewed above, to fill-in any gaps of process, which were not captured by the documentation and to seek confirmation of the process – i.e. some process elements may be covered by practices but are not documented. We carried out several days of interviews with team leaders from within the utility. For scheduling purposes, the interviews were a series of Skype-based audio/video meetings in which Vanry could ask specific questions and work interactively to delve into the details of the work products and the process used to develop them. These interviews also inquired into the application of the ACA findings, customer engagement priorities, and the C55 business case and optimization processes leading to the investment plans in the DSP.

Vanry's approach to the interviews was to engage with the Alectra team in each of the areas of the DSP so that we were able to test the depth of their understanding of their own analysis and thus the robustness of their conclusions and recommended investment plans. In so doing, we were able to assess both the process and the personnel and their ability to use the processes and their skills to deliver the requisite level of thinking, analysis and decision making to develop a high-quality DSP.

Assessment and Documentation:

This step entailed the synthesis of all the reviews and interviews conducted earlier. The Vanry assessment included the following:

1. Review of the formulations used to create the Health Indices, and the initial investment needs proposals based on the ACA;
2. The approach used to develop pacing options, which were submitted to the customers for comment; and
3. Development of business cases to support prioritization of specific projects comprising the selected pacing option to meet the five-year objectives.

Vanry assessed the appropriateness of these elements for creating the 5-year investment plan in comparison with industry-leading practice, principals of asset management, and stated OEB requirements.

It is during this stage that we undertook the analysis of all that we found against industry leading practices and against the required OEB performance outcomes. The assessment first considered the reasonableness of the assumptions and of the critical information and data used as input. The leading practice assessment evaluated the methodology of condition assessment and life cycle optimization, the investment decision-making process, alignment criteria to strategic drivers (internal and OEB), and robustness of the process for repeatability. Vanry's analysis included the identification of key assets, based on materiality and risk, review of assumptions and inputs to identify risk, integration of customer feedback, and reasonableness of the approach for developing and applying inputs and weighting for criticality determination.

System Investment Plan Review

Review and Analysis:

This stage of the effort entailed the review of the 5-year investment decisions. While the Asset Management Process Review evaluated the information used, the methodology applied, and the process to arrive at the investment plan, and provided an opinion on the work, the System Investment Plan review entailed the assessment of the overall investment plan relative to Alectra's strategy and customer and regulator expectations. Accordingly, this work comprised reviewing Alectra's documentation of its 5-year investment plan with the awareness that this is the primary tool for communicating to customers, the regulator, shareholders and stakeholders as to what those plans are. As such, this work is a synthesis of the Alectra work reviewed into a strategic document of investment plans. The Vanry analysis entailed considering the specific needs as defined by the assets (asset condition), potential other investment requirements (growth) and those attributes which are important to customers, stakeholders, and conform with OEB requirements.

The analysis activities entailed review of the latest version of the DSP, past messages and positioning of similar evidence by Alectra to the OEB, and similar earlier filings by Alectra affiliates before the OEB. The initiation step of documentation collection as well as the interviews in the initial stage of work were the primary source of this information. The analysis focused on completeness and appropriateness of the Investment Plan, and providing a high-level comparison to the maturity of the DSP vis-a-vis leading practices. Specifically, the dimensions on which this analysis was carried out were: needs, preferences and expectations as represented by customers, an understanding of the needs of stakeholders; appropriate capital for operational effectiveness relative to leading practices, Alectra standards and OEB requirements; comprehensiveness and robustness of justification and prioritization relative to balancing the value attributes of reliability, risk mitigation and costs; and positioning the investments relative to the long-term sustainability of the assets and business (e.g., neither overbuilding, nor harvesting the assets for short-term gain).

Assessments and Documentation:

This step builds directly on the previous step and synthesizes all the earlier work. The assessment first considered the validity and consistency of the assumptions and veracity of the information and inputs on which the Alectra analyses was conducted. This work was also focussed on identifying gaps, if any, in the supporting documentation input and validating the key assumptions as well as providing a high-level comparison of the DSP to leading practices.

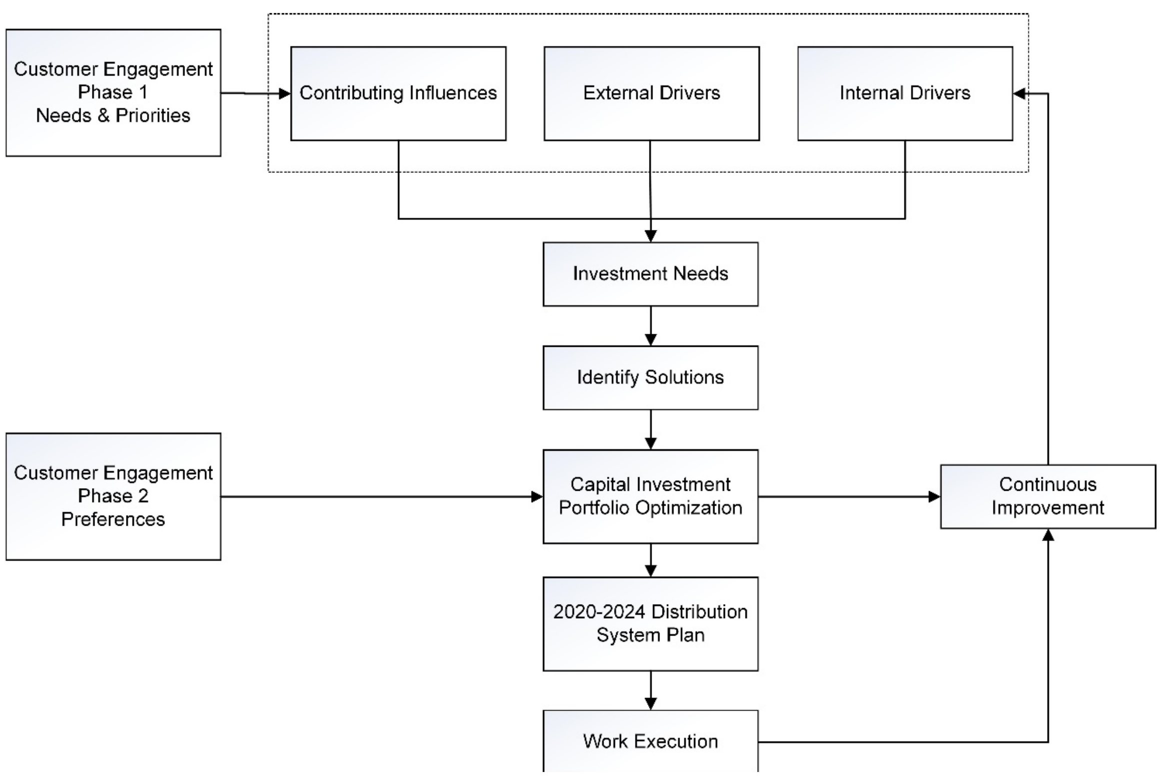
Following the analytical phase, we prepared this report which is a summary and conclusion of our review. This report opines on the reasonableness of the overall process used to generate the DSP, the decisions therein, the inputs and assumptions used, and thus the appropriateness of the planned investments. The report comments on the robustness of the process to reach the investment plan and documents the work to complete this assessment.

Observations and Assessments

Asset Management Framework

The Asset Management Framework includes the tools and processes used to identify need, create spending options, select projects, and prioritize the portfolio to create the final recommended spending plan. Although every spending decision is technically a part of this plan, the primary focus is on renewal of aging assets and other large capital projects.

Following the OEB's Decision and Order in EB-2016-0025, and other matters, Alectra indicated that it would file a consolidated 5-year DSP in 2019. Guided by its Corporate Strategic Goals and Objectives, customer input, its Asset Management Framework, and the OEB's requirements, Alectra established the basis for the consolidated DSP. The Asset Management Framework set the foundation for the DSP and all planned capital investments. Stemming from the Asset Management Framework is the Asset Management process which is discussed in section 5.2.1 of the DSP and is as shown below.



The following sections summarize our review and comments on the Alectra Asset Management process, based on the DSP report and its supporting documentation.

The process is initially targeted towards an assessment of investment needs in the distribution system. The drivers associated with the creation of investment needs are three-fold, namely:

- Contributing Influences which consist, primarily, of customers' input reflected in DSP-specific customer engagement and feed-back from its customer base. Also included are renewable energy generation demands, technical obsolescence and emerging technologies, the results of regional planning and coordination with other utilities and municipalities;
- External Drivers, which consist of mandatory requirements that Alectra must meet. For example, public safety; and
- Internal Drivers which are Corporate Objectives by Alectra Utilities management such as reliability and service goals. Asset Condition Assessment is an important input to the investment needs assessment.

Historically, Alectra has used an external consultant to carry out its Asset Condition Assessment (ACA). However, with the creation of a single entity, Alectra decided to establish a single asset management protocol which harmonized the various approaches used by each member of the consolidated utility, including Guelph Hydro. This was by no means an easy task as each legacy company had its own approach to asset condition assessment, data storage, maintenance practices, etc. However, the consolidation was achieved with success and the resulting harmonized asset condition assessment methodology was used as the basis for identifying those assets which were likely candidates for investment in the 2020-2024 period. The Asset Condition Assessment (ACA) - 2018 used is included as Appendix D to the DSP.

The ACA methodology adopted was evaluated by an external consultant (Kinectrics Inc.) in the form of an Assurance Review, which is included as Appendix E to the DSP. The principal conclusions were as follows:

- "The ACA should fulfill its intended function…. It represents a significant step in establishing corporate-wide, consistent Asset Management processes;" and
- "The ACA methodology utilized in the (Alectra's Asset Condition Assessment-2018) report is in line with good utility practices. It provides the required input regarding condition-based asset needs."

Vanry is in general agreement with the conclusions stated above, subject to the recommendations made in this review report.

The output from the ACA, known as the Health Index, is a measure of the condition of each asset in the nine asset classes selected by Alectra for distribution equipment evaluation and the three asset classes selected by Alectra for Station equipment evaluation. The results are categorized as Very Good, Good, Fair, Poor and Very Poor. Once the Poor and Very Poor condition assets are identified, Alectra's subject matter experts (SMEs) develop investment options that might be used to address the degraded condition of those parts of the system and meet the other drivers identified above. Alectra SMEs review the needs of specific asset groups as well as undertake reviews of concentrations of needs of different asset types to identify projects that could resolve multiple poor condition assets in a single project, single planned outage event. This type of overlay work results in fewer planned outages and tends to bring economies of scale to the work being undertaken.

The investment options are identified on a project-by-project basis, priced and entered into Alectra's Value Framework Implementation program developed by a third party, Copperleaf, for optimization and inclusion or deferment in the proposed DSP. This program is known as C55.

The value framework used by Alectra in its application of C55 is based on multiple rounds of customer interface, wherein Alectra's customers offered opinions about how they value trade-offs between competing investment drivers. For example, residential customers largely valued low rates over improved reliability, whereas larger commercial customers were the reverse. Similar priorities were established for other drivers. This feedback was incorporated into the C55 Value Framework, so that when projects are scored and prioritized, the objectives of Alectra's customers are considered.

Multiple pacing options (e.g., accelerated, moderate and slow), were identified for each investment group along with their rate and reliability impacts, and this information was presented to customer groups to select their preferred option. Typically, the customer base has selected the recommended course of action for preference. Again, typically, Alectra has recommended a middle-of-the-road strategy for pacing its investment needs opportunities, i.e. neither too aggressive, with an attendant high rate impact, nor too slow, with the possibility of making reliability worse than existing.

Once the pacing option is selected by customers, Alectra's Project Owners identify specific projects that will make up the investment group. Projects are selected by considering the following:

1. ACA, assets in Poor or Very Poor condition;
2. Areas with past poor performance;
3. High risk assets or regions. This is not stated explicitly in the documentation but was noted by staff in our interviews and is the basis for the "overlay" analysis that Alectra SMEs conduct; and
4. System planning needs and other drivers.

At present, the process for consolidating these drivers is somewhat informal. SMEs review the relevant data as a group and identify projects that they believe will result in high net benefits. They then create business cases for these projects, including alternatives where appropriate such as where there are multiple potential solutions to address a specific risk or issue, and score them in C55.

Vanry believes that the process Alectra used in the development of the DSP is sound. In our discussions with the Alectra team we have indicated that as part of its continuous improvement plans, this process could be improved by adding a risk-based evaluation of the opportunities available as business cases, to move from a condition-based recommendation to a risk-based selection which would enable a better selection of projects based on avoided risk and other benefits. Adoption of this risk-based concept would provide many benefits. It would:

- Reinforce the idea that end-of-life is an economic decision, not just age or condition based;

- Help to ensure that the projects identified are not only good projects, in the sense that they provide net benefit to customers, but that they are the *best* projects available. E.g., it is possible that, say, replacement of a section of underground cable produces net benefit in C55, but that the *optimal* strategy would be to wait a few more years. (Note that this is different from the way C55 looks at delaying a project.);
- Support evaluation of complex options such as multiple-asset projects, reconfiguration, repair/replace decisions, spares, voltage conversion, and even new capacity additions;
- Allow Alectra to continue to improve on its processes through expansion of the detailed cost benefit analysis. For example, C55 has the ability to model increasing failure probability over time in five-year steps. However, the SMEs will recognize that expected risk increases year-by-year. There are similar subtleties with regard to failure scenarios and consequence cost. (Note that this is not intended as a slight on C55 or on the work that Alectra has done to-date. We are impressed by the model and Alectra's use of it. However, it is best suited for choosing from among projects that have already been evaluated and found to be cost-effective.); and
- Help to filter the Value Framework into the decision-making at all levels of the organization. The more contact the people who are involved in recommending spending have with the Value Framework, the better.

This concept was discussed with Alectra's asset condition assessment staff during our interviews. Staff indicated that they were aware of this opportunity to refine Alectra's business case selection process in this manner and planned to evaluate and develop such a process in the future. We would consider this development a part of the stated continuous improvement objective and represent a "best-practice" initiative.

Areas of Best Practice and Comments

The following is a comparison of Alectra's current and planned AM processes with industry-leading practice in key areas.

Failure probability

The meaning of failure is clearly defined and consistently applied (e.g., end-of-life failure events that require replacement). The likelihood of failure is determined based on condition, age and special features related to the installation or manufacture of an asset that increase or decrease its probability of failure relative to the population overall (e.g., harsh environment, loading). Failure probability projections are calculated or correlated with available historical failure data and subject-matter expertise.

Alectra has removed failure projections from its ACA process, which we regard as an improvement. However, there is still work to be done to improve failure probability projections. Based on discussions with staff, we see that Alectra is developing utility-specific failure probability estimates (e.g., Weibull curves). We encourage this effort, and have the following recommendations:

- Look for opportunities to share information with peer utilities, especially those nearby. Having large data sets for statistical analyses of failure rates is helpful;
- Keep in mind that failure probability is often a function of both health and age for a given asset type. Consider ways of calibrating Alectra's health index formulations and failure probability estimates against one another; and
- Recent applications of advanced analytics have shown promise in the utility arena. Consider opportunities to apply these techniques. This may be especially valuable for asset classes like underground cable, where specific condition data are hard to find, and for particular, high-criticality assets where the incentive to avoid failure is strongest.

Consequences of failure

Failure consequences are monetized and related directly back to the customer as an outage cost or willingness-to-pay social cost. Consequence costs are intended to reflect the perceived cost to the customer, the utility and society. For example, how much would a customer be willing to pay monthly to reduce or avoid power outage events? Where appropriate, multiple failure scenarios are considered and weighted according to their relative likelihoods.

Alectra has developed a scale for comparing all consequences of failure on an equal footing. Strictly speaking, the unit used is not dollars, but the conversion to dollars is clear. Customer outage costs are based on survey data. Although the outage costs used are on the low end of the range of published data, Alectra has a good reason for choosing the survey they did: namely, the stated priority of low rates over improved reliability from most of their customers.

Failure scenarios are modeled in C55. If there are multiple failure scenarios (e.g., corrective maintenance, catastrophic) related to a particular project, the Project Owner must do this work off-sheet. Our recommendation to implement a standardized risk-assessment process parallel to ACA would simplify this process and ensure consistency.

Other consequence categories, such as safety and regulatory effects are similarly modeled. One underground cable project we reviewed with Alectra indicated a relatively large "compliance" driver – about a third of the total risk was compliance. This is often a red flag because we find that SMEs often over-state the likelihood and cost of regulatory problems caused by simple asset failure. We discussed this example in some detail with Alectra, and we were pleased to find that the compliance risk in this example represented very concrete cost related to customer complaints due to repeated outages from cable failure. Alectra confirmed that this cost was specific to the project in question and would not generally be present in a cable project. This is commendable for two reasons. First, it shows that Alectra is not "cooking the books" by adding vague risks to make their projects pencil out. Second, it shows that Alectra is considering the increased risk to customers with poor service already, e.g., worst-performing feeders.

Because of its customer interface efforts, Alectra will have an interesting opportunity to compare the customer outage costs (and other values) used in C55 to the implied costs due to their selected spending options. For example, if customers select the accelerated cable option, that means that the decrease in outages for the faster option was worth the extra cost in rates in their view, and that the decreased rates from the slower options were not worth the increase in outages (both relative to the recommended option). The precision of these results will not be high; there will be a mix of drivers and of customer types and a variety of preferred options across the population. However, the calculation will allow Alectra to confirm whether the Value Framework appears to match customer preferences. Another good test will be to see if customers selected roughly the same ratio of increased cost to increased performance across all investment groups. In principle, the marginal benefit of every spending program or investment group should be the same – otherwise Alectra should move resources from the lower-performing investments to the higher-performing ones. If the customers are able to roughly approximate this, it will be evidence that they understood the exercise and gave meaningful answers.

Risk assessment

Asset risk is quantified in terms of actual failure probability and expected consequence cost of failure in terms that can be used in business cases and the budgeting process. Risk is included in business cases both as a benefit of spending (e.g., avoided risk) and as part of the cost of the work (e.g., risk of cost overrun).

As noted above, we recommend a systematic risk-assessment process, starting at the asset level, used to support project development and selection, and finally used to score projects in C55. This should use the failure probability and consequence methods described above and already in development by Alectra.

Determining end of life and life-cycle cost

Assets at end of life are identified according to a systematic approach, balancing the cost of continued operation against the cost of replacement to minimize life-cycle cost of ownership. Other interventions, e.g., refurbishment, are considered. For a given strategy, the life-cycle cost of ownership and other cost and risk-streams associated with the asset are produced.

Alectra has not yet developed a life-cycle cost model, which would follow easily once the risk assessment is in place. OEB's filing requirements state that, "An understanding of a distributor's asset lifecycle optimization policies and practices will support the regulatory assessment of system renewal investments and decisions to refurbish rather than replace system assets." Use of the standard amortization schedules developed by Kinectrics is not a substitute for life-cycle cost optimization. As such, we recommend that Alectra continue its good work in developing a life-cycle optimization approach. Considerations of life-cycle cost are central not only to optimizing replacement timing, but also to the other spending decisions we have mentioned elsewhere (e.g., multiple assets, system configuration, repair/replace).

We do not regard the lack of a life-cycle cost model as a serious deficiency at this point. Actually, we see the steps that Alectra has taken in the last 18 months as making significant progress towards the development of a robust LCP. First, the task of integrating the practices of the legacy utilities is a large one. It is not unreasonable for life-cycle cost modeling to follow ACA and C55, which Alectra has been focused on. Second, the largest spending categories (e.g., underground cable) have more projects available than can be executed in the near term, which means that Alectra has plenty of cost-effective work to do before it needs to worry too much about fine-tuning its selection process. We would expect that as Alectra works its way through the five-year plan, updating the project evaluations based on life-cycle cost will grow in importance.

Use of available data

Available test and inspection data are used to assess condition; failure projections are based on historical failure data or industry data; criticality assessment is based on customer count or load and customer type (e.g., residential, commercial/industrial).

Alectra has developed a comprehensive system for storage of data relevant to asset-level spending decisions, including Cascade and its in-house ACA model. This system appears to be very good. The fact that ACA has been migrated out of Microsoft Excel means that this model will be a good place to develop further capabilities, such as criticality and risk assessments. We recommend incorporating criticality data needed for calculating risk, in the same terms used in C55, into this model.

Use of subject-matter expertise

Tacit knowledge of subject-matter experts (SMEs) is incorporated into the assessment process. Attention is focused on their areas of expertise (e.g., how best to assess condition) as opposed to complex questions outside it (e.g., how many transformers should we replace each year). SME input is documented explicitly for review and improvement over time.

Alectra is making proper use of its subject-matter experts. We are impressed by the strength of the SME team. There are several recommendations in this document that we believe will be helpful for the SME team to focus them where their strengths are greatest, namely failure probability curve development and risk assessment.

Continual improvement

A key tenet of asset management is continual improvement. We recognize Alectra's efforts in this area and commend them for their progress. Improvement is of course made difficult by the amalgamation of utilities, but despite this Alectra has moved forward.

Long-range projections

Aging asset populations include a projection of future spending needs based on expected future degradation and risk.

Alectra does not yet have a system for long-range projections, although this capability is in process. We recommend that the final approach consider not only asset aging and condition, but also risk and life-cycle cost. Long-range projections should include unplanned spending, based on actual failure probability estimates.

Business cases

Spending recommendations have an accompanying business case that summarizes the problem statement, compares alternatives, and makes a recommendation. All costs and benefits are quantified from the customers' perspective; do-nothing alternative is considered; assumptions are stated explicitly and quantitatively.

Alectra has a strong business case process using C55. Our only concern is the way projects are identified for inclusion in the business case process. We recommend a risk-based approach incorporating life-cycle cost optimization to identify projects. This approach should use actual estimates of failure probability and consequences quantified in the same way as C55. These recommendations are described in detail elsewhere in this report.

Customer focus

Customer focus is perhaps the most important element of asset management. Spending decisions are to be made with the interests of the customer in mind. Alectra has made significant strides in this area.

First, the benefit and risk scoring in C55 is performed from the perspective of customers. Customer outage costs, compliance costs, and of course direct costs (the examples we focused on most in our review) are all borne by customers directly or indirectly. This represents industry best practice.

Second, Alectra has engaged in an extremely aggressive program of customer interface. This included a first level of interface wherein customers noted their priorities among competing drivers (e.g., rates versus reliability), and then a second level wherein customers were given rate and value information about proposed investment options and asked to state their preferences. The first level was the basis for selecting investment options and developing the value framework. The second level was the basis for project selection and inclusion in C55.

As far as we know, this level of interface is unique in the industry. Although it was surely a large effort, and although it risks complicating the AM process by expanding the range of variables significantly (i.e., value framework, customer input) we commend Alectra for undertaking it and for taking the input seriously.

Prioritization across investments, portfolio management

Spending on replacement, refurbishment, maintenance and other options is directly compared in equal terms to optimize spending plans and to prioritize across investment groups. Prioritization includes the ability to respond to multiple resource constraints (e.g., available capital, field personnel FTEs, maximum allowable safety risk, etc.) and to show decision-makers the trade-offs between cost and benefits, including avoided risk of failure, from accepting or rejecting projects or investment groups.

Alectra has implemented C55 which is an excellent tool for prioritization and portfolio management. It supports scenario analysis, constraints, and sensitivity. We recommend that C55 be expanded to include not only capital spending but also maintenance programs, especially where they have life-cycle cost or risk implications.

Conclusions:

The Vanry team has conducted a thorough review of the Alectra 2020 – 2024 DSP, its supporting materials, underlying analysis; including discussions/interviews with the Alectra personnel responsible for the analysis and the preparation of the DSP.

Overall, we find the process used, the underlying analysis and the capability and thinking of the people responsible for the DSP all to be high caliber. In our view the resulting DSP is rational, well reasoned and fact based. It is the product of a clear understanding of the customer's desires, the needs and requirements of external stakeholders (including communities and other impacted infrastructure providers) as well as corporate drivers and regulatory requirements.

The process and methodologies used to develop the underlying investment proposals and the resulting DSP appear to be sound and to have been applied in a consistent manner throughout the organization.

Alectra has demonstrated significant improvements in process, methodologies and application of decision support tools over the last 18 months. It has unified the process across the legacy utilities in an effective manner (this was done quickly and effectively in our view in comparison to what we have seen in other utility mergers). This was no trivial task and the fact that Alectra was able to accomplish both this unification of approaches, while also developing and preparing a consolidated DSP for the merged companies, is impressive and speaks to the calibre of people, process and leadership that Alectra has deployed.

We believe that the DSP meets the OEB filing requirements and that the investment levels that it is seeking are reasonable, appropriate and align with the needs and interests of the customers and critical external stakeholders.

The Vanry team does see a few potential areas for concern. These do not stem from the process or the methodology. Our concerns lie in a small number of decisions that Alectra has taken that Vanry believes could have potential implications for the customers and Alectra.

1. Alectra like many utilities in North America, is battling a chronic failure of Underground Residential Distribution ("URD") cable, referred to by Alectra in its DSP documentation as XLPE. Alectra, appropriately, is allocating a large percentage of its system investment to the proactive replacement of the failure prone URD cable and associated assets. The analysis in the DSP, and our experience with other utilities suggests that at the proposed level of investment, which is significant, may not enable Alectra to stay ahead of the deterioration rates in its URD fleet. It is well understood across the North American distribution sector that reactive replacement work is more costly than proactive replacement work by anywhere from 2 to 6 times. Capital investments in proactive work can reduce the costs of reactive work (both Capital and OMA), often to a better cost impact to customers. This often requires capital investment up front, with the payback to the customer being seen over the balance of the planning cycle or rate making period.

Conversely, utilities that reduce proactive replacement as a means of reducing investment or rates, most often find themselves being pulled into a vicious cycle of having more of their planned replacement funding being consumed with responding to reactive replacements. This reduces the amount of planned replacements that can be undertaken, which in turn leads to more reactive spending. Once started, the vicious cycle is extremely difficult to exit and can turn into a so called "death spiral" where all of the planned spending is consumed in a fully reactive mode and reliability deteriorates to universally unacceptable levels.

We are concerned that Alectra may not have allocated sufficient funding required to keep up with the cable failure rates. This leaves Alectra and its customers exposed to risk of entering a vicious cycle, if any of the following should occur:

- Alectra is not able to secure the investment levels that it seeks for URD and associated equipment replacements;
- Alectra is not able to execute the work that it has in the plan for URD replacements due to resource limitations (availability of personnel, or as a result of other emergent work such as road widening or storm response) beyond its current estimated levels; or
- The failure rates for the URD cable increase above the current projections.

While we understand, and greatly respect, that Alectra has selected this level of investment in in its efforts to balance rates/costs to customers we are concerned that the deference to customer concerns regarding rates may have overweighed cost and underweighted risk. We recognize that Alectra has selected the most aggressive investment option that it had proposed to customers and yet we believe that Alectra should consider increasing the level of URD replacements in its plan to put further distance between Alectra and the threshold of the vicious cycle. We believe that doing so would ultimately serve the customers' concerns regarding cost, while also ensuring that there is no deterioration in reliability. Should Alectra, not elect to increase the investment in URD replacement above what it has proposed in the DSP, we strongly encourage Alectra to ensure that it secures and deploys all of the investment that it has proposed and that Alectra not allow itself to be distracted from executing on the replacement of the URD cables in its plan.

2. Alectra, in deference to customer concerns about costs, has elected to defer investments related to DER, specifically the Neighborhood DER Pilot ($9.8M). Based on our work with other utilities, around the globe, we believe that it is critical that distribution utilities invest in technologies that will allow them to integrate and coordinate dispatch of DERs and other Grid Edge technologies. The inability on the part of the distributers to have visibility to and to interact with DERs and Grid Edge devices has led to significant negative consequences for customers.

   For example, Hawaii Electric has now reached a level of saturation of DER on its system that has resulted in voltage instability island wide on each of the islands and as a result, HECO has placed a moratorium (up to 2 years) on any new residential roof top solar. This comes at a time when the costs of new roof top solar have fallen into the affordable range for middle- and low-income customers. The lack of visibility and coordination capability has resulted in an inequity of costs as more affluent customers have are paying less and more of the system cost burdens are falling to middle- and low-income customers.

Similar situations are occurring in California with the lack of visibility and control of DER and Grid Edge devices have threatened the reliability of the system. In the previous fire season in California, the smoke from the fires moved into the Bay Area and the resulting solar obscuration reduced solar panel output by 90% across the region. The result was significant spikes in load for the distribution system as many of the customers with solar had added significant load behind the meters that the utility could not see and had not been required to serve. When the solar output dropped the distribution system was severely stressed and many areas were at the verge of collapse. The impact on generation portfolios was also staggering. It created significant unexpected volatility in the market and resulted in much higher costs than any providers had anticipated and planned for.

Vanry believes that Alectra should endeavor to continue its work on understanding the most effective ways to interface and interact with DERs, EVs and other Grid Edge devices, and to do so before there is significant penetration in its system. Doing so will allow Alectra to make rational and appropriate proposals for investments in technology that will ultimately result in optimal cost for delivered energy for customers, regardless of the source of energy.

Alectra's current thinking about these systems is progressive and consistent with thought leaders in the industry. If Alectra does not progress and test these capabilities we are concerned that it could fall behind and end up working in a reactive approach (Hawaii and California) which will ultimately result in higher costs and risk for customers, especially lower- and middle-income customers, who are most vulnerable. We understand the concerns of Alectra's customers, and why Alectra might defer the pilot investments. In the end, we believe that deferring the investments could lead to higher costs for customers in the near future.

Recommendations:

We recognize and applaud Alectra's demonstrated commitment to continuous improvement. As we highlight in Appendix A, Alectra has taken recommendations in previous DSP reviews to heart and acted upon them with speed and diligence. In keeping with Alectra's commitment to continuous improvement we offer the following recommendations for Alectra's consideration as it seeks to further develop and enhance its asset management capabilities. These recommendations should not be seen as a deficiency in any way, rather they are a set of logical next steps to support Alectra's growth in capability.

1. We recommend that Alectra continue its good work in developing a life-cycle optimization approach. The process for continuous improvement plans could be improved by adding a risk-based evaluation of the opportunities available as business cases, to move from a condition-based recommendation to a systematic risk-based selection, in parallel with ACA and using the same assumptions that are used in C55, which would enable a better selection of projects based on avoided risk and other benefits.

2. Alectra should consider looking for additional and broader opportunities to share information with peer utilities, especially those nearby. Having large data sets for statistical analyses of failure rates is helpful.

3. Alectra should continue to keep in mind and reflect that failure probability is often a function of both health and age for a given asset type. Now that Alectra has improved its ACA and brought the work in house, it should develop methods for calibrating Alectra's health index formulations and failure probability estimates against one another.

4. Recent applications of advanced analytics have shown promise in the utility arena. Alectra should consider opportunities to apply these techniques. This may be especially valuable for asset classes like underground cable, where specific condition data are hard to find, and for particular, high-criticality assets where the incentive to avoid failure is strongest.

5. We would expect that as Alectra works its way through the five-year plan, updating the project evaluations based on life-cycle cost will grow in importance. We suggest that Alectra anticipates this and ensures that it is undertaking a deliberate review and analysis of the results and feeding the learning back into the project/investment development plans.

6. We understand that Alectra has plans to develop long-range projections that include potential impacts from unplanned spending, based on actual failure probability estimates. We strongly encourage this and suggest that Alectra accelerates this work to the greatest extent possible. We believe that it will be a useful tool in evaluation of costs of deferral of investment, which will become critical in the future.

7. We recommend that C55 be expanded to include not only capital spending but also maintenance programs, especially where they have life-cycle cost or risk implications. This is a natural next step in the evolution of Alectra's AM capabilities and processes.

8. We believe that Alectra should continue to closely examine the level of URD replacements in its plan and to monitor the actual failures compared to predicted failures. The intent is that Alectra put further distance between itself and the threshold of the vicious cycle. We believe that doing so will ultimately serve the customers' concerns regarding cost, while also ensuring that there is no deterioration in reliability.

Appendix A – Observations regarding Alectra's actions to respond to recommendations included in the Vanry report for the Alectra Utilities 2017 DSP for the Enersource Rate Zone

Past Recommendations and Current Date Observations

In Vanry's review of the Alectra Utilities 2017 DSP for the Enersource Rate Zone, we made a total of 22 recommendations related to the asset management approach. Below is a summary of the recommendations and the response by Alectra to-date. Overall, we are pleased to see that Alectra has responded to our recommendations. The following is a list of our previous recommendations and our observations regarding how Alectra has responded to those recommendations.

The italicized text reflects the recommendations made by Vanry in its review of the 2017 DSP. The indented text reflects our observations as of May 2019 with respect to each of the recommendations.

1. *In our experience, there has been substantial value in evaluation of the condition of protective relays and SCADA systems, particularly where older generation systems are still in service and can affect reliability or data collection. We recommend Alectra-Mississauga consider including these classes in future ACA analyses.*

    Alectra has not yet integrated SCADA or relays into its ACA process. At present there are no investment packages for replacement or upgrade of any of these assets in the DSP. According to Table 5.3.2, there are still some older-style electromechanical and electronic relays in service (approximately 40 percent of the total, mainly at MS stations), which may be good candidates for upgrade. Given that Alectra's focus has been on integrating asset management functions from the legacy utilities, it is not surprising that these new assets have not yet been evaluated. Based on our discussions with Alectra staff, we understand that they will be included in the future.

    Alectra is proposing a SCADA investment, described in Appendix A11, focused on SCADA-enabled field switches. This is a reliability-driven approach but is separate from a risk-based program that may result from bringing station SCADA into the ACA process.

    Given that the ACA is focused only on health and not risk, the need to include relays and SCADA is significantly reduced. Replacement of these assets is driven primarily by obsolescence, increased functionality of modern equipment, and risk of failure unrelated to observable condition. We do not believe that a health index calculation for these assets is necessary, however a risk-based approach to replacement or upgrade, similar to replacement planning for other assets, is recommended.

2. *Furan analysis is used by some utilities as a secondary test to confirm the condition of suspect transformers. We recommend Alectra-Mississauga confer with the SMEs at its sister utilities in Alectra to further consider furan analysis as an enterprise-wide, end-of-life metric.*

Alectra has implemented a process of furan testing of station transformers as part of its normal testing process. The results of furan tests are integrated into transformer health calculations.

3. *We agree in general with the changes made to the HI formulations. We also caution Alectra-Mississauga to be contemplative and deliberate in making future changes in order to support trending of condition over time.*

   Based on our review of the ACA and discussion with Alectra staff, it is apparent that Alectra is exercising due caution in modifying its health index formulation in order to ensure the ability to trend over time. This point was raised by them more than once.

4. *We recommend Alectra-Mississauga exclude all criteria that are not measures of condition, such as age and loading, from the HI formulations. The Health Index ("HI") should be a snapshot of the current condition of the asset relative to end of life, based on testing and inspection. Criteria such as age and loading, tell us that we would expect to find the asset in better or worse condition, all things being equal, but are not themselves measures of condition.*

   Age is still included in many health index formulations. In Appendix D, Alectra explains why age is included. For example, in section 5.1.4, the report states, "Age represents deterioration due to other factors not captured by the other components of the model." The driver for the recommendation to remove age is past comments by regulators that age is not a valid driver for replacement and should be kept separate from health. Given that Alectra's fundamental goal in calculating asset health is to make an estimate of failure probability, we believe that their argument for including age is reasonable.

5. *There are many places where the details of the ACA calculations do not match the report, presumably due to ongoing adjustments based on SME input. Updating the ACA report would entail a significant amount of work and would have little, if any, effect on proposed spending. We recommend leaving it as-is and noting that some results have been superseded. In cases where errors have been identified (i.e., not just changes in the weightings), we recommend correcting the calculations for future reference. We recognize that Alectra-Mississauga has already reviewed any business cases where asset health scoring may have changed.*

   This has been addressed through Alectra undertaking the ACA with its own staff and process.

6. *For future ACA reports, we recommend clarifying where the criteria scoring tables are intended to show only the general range of scores and not the details of how all possible field inputs are scored.*

   Alectra has addressed this in its current ACA approach.

7. *For future ACA analyses, we recommend reality checking the failure projections against recent failure history and recalibrating them if needed. Failure probability projections should be based on an explicit definition of failure, including multiple scenarios where appropriate. Alectra-Mississauga already makes good use of its failure history data and further integration of the actual data with the ACA analyses will be beneficial.*

   Alectra is not making projections of failure based on Health Index and Expected or Total Useful Life. EUL and TUL are used only for calculating the age component of health indices. Failure probability estimates in the business cases are based on past failure rates where possible, and a combination of available data and SME judgment where sufficient historical data are not available. For example:

   - Underground cable replacement or injection business cases use the historical failure rate of the region to calculate the reliability value of the investment.
   - Station switchgear replacement business cases use the subjective judgment of SMEs to estimate failure probability because these failures are not frequent enough to have developed reliable data.

   Based on our discussions with Alectra staff, we understand that they are in the process of developing utility-specific failure probability curves. We agree that this is the correct approach. We recommend that Alectra consider opportunities to share data with its peer utilities.

8. *We recommend considering additional failure probability flags from known bad actors, such as tap-changers and type-U bushings. These should be based on actual data wherever possible.*

   Alectra has incorporated health index multipliers in cases where extreme conditions are expected to have outsized effects on asset health. For example, the distribution line transformer has a field health index multiplier whereby if either of the condition criteria shows “major” degradation, the health index is multiplied by 0.25, which puts the asset in Very Poor condition.

9. *We recommend expanding the proactive replacement approach to include the following asset classes:*
   a. *Pole- and pad-mount transformers where there may be PCB-contaminated oil;*
   b. *Vault transformers;*
   c. *Underground cable; and*
   d. *Protective relays (not included in ACA).*

   Alectra has expanded its ACA process to address all of the assets listed above, except relays and SCADA as noted previously, and each has a proactive investment group associated with it, described in Appendix A.

10. *The business case analysis models, which may be based on the output of the ACA and used by Alectra-Mississauga to evaluate actual spending proposals significantly improves on the risk assessment in the ACA. The business case model considers a wider range of categories such as safety, customer minutes of outage and customer satisfaction, and these values are estimated in a more granular way. We recommend migrating this approach to the ACA criticality assessment.*

    Alectra has removed risk from its ACA process; risk is addressed in the business cases using C55. We do not recommend re-introducing risk to the ACA, however a systematic risk assessment to support project identification (not only evaluation) is recommended. This assessment should quantify risk in the same terms used by C55.

11. *Long-range projections on spending should include estimates of unplanned replacements, even for asset classes with proactive replacement programs.*

    Long-range spending forecasts, including projections of future failures, are in process but have not yet been completed. At present, projected spending for most investment groups extends to the end of the DSP period. Alectra is working to extend these, and we recommend that unplanned replacements be a part of them.

12. *Unplanned replacement estimates for all assets should be based on actual probability of failure, not smoothed projections.*

    Alectra has removed the smoothed unplanned replacement projections from the ACA. Reactive spending is not estimated by asset class; instead Alectra has made a top-down estimate of reactive spending, based on extrapolating past years' spending. This is certainly a more accurate prediction of total reactive spending than one based on rolling estimates at the asset class level. As Alectra works through the backlog of equipment slated for replacement, we anticipate that the trending increase in reactive spending will slow or possibly reverse, provided that Alectra invests sufficient resources (financial and human) to ensure that the volume of planned replacements stay ahead of the expected level of deterioration and unplanned failures. We recommend that Alectra review this projection at that time and adjust as needed.

13. *We recommend Alectra-Mississauga apply a data availability threshold for "valid" HI calculations. Typical standards are 70% or 50% available, weighted by the weightings in the formulation.*

    Alectra applies a data availability criterion of 50%, based on its DAI, for calculating a valid health index. Major stations assets (transformers, breakers, switchgear) have full data, so this applies mainly to distribution assets. Alectra is implementing a three-year inspection cycle for all distribution assets, so we anticipate that data availability will cease to be an issue in short order.

14. *We believe that Alectra should give serious consideration to bringing the ACA process in-house. Alectra could still rely on external consultants for support, as needed, in executing the process. We believe that this would be a step that is consistent with the evolution of Alectra and would enhance and streamline the overall process of developing ACA and using the results to identify investment needs. It would ensure consistent quality of process and alignment with Alectra's objectives. We also believe that given that Alectra's other operating regions also perform ACAs, there would be value in combining the knowledge of the respective SMEs, as well as cost savings from economies of scale.*

    As recommended, Alectra has brought the ACA process in-house. Not only have they taken over the ACA process, they have substantially improved it and have built a new SQL-based tool to support it. The complexity of integrating data from multiple utilities, with users at multiple locations, made this a difficult and complex task. We commend Alectra for accomplishing it and delivering a high-quality consolidated ACA for use in the current DSP.

15. *Alectra-Mississauga has not been in the practice of conducting sensitivity analysis around changed assumptions in ACA, especially failure probability and criticality. We believe that in addition to refining the methodology adding this capability, which may require bringing the ACA work in-house, would enable Alectra-Mississauga to better stress test its assumptions and its plans, especially as the ACA becomes a more integral part of the overall planning process.*

    Sensitivity analysis is not performed on the business cases themselves. C55 evaluates the portfolio using multiple scenarios (i.e., risk and spending constraints), which provides some view of sensitivity at a portfolio level. C55 will be a convenient place to perform additional sensitivity analyses in the future. We recommend that the scenario analyses be expanded to include not only risk and spending constraints, but also changes to the value framework. For example, how sensitive is our spending plan to assumed customer outage costs or the value of improved safety?

16. *Alectra-Mississauga would benefit from a more quantitative cost/benefit approach to business cases. This does not necessarily mean expressing all benefits in dollars (although it may), but it should at a minimum mean carefully crafting the scoring scales so that planners and asset managers have clear guidance for scoring projects. We recommend a review of the scoring criteria and approach to ensure that these points have been considered. Once this is complete, it will be possible for Alectra-Mississauga to require those proposing spending to a) demonstrate that their preferred alternative is more cost effective than the other and b) that the proposal produces net benefit to customers and other stakeholders. This ability may be the single most important outcome of an asset management process.*

Alectra has developed a consistent approach to scoring projects, based on the value framework in C55. The process includes training for Project Owners to ensure consistency and that they understand the objective and interpretation of the criteria. Alternatives are included not only in C55, but also at the customer interface.

17. *We recommend developing a guide or standards for users defining the base case and scoring projects in the business case template.*

    This has been adopted and is included in the C55 process implemented by Alectra.

18. *We recommend appointing one or more asset management staff as business case experts who will be involved in each business case. This will ensure consistency as Alectra continues through the merger and begins standardizing the process across all operating regions.*

    Alectra has created a Capital Investment Steering Committee whose members review all business cases to ensure consistent scoring across Project Owners. There is also a training program for Project Owners to educate them on the scoring approach and assumptions. According to Alectra staff, these training sessions have been a productive forum for discussion among the Project Owners about how to consider risks and benefits of various types of projects. This kind of discussion is extremely valuable for consistency and, especially, for taking advantage of all of the experience and intelligence of the group. Finally, the asset management team reviews business cases for projects proposed in their respective areas. Overall, we believe that this process provides good oversight and consistency.

19. *In the last year, Alectra-Mississauga has become more attuned to CEMI (Customers Experiencing Multiple Interruptions) and has noticed that there are pockets of poor performance on some of the better performing feeders and pockets of better performance on worse performing feeders. We encourage Alectra to continue to explore this measure and its implications.*

    Poor performing areas are point of emphasis in the business cases we have reviewed, particularly those related to underground cable, which we have reviewed in the most detail. Historical performance is considered alongside asset health and risk when identifying projects. The benefit of improved CEMI is captured as avoided regulatory risk in the C55 business cases.

20. *Alectra-Mississauga has recognized that there are still more improvements that it can make in the use of business cases, in expanding the application of business cases to all of its investment opportunities and in leveraging its GIS and performance data to strengthen cause and affect analysis. We encourage Alectra-Mississauga to continue this evolution, and we note*

that its current approach is already consistent with better performing asset management organizations.

Alectra has continued to move its business case process forward, despite the difficultly of integrating multiple legacy utilities. There are still opportunities to improve the process by leveraging visualization, data analysis, and risk assessment tools and processes. We recommend Alectra consider these opportunities as it continues to develop and improve its methods and processes.

21. *We encourage Alectra-Mississauga to continue to improve its ability to link all of its investments to highly definable value and risk benefits, including efficiency gains.*

Alectra has taken a strong step forward in this area in two ways. First, the customer interface efforts ensure that customers are aware of the trade-offs between cost and benefits and have an opportunity to comment directly on their preferences. Second, Alectra has developed consistent project scoring methods through the value framework in C55.

22. *Like many utilities in North America, Alectra-Mississauga is now looking to consider the far-reaching impacts of increased activity in Distributed Energy Resources, micro grids, EV/PHEV and other technologies on the distribution system and on the services that it provides or offers to its customers. We believe that this is an area in which Alectra-Mississauga should continue to delve more deeply.*

The value of DER, microgrid, and other advance utility technologies are still potentially of benefit to Alectra and its customers. We are aware that the customer interface effort suggested they place a lower value on them than might have been anticipated. Although this creates some tension between regulator-driven requirements and perceived customer needs, we believe that the long-term benefits are likely substantial. We have seen significant disruption in places where utilities have gotten behind their customers' expectations in these areas, and we recommend that Alectra continues to keep them on the table for consideration in customer interface, business cases, and strategy.

Appendix B – Resumes of project team

Stewart Ramsay

Executive Consultant

PROFESSIONAL OVERVIEW

Stewart Ramsay is an Executive Consultant with Vanry + Associates, Inc. He has more than 30 years of experience in leadership, consulting and engineering roles in the global utility and manufacturing industries. An experienced utility and technology executive valued for his “start-up” and “turn around” capabilities. He has extensive expertise in strategic planning, organizational effectiveness and asset management and performance management. An expert on industry strategic directions and the nexus of technology, processes, and people/culture, Stewart is often engaged in supporting clients make significant shifts in perspectives and performance. He has contributed to the development of regulatory strategy at both a national and state/provincial level in several countries.

Core Competencies

- Leadership
- Leadership Skills Development
- Asset Management
- Culture Change
- Program Management
- Performance Management
- Strategy Development
- Operational Effectiveness
- Personnel Growth & Development
- Team Facilitation
- Executive Coaching

Industry Experience

Eskom Transmission

Contracted by the MD (Chief Executive) of the Transmission Business for Eskom (largest utility in South Africa and national transmission grid operator) to undertake a review and realignment of the entire Transmission organization based on world class AM and Operational processes. We worked with the MD and his direct reports to define the outcomes for the work and for the resulting processes.

BCTC

Provided facilitation and subject matter expertise to support BCTC in refining and improving its end to end Asset Management and Asset Investment processes. The process definition and development included all of the traditional asset management processes as well as R&D, competitive intelligence, risk management, and integration with finance, supply chain, regulatory and operations. The engagement was deliberately light touch with the consultants providing frameworks, facilitation, and reference expertise and the client carrying out the bulk of the work. The intent was to enable the client personnel to become self-sufficient in process design and implementation.

BC Hydro

Provided facilitation and subject matter expertise to support the reintegration of BCTC into BC Hydro (forced merger), and the integration of the Transmission and Distribution Asset Management, Planning and Engineering organizations into a single unit. The project was carried out in an environment of significant mutual animosity and distrust between teams made up of members from the two historical organizations. Provided strong facilitation, frameworks, a neutral voice and perspective, best practice knowledge of each of the key operational areas. Focused the teams on the expected/promised outcomes.

Hydro Ottawa

Provided support in the development and refinement of overall operations effectiveness of the COO's organization (represents 75% of total personnel and 90% of total expenditures). Provided facilitation via subject matter experts to review and refine the Asset Management, Operations, and Customer Service processes, and interfaced/integrated with Finance, Supply Chain, Fleet, IT and HR processes. Worked directly with the COO and his direct reports to support their ability to lead the process changes and the cultural shifts required to enable Hydro Ottawa to move to become the leading utility in the province. Aligned the work with HO's corporate, technology and regulatory strategies. Provided coaching and support in building internal capabilities of the organization to carry on continuous improvement and the definition of new processes to respond to emerging requirements from the regulator.

GPU Energy / First Energy

Enterprise-wide (generation had been divested) process redesign focused on increasing efficiency and effectiveness of the organization. The project included cross-functional design teams facilitated by consultants with process and subject matter expertise. The project included development and transfer of skills to internal teams in the areas of process design and skills related to collaboration, trust building and communications. The project included representatives of the unionized workforce in an environment of significant distrust between union and management.

Relevant Work Experience

- As the CEO of Smart Wire Grid, Inc. (a manufacturer of advanced power flow control technology), Stewart led a startup organization that partnered with ARPA-e and took technology from laboratory to pilot project in 8 months and from laboratory to commercial sales in less than 1 year. He provided the vision and leadership for the groundbreaking technology and worked with industry and regulators to hasten its acceptance and adoption. He forged manufacturing partnerships to bring ISO 9001 level production to this startup.
- As the President of CTC Cable, (the manufacturer of the advanced High Temperature – Low Sag conductor) Stewart provided the leadership necessary to turn around the technical, operational and financial performance of the company. He worked with industry to build the trust and acceptance of the advanced conductor technology and provided the strategy and leadership that rebuilt the global sales of the product. He led the strategy and effort for the development of global manufacturing partnerships in the EU, China, Latin America and Indonesia.
- As an officer at both American Electric Power and Pacific Gas and Electric, Stewart was heavily involved in innovative approaches to modernizing the grid. He has been a strong proponent of the creation of adaptive, self-healing grids using a range of smart grid technologies on both the utility and customer side of the meter. He led the adoption of distributed resources and energy storage at both utilities. In both organizations he led significant advances in the adoption of innovation shifting capabilities and culture. Stewart collaborated with regulators to establish performance targets tied to funding of investments. Stewart was the lead officer in the development and delivery of corporate wide internal leadership development programs at PG&E.

Education and Credentials

- BSEE, Northeastern University, Boston, MA
- Member Advisory Committee, Peak Reliability
- Board Member, Expert Advisors to the California Emerging Technology Fund
- Professional Engineer License, State of Florida (inactive)

Julius Pataky
Executive Consultant

PROFESSIONAL OVERVIEW

Julius Pataky is a Senior Partner with Vanry + Associates, Inc. Julius is an executive with 35 years' progressive industry and consulting experience in the energy industry, with demonstrated leadership skills in building effective teams, leading transformation and bringing innovation to the business. Most recently he has led the areas of system planning and asset management in an outsourced services business model. Previous experience includes policy and strategy development, business development, negotiations, risk management, contracts, business process improvement, and regulatory proceedings. Experienced in supply chain, energy supply portfolio management, tariff and toll design, storage development, risk assessment and leadership of professional staff with accomplishments including negotiation of significant commercial relationships, successful regulatory applications, collaborative development of government industry policy, innovative analysis for strategic decision making and staff mentoring.

Core Competencies

- Leadership
- Leadership Skills Development
- Facilitation & Mentoring
- Executive Coaching
- Strategy
- Business Transformation
- Program Development & Delivery
- Performance Management

Industry Experience

South Coast Transportation (TransLink)

As a Partner for a Big 4 consultancy in the role of executive lead, guided the initial development of the transformation program for a regional multi-modal transportation authority. The enterprise-wide engagement covered 8 business units across 3 operating companies with assets of $10B. This engagement entailed the development of Asset Management Plan, including the asset management improvement road map, for the enterprise and its operating companies, the development of a Decision Support Tool as well as the development of an Asset Planning System (sustainment investment planning tool). Julius led the team to have all program elements accepted the organization, to have other related initiatives include in the transformation plan and to have the specific improvements adopted by the organization in record time. He provided advice to the executive sponsor, coached the client's program director and facilitated key sessions with the leaders of operating groups and executives.

FortisBC

As a Partner for a Big 4 consultancy, led the assessment of asset management processes and developed a strategic roadmap for transforming asset management capability of this integrated, 1.2 million-customer, power and gas utility. The multiphase projects included: vision development, road map to implementation, organizational alignment and capabilities, planning process integration, risk framework development and supporting technology strategy as well as supporting the regulatory application for these improvements. In addition to leading the organization to adopt leading asset management practices, this also required creating alignment between the newly integrated Gas and Electric Business; the 150,000-customer electric utility had recently acquired the 1.1 million customer gas utility. The program was highly successful as the regulator approved funding costs and the team continues to support the transformation.

Enbridge

As a Senior Manager for a Big 4 consultancy, was the engagement manager for strategic sourcing transformation for an integrated North American energy transporter and retailer. This engagement delivered savings of $30 million on expenditures of $200 million and developed eProcurement and organizational recommendations. Commodities included in demonstration and training of methodology included: Meters, Pipes, Valves & Components, Mechanical Fabrication & Installation, Inspection Services, Pumps & Electric Motors, Telecommunication Services, IT Services (staff augmentation) and Construction Services, Notable results included leading the 1.2 million gas distribution business to alter core facility design, fabricate and delivery (outsourcing) methods.

SaskEnergy

As a Partner for a Big 4 consultancy, led the development of assessment and the best practice review of an integrated (wellhead-to-burner tip) natural gas utility's capital project portfolio management processes. This project included the identification of 13 improvement areas across people, process and technology followed to two engagements to assist the client with the implementation of Project Program Risk Evaluation, Standardized Roles and Responsibilities, Terms, and Deliverables and the CPPM Technology Road Map, specifically the capabilities of the ERP system for this purpose.

Placer Dome

As a Senior Manager for a Big 4 consultancy, was the engagement manager for strategic sourcing transformation for an integrated, global mining company. The engagement entailed the development of a Supply Chain Strategy and related implementation plan for its worldwide mine operations using the Accelerated Solutions Environment. The development of this strategy identified US$70 million in annual savings across its 18 mines and was the first time the organization had achieved an integrated strategy under its autonomous business model with multi-cultural leadership from all continents. The team continued with the implementation of the first phase of the strategy delivering about $13 million on annual expenditures of $100 million.

Relevant Work Experience

- As VP, Asset Investment Management, Transmission & Distribution for BC Hydro, Julius was responsible for and designed the strategic vision and operating plans for maintaining and building the transmission and distribution assets to serve the needs of customers and enhance value to ratepayers. The transmission and distribution system comprised $7B in assets supporting 1.6 million customers. He oversaw the development and performance assessment, led the planning activities for asset growth, replacement and maintenance; led the capital planning process ($10B, 10-year plan) and the maintenance planning process ($200M/yr.) of the delivery grid. His accomplishments included:
    - Led change and merger activities of BC Transmission (BCTC) into BC Hydro and initiated the integration of two organizational units arising from the re-integration of BCTC and BC Hydro and continued a transformational change in asset investment management started earlier in BCTC.
    - Led the integration of non-utility team leaders with legacy utility professionals to generate change and innovation. Achieved record level engagement and strategic alignment with the leadership team.
    - Led the development of new asset management decision methodologies and software tool, which won an innovation award by the Institute of Engineering and Technology (UK).
    - In collaboration with Hydro Quebec developed a transmission line inspection robot, which won the Edison Electric International Award.
- Julius has 18 years experience in the integrated gas business of the ATCO Group. In the last role he was responsible for all aspects of the management of a 200 BCF gas supply portfolio for two gas utilities in Alberta; the portfolio was valued at $500 million annually. Gas supply management responsibilities included core market portfolio design, storage design, supply planning, supply procurement, risk management, gas pricing and tariffs, supply/demand and price forecasting as well as regulatory jurisprudence. Some of his accomplishments include:
    - The application of innovative modeling approaches to gas supply portfolio risk management
    - Managed and directed the application and regulatory defense of the gas portfolio costs such that all costs were approved by the regulator despite volatile gas prices.
    - Collaborated with Alberta Ministry of Energy, regulatory, industry and consumer groups in developing new policies, tariffs and portfolio management approaches during the period of gas market deregulation, restructuring emergency gas diversion, gas storage and retail direct sales policies.

Education and Credentials

- BASc (Engineering), University of British Columbia, Vancouver, BC
- MBA, Richard Ivey School of Business, University of Western Ontario. London, ON
- Registered Professional Engineer, (APEGBC), Province of British Columbia
- Corporate Licensing Task Force, APEGBC

Darin Johnson

President, BIS Consulting LLC

PROFESSIONAL OVERVIEW

Darin Johnson is the President and director of the asset management practice at BIS Consulting, LLC. His experience includes risk analysis, capital planning, and life-cycle cost analysis for electric transmission and distribution, water/wastewater, and hydro and thermal generation facilities. This work addresses the full range of asset management program development, from framework and strategic planning through implementation of decision-support methodologies and business processes to justify and prioritize replacement of aging assets and other spending programs.

Core Competencies

- Decision Support Methodologies
- Risk-based economic evaluation
- Capital planning and prioritization
- Statistical analysis of failure data
- Asset management strategic planning

Industry Experience

Economic life evaluation process; Portland General Electric
Worked with newly formed Strategic Asset Management group at PGE to develop a process and supporting tools for asset related spending decisions. First phase addressed circuit breakers and underground cable, results currently being implemented. Currently addressing station transformers, relays, and switches, as well as a one-off business case to evaluate options for managing overhead and pad mount transformers with possible PCB contamination. The approach has been successfully rolled out for regulatory, engineering, and executive audiences.

Feeder Investment Model; Toronto Hydro
Created a risk-based economic model for optimizing the timing and scope of refurbishment programs on feeder lines assets, including overhead lines, underground cables, and other equipment. The outputs of this model feeder directly into a standardized business case template, which quantifies the scope of the project, its cost, and the expected

benefit in terms of improved reliability. The business cases were used by Toronto Hydro as part of a successful rate case to their regulator.

Aging infrastructure process review and implementation; Puget Sound Energy
Performed a process review of programs for managing aging transmission and distribution infrastructure, including condition and risk assessment, compared with industry standard and best-practice for advanced asset management utilities. Based on recommendations, PSE implemented a program that includes best-practice health indexing and tools for optimizing replacement or refurbishment of assets based on balancing risk of failure against capital spending.

Predictive Maintenance Tool; Duke Energy, Midwest Commercial Generation
Developed a tool for evaluating the life-cycle cost tradeoffs between replacement and refurbishment strategies of assets at multiple coal-fired generating facilities. Work included development of failure projections, facilitation guides for eliciting expert criticality data, a prototype model and integration strategy, and support for capital planning and prioritization.

Station Transformer Long-Range Plan; Seattle City Light
Developed a process and supporting tools for evaluating station transformers in City Lights transmission and distribution system to identify which are at end of life and what should be the long-term plan for replacement. The approach integrated SCL's existing health index process with estimates of consequence cost, including customer outages, and failure probability. Output of this analysis is being integrated into the six-year horizon plan.

Due-diligence review of asset management practices; Horizon Utilities
Worked as a sub-contractor to Vanry Associates through Horizon Utilities, on behalf of counsel, to undertake an independent, third-party review in support of the due diligence process related to the potential merger of four Local Distribution Companies The scope of the review was to evaluate the respective Asset Condition Assessment methodologies and resulting capital investment planning processes, as well as to assess the overall asset health and subsequent 20-year investment for each of the four LDCs. The review was conducted under a highly compressed time frame. Conducted in-person interviews at each of the LDCs and worked with each of the LDCs to ensure a clear understanding of each of their processes. Provided assessment of the each of the utilities' practices, as well as other observations regarding asset management capabilities.

Education and Credentials

- B.S. Mechanical Engineering, University of Washington
- Licensed Mechanical Engineer Washington State

Neil M. Reid

Vice President, BIS Consulting LLC

PROFESSIONAL OVERVIEW

Mr. Reid's experience includes asset management, conceptual engineering, project management and scheduling, preliminary and final design, cost estimating and control, equipment specification, construction management and testing of hydroelectric, fossil and nuclear power plants, high voltage substations, transmission, and distribution systems.

In addition to design, Mr. Reid has an extensive background in managing, defining and evaluating power supply interconnection plans, power and energy requirements, and load flow, short circuit, and voltage drop studies. He has provided expert testimony related to electric power system operation and safety. Mr. Reid is a registered Professional Engineer in several states in the United States of America and is qualified for registration in Canada and as a Chartered Engineer in the United Kingdom.

Core Competencies

- Condition Assessment & Health Indexing
- Project Management
- Transmission and Distribution Systems Engineering

Industry Experience

Alectra Utilities Corporation, Ontario, Canada

Lead consultant for Asset Condition Assessment review of the model(s) used by Alectra for development of the capital investments for its 2017 Distribution System Plan (DSP). Responsible for review of asset plans for investments designed to meet growth, safety and reliability needs. Provided recommendations for detailed and overall improvements to the DSP.

BCTC, British Columbia, Canada, Asset Condition Assessment and Baseline Study

Project Manager. Led a comprehensive Asset Condition Assessment and Baseline Study of all physical assets managed by British Columbia report to support a filing to the BC Utilities Commission**.** He was responsible for an update of the study in 2010.

Capital Improvement Program Review, Seattle City Light, Seattle, Washington
Principal-in-Charge and Project Manager. Led the capital improvement program review which was requested by the Seattle City Council. The aim of the project was to determine if the City's major ($150 million/year) capital investment in its electric power facilities was prudent. The first part of the project was a physical review of the condition of the utility's capital facilities, including hydroelectric plants, substations, transmission and distribution facilities, downtown network, and general plant. The second was a review of the utility's internal processes and controls used to formulate, budget, approve and manage capital improvement programs and projects**.**

Condition, Criticality, and Risk Assessment Process; Eskom Transmission, South Africa
Led the BIS team as part of an overall asset management project to develop a process and tools to justify replacement of aging transmission equipment. Facilitated condition assessment of all transmission assets and a business case to support the decision to repair, replace, or refurbish a high-voltage gas-insulated substation. The business case quantified the benefit of the preferred option as well as its priority relative to other spending alternatives.

Asset Condition Assessment, Hydro One, Toronto, Ontario, Canada
Assistant Project Manager. Assisted in leading a comprehensive Asset Condition Assessment program of all physical assets owned and operated by Hydro One (formerly Ontario Hydro) and preparation of an independent report to support a filing to the Ontario Electric Board.

Asset Management Plan, Hydro Ottawa Limited, Ottawa, Ontario, Canada
Special Consultant. Consulted to the team working with Hydro Ottawa Limited for development of a comprehensive Asset Management Plan.

Primary Power Equipment Asset Management Analysis, Several Clients, Washington
Project Manager. Led risk-based asset management analyses of primary power equipment for several clients, including Bonneville Power Administration, Bureau of Reclamation, Puget Sound Energy, Seattle City Light and Chelan Public Utility District.

Asset Due Diligence Report Review, Trans Alta Utilities, Calgary, Alberta, Canada
Project Manager and Lead Electrical Engineer. Led owner's review of the Asset Due Diligence report prepared by Trans-Elect for the acquisition of the transmission assets of Trans Alta Utilities, Alberta. The transmission system consists of 11,600km overhead lines and 269 substations operating at voltages of 500kV, 240kV, 138kV and 69kV.

Rock Island Hydroelectric Power Plant Condition Assessment, Chelan Public Utility District, Wenatchee, Washington
Lead Electrical Engineer. Led condition assessment, life extension planning and upgrade study for electrical equipment at the Rock Island hydroelectric power plant on the Columbia River. The plant consists of two powerhouses containing a total of 18 propellers, Kaplan and bulb type units with a total capacity of approximately 600 MW.

Engineering and Design
Mr. Reid has over 30 years' experience in evaluation, design, planning, construction management, and condition assessment of electric power transmission and distribution facilities and equipment. This includes work as a design engineer and project manager, as well as consulting work to support long range technical and financial planning.

Education and Credentials

- B.S. Electrical Engineering, University of Bristol, England
- Professional Engineer in 7 States
- Over 40 years of relevant experience in electrical power systems

Appendix H

Regional Planning Reports

Alectra Utilities

Distribution System Plan (2020-2024)

SOUTH GEORGIAN BAY/ MUSKOKA REGION
SCOPING ASSESSMENT OUTCOME REPORT

June 22, 2015

Independent Electricity System Operator

Contents

South Georgian Bay/Muskoka Study Team

Company
Independent Electricity System Operator
Hydro One Networks Inc. (Transmission)
Hydro One Networks Inc. (Distribution)
InnPower
Lakeland Power
Midland PUC
Newmarket-Tay Power
Orangeville Hydro
Orillia Power
PowerStream
PowerStream COLLUS
Veridian Connections
Wasaga Distribution

1 South Georgian Bay/Muskoka Scoping Assessment Outcome

Scoping Assessment Outcome Report Summary			
Region:	South Georgian Bay/Muskoka		
Start Date	March 23, 2015	**End Date**	June 22, 2015

1. Introduction

This Scoping Assessment Outcome Report is part of the Ontario Energy Board's ("OEB" or "Board") Regional Planning process. The Board endorsed the Planning Process Working Group's Report to the Board in May 2013 and formalized the process timelines through changes to the Transmission System Code and Distribution System Code in August 2013.

The first stage in the regional planning process, the Needs Assessment, was carried out by Hydro One Networks Inc. ("Hydro One") for the South Georgian Bay/Muskoka region. The purpose of the Needs Assessment is to identify if there are any electricity needs in the region requiring regional coordination. The final Needs Assessment report[1] was issued on March 3, 2015 and concluded that some needs in the region may require regional coordination, and these needs should be reviewed further under the IESO-led Scoping Assessment process, which is the second stage in the regional planning process.

The IESO, in collaboration with the Regional Participants, further reviewed the needs identified, in combination with information collected as part of the Needs Screening, and information on potential wires and non-wires alternatives, to assess and determine the best planning approach for the whole or parts of the region: an integrated regional resource plan ("IRRP"), a regional infrastructure plan ("RIP") or that regional coordination is not required and the planning can simply be done between the Transmitter and its customers.

This Scoping Assessment report:

- Defines the sub-regions for needs requiring regional coordination as identified in the Needs Screening report;
- Determines the appropriate regional planning approach and scope for each sub-region with identified needs requiring regional coordination;
- Establishes a Terms of Reference in the case where an IRRP is the recommended approach for the sub-region(s);
- Establishes a working group for each sub-region recommended for an IRRP or a RIP.

2. Team

The Scoping Assessment was carried out with the following Regional Participants:

- Independent Electricity System Operator ("IESO")
- Hydro One Networks Inc. ("Hydro One Transmission")

[1] The Needs Assessment report for the Southern Georgian Bay/Muskoka Region can be found at http://www.hydroone.com/RegionalPlanning/SGB-Muskoka/Pages/default.aspx

- Hydro One Networks Inc. (“Hydro One Distribution”)
- InnPower
- Lakeland Power
- Midland PUC
- Newmarket-Tay Power
- Orangeville Hydro
- Orillia Power
- PowerStream
- PowerStream COLLUS
- Veridian Connections
- Wasaga Distribution

3. Categories of Needs, Analysis and Results

I. Overview of the Region

The South Georgian Bay/ Muskoka region is located in central Ontario and includes all or part of the following Counties and Districts: the County of Simcoe County, County of Dufferin, District of Muskoka, District of Parry Sound and County of Grey. For electricity planning purposes, the planning region is defined by electricity infrastructure boundaries, not municipal boundaries.

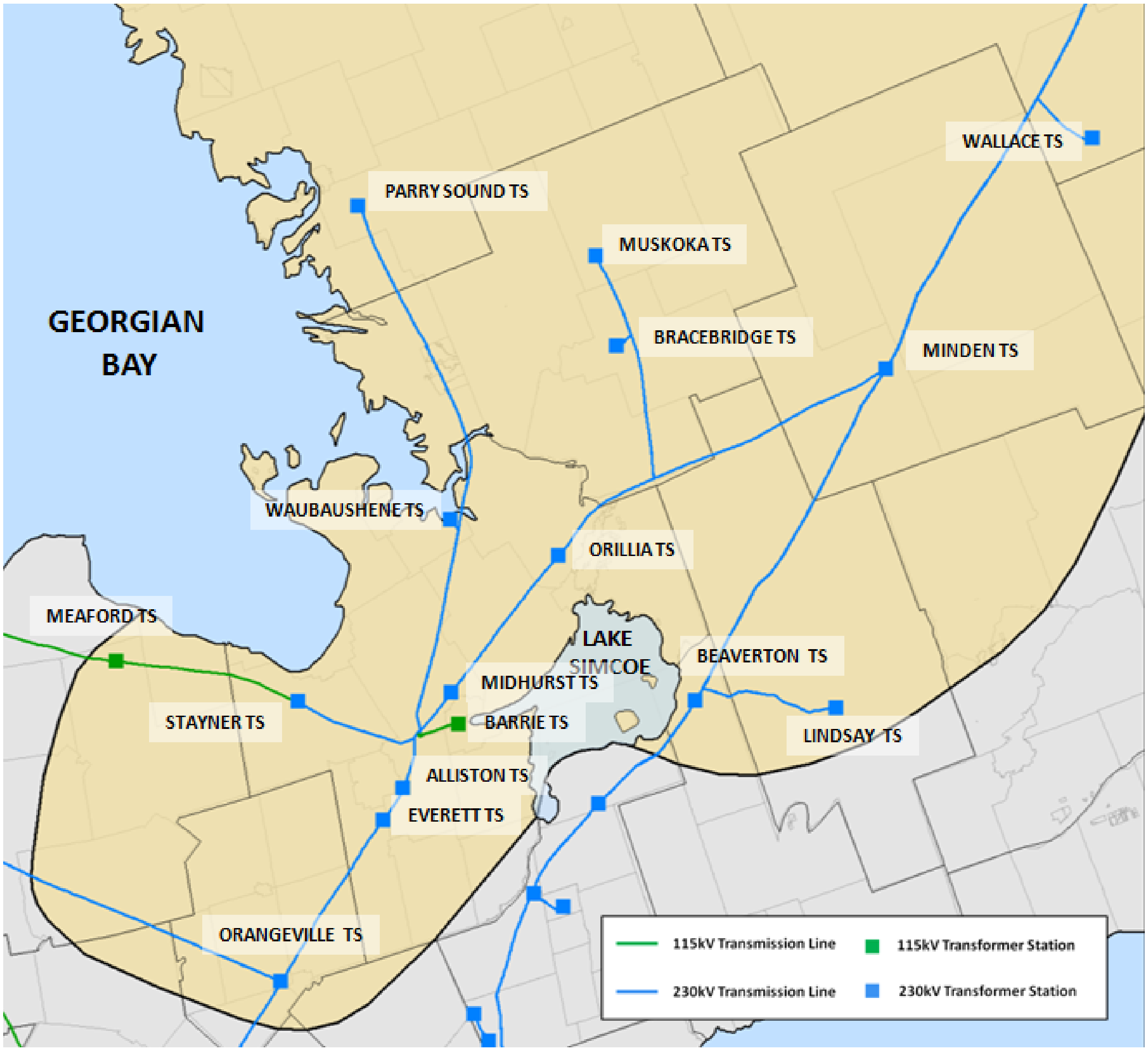
The region also includes the following First Nations:

- Henvey Inlet
- Magnetawan
- Shawanaga
- Wasauksing
- Moose Deer Point
- Beausoleil
- Wahta Mohawks
- Chippewas of Rama
- Chippewas of Georgina Island
- Mississaugas of Scugog

The electricity infrastructure supplying the South Georgian Bay/Muskoka region is shown in Figure 1. The region is supplied from 115 kV and 230 kV transmission lines and stations that connect at the Essa transformer station (“TS”). The 500/230 kV auto-transformers at Essa TS provide the major source of supply to the area.

The southern portion of this region is summer-peaking (i.e., electricity demand is highest during the summer months), and is characterized by strong forecast growth, particularly in the Barrie and Innisfil areas. The northern part of the region is winter peaking (i.e., electricity demand is highest during the winter months), and growth is forecast to be more gradual.

Figure 1. South Georgian Bay/Muskoka Region Electricity Infrastructure



NOTE: Region is defined by electricity infrastructure; geographical boundaries are approximate.

II. <u>Needs Identified</u>

Hydro One's Needs Assessment report identified the following needs in the South Georgian Bay Muskoka Region, based on a 10-year demand forecast.

115 kV and 230 kV Lines and Auto-Transformers

- The 230/115 kV auto-transformers at Essa TS are expected to exceed their 10-day Long Term Rating (LTR) upon loss of the companion auto-transformer. This need is forecast to arise in the near term for the T1 auto-transformer, and the medium term for T2.
- The 115 kV circuit E3B, which supplies Barrie TS radially from Essa TS, is expected to exceed its Long Term Emergency (LTE) rating upon loss of the companion circuit in the near-term.

115 kV and 230 kV Transmission Stations

The following stations are expected to exceed their normal supply capacity:

Station	Timing of Peak Demand	Timing of Need
Barrie TS	Summer	Today
Muskoka TS	Winter	Near-term
Parry Sound TS	Winter	Today
Midhurst TS	Summer	Medium term, if potential new commercial operations materialize
Minden	Winter	Long term*
Waubaushene	Winter	Long term*

*In the Needs Assessment report, no needs were identified for the Minden and Waubaushene stations based on the 10-year net demand forecast, which includes conservation and demand management ("CDM") and distributed generation ("DG"). Based on the gross load forecast, which does not include CDM or DG, needs were identified within the 10-year horizon. These needs can therefore be expected to appear in the long term (after 10 years) based on net load.

Load Restoration Needs

Potential needs related to restoring loads after a major outage were identified in the Needs Assessment report. This analysis was further developed through the Scoping Assessment Process. Based on this assessment, the following restoration needs were identified:

Circuits	Load Restoration Criterion not met
M6E+M7E	30 min and 4 hours
E8V+E9V	4 hours

In addition, loading on M80/81B and E26/27 is currently around 150 MW. Based on current load transfer capability, load restoration criteria can be met in the near term. However, with load growth, restoration needs may emerge in the longer term. The IESO will monitor growth in the affected areas, and potential future needs will be re-assessed in the next regional planning cycle.

Bulk System Needs

The following needs were identified for the bulk system supplying the Region:

- Excessive post-contingency voltage declines may occur upon losing one of the 500/230 kV auto-transformers at Essa TS when the other is out of service.
- Overloads of 115 kV circuit S2S and the Stayner T1 auto-transformer may results from increased generation in the Bruce area.

Aging Infrastructure / Replacement Plans

The following infrastructure is expected to reach its end-of-life or is the subject of sustainment activities within the study period.

Equipment	Date
Barrie TS—115/44 kV transformers	2018-2020*
Minden TS—230/44 kV transformers and possible rebuild of low-voltage switchyard	2019
Orangeville TS—230-44/27.6 kV transformers and associated low-voltage equipment	2017
M6/7E—ground clearance on several sections to be increased. This may increase the thermal	2015

capability of this line.	
E3/4B	These circuits are about 50-60 years old. Hydro One expects to undertake sustainment work on these facilities within the next 20 years.
Essa TS - 230/115kV Autotransformer (T1)	~2020

* Hydro One identified this need to be addressed by 2018 in the Needs Assessment report. This need may be pushed out to and managed until 2020 to accommodate the lead time of alternatives to address it.

Reliability Needs
Regional Participants identified reliability needs that they would like to see included in the regional planning process. Two types of reliability needs were identified: distribution system reliability concerns related to long 44kV feeders in the northern part of the Region; and a lack of supply redundancy. To the extent that these needs can be coordinated with other regional needs, the Regional Participants agreed to address them as part of the regional planning process.

III. Analysis of Needs and Identification of Sub-Regions

The Regional Participants have discussed the needs in the South Georgian Bay/ Muskoka area and have identified two sub-regions for further study through the regional planning process. The two sub-regions, "Barrie/Innisfil" and "Parry Sound/Muskoka", are shown in Figure 2.

Barrie/Innisfil Sub-Region
Strong electricity demand growth is forecast for the Barrie/Innisfil area, consistent with the provincial *Growth Plan for the Greater Golden Horseshoe, 2006*. This sub-region is summer-peaking, and includes the following infrastructure:

- Stations—Midhurst TS, Barrie TS, Everett TS, Alliston TS
- Transmission circuits—E8/9V, E3/4B, M6/7E (Essa-Midhurst section)
- 230/115 kV auto-transformers at Essa TS

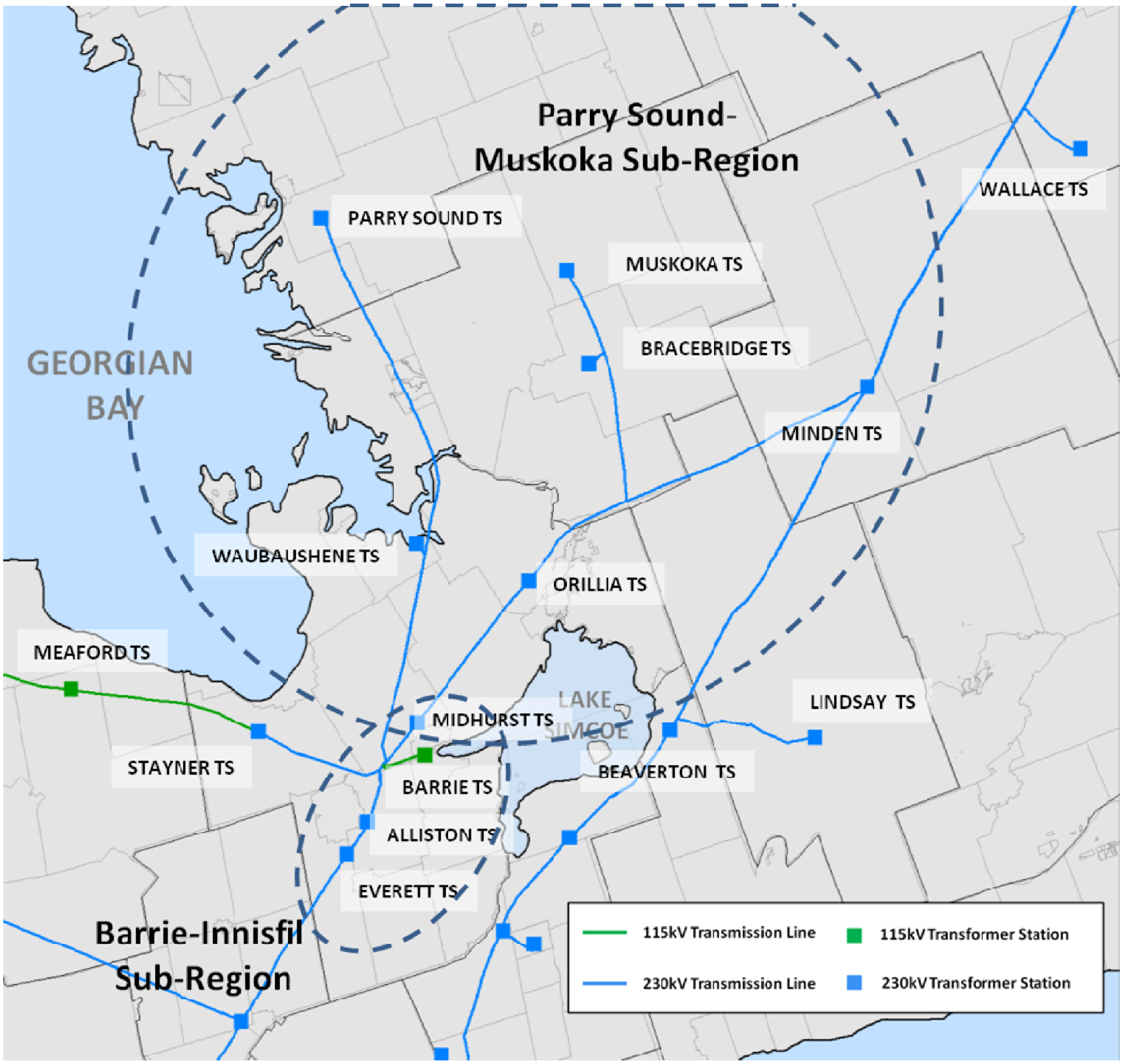
Customers in this sub-region are supplied by PowerStream, InnPower and Hydro One Distribution.

The needs in this sub-region include addressing growth (expressed in the Needs Assessment as overloaded infrastructure at Barrie TS, the E3B circuit, and the Essa 230/115 kV auto-transformers), and meeting load restoration criteria (E8/9V). In addition, with the Barrie TS transformers nearing their end-of-life, the plan for their replacement needs to be coordinated with the above growth-related needs. Options include maintaining Barrie TS as a 115 kV station (like-for-like replacement) or upgrading it to 230 kV, thereby increasing its capacity. The upstream infrastructure supplying the station—the Essa 230/115 kV auto-transformers and the E3/4B transmission line—will also be impacted by this decision and the associated costs and impacts must be considered.

While it is recognized that, with the need to replace Barrie TS equipment, a wires solution will necessarily be part of the plan for this sub-region, the growth-related needs in the area may be met by a combination of wires and non-wires solutions. In addition, the decisions made in this area will have broad impacts, involving multiple local distribution companies ("LDCs") and provincial ratepayers. Therefore, the Regional Participants propose that this sub-region be studied through the IRRP process.

The Barrie TS infrastructure is currently scheduled for replacement in 2018, however the existing equipment can be managed until 2020 if required. Nonetheless, a decision needs to be made as soon as possible in order to allow enough lead time to plan and bring new equipment into service. Therefore, rather than wait for the outcome of the IRRP (which typically takes 18 months), the Terms of Reference for the Barrie/Innisfil IRRP specifies that a decision on the wires component of the integrated solution will be made early in the IRRP process. At that time, wires planning would be initiated through a hand-off letter to the Transmitter.

Figure 2. South Georgian Bay/Muskoka Sub-Regions



NOTE: Region and sub-regions are defined by electricity infrastructure; geographical boundaries are approximate.

Parry Sound/Muskoka Sub-Region

This sub-region is winter-peaking, and is characterized by relatively slow growth. It includes the following infrastructure:

- Stations—Parry Sound TS, Waubaushene TS, Orillia TS, Bracebridge TS, Muskoka TS, Minden TS
- Transmission circuits—M6/7E, E26/27

Customers in this sub-region are supplied by Hydro One Distribution, Lakeland Power, Midland PUC, Newmarket-Tay Power, Orillia Power, and Veridian Connections.

The needs in this sub-region include:

- Addressing capacity needs at several stations
- Enabling loads to be restored within the timeframes laid out in the ORTAC criteria in the event of a major outage on M6/7E
- Coordinating asset replacement plans at Minden TS with regional needs, as appropriate
- Coordinating solutions to address distribution reliability concerns due to long feeder lengths with regional capacity needs, as appropriate
- Addressing reliability concerns related to a lack of supply redundancy.

With the relatively slow electricity demand growth forecast for this sub-region, the Regional Participants agreed that there may be opportunities for non-wires solutions to defer major capital investment. Therefore, it is proposed that this sub-region be studied through the IRRP process.

Needs to be Addressed through Bulk System Planning

The Essa TS 500/230 kV auto-transformers are bulk system assets that provide the major source of supply to the whole South Georgian Bay/Muskoka Region. Therefore, the Regional Participants agreed that the need associated with these assets be studied by the IESO as part of bulk system planning. Given the importance of this infrastructure to the Region, it was suggested that this planning be conducted in parallel with the IRRPs, and that the IESO involve the Regional Participants in the planning process.

The IESO will also undertake study of the S2S/Stayner auto-transformer issue arising due to increased generation in the Bruce area through the bulk planning process.

Needs to be Addressed through Local Planning

The Regional Participants agreed that the replacement of the Orangeville TS transformer and associated low-voltage equipment does not require regional coordination and can be addressed through local planning involving the transmitter and affected LDC.

4. Conclusion

The Scoping Assessment concludes that:

- An IRRP be undertaken to address the needs in the Barrie/Innisfil sub-region
- An IRRP be undertaken to address the needs in the Parry Sound/Muskoka sub-region
- Additional needs identified in the Needs Assessment will be addressed through other processes as follows:
    - Essa 500/230 kV autotransformers—bulk system planning (IESO), with regular updates

to/ input from the Regional Planning Participants

- S2S/Stayner auto-transformer issue—bulk system planning (IESO)
- Orangeville TS transformer replacement—local planning by transmitter and LDC

The draft Terms of Reference for the Barrie/Innisfil and the Parry Sound/Muskoka IRRPs are attached.

2 Barrie/Innisfil IRRP Terms of Reference

1. Introduction and Background

These Terms of Reference establish the objectives, scope, key assumptions, roles and responsibilities, activities, deliverables and timelines for an Integrated Regional Resource Plan ("IRRP") of the Barrie/Innisfil sub-region.

Based on the potential for demand growth within this sub-region, limits on the capability of the transmission capacity supplying the area, and opportunities for coordinating demand and supply options, an integrated regional resource planning approach is recommended.

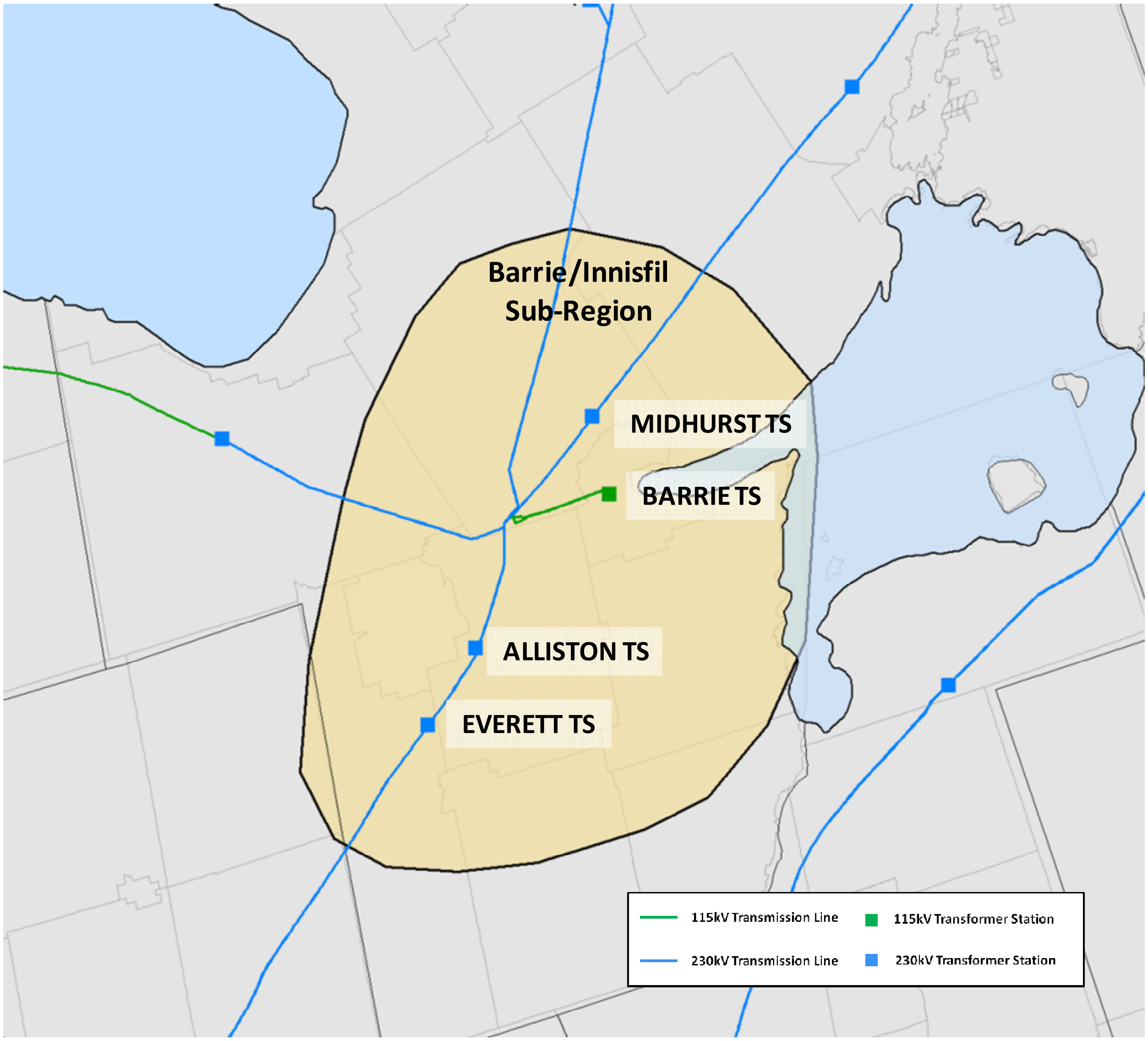
Barrie/Innisfil sub-region

The Barrie/Innisfil sub-region is a summer-peaking region that includes the City of Barrie, the Town of Innisfil, and customers in surrounding municipalities supplied from the Barrie, Midhurst, Everett and Alliston transformer stations (TS). The approximate geographical boundaries of the sub-region are shown in Figure 3.

The sub-region includes all or part of the following municipalities:

- City of Barrie
- Town of Innisfil
- Township of Essa
- Township of Springwater
- Township of Clearview
- Township of Mulmur
- Township of Adjala-Tosorontio
- Town of New Tecumseth
- Town of Bradford West Gwillimbury

Figure 3. Barrie/Innisfil Sub-Region



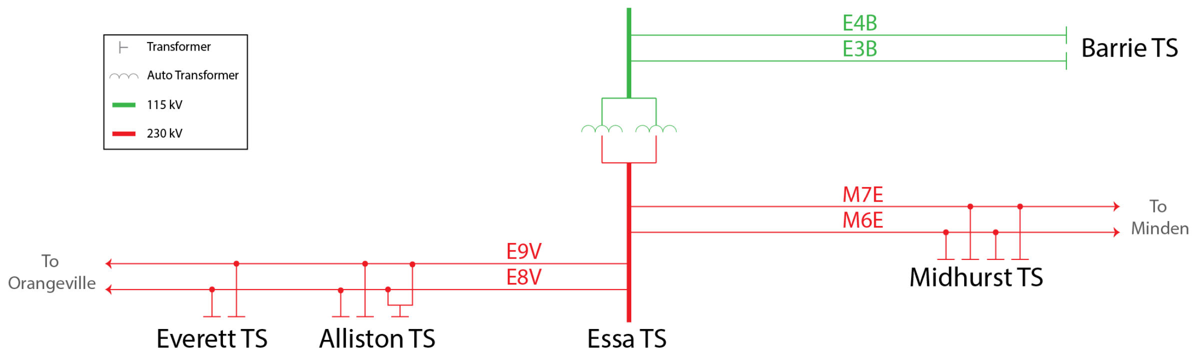
Source: IESO

NOTE: The sub-region is defined by electricity infrastructure; geographical boundaries are approximate.

Barrie/Innisfil Electricity System

The electricity system supplying the Barrie/Innisfil sub-region is shown in Figure 4.

Figure 4. Barrie/Innisfil Electricity System



Source: IESO

<u>Background</u>

Two planning studies have been conducted in the South Simcoe area in the last 12 years.

In November of 2003, a joint utility planning study was initiated between six LDCs in Simcoe County, one large industrial customer and Hydro One Transmission to assess the supply and reliability needs of Simcoe County. The study recommended the implementation of two transmission projects to supply forecast growth in the Meaford/Collingwood and South Simcoe areas: the addition of Everett TS, which came into service in 2007 and the Southern Georgian Bay Transmission Reinforcement, which involved upgrading the Essa-to-Stayner line to 230 kV and installing a 230/115 kV auto-transformer at Stayner TS, came into service in 2009.

In 2010, Hydro One Transmission initiated a regional supply planning study of the South Simcoe area. Together with the Ontario Power Authority (now the Independent Electricity System Operator), PowerStream, Innisfil Power, and Hydro One Distribution, a study report was prepared in 2011 that recommended the installation of low voltage capacitors at Midhurst TS, which was completed in 2012 and for Innisfil Hydro to make a formal request to Hydro One for additional transformation capacity.

2. Objectives

1. To assess the adequacy of electricity supply to customers in the Barrie/Innisfil sub-region over the next 20 years.
2. To coordinate customer-driven electricity needs with major asset renewal needs, and develop a flexible, comprehensive, integrated electricity plan for the Barrie/Innisfil sub-region.
3. To develop an implementation plan, while maintaining flexibility in order to accommodate changes in key assumptions over time.

3. Scope

This IRRP will develop and recommend an integrated plan to meet the needs of the Barrie/Innisfil sub-region. The plan is a joint initiative involving PowerStream, InnPower, Hydro One Distribution, Hydro

One Transmission, and the IESO, and will incorporate input from community engagement. The plan will integrate forecast electricity demand growth, conservation and demand management ("CDM") in the area with transmission and distribution system capability, end-of-life of major facilities in the area, relevant community plans, other bulk system developments, and Feed-in Tariff ("FIT") and other generation uptake through province-wide programs, and will develop an integrated plan to address needs.

This IRRP will address regional needs in the Barrie/Innisfil area. Specifically, the following existing infrastructure is included in the scope of this study:

- 230/115 kV auto-transformers at Essa TS
- Stations—Midhurst TS, Barrie TS, Everett TS, Alliston TS
- Transmission circuits—E8/9V, E3/4B, M6/7E (Essa-Midhurst section)

The adequacy of the bulk system supplying the area (i.e., the 500/230 kV auto-transformers at Essa TS) is being assessed by the IESO in parallel with this study through a separate bulk system planning process. Results of that study will be shared with the Working Group as they become available.

The Barrie/Innisfil IRRP will:

- Prepare a 20-year electricity demand forecast and establish needs over this timeframe.
- Examine the Load Meeting Capability and reliability of the existing transmission system supplying the Barrie/Innisfil sub-region, taking into account facility ratings and performance of transmission elements, transformers, local generation, and other facilities such as reactive power devices.
- Establish feasible integrated alternatives to address remaining needs, including a mix of CDM, generation, transmission and distribution facilities, and other electricity system initiatives in order to address the needs of the Barrie/Innisfil sub-region.
- Assess end-of-life needs in the context of longer-term capacity needs and impacts on other connection and network facilities in the area, and hand off the wires component of the integrated solution early in the IRRP process in order to allow enough lead time to address the end-of-life of the Barrie TS transformers
- Evaluate options using decision-making criteria including but not limited to: technical feasibility, economics, reliability performance, environmental and social factors.

4. Data and Assumptions

The plan will consider the following data and assumptions:

- Demand Data
    - Historical coincident peak demand information for the sub-region
    - Historical weather correction, median and extreme conditions
    - Gross peak demand forecast scenarios by sub-region, TS, etc.
    - Coincident peak demand data including transmission-connected customers
    - Identified potential future load customers

- Conservation and Demand Management
    - LDC CDM plans
    - Incorporation of verified LDC results and progression towards OEB targets, and any other CDM programs/opportunities in the area
    - Long-term conservation forecast for LDC customers, based on sub-region's share of the 2013 Long-Term Energy Plan target
    - Conservation potential studies, if available
    - Potential for CDM at transmission-connected customers' facilities

- Local resources
    - Existing local generation, including distributed generation ("DG"), district energy, customer-based generation, Non-Utility Generators and hydroelectric facilities as applicable
    - Existing or committed renewable generation from Feed-in-Tariff ("FIT") and non-FIT procurements
    - Future district energy plans, combined heat and power, energy storage, or other generation proposals

- Relevant local plans, as applicable
    - LDC Distribution System Plans
    - Community Energy Plans and Municipal Energy Plans
    - Municipal Growth Plans

- Criteria, codes and other requirements
    - Ontario Resource and Transmission Assessment Criteria ("ORTAC")
        - Supply capability
        - Load security
        - Load restoration requirements
    - NERC and NPCC reliability criteria, as applicable
    - OEB Transmission System Code
    - OEB Distribution System Code
    - Reliability considerations, such as the frequency and duration of interruptions to customers
    - Other applicable requirements

- Existing system capability
    - Transmission line ratings as per transmitter records
    - System capability as per current IESO PSS/E base cases
    - Transformer station ratings (10-day LTR) as per asset owner
    - Load transfer capability
    - Technical and operating characteristics of local generation

- Bulk System considerations to be applied to the existing area network
    - Essa 500/230 kV auto-transformer capability
    - North-South Tie flow assumptions

- End-of-life asset considerations/sustainment plans
    - Transmission assets, in particular Barrie TS transformers
    - Distribution assets

- Other considerations, as applicable

5. Working Group

The core Working Group will consist of planning representative/s from the following organizations:

- Independent Electricity System Operator *(Team Lead for IRRP)*
- Hydro One Transmission
- PowerStream
- InnPower
- Hydro One Distribution

Authority and Funding

Each entity involved in the study will be responsible for complying with regulatory requirements as applicable to the actions/tasks assigned to that entity under the implementation plan resulting from this IRRP. For the duration of the study process, each participant is responsible for their own funding.

5. Engagement

Integrating early and sustained engagement with communities and stakeholders in the planning process was recommended to and adopted by the provincial government to enhance the regional planning and siting processes in 2013. These recommendations were subsequently referenced in the 2013 Long Term Energy Plan. As such, the Working Group is committed to conducting plan-level engagement throughout the development of the Barrie/Innisfil IRRP.

The first step in engagement will consist of meetings with municipalities and First Nation communities within the planning area, First Nation communities who may have an interest in the planning area and the Métis Nation of Ontario to discuss regional planning, the development of the Barrie/Innisfil plan, and integrated solutions.

This will be followed by the establishment of a Local Advisory Committee for local community members to provide input and recommendations throughout the planning process, including information on local priorities and ideas on the design of community engagement strategies. Broad community engagement will be conducted to obtain public input in the development of the plan.

6. Activities, Timeline and Primary Accountability

	Activity	Lead Responsibility	Deliverable(s)	Timeframe
1	**Prepare Terms of Reference considering stakeholder input**	*IESO*	- Finalized Terms of Reference	Q2 2015
2	**Develop the Planning Forecast for the sub-**		- Long-term planning	Q3 2015

	region		forecast scenarios	
	- Establish historical coincident peak demand information	*IESO*		
	- Establish historical weather correction, median and extreme conditions	*IESO*		
	- Establish gross peak demand forecast	*LDCs*		
	- Establish existing, committed and potential DG	*LDCs*		
	- Establish near- and long-term conservation forecasts based on LDC CDM plans and LTEP CDM targets	*IESO*		
	- Develop planning forecast scenarios - including the impacts of CDM, DG and extreme weather conditions	*IESO*		
3	**Provide information on load transfer capabilities under normal and emergency conditions**	*LDCs*	- Load transfer capabilities under normal and emergency conditions	Q3 2015
4	**Provide and review relevant community plans, if applicable**	*LDCs and IESO*	- Relevant community plans	Q3 2015
5	**Complete system studies to identify needs over a twenty-year period** - Obtain PSS/E base case Include bulk system assumptions as identified in Key Assumptions - Apply reliability criteria as defined in ORTAC to demand forecast scenarios - Confirm and refine the need(s) and timing/load levels	*IESO, Hydro One Transmission*	- Summary of needs based on demand forecast scenarios for the 20-year planning horizon	Q3-Q4 2015
6	**Develop Options and Alternatives**		- Develop flexible planning options for forecast scenarios	Q3-Q4 2015
	Develop conservation options	*IESO and LDCs*		
	Develop local generation options	*IESO and LDCs*		
	Develop transmission (see Action 7 below) and distribution options	*Hydro One Transmission, and LDCs*		
	Develop options involving other electricity initiatives (e.g., smart grid, storage)	*IESO/ LDCs with support as needed*		
	Develop portfolios of integrated alternatives	*All*		
	Technical comparison and evaluation	*All*		
7	**Early Wires Planning**		- Cost, feasibility and reliability performance of potential wires options - Detailed option development	Q3-Q4 2015
	Identify potential wires options to address Barrie TS end-of-life and local capacity needs	*Hydro One Transmission*		
	Provide information on cost, feasibility and reliability performance of identified wires options for the purpose of developing integrated solutions			

	Conduct detailed studies of wires options to ensure in-service date for Barrie TS transformer replacement can be met			
8	**Plan and Undertake Community & Stakeholder Engagement**		- Community and Stakeholder Engagement Plan - Input from local communities	
	- Establish engagement subcommittee of the Working Group (if required)	*All*		Q3 2015
	- Early engagement with local municipalities and First Nation communities within study area, First Nation communities who may have an interest in the study area, and the Métis Nation of Ontario	*All*		Q3-Q4 2015
	- Establish Local Advisory Committee and develop broader community engagement plan with LAC input	*All*		Q3-Q4 2015
	- Develop communications materials	*All*		Q1-Q2 2016
	- Undertake community and stakeholder engagement	*All*		
	- Summarize input and incorporate feedback	*All*		
9	**Hand off Wires Component of Integrated Solution**	*IESO*	- Hand-off letter to Hydro One	Q4 2015
10	**Develop long-term recommendations and implementation plan based on community and stakeholder input**	*IESO*	- Implementation plan - Monitoring activities and identification of decision triggers - Hand-off letters - Procedures for annual review	Q3 2016
11	**Prepare the IRRP report detailing the recommended near, medium and long-term plan for approval by all parties**	*IESO*	- IRRP report	Q4 2016

3 Parry Sound/Muskoka IRRP Terms of Reference

1. Introduction and Background

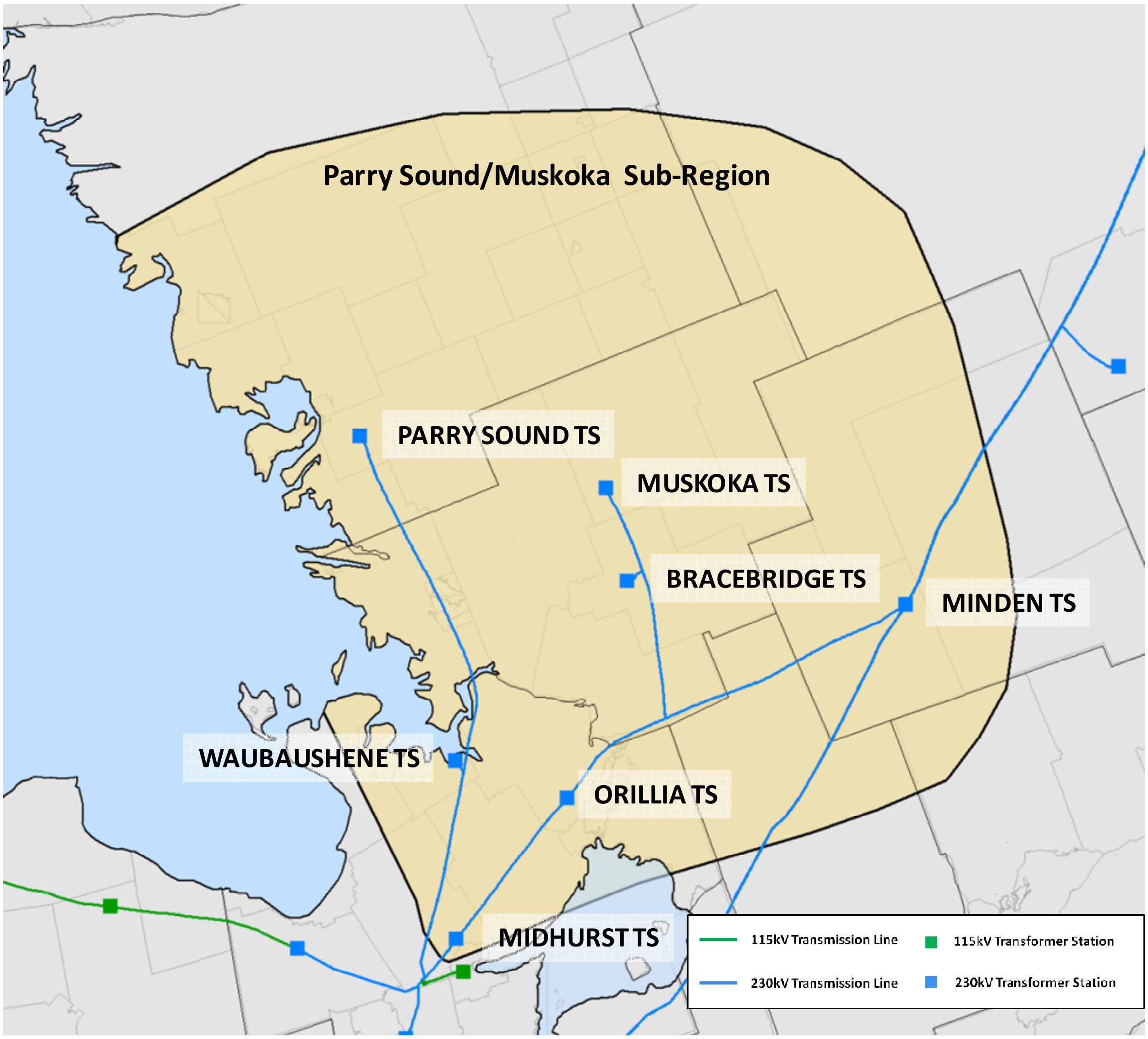
These Terms of Reference establish the objectives, scope, key assumptions, roles and responsibilities, activities, deliverables and timelines for an Integrated Regional Resource Plan ("IRRP") of the Parry Sound/Muskoka sub-region.

Based on the potential for demand growth within this sub-region, limits on the capability of the transmission capacity supplying the area, and opportunities for coordinating demand and supply options, an integrated regional resource planning approach is recommended.

Parry Sound/Muskoka sub-region

The Parry Sound/Muskoka sub-region is a winter-peaking region and it roughly encompasses the Districts of Muskoka and Parry Sound. The approximate geographical boundaries of the sub-region are shown in Figure 5.

Figure 5. Parry Sound/Muskoka Sub-Region



Source: IESO

NOTES: (1) The sub-region is defined by electricity infrastructure; geographical boundaries are approximate. (2) Midhurst TS is included in the scope of the Parry Sound/Muskoka IRRP for the purpose of evaluating restoration needs on the Essa-to-Minden transmission line (M6/7E). Supply and transformer station capacity at Midhurst TS are being addressed through the Barrie/Innisfil IRRP, are thus is not in scope for the Parry Sound/Muskoka IRRP.

The sub-region includes all or part of the following municipalities:

- City of Orillia
- Municipality of Highlands East
- Municipality of Magnetawan

- Municipality of McDougall
- Municipality of Whitestone
- Town of Bracebridge
- Town of Gravenhurst
- Town of Huntsville
- Town of Kearney
- Town of Midland
- Town of Parry Sound
- Town of Penetanguishene
- Township of Algonquin Highlands
- Township of Armour
- Township of Carling
- Township of Georgian Bay
- Township of Joly
- Township of Lake of Bays
- Township of McKellar
- Township of McMurrich-Monteith
- Township of Minden Hills
- Township of Muskoka Lakes
- Township of Oro-Medonte
- Township of Perry
- Township of Ramara
- Township of Ryerson
- Township of Seguin
- Township of Severn
- Township of Strong
- Township of Tay
- Township of the Archipelago
- Township of Tiny
- United Townships of Dysart, Dudley, Harcourt, Guilford, Harburn, Bruton, Havelock, Eyre and Clyde
- Village of Burk's Falls
- Village of Sundridge

The Parry Sound/Muskoka sub-region also includes the following First Nations:

- Henvey Inlet
- Magnetawan
- Shawanaga
- Wasauksing

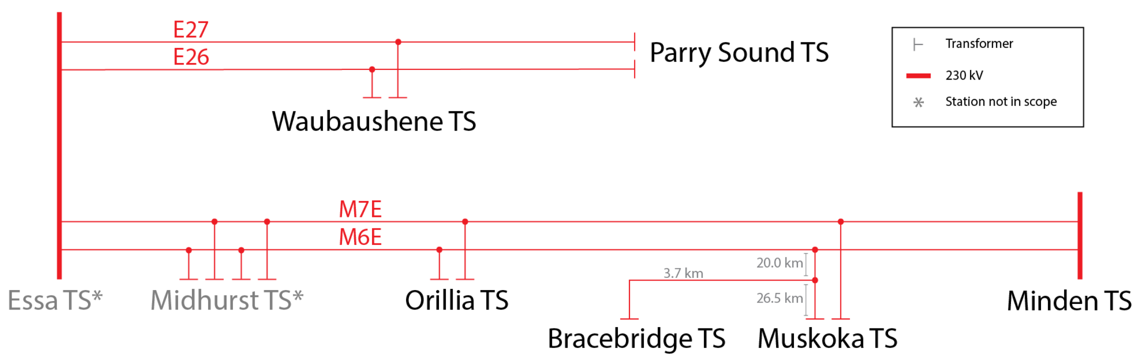
- Moose Deer Point
- Beausoleil
- Wahta Mohawks
- Chippewas of Rama

Engagement on this regional plan may be extended to include additional communities outside of the IRRP area boundaries.

Parry Sound/Muskoka Electricity System

The electricity system supplying the Parry Sound/Muskoka sub-region is shown in Figure 6.

Figure 6. Parry Sound/Muskoka Electricity System



Source: IESO

2. Objectives

1. To assess the adequacy of electricity supply to customers in the Parry Sound/Muskoka sub-region over the next 20 years.
2. To develop a flexible, comprehensive, integrated electricity plan for the Parry Sound/Muskoka sub-region.
3. To develop an implementation plan, while maintaining flexibility in order to accommodate changes in key assumptions over time.

3. Scope

This IRRP will develop and recommend an integrated plan to meet the needs of the Parry Sound/Muskoka sub-region. The plan is a joint initiative involving Lakeland Power, Midland PUC, Newmarket-Tay Power, Orillia Power, PowerStream, Veridian Connections, Hydro One Distribution, Hydro One Transmission, and the IESO, and will incorporate input from community engagement. The plan will integrate forecast electricity demand growth, conservation and demand management ("CDM") in the area with transmission and distribution system capability, end-of-life of major facilities in the area, relevant community plans, other bulk system developments, and Feed-in Tariff ("FIT") and other generation uptake through province-wide programs, and will develop an integrated plan to address needs.

This IRRP will address regional needs in the Parry Sound/Muskoka area. Specifically, the following existing infrastructure is included in the scope of this study:

- Stations—Parry Sound TS, Waubaushene TS, Orillia TS, Bracebridge TS, Muskoka TS, Minden TS
- Transmission circuits—M6/7E, E26/27

The adequacy of the bulk system supplying the area (i.e., the 500/230 kV auto-transformers at Essa TS) is being assessed by the IESO in parallel with this study through a separate bulk system planning process. Results of that study will be shared with the Working Group as they become available.

The Parry Sound/Muskoka IRRP will:

- Prepare a 20-year electricity demand forecast and establish needs over this timeframe
- Examine the Load Meeting Capability and reliability of the existing transmission system supplying the Parry Sound/Muskoka sub-region, taking into account facility ratings and performance of transmission elements, transformers, local generation, and other facilities such as reactive power devices
- Establish feasible integrated alternatives including a mix of CDM, generation, transmission and distribution facilities, and other electricity system initiatives in order to address the needs of the Parry Sound/Muskoka sub-region
- Evaluate options using decision-making criteria including but not limited to: technical feasibility, economics, reliability performance, environmental and social factors

4. Data and Assumptions

The plan will consider the following data and assumptions:

- Demand Data
    - Historical coincident peak demand information for the sub-region
    - Historical weather correction, median and extreme conditions
    - Gross peak demand forecast scenarios by sub-region, TS, etc.
    - Coincident peak demand data including transmission-connected customers
    - Identified potential future load customers

- Conservation and Demand Management
    - LDC CDM plans
    - Incorporation of verified LDC results and progression towards OEB targets, and any other CDM programs/opportunities in the area
    - Long-term conservation forecast for LDC customers, based on sub-region’s share of the 2013 Long-Term Energy Plan target
    - Conservation potential studies, if available
    - Potential for CDM at transmission-connected customers’ facilities

- Local resources
  - Existing local generation, including distributed generation ("DG"), district energy, customer-based generation, Non-Utility Generators and hydroelectric facilities as applicable
  - Existing or committed renewable generation from Feed-in-Tariff ("FIT") and non-FIT procurements
  - Future district energy plans, combined heat and power, energy storage, or other generation proposals

- Relevant local plans, as applicable
  - LDC Distribution System Plans
  - Community Energy Plans and Municipal Energy Plans
  - Municipal Growth Plans

- Criteria, codes and other requirements
  - Ontario Resource and Transmission Assessment Criteria ("ORTAC")
    - Supply capability
    - Load security
    - Load restoration requirements
  - NERC and NPCC reliability criteria, as applicable
  - OEB Transmission System Code
  - OEB Distribution System Code
  - Reliability considerations, such as the frequency and duration of interruptions to customers
  - Other applicable requirements

- Existing system capability
  - Transmission line ratings as per transmitter records
  - System capability as per current IESO PSS/E base cases
  - Transformer station ratings (10-day LTR) as per asset owner
  - Load transfer capability
  - Technical and operating characteristics of local generation

- Bulk System considerations to be applied to the existing area network
  - Essa 500/230 kV auto-transformer capability
  - North-South Tie flow assumptions

- End-of-life asset considerations/sustainment plans
  - Transmission assets
  - Distribution assets

- Other considerations, as applicable

5. Working Group

The core Working Group will consist of planning representative/s from the following organizations:

- Independent Electricity System Operator *(Team Lead for IRRP)*
- Hydro One Transmission
- Hydro One Distribution
- Lakeland Power
- Midland PUC
- Newmarket-Tay Power
- Orillia Power
- PowerStream
- Veridian Connections

Authority and Funding

Each entity involved in the study will be responsible for complying with regulatory requirements as applicable to the actions/tasks assigned to that entity under the implementation plan resulting from this IRRP. For the duration of the study process, each participant is responsible for their own funding.

5. Engagement

Integrating early and sustained engagement with communities and stakeholders in the planning process was recommended to and adopted by the provincial government to enhance the regional planning and siting processes in 2013. These recommendations were subsequently referenced in the 2013 Long Term Energy Plan. As such, the Working Group is committed to conducting plan-level engagement throughout the development of the Parry Sound/Muskoka IRRP.

The first step in engagement will consist of meetings with municipalities and First Nation communities within the planning area, First Nation communities who may have an interest in the planning area and the Métis Nation of Ontario to discuss regional planning, the development of the Parry Sound/Muskoka plan, and integrated solutions.

This will be followed by the establishment of a Local Advisory Committee for local community members to provide input and recommendations throughout the planning process, including information on local priorities and ideas on the design of community engagement strategies. Broad community engagement will be conducted to obtain public input in the development of the plan.

6. Activities, Timeline and Primary Accountability

	Activity	Lead Responsibility	Deliverable(s)	Timeframe
1	**Prepare Terms of Reference considering stakeholder input**	*IESO*	- Finalized Terms of Reference	Q2 2015
2	**Develop the Planning Forecast for the sub-region**		- Long-term planning forecast scenarios	Q3 2015
	- Establish historical coincident peak demand information	*IESO*		
	- Establish historical weather correction, median and extreme conditions	*IESO*		

	- Establish gross peak demand forecast for LDC service areas	*LDCs*		
	- Establish existing, committed and potential DG	*LDCs*		
	- Establish near- and long-term conservation forecast based on LDC CDM plans and LTEP target	*IESO*		
	- Develop planning forecast scenarios - including the impacts of CDM, DG and extreme weather conditions	*IESO*		
3	**Provide information on load transfer capabilities under normal and emergency conditions**	*LDCs*	- Load transfer capabilities under normal and emergency conditions	Q3 2015
4	**Provide and review relevant community plans, if applicable**	*LDCs, First Nations and IESO*	- Relevant community plans	Q3 2015
5	**Complete system studies to identify needs** - Obtain PSS/E base case - Include bulk system assumptions as identified in Key Assumptions - Apply reliability criteria as defined in ORTAC to demand forecast scenarios - Confirm and refine the need(s) and timing/load levels	*IESO, Hydro One Transmission*	- Summary of needs based on demand forecast scenarios for the 20-year planning horizon	Q4 2015
6	**Develop Options and Alternatives**		- Develop flexible planning options for forecast scenarios	Q1 2016
	- Identify solutions requiring immediate implementation and prepare hand-off letters to responsible parties (if applicable)	*IESO*		
	- Develop conservation options	*IESO and LDCs*		
	- Develop local generation options	*IESO and LDCs*		
	- Develop transmission and/or distribution options including maximizing existing infrastructure capability	*IESO, Hydro One Transmission and LDCs*		
	- Develop options involving other electricity initiatives (e.g., smart grid, storage)	*IESO/ LDCs with support as needed*		
	- Develop portfolios of integrated alternatives	*All*		
	- Technical comparison and evaluation	*All*		
7	**Plan and Undertake Community & Stakeholder Engagement**		- Community and Stakeholder Engagement Plan - Input from local communities, First Nation communities, and Métis Nation of Ontario	
	- Establish engagement subcommittee of the Working Group (if required)	*All*		Q3 2015
	- Early engagement with local municipalities and First Nation communities within study area, First Nation communities who may have an interest in the study area, and the	*All*		Q3-Q4 2015

	Métis Nation of Ontario			
	- Establish Local Advisory Committee and First Nations Local Advisory Committee and develop broader community engagement plan with LAC input	*All*		Q4 2015
	- Develop communications materials	*All*		Q1-Q2 2016
	- Undertake community and stakeholder engagement	*All*		
	- Summarize input and incorporate feedback	*All*		
8	**Develop long-term recommendations and implementation plan based on community and stakeholder input**	*IESO*	- Implementation plan - Monitoring activities and identification of decision triggers - Hand-off letters - Procedures for annual review	Q3 2016
9	**Prepare the IRRP report detailing the recommended near, medium and long-term plan for approval by all parties**	*IESO*	- IRRP report	Q4 2016

4 List of Acronyms

CDM	Conservation and Demand Management
DG	Distributed Generation
FIT	Feed-in-Tariff
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	kilovolt
LAC	Local Advisory Committee
LDC	Local Distribution Company
MW	Megawatt
NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council
OEB	Ontario Energy Board
ORTAC	Ontario Resource and Transmission Assessment Criteria
RIP	Regional Infrastructure Plan
RPP	Regional Planning Process
TS	Transformer Station

BARRIE / INNISFIL SUB-REGION
INTEGRATED REGIONAL RESOURCE PLAN

Part of the South Georgian Bay/Muskoka Planning Region | December 16, 2016

ieso
Connecting Today. Powering Tomorrow.

Integrated Regional Resource Plan

Barrie/Innisfil Sub-region

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

The IESO prepared the IRRP on behalf of the Barrie/Innisfil Sub-region Working Group (the "Working Group"), which included the following members:

- Independent Electricity System Operator
- PowerStream Inc.
- InnPower Corporation
- Hydro One Networks Inc. (Distribution)
- Hydro One Networks Inc. (Transmission)

The Working Group assessed the adequacy of electricity supply to customers in the Barrie/Innisfil 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 Barrie/Innisfil Sub-region; and developed an implementation plan for the recommended options, while maintaining flexibility in order to accommodate changes in key conditions over time.

The Working Group members agree with the IRRP's recommendations and support implementation of the plan through the recommended actions, subject to obtaining all necessary regulatory and other approvals.

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List of Abbreviations

Abbreviations	Descriptions
CDM or Conservation	Conservation and Demand Management
CFF	Conservation First Framework
CT	Current Transformer
DG	Distributed Generation
DR	Demand Response
EA	Environmental Assessment
FIT	Feed-in Tariff
Hydro One	Hydro One Networks Inc.
IESO	Independent Electricity System Operator
IAP	Industrial Accelerator Program
Innisfil Hydro	Innisfil Hydro Distribution Inc.
InnPower	InnPower Corporation
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
LAC	Local Advisory Committee
LAP	Local Achievable Potential
LDC	Local Distribution Company
LMC	Load Meeting Capability
LTEP	(2013) Long-Term Energy Plan
LTR	Limited Time Rating
MS	Municipal Substation
MVA	Mega Volt Amp
MW	Megawatt
OEB or Board	Ontario Energy Board
OPA	Ontario Power Authority
ORTAC	Ontario Resource and Transmission Assessment Criteria
PowerStream	PowerStream Inc.

Abbreviations	Descriptions
PPWG	Planning Process Working Group
PPWG Report	Planning Process Working Group Report to the Board
RIP	Regional Infrastructure Plan
ROW	Right-of-Way
TOU	Time-of-Use
TPS	Traction Power Station
TS	Transformer Station
TWh	Terawatt-Hours
Working Group	Technical Working Group for Barrie/Innisfil Sub-region IRRP

1. Introduction

This Integrated Regional Resource Plan ("IRRP") addresses the electricity needs for the Barrie/Innisfil Sub-region over the next 20 years. This report was prepared by the Independent Electricity System Operator ("IESO") on behalf of the technical Working Group composed of the IESO, PowerStream Inc. ("PowerStream"), InnPower Corporation ("InnPower"), Hydro One Distribution and Hydro One Transmission.[1]

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's regional planning process, transmitters, distributers and the IESO are required to carry out regional planning activities for 21 electricity planning regions at least once every five years. The Barrie/Innisfil Sub-region is within the South Georgian Bay/Muskoka planning region, one of the OEB's 21 identified areas (Figure 1-1).

Figure 1-1: Map of the South Georgian Bay/Muskoka Region

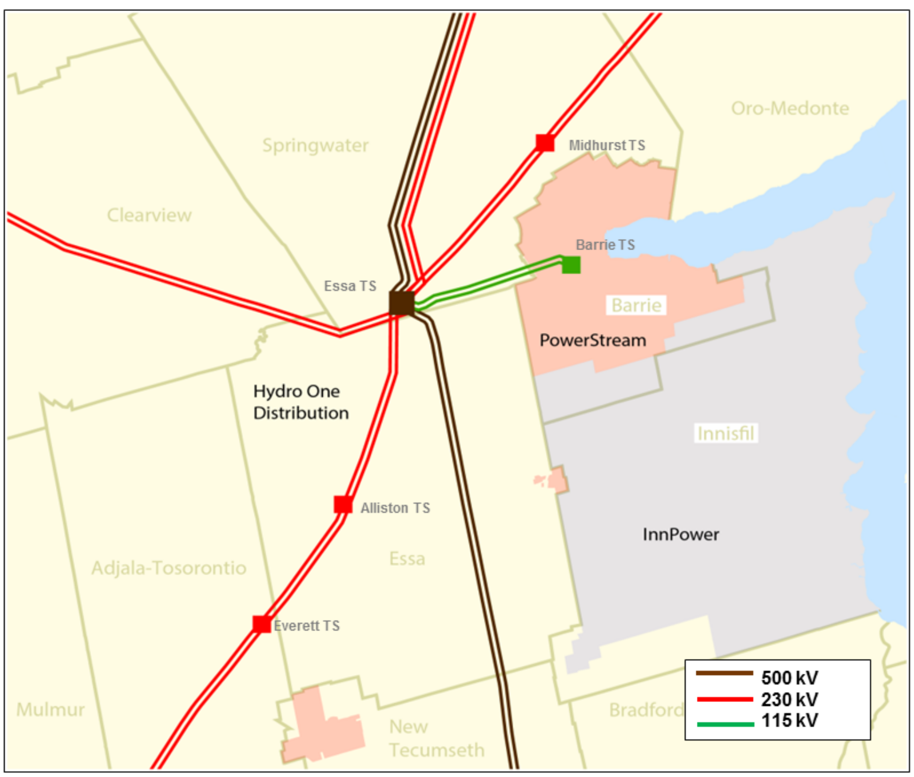
[1] For the purpose of this report, "Hydro One Transmission" and "Hydro One Distribution" are used to differentiate the transmission and distribution accountabilities of Hydro One Networks Inc. ("Hydro One"), respectively.

The Barrie/Innisfil Sub-region roughly encompasses the following municipalities:

- City of Barrie
- Town of Innisfil
- Township of Essa
- Township of Springwater
- Township of Clearview
- Township of Mulmur
- Township of Adjala-Tosorontio
- Town of New Tecumseth
- Town of Bradford West Gwillimbury

The study is focused on addressing the forecast load growth in south Barrie and the Town of Innisfil; however, it considers other needs throughout the sub-region. The study area is shown in Figure 1-2, along with the service area of each local distribution company ("LDC") in the sub-region.

Figure 1-2: Map of Barrie/Innisfil Sub-region



This IRRP identifies power system capacity and reliability requirements, and coordinates the options to meet customer needs in the sub-region over the next 20 years. Specifically, this IRRP identifies immediate investments that are required to meet near- and medium-term needs in the sub-region, respecting the lead time for development.

This IRRP also identifies options to meet long-term needs, but given forecast uncertainty, the longer development lead time and the potential for technological change, the plan maintains flexibility for long-term options and does not recommend specific investments or projects at this time. Instead, the long-term plan identifies near-term actions to consider alternatives, engage with the community, and gather information to lay the groundwork for determining options for future analysis. 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 decisions should any be needed at that time.

This report is organized as follows:

- A summary of the recommended plan for the Barrie/Innisfil Sub-region 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 the Barrie/Innisfil Sub-region and the study scope are discussed in Section 4;
- Demand forecast scenarios, and conservation and distributed generation ("DG") assumptions, are described in Section 5;
- Electricity needs in the Barrie/Innisfil Sub-region are presented in Section 6;
- Alternatives and recommendations for meeting needs are addressed in Sections 7 and 8;
- A summary of engagement to date and moving forward is provided in Section 9; and
- A conclusion is provided in Section 10.

2. The Integrated Regional Resource Plan

The Barrie/Innisfil Sub-region IRRP provides recommendations to address the sub-region's forecast electricity needs over the next 20 years, based on the application of the IESO's Ontario Resource and Transmission Assessment Criteria ("ORTAC"). This IRRP identifies forecast electricity needs in the sub-region over the near term (up to five years, or 2015 through 2019), medium term (six to 10 years, or 2020 through 2024) and longer term (11-20 years, or 2025 through 2034). These planning horizons are distinguished in the IRRP to reflect the different levels of forecast certainty, lead time for development, and planning commitment required over these time horizons. The IRRP was developed based on consideration of planning criteria, including reliability, cost, feasibility and flexibility; and, in the near term, it seeks to maximize the use of existing electricity system assets.

This IRRP identifies and recommends specific projects for implementation in the near term. This is necessary to ensure that they are in-service in time to address the area's more urgent needs, respecting the lead-time for development of the recommended projects or actions. This IRRP also identifies possible long-term electricity needs. However, as these needs are forecast to arise in the future, it is not necessary, nor would it be prudent given forecast uncertainty and the potential for technological change, to recommend specific projects at this time. Instead, near-term actions are identified 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 further discussion at that time.

The Barrie/Innisfil IRRP includes a near-term project to rebuild Barrie Transformer Station ("TS"). Given the timing of the need, the Working Group issued a hand-off letter in December 2015 to request that Hydro One begin development work on this project.[2] The need and rationale for this near-term project are outlined in Section 6.2.1. The full near-, medium-, and long-term plans are summarized below.

2.1 Near-Term and Medium-Term Plan (2015-2024)

The plan to meet the near- and medium-term needs of electricity customers in the Barrie/Innisfil Sub-region was developed to maximize the use of the existing electricity system in consideration of planning criteria such as reliability, cost, and feasibility, as outlined earlier in

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[2] http://www.ieso.ca/Documents/Regional-Planning/South-Georgian-Bay-Muskoka/Barrie/Innisfil_IESO-letter-to-HydroOne-20151207.pdf

Section 2. The near-term plan was also developed to be consistent with the long-term development of the sub-region's electricity system.

To address the near-term end-of-life and capacity needs at Barrie TS, the aforementioned new transmission project to rebuild Barrie TS is underway. The near- and medium-term plan also includes a load transfer to be completed by PowerStream to relieve Barrie TS, and a feeder relocation and expansion project, to be carried out by InnPower and Hydro One Distribution, to increase InnPower's feeder supply capacity from Barrie TS. The elements of the plan are outlined in further detail below.

Recommended Actions

1. Rebuild and Uprate Barrie TS and E3/4B to 230 kV

To mitigate challenges posed by both Barrie TS and related 115 ("kilovolt") kV supply infrastructure reaching end-of-life, and to address the near-term capacity needs at Barrie TS, Hydro One is developing the "Barrie Area Transmission Reinforcement" project. The project will rebuild the existing Barrie TS and uprate its existing supply from 115 kV to 230 kV, increasing the supply capacity to the area. A Class Environmental Assessment ("EA") process is currently underway. The existing Barrie TS site is well situated for supplying the near- and medium-term forecast load growth in the south Barrie and Innisfil areas. The targeted in-service date for the project is the end of 2020.

2. PowerStream Load Transfer – From Barrie TS to Midhurst TS

PowerStream is planning to transfer up to 27 ("megawatt") MW of load from Barrie TS to Midhurst TS by 2020, assuming full data centre load growth. This will increase the incremental capacity available at Barrie TS and provide additional transfer points between Barrie TS and Midhurst TS. This will address near-term capacity needs and provide additional reliability benefits during emergency situations.

3. Relocate and Expand InnPower Feeder Supply from Barrie TS

Currently, Hydro One Distribution is allocated one feeder from the existing Barrie TS, the 13M3 feeder, which is used solely to supply their embedded LDC InnPower. The capacity of this feeder is forecast to be exceeded in 2020. The rebuilt Barrie TS will include one additional feeder position, which can be used to address this need. Additionally, the existing InnPower supply uses an idle Hydro One Transmission right-of-way ("ROW"). The use of this ROW for sub-transmission purposes limits future long-term options for new transmission facilities in the south Barrie and Innisfil area. It is recommended that Hydro One Distribution and InnPower develop a plan to build new 44 kV feeders to support InnPower's forecast growth and enable the existing 13M3 feeder to be relocated out of the Hydro One Transmission corridor. The proposed in-service date for the new feeders is the end of 2020.

2.2 Longer-Term Plan (2025-2034)

In the long-term, the Barrie/Innisfil Sub-region's electricity system is expected to reach its capacity. This is based on the IRRP planning forecast presented in Section 5.6, which is consistent with municipal growth plans and the province's *Places to Grow Act, 2005*. Beginning in the mid to late 2020s, there is a forecast need for new transformer station capacity, particularly in the south Barrie and Innisfil areas. The capacity of the upgraded Barrie TS and the existing Everett TS are forecast to be exceeded in 2026 and 2027, respectively. Transformer station capacity in the Barrie area is forecast to be exceeded in 2031, and the sub-region's transformer capacity is forecast to be exceeded by the end of the study period in 2034. Additionally, in 2034, there is a need for supply capacity for the broader South Georgian Bay/Muskoka Region based on the ratings of the 230/500 kV autotransformers at Essa TS. Any plans to address the station capacity needs must be coordinated with a plan to address this long-term transmission system needs at Essa TS, as they are interrelated.

A number of alternatives are possible to meet the sub-region's long-term needs. While specific solutions do not need to be committed today, it is appropriate to begin work now to gather information, monitor developments, engage the community, and develop alternatives to support decision making in the next iteration of the IRRP.

This IRRP sets out near-term actions required to ensure that options remain available to address future needs, if and when they arise.

Recommended Actions

1. Implement Conservation and Distributed Generation

The implementation of provincial conservation targets established in the 2013 Long-Term Energy Plan ("LTEP") is a key near-term action of the Barrie/Innisfil Sub-region's long-term plan. In developing the demand forecast, peak demand impacts associated with meeting provincial targets were assumed before identifying the residual needs; this is consistent with the province's Conservation First policy.[3] Meeting provincial conservation targets amounts to approximately 37 MW, or 19%, of the forecast demand growth, during the first 10 years, and a total of 82 MW, or 23% of the total forecast demand growth, by the end of the study period.

To ensure these savings materialize, it is recommended that the LDCs' conservation efforts be focused as much as possible on measures that will contribute to meeting the Conservation First energy targets while also maximizing peak demand reductions. The monitoring of conservation success will lay the foundation for the long-term plan by evaluating the performance of specific conservation measures in the sub-region and assessing potential for additional conservation.

Provincial programs that encourage the development of DG can also contribute to reducing peak demand in the sub-region; these will, in part, depend 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. Barrie TS Local Achievable Potential Study

Due to the long-term capacity need forecast for the south Barrie and Innisfil areas, PowerStream and InnPower, with support from the IESO's conservation fund, will be undertaking a Local Achievable Potential ("LAP") study for the Barrie TS service area. This study aims to determine demand savings potential through conservation and demand management ("CDM" or "conservation") for the Barrie TS area, above and beyond what is attributed to the LTEP targets already accounted for in the planning demand forecast. The study will also help determine options for acquiring this potential (e.g., incentives and adders to existing CDM programs, new programs, behind-the-meter generation, energy storage, etc.). The study will provide a better understanding of the costs and feasibility of conservation and demand management measures to address capacity needs in the area to better inform options for the next planning cycle. The study may also examine options to manage new demand from increased electrification that may result from Ontario's Climate Change Action Plan.

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[3] Conservation First: A Renewed Vision for Energy Conservation in Ontario: http://www.energy.gov.on.ca/en/conservation-first/

3. Undertake Community Engagement

Broad community and public engagement, including discussions with local Indigenous communities, is essential to develop the long-term plan. It is recommended that engagement involve several phases addressing: public education/awareness of electricity issues, planning, technologies, and regulatory requirements; fostering an understanding of community growth and its relationship to electricity needs; understanding the pros and cons of various alternatives to meeting long-term needs; and obtaining input on community preferences for various approaches to meeting longer-term needs.

To obtain input and advice on the engagement plans for the Barrie/Innisfil Sub-region, the Working Group will establish a Local Advisory Committee ("LAC") consisting of community representatives and stakeholders.

4. Increase the Limited Time Rating of Everett TS

The existing ratios of the current transformers[4] ("CT") at Everett TS are causing a limitation beyond the limited time rating[5] ("LTR") of the station transformers. Since the minimum station load has increased sufficiently, Hydro One can update the CT ratios, allowing the full LTR of the existing transformers to be utilized. Everett TS is forecast to exceed its existing de-rated LTR in 2027; the Working Group will monitor the station load and request that Hydro One take action to change the CT ratios if necessary before the next regional planning cycle.

5. Explore Conversion of the 13M3 115 kV Corridor to 230 kV

Metrolinx has applied for connection to the transmission system in the Barrie area. They will connect to the new 230 kV transmission lines created as part of the Barrie Area Transmission Reinforcement project. It is recommended that Hydro One works to ensure the development work for the Metrolinx connection project will allow for future expansion of the transmission system south toward Innisfil. The Working Group will monitor the need for additional development work for the corridor between planning cycles.

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[4] Current transformers are instrument transformers used for measurements for metering/loading data or for generating signals for protective devices. Since the current on the actual system is usually too high to be either economically or practically measured or to supply a signal to a protective device, the current transformer lowers the current to an acceptable level. The ratio between these two current values is the "CT ratio".

[5] The limited time rating is a property of an individual transformer, representing its ability to withstand the thermal stress of short duration use (10 days) at the given capacity, above its standard rating, without experiencing any degradation in asset condition as a result.

6. Develop Community-Based Solutions

There is the potential for emerging technologies and innovative solutions to address the long-term needs in the Barrie/Innisfil Sub-region. These could include combinations of conservation, district heating, local generation, storage, off-grid solutions, and other emerging technologies. However, before such technologies can be relied upon to address regional capacity needs, it is necessary to identify the opportunities available in the Barrie area, test the performance of these technologies, and demonstrate how these technologies can be "bundled" to provide firm capacity resources at the local level. In addition, the cost responsibility and payment mechanisms for these options still need to be assessed.

PowerStream has implemented a pilot project in their southern service territory to study the benefits and economics of aggregated customer-side generation and storage. The results of this study can be used to inform future discussion and the development of non-wires solutions for the long-term needs in the sub-region for the next planning cycle.

7. Monitor Demand Growth, Conservation Achievement and Distributed Generation Uptake

On an annual basis, the IESO, with the Working Group, will review CDM achievement, the uptake of provincial distributed generation projects, and actual demand growth in the Barrie/Innisfil Sub-region. This information will be used to determine when decisions on the long-term plan are required, and to inform the next cycle of regional planning for the area. Information on conservation and DG is also a useful input into the ongoing development of non-wires options as potential long-term solutions.

8. Initiate the Next Regional Planning Cycle Early, if Needed

Along with the indices outlined in point 7 above, the Working Group will monitor changes in growth targets, progress in servicing greenfield lands, transit electrification in the area, results of the LAP study for Barrie TS, and any significant changes in the area's forecast growth. If monitoring activities determine that area growth is on pace with the high forecast scenario, it may be necessary to initiate the next iteration of the regional planning process earlier than 2020 given the lead time for the long-term supply options.

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 former Ontario Power Authority ("OPA") carried out 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 the fall of 2012, the Board convened a 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, and in May 2013, the PPWG released its report to the Board[6] ("PPWG Report"), setting out the new regional planning process. Twenty-one electricity planning regions were identified in the PPWG Report, and a phased schedule for completion was outlined. The Board endorsed the PPWG 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's licence changes required it to lead a number of aspects of regional planning. After the merger of the IESO and the OPA on January 1, 2015, the regional planning roles identified in the OPA's licence were to become the responsibility of the new IESO

The regional planning process begins with a Needs Assessment 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 what type of planning is required for each region. A Scoping Assessment explored whether a

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[6] http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2011-0043/PPWG_Regional_Planning_Report_to_the_Board_App.pdf

comprehensive IRRP is required, which considers conservation, generation, transmission, and distribution solutions, or whether a more limited "wires" solution is the preferable option, in which case a transmission and distribution focused Regional Infrastructure Plan ("RIP") can be undertaken instead. There may also be regions where infrastructure investments do not require regional coordination and so 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 and a preliminary Terms of Reference. If an IRRP is the identified outcome, the IESO is required to complete the IRRP within 18 months. If an RIP is the identified outcome, 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 draft Scoping Assessment Outcome Report is posted to the IESO's website for a two week public comment period prior to finalization.

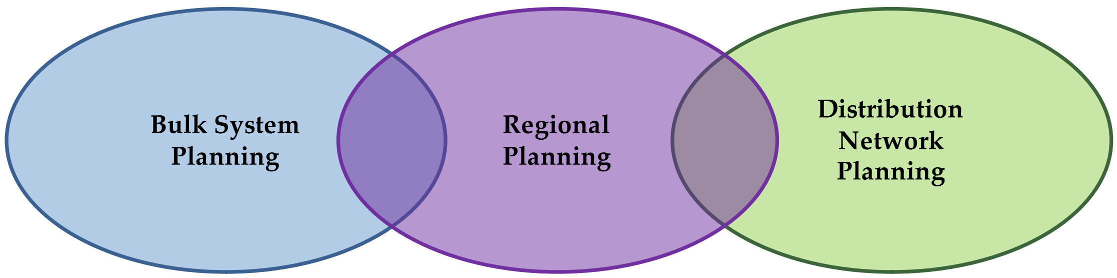
The final IRRPs and RIPs are posted on the IESO's and the relevant transmitter's websites, and may be referenced and submitted to the Board as supporting evidence in rate or "Leave to Construct" applications for specific infrastructure investments. These documents are also useful for municipalities, First Nation communities and Métis community councils for planning, and for conservation and energy management purposes. They are also a useful source of information for individual large customers that may be involved in the region, and for other parties seeking an understanding of local electricity growth, CDM and infrastructure requirements. Regional planning is not the only type of electricity planning that is undertaken in Ontario. As shown in Figure 3-1, there are three levels of planning that are carried out for the electricity system in Ontario:

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

Planning at the bulk system level typically considers the 230 kV and 500 kV network and examines province-wide system issues. Bulk system planning considers not only the major transmission facilities or "wires", but it also assesses the resources needed to adequately supply the province. This type of planning is typically carried out by the IESO pursuant to government policy. Distribution planning, which is carried out by LDCs, considers specific investments in an LDC's territory at distribution level voltages.

Regional planning can overlap with bulk system planning. For example, overlaps can occur at interface points where there may be regional resource options to address a bulk system issue. Similarly, regional planning can overlap with the distribution planning of LDCs. For example, overlaps can occur when a distribution solution addresses the needs of the broader local area or region. Therefore, it is important for regional planning to be coordinated with both bulk and distribution system planning, as it is the link between all levels of planning.

Figure 3-1: Levels of Electricity System Planning



Bulk System Planning

- 500 kV & 230 kV transmission
- Interconnections
- Inter-area network transfer capabilities
- 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- and 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 and security)
- Distribution connected generation and CDM resources
- LDC demand forecasts
- Near- and medium-term focused

By recognizing the linkages with bulk and distribution system planning, and coordinating the multiple needs identified within a region over the long term, the regional planning process provides a comprehensive assessment of a region's electricity needs. Regional planning aligns near- and long-term solutions and puts specific investments and recommendations coming out of the plan into perspective. Furthermore, regional planning optimizes ratepayer interests by avoiding piecemeal planning and asset duplication, and allows Ontario ratepayer interests to be represented along with the interests of LDC ratepayers, and individual large customers. IRRPs evaluate the multiple options that are available to meet the 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.

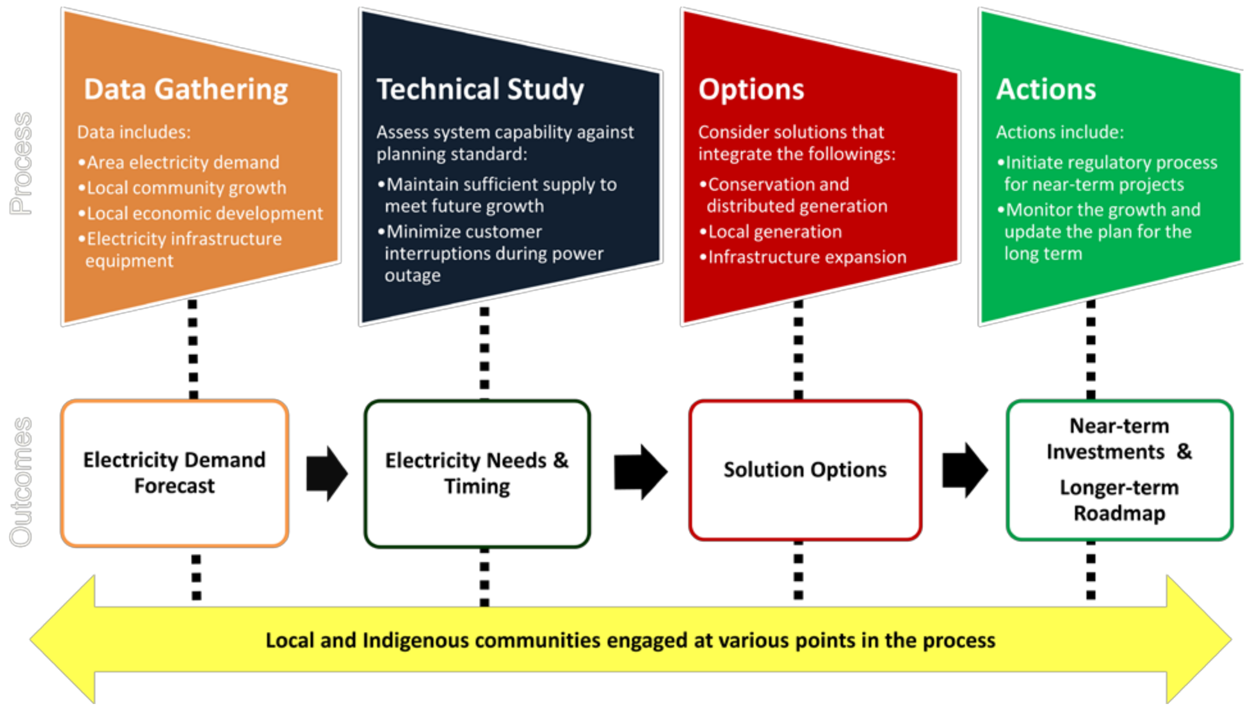
3.2 The IESO's Approach to Regional Planning

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—as compared to 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 implement the specified solutions. 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 the Working Group 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 Indigenous communities who may have an interest in the area. The steps of an IRRP are illustrated in Figure 3-2, below.

Figure 3-2: Steps in the IRRP Process



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 triggers the initiation of the transmitter's RIP process to develop those options. Other recommendations in the IRRP may include: development of conservation, local generation, community engagement, or information gathering to support future iterations of the regional planning process in the region or sub-region.

3.3 Barrie / Innisfil Sub-region Working Group and IRRP Development

The process to develop the Barrie/Innisfil IRRP was initiated in 2015 with the release of the Needs Assessment report for the South Georgian Bay/Muskoka Region. This product was prepared by Hydro One Transmission with participation from the IESO, PowerSteam, Innisfil Hydro Distribution Inc. ("Innisfil Hydro"),[7] Orangeville Hydro Ltd., Veridian Connections Inc. and Hydro One Distribution. The Needs Screening process was carried out to identify needs

[7] Innisfil Hydro Distribution Inc. became InnPower Corporation on November 4, 2014. This was reflected the OEB's amendment to the licensee name on their electricity distribution licence on December 4, 2014 (EB-2014-0297).

that may require coordinated regional planning in the South Georgian Bay/Muskoka Region. The subsequent Scoping Assessment Report produced by the IESO recommended that the needs identified for the Barrie/Innisfil Sub-region should be further pursued through an IRRP owing to the potential for coordinated solutions and significant assets reaching end-of-life.

In 2015 the Working Group was formed to develop Terms of Reference for this IRRP, gather data, identify near- to long-term needs in the sub-region, and recommend the near- and medium-term actions.

4. Background and Study Scope

Two planning studies have been conducted in the South Simcoe area – now referred to as the Barrie/Innisfil Sub-region – in the last 12 years.

First, in November 2003, a joint utility planning study was initiated by six LDCs in Simcoe County, one large industrial customer, and Hydro One Transmission, to assess the supply and reliability needs of Simcoe County. The study recommended the implementation of two transmission projects to supply forecast growth in the Meaford/Collingwood and South Simcoe areas: the addition of Everett TS, which came into service in 2007 and the Southern Georgian Bay Transmission Reinforcement, which involved upgrading the 115 kV Essa-to-Stayner line to 230 kV and installing a 230/115 kV autotransformer at Stayner TS, which came into service in 2009.

Second, in 2010, Hydro One Transmission initiated a regional supply planning study of the South Simcoe area. Together with the OPA (now merged with the IESO), PowerStream, Innisfil Hydro, and Hydro One Distribution, Hydro One Transmission prepared a study report in 2011 that recommended the installation of low voltage capacitors at Midhurst TS and Orillia TS, completed in 2012, and recommended that Innisfil Hydro (now InnPower) make a formal request to Hydro One for additional transformation capacity.

Building on these past regional studies and taking into account updates to activities in the region and LDCs' load forecasts, this report presents an IRRP for the Barrie/Innisfil Sub-region for the 20-year period from 2015 to 2034. To set the context for this IRRP, the scope of the planning study and the sub-region's existing electricity system are described in Section 4.1.

4.1 Study Scope

This IRRP develops and recommends options to meet the supply needs of the Barrie/Innisfil Sub-region in the near, medium, and long term. The plan was prepared by the IESO on behalf of the Working Group. The plan includes consideration of forecast electricity demand growth, CDM, transmission and distribution system capability, relevant community plans, developments on the bulk transmission system, and generation uptake through the Feed-in Tariff ("FIT") and other province-wide programs.

This IRRP addresses regional needs in the Barrie/Innisfil Sub-region, including adequacy, security, and relevant end-of-life asset considerations.

The following transmission facilities were included in the scope of this study:

- 230/115 kV autotransformers at Essa TS
- Stations—Barrie TS, Midhurst TS, Alliston TS, and Everett TS
- Transmission circuits—E8/9V, E3/4B, M6/7E (Essa to Midhurst section)

The Barrie/Innisfil Sub-region is supplied from the two 500/230 kV autotransformers at Essa TS. These transformers form part of the bulk transmission system, as they are impacted by changes in the broader Ontario electricity system, rather than the local system. Specifically, the autotransformers are impacted by bulk power system flows on the north-south transmission interface, driven by changing generation and load patterns in northern and southern Ontario. Accordingly, the Essa autotransformers were assessed through a separate bulk planning study by the IESO. However, results of the bulk study that have regional implication are discussed in this IRRP.

The Barrie/Innisfil Sub-region and its supply infrastructure are shown in Figure 4-1 and Figure 4-2.

Figure 4-1: Regional Transmission Facilities

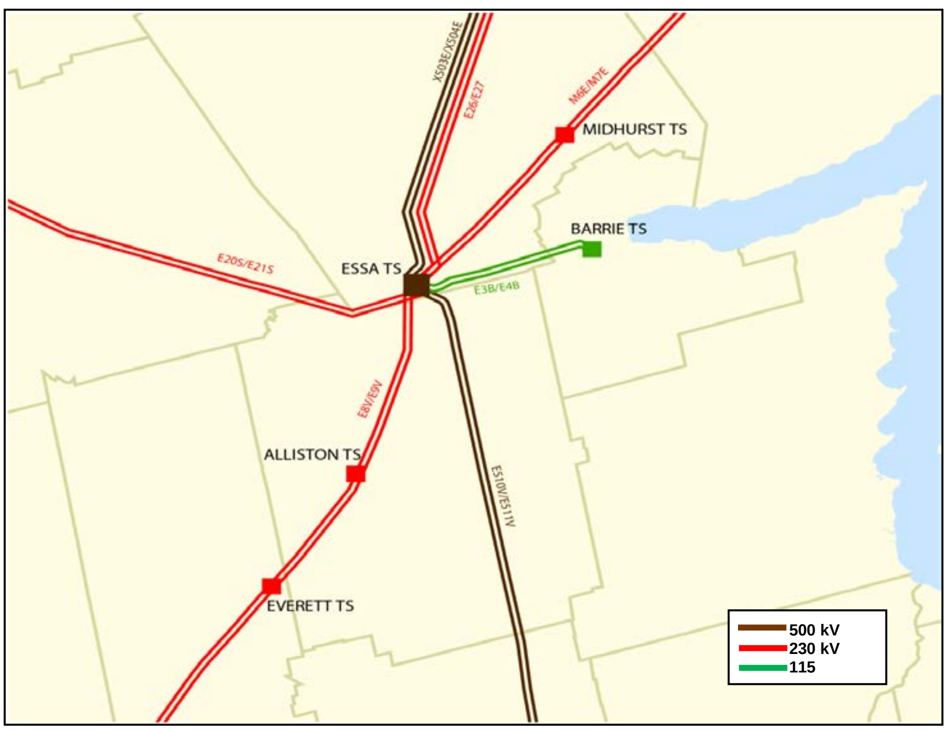
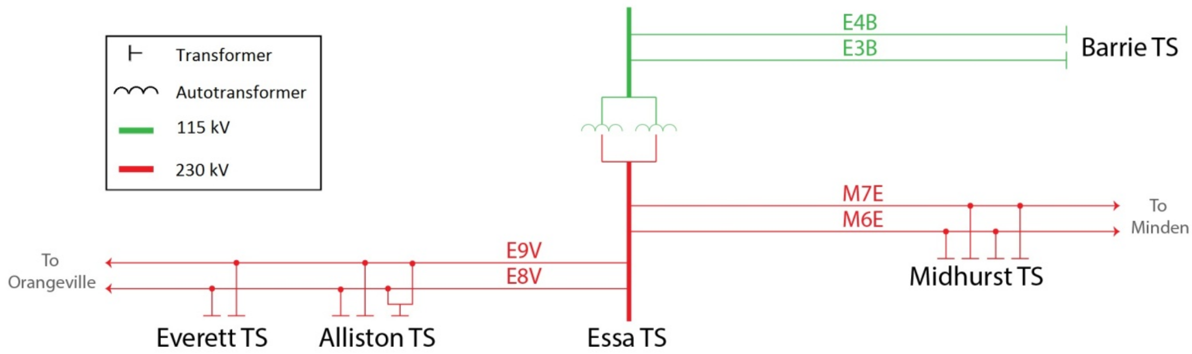


Figure 4-2: Barrie/Innisfil Sub-region Electrical Sub-systems



The Barrie/Innisfil IRRP was developed by completing the following steps:

- Preparing a 20-year electricity demand forecast and establishing needs over this timeframe.
- Examining the load meeting capability ("LMC") and reliability of the existing transmission system supplying the Barrie/Innisfil Sub-region, taking into account facility ratings and performance of transmission elements, transformers, local generation, and other facilities such as reactive power devices. Needs were established by applying ORTAC.
- Establishing feasible integrated alternatives to address needs, including a mix of CDM, generation, transmission and distribution facilities, and other electricity system initiatives.
- Evaluating options using decision-making criteria that include: technical feasibility, cost, reliability performance, flexibility, environmental and social factors.
- Developing and communicating findings, conclusions and recommendations.

5. Demand Forecast

This section outlines the forecast of electricity demand within the Barrie/Innisfil Sub-region. It highlights the assumptions made for peak demand load forecasts, and the contribution of conservation and DG to reducing peak demand. 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 referred to as "coincident peak demand". Typically this represents the time when assets are most stressed and resources most constrained. This differs from a non-coincident peak, which is measured by summing each station's individual peak, regardless of whether each station's peaks occur at a different time than the area's overall peak.

Within the Barrie/Innisfil Sub-region, 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. The Working Group determined the co-incident and non-coincident area peaks for the sub-region are fairly equivalent since they correspond with this weather-related peak. Hence, the non-coincident peak for each station was used as the basis of the load forecast starting point.

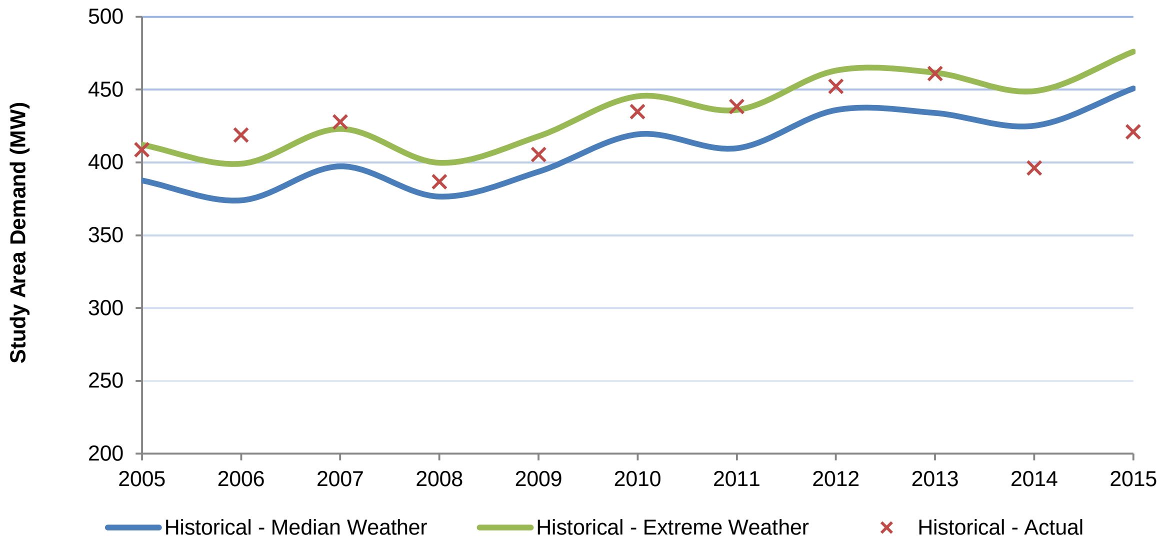
Section 5.1 begins by describing the historic electricity demand trends in the sub-region from 2005 to 2015. Section 5.2 describes the demand forecast used in this study and the methodology used to develop it.

5.1 Historical Demand

The coincident peak electrical demand for the Barrie/Innisfil Sub-region is shown in Figure 5-1. The historical data (in red) shows the coincident peak demand for the year.

The historical demand adjusted for extreme and median weather (in green and blue, respectively) shows the demand at the same hour, but adjusted to reflect the expected behaviour under the applicable weather conditions. Correction factors between historical, median and extreme conditions are produced on a zonal basis by Hydro One, the transmitter in this area.

Figure 5-1: Historical Peak Demand in the Barrie/Innisfil Sub-region



The weather corrected peak shows that demand has been generally increasing since 2005. However, the data for the summer of 2014 and 2015 should be regarded as less reliable due to abnormally cool summer conditions. Although weather correction has been applied in all cases, these methodologies are generally not designed to make such extreme adjustments (i.e., as required for the summers of 2014 and 2015).

5.2 Demand Forecast Methodology

For the purpose of the IRRP, a 20-year planning forecast was developed to assess electricity supply and reliability needs at the regional level.

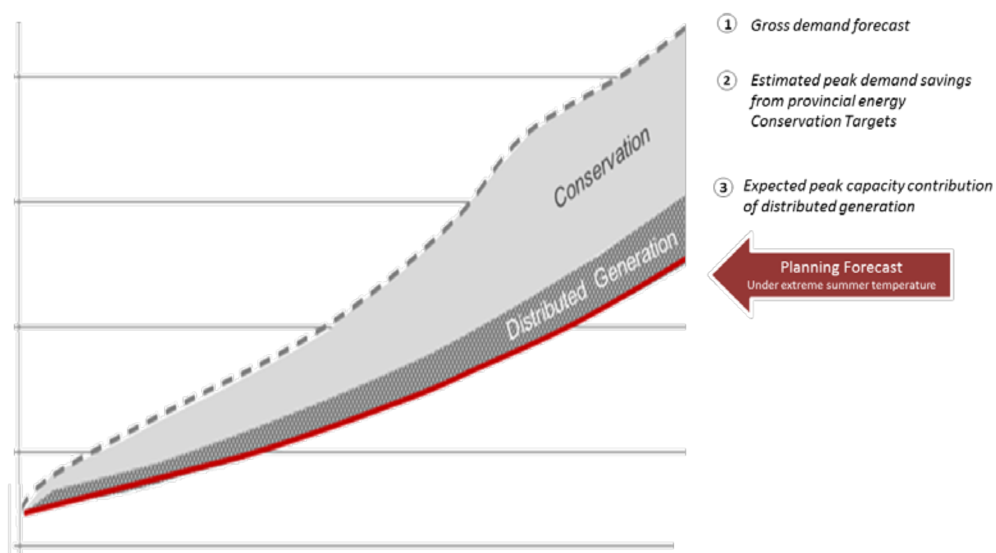
Regional electricity needs are driven by the limits of the transmission infrastructure supplying an area, which is sized to meet peak demand requirements. Regional planning therefore typically focuses on the growth in regional-coincident peak demand.

The 20-year planning forecast is divided notionally into three timeframes. The near term (0-5 years) has the highest degree of certainty; any near-term needs are typically met using regional transmission or distribution solutions as other methods (i.e., DG or CDM) are still being tested to determine if their lead-times will be suitable to meet near-term timelines. The medium term (5-10 years), however, provides more lead time to develop and incorporate DG and CDM options.

The long-term forecast covers the 10-20 year period and has the lowest degree of certainty. It is used for the identification of potential longer-term needs, and for the consideration and development of integrated solutions (including CDM, DG, and major transmission upgrades). To address the relative uncertainty of long-term needs, a high and a low forecast scenario were created. Early identification of potential long-term needs and potential solutions makes it possible to begin engagement with the local community and all levels of government long before the need is triggered. This provides the greatest opportunity to gain input on decision making, and to ensure local planning can account for new infrastructure.

The regional peak demand forecast was developed as shown in Figure 5-2. Gross demand forecasts, assuming normal-year weather conditions, were provided by the LDCs and the transmission-connected customers in each LDC's service territory. The LDC forecasts are based on growth projections included in regional and municipal plans, which in turn reflect the province's Growth Plan for the Greater Golden Horseshoe, 2006, as amended. These forecasts were then modified to produce a planning forecast (i.e., they were adjusted to reflect the peak demand impacts of provincial conservation targets, DG contracted through provincial programs such as FIT and microFIT, and to reflect extreme weather conditions). The planning forecast was then used to assess any growth-related electricity needs in the region.

Figure 5-2: Development of Demand Forecast



Using a planning forecast that is net of provincial conservation targets is consistent with the province's Conservation First policy. However, it also assumes that the targets will be met and that the targets, which are energy-based, will produce corresponding local peak demand reductions. An important aspect of plan implementation will be monitoring the actual peak demand impacts of conservation programs delivered by the area LDCs and, as necessary, adapting the plan. Additional details related to the development of the demand forecast are provided in Appendix A.

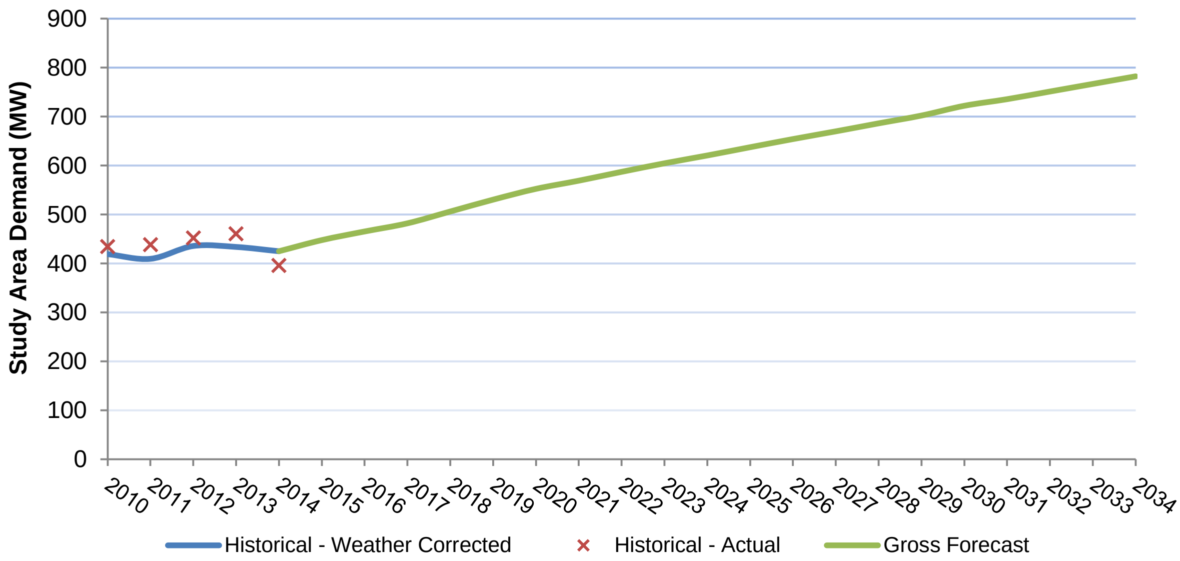
5.3 Gross Demand Forecast

Each participating LDC in the Barrie/Innisfil Sub-region prepared gross demand forecasts at the transformer station level, or at the bus level for multi-bus stations. Gross demand forecasts account for increases in demand from new or intensified development, but they do not account for the impact of new conservation measures such as codes and standards or demand response ("DR") programs. However, LDCs are expected to account for changes in consumer demand resulting from typical efficiency improvements and response to increasing electricity prices, which is termed "natural conservation".

LDCs have the best information on customer and regional growth expectations in the near and medium term since they have the most direct involvement with their customers. Most LDCs 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 for similar customer types. More details on the LDCs' load forecast assumptions can be found in Appendix A.

The graph below shows the gross demand forecast information provided by LDCs for the Barrie/Innisfil Sub-region, with historical data points provided for comparison. The gross forecast provided by the LDCs, shown in Figure 5-3, is for median weather conditions.

Figure 5-3: Barrie/Innisfil Sub-region Gross Forecast



Total annual growth averages 3% per year for the study area over the 20-year planning horizon. Growth is highest in the first 10 years at an average of 3.7% per year, before reducing to an average of 2.3% per year for the following 10 years. Although the forecast is shown for the entire study area, individual stations are forecast to experience different growth rates.

To address development uncertainty in the area, the LDCs also produced a forecast for both a high and a low growth scenario. While the needs assessment was conducted based on the reference load growth scenario, the high and low forecasts were used for evaluating the robustness of different medium- and long-term options. The regional gross growth rate ranges from 2.2% per year in the low scenario to 3.9% per year in the high.

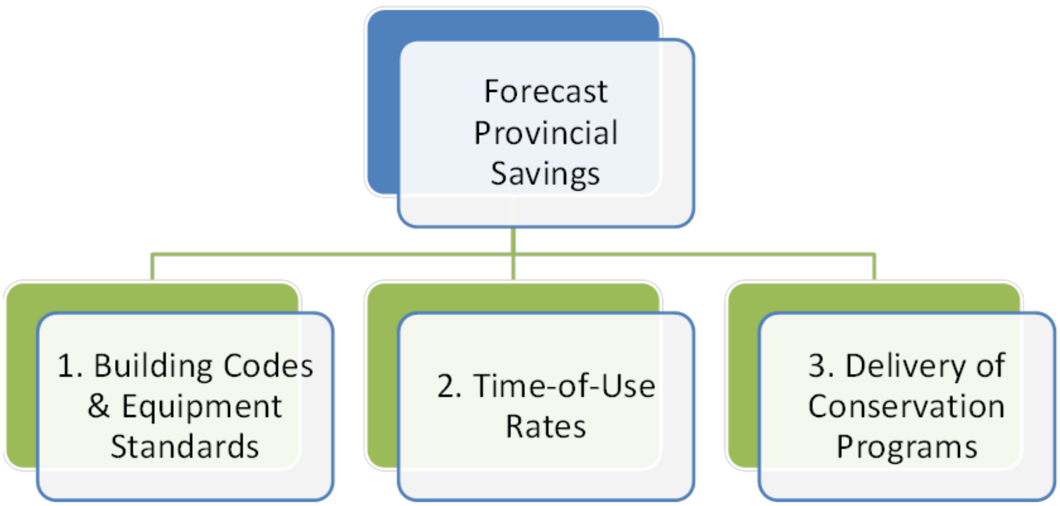
The forecasts were provided based on best available information and, as appropriate, will be updated going forward. The gross demand forecasts by station for the reference, high and low scenarios are provided in Appendix A.

5.4 Conservation Assumed in the Forecast

Conservation is achieved through a mix of program-related activities, rate structures, and mandated efficiencies from building codes and equipment standards. It plays a key role in maximizing the use of existing assets and maintaining reliable supply by offsetting a portion of a region’s growth, helping to keep demand within equipment capability. The conservation savings forecast for the Barrie/Innisfil Sub-region have been applied to the gross peak demand forecast for median weather, along with DG resources (described in Section 5.5), to determine the net peak demand for the sub-region.

In December 2013 the Ministry of Energy released a revised LTEP that outlined a provincial conservation target of 30 terawatt-hours ("TWh") of energy savings by 2032. To estimate the impact of the conservation savings in the sub-region, in terms of impact to peak demand, the forecast provincial savings were divided into three main categories:

Figure 5-4: Categories of Conservation Savings



1. *Savings due to Building Codes & Equipment Standards*
2. *Savings due to Time-of-Use Rate Structures*
3. *Savings due to the delivery of Conservation Programs*

For the Barrie/Innisfil Sub-region, the impacts of the estimated savings for each category were further broken down by the residential, commercial and industrial customer sectors. The IESO worked together with the LDCs to establish a methodology to estimate the electrical demand impacts of the energy targets by these three customer sectors. This provides a better resolution for the forecast conservation, as conservation potential estimates vary by sector due to different energy consumption characteristics and applicable measures.

For the Barrie/Innisfil Sub-region, LDCs were requested to provide both their gross demand forecast and a breakdown of electrical demand by sector for each TS. Once sectoral gross demand at each TS was estimated, the next step was to estimate peak demand savings for each conservation category: codes and standards, time-of-use rates, and conservation programs. The estimate for each of the three savings groups was done separately due to their unique characteristics and the available data. The final estimated conservation peak demand reduction, 82 MW by 2034, was applied to the gross demand to create the planning forecast. Table 5-1 provides the conservation peak demand savings for a selection of the forecast years.

Table 5-1: Peak Demand MW Savings from 2013 LTEP Conservation Targets, Select Years

Year	2016	2018	2020	2022	2024	2026	2028	2030	2032
Savings (MW)	5	12	19	28	37	48	60	73	80

Additional conservation forecast details are provided in Appendix A.

5.5 Distributed Generation Assumed in the Forecast

In addition to conservation resources, DG in the Barrie/Innisfil Sub-region is also forecast to offset peak demand requirements. The introduction of the *Green Energy and Green Economy Act, 2009*, and the associated development of Ontario's FIT program, has increased the significance of distributed renewable generation in Ontario. This renewable generation, while intermittent in nature, contributes to meeting the electricity demands of the province.

After applying the conservation savings to the demand forecast as described above, the forecast is further reduced by the expected peak contribution from contracted, but not yet in-service, DG in the sub-region. The effects of projects that were already in-service prior to the base year of the forecast were not included as they are already embedded in the actual demand, which is the starting point for the forecast. Potential future (but uncontracted) DG uptake was not included and is instead considered as an option for meeting identified needs.

Based on the IESO contract list as of June 2015, new DG projects are expected to offset an incremental 3.2 MW of peak demand within the Barrie/Innisfil Sub-region by 2018. Most distribution connected contracted generators included in the forecast are small-scale solar projects (< 500 kW); however, there are some larger FIT (< 10 MW) solar projects connecting at Midhurst TS. A capacity contribution of 22%, to the regional peak, has been assumed to account for the expected output of the local solar resources during summer peak conditions.

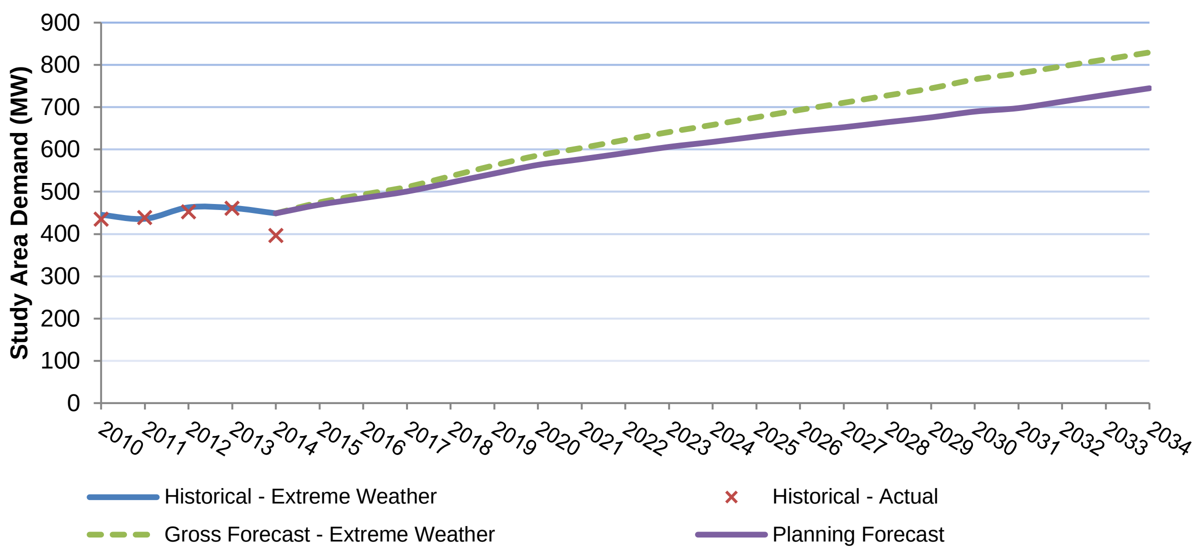
Additional details of the regional demand reductions from province-wide DG programs are provided in Appendix A.

5.6 Planning Forecasts

After taking into consideration the combined impacts of conservation and DG, a 20-year planning forecast was produced.

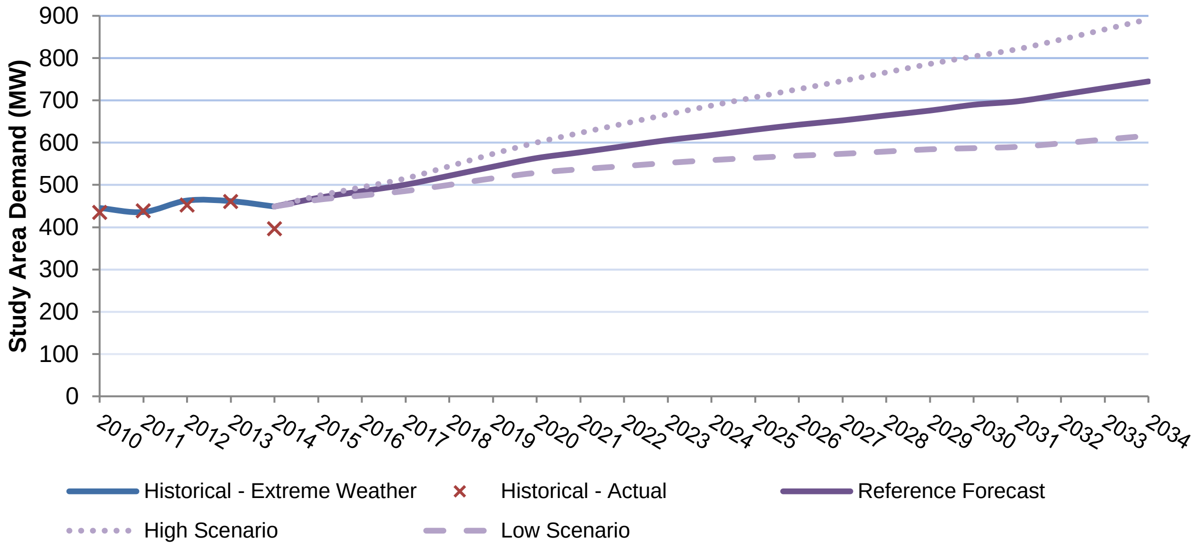
Figure 5-5 below illustrates the planning forecast, along with historic demand in the area. Note that the planning forecast has been adjusted for extreme weather conditions. For comparison in Figure 5-5 the gross forecast has also been adjusted for extreme weather conditions. Further details of the planning forecast scenarios are provided in Appendix A.

Figure 5-5: Barrie/Innisfil Sub-region Planning Forecast



The net forecast for the high, low and reference scenarios are shown in Figure 5-6. Further information on the high and low scenarios and each of the LDC's load forecast assumptions can be found in Appendix A.

Figure 5-6: Barrie/Innisfil Sub-region High and Low Demand Forecast Scenarios



6. Needs

Based on the planning forecasts, system capability, and application of provincial planning criteria, the Barrie/Innisfil Sub-region Working Group identified electricity needs in the near, medium, and long term. This section describes the identified needs for these three time horizons in the Barrie/Innisfil Sub-region.

6.1 Needs Assessment Methodology

ORTAC,[8] the provincial standard for assessing the reliability of the transmission system, was applied to assess supply capacity and reliability needs. ORTAC includes criteria related to the assessment of the bulk transmission system, as well as the assessment of local or regional reliability requirements (see Appendix B for more details).

By applying these criteria, two broad categories of needs have been identified for the Barrie/Innisfil Sub-region IRRP:

- **Transformer Station Capacity** describes the electricity system's ability to deliver power to the local distribution network through the regional step-down transformer stations. The capacity rating of a transformer station is the maximum demand that can be supplied by the station and is limited by the station equipment. Station ratings are often determined based on the 10-day LTR of a station's smallest transformer(s) under the assumption that the largest transformer is out of service.[9]
- **Supply Capacity** is the electricity system's ability to provide continuous supply to a local area. This is limited by the LMC of the transmission supply to the area. The LMC is determined by evaluating the maximum demand that can be supplied to an area accounting for limitations of the transmission element(s) (e.g., a transmission line, group of lines, or autotransformer), when subjected to contingencies and criteria prescribed by ORTAC. LMC studies are conducted using power system simulations analysis (see Appendix B for more details). Supply capacity needs are identified when the peak demand for the area exceeds the LMC.

The needs assessment also identifies requirements related to equipment end-of-life and planned sustainment activities. Equipment reaching end-of-life and planned sustainment activities have

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

[9] A transformer station can also be limited when downstream or upstream equipment (e.g., breakers, disconnect switches, low voltage bus, high voltage circuits, etc.) are undersized relative to the transformer rating. LTR is further defined on page 8.

a significant impact on the needs assessment and option development for the Barrie/Innisfil Sub-region.

6.2 Local Electricity Supply and Reliability Needs

The needs assessment for the Barrie/Innisfil IRRP focused on identifying needs for local transformer stations and related supply infrastructure. The impact of all three demand forecast scenarios (reference, high, and low – see Section 5.6) on the local transmission infrastructure was evaluated. Near-, medium-, and long-term capacity needs were identified for the south Barrie and Innisfil areas for the reference scenario, along with a long-term capacity need at Everett TS. End-of-life infrastructure needs were also identified in the area.

6.2.1 Near- and Medium-Term Needs

The near- and medium-term needs identified for the Barrie TS service area were considered together since the infrastructure impacted is common to all identified needs. The near- and medium-term needs are summarized in Table 6-1.

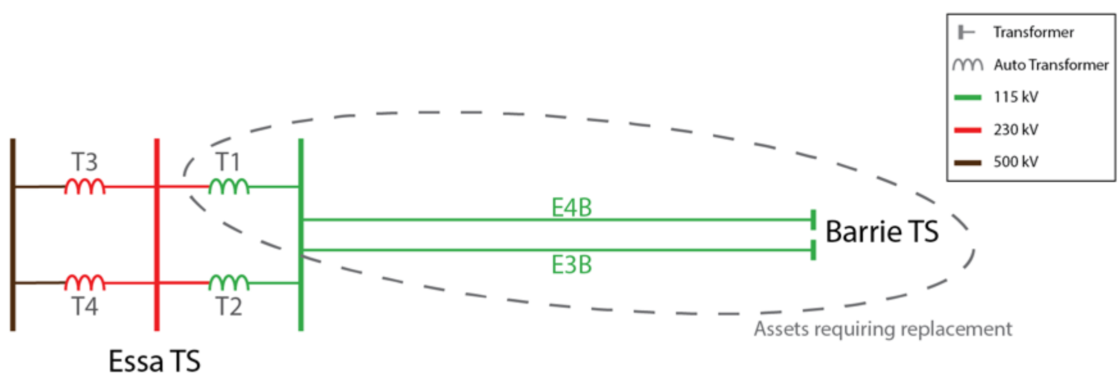
Table 6-1: Barrie/Innisfil Sub-region Near- and Medium-Term Electricity Needs

Need	Description	Timing
End-of-Life	Hydro One has identified Barrie TS and components of its 115 kV supply infrastructure to be nearing their end-of-life.	2020
Transformer Station Capacity	Net demand growth in the southern portion of the City of Barrie and in the Town of Innisfil is forecast to exacerbate the existing transformer station capacity need at Barrie TS. Barrie TS also lacks additional feeder positions to accommodate future growth in Innisfil.	Today
Supply Capacity	The net demand growth is forecast to exceed the LMC of the 115 kV supply to Barrie TS (E3/4B).	2019

Hydro One Transmission identified existing sustainment initiatives at Barrie TS driven by the 115/44 kV station transformers reaching end-of-life, along with the 44 kV switchgear, circuit breakers, disconnect switches and other station equipment.

Barrie TS was placed in-service in 1962. The 44 kV switchyard assets at Barrie TS have been identified by Hydro One as being in need of replacement in the near term. Barrie TS is currently supplied by the 230/115 kV autotransformers at Essa TS via the Essa 115 kV switchyard and 115 kV circuits E3/4B. These assets were built in the 1950s, with many of them already exceeding their expected life and in need of replacement in the near and medium term. Figure 6-1 depicts the significant assets that Hydro One has identified as requiring replacement in the near term.

Figure 6-1: Single Line Diagram Detailing Existing Supply of Barrie TS and Assets Requiring Replacement



The timing and replacement options for Barrie TS were discussed among the Working Group members. It was agreed that based on the existing and forecast station demand, that Barrie TS and E3/4B should be rebuilt to 230 kV, with 75/125 Mega Volt Amp ("MVA") 44/230 kV transformers. This means that the end-of-life replacement of Barrie TS will add approximately 50 MW of incremental supply capacity in the south Barrie and Innisfil area. Details of the alternatives considered by the Working Group can be found in Appendix B.

Barrie TS is forecast to experience the highest average yearly growth rate of any TS in the study area over the 20 year planning period, for all load growth scenarios. This is driven by the large amount of growth set out in the local municipal plans and in the province's Growth Plan for the Greater Golden Horseshoe, 2006, as amended, which identify the City of Barrie as an urban growth centre.

Effective January 1, 2010, the City of Barrie annexed approximately 5,700 acres of land from the Town of Innisfil to accommodate its forecast growth. These annexed lands are within the Barrie TS service area, and their development contributes to a large portion of the station's forecast growth. Barrie TS growth is also influenced by the recent and continued development of data centres in the City of Barrie, and forecast growth in the Town of Innisfil, including the proposed industrial and commercial development of Innisfil Heights near Highway 400.

Barrie TS is currently utilized by two LDCs, PowerStream and InnPower.

Figure 6-2: Forecast Summer Demand for Barrie TS - Reference Scenario

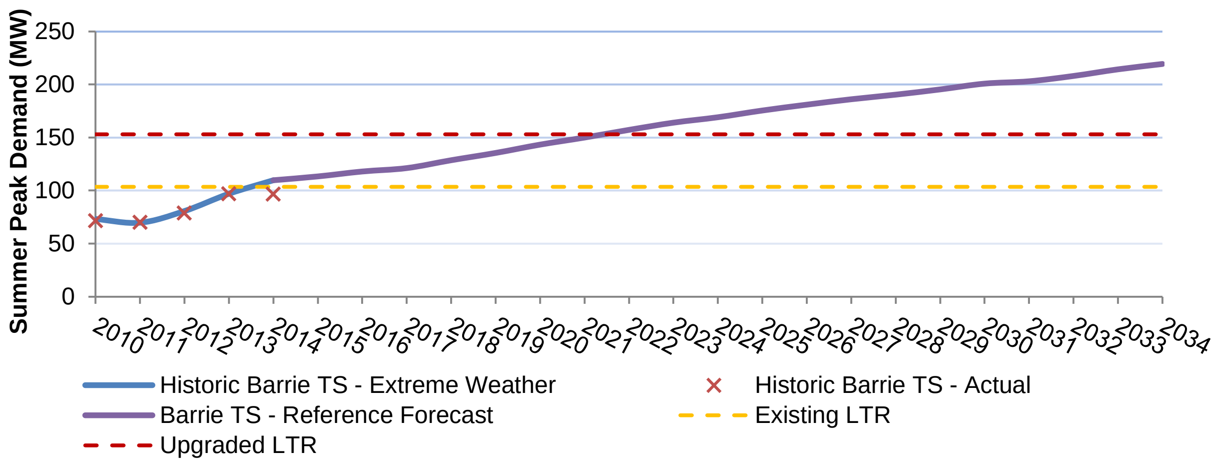


Figure 6-2 shows the forecast load growth for Barrie TS under the assumptions from the reference scenario, along with the existing LTR of Barrie TS and the future LTR of the uprated Barrie TS. Based on the forecast provided by the LDCs, Barrie TS would have exceeded its existing LTR by 2015 and will exceed the uprated LTR by 2022. By the end of the study period, there is approximately 66 MW of forecast capacity need that cannot be supplied by the uprated Barrie TS.

Currently all seven existing 44 kV feeder positions available at Barrie TS have been allocated to an LDC. Six of these feeders are used to supply PowerStream customers and one to supply InnPower. Based on the normal operating rating of the 44 kV feeder supplying InnPower, there will be a need for additional feeder capacity and a new feeder position by 2020 for the reference forecast scenario. The uprated Barrie TS will have a total of eight feeder positions, meaning there will be an additional position available as an option to supply future load growth in both south Barrie and Innisfil.

In addition to the limitation posed by the transformers at Barrie TS, the existing upstream 115 kV transmission supply is forecast to exceed its limit. The 115 kV circuits that supply Barrie TS are E3/4B. E3B is expected to exceed its LMC in 2019. These 115 kV circuits are supplied by two 230/115 kV autotransformers at Essa TS. The most limiting of these transformers is expected to exceed its LTR in 2020. By upgrading the Barrie TS supply to 230 kV, it ensures that future load growth at Barrie TS, up to its new LTR, can be accommodated, and there will be remaining line capacity to accommodate future load customers in the area at 230 kV.

6.2.2 Long-Term Capacity Needs

Long-term capacity needs were identified at both the transformer station level and the sub-area/sub-region level. Two different sub-system levels were defined based on both the ability to transfer load on the distribution system, and on the overall electrical supply to the area. The two areas defined for the purpose of the needs assessment are the “Barrie Sub-area” – defined below – as well as the established “Barrie/Innisfil Sub-region”.

In the long term, transformer capacity needs arise for Everett TS and for the broader Barrie Sub-area. At the end of the study period, both a transformer capacity need and a supply capacity need arise for the broader Barrie/Innisfil Sub-region. These needs, along with their timing and influencing factors, are discussed in more detail below.

Everett TS

The transformer station capacity need at Everett TS is a long-term need. Everett TS is a relatively new transformer station, which came into service in late 2007 to address capacity needs in the South Simcoe area, relieving Alliston TS. Everett TS is forecast to supply load growth in the Town of New Tecumseth, primarily Alliston and the surrounding area.

Figure 6-3: Forecast Summer Demand for Everett TS - Reference Scenario

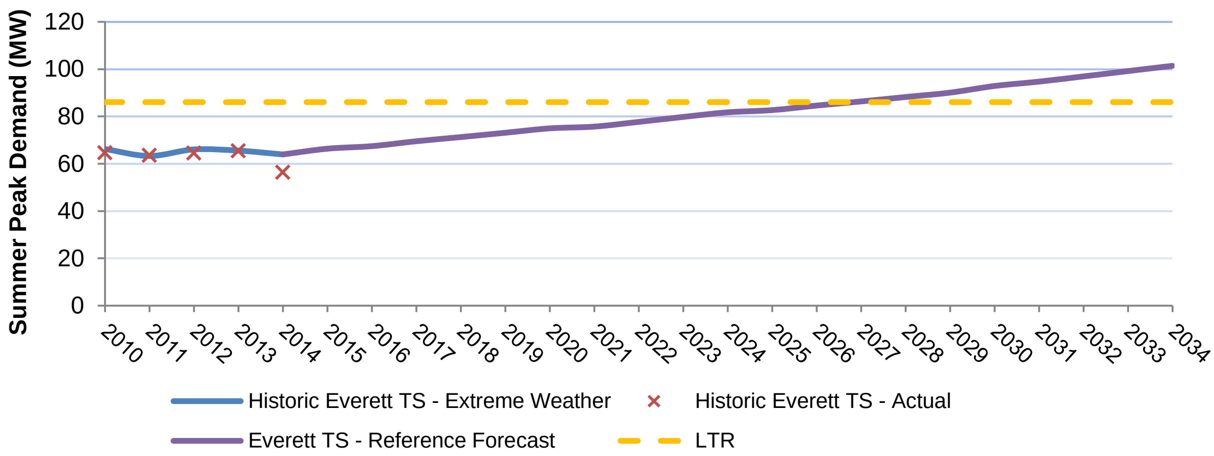


Figure 6-3 shows the forecast load growth for Everett TS under assumptions from the reference scenario. Based on the forecast provided by the LDCs, Everett TS will exceed its current LTR in 2027. By the end of the study period, there is approximately 15 MW of forecast capacity need that cannot be supplied by Everett TS.

A capacity need at Everett TS was identified in both the 2011 South Simcoe study and in the latest Needs Assessment completed by Hydro One for this regional planning cycle. Both studies outlined that this capacity need can be addressed by changing the CT ratios, which are currently limiting the station LTR, once the station's minimum load exceeds 8 MVA. Since 2011, the minimum load at Everett TS has surpassed 8 MVA meaning the CT ratios can now be changed whenever the additional capacity is required. This would defer the capacity need at Everett TS beyond the study period.

Barrie Sub-area

The Barrie Sub-area is defined as the area serviced by both Midhurst TS and Barrie TS, recognizing geographical overlap in their service areas. Ties exist between the stations for emergency load transfers, and there is potential for permanent load transfers or for a choice between the two stations when servicing new load.

The LMC of the Barrie Sub-area is defined as the combined LTRs of Midhurst TS and Barrie TS. The ability to fully utilize this firm capacity, however, is constrained by the feasibility or cost effectiveness of any load transfers or optimization of the distribution system. The available capacity in the Barrie Sub-area is also increased by the uprating of Barrie TS discussed in Section 6.2.1.

Figure 6-4: Summer Demand Forecast for the Barrie Sub-area - Reference Scenario

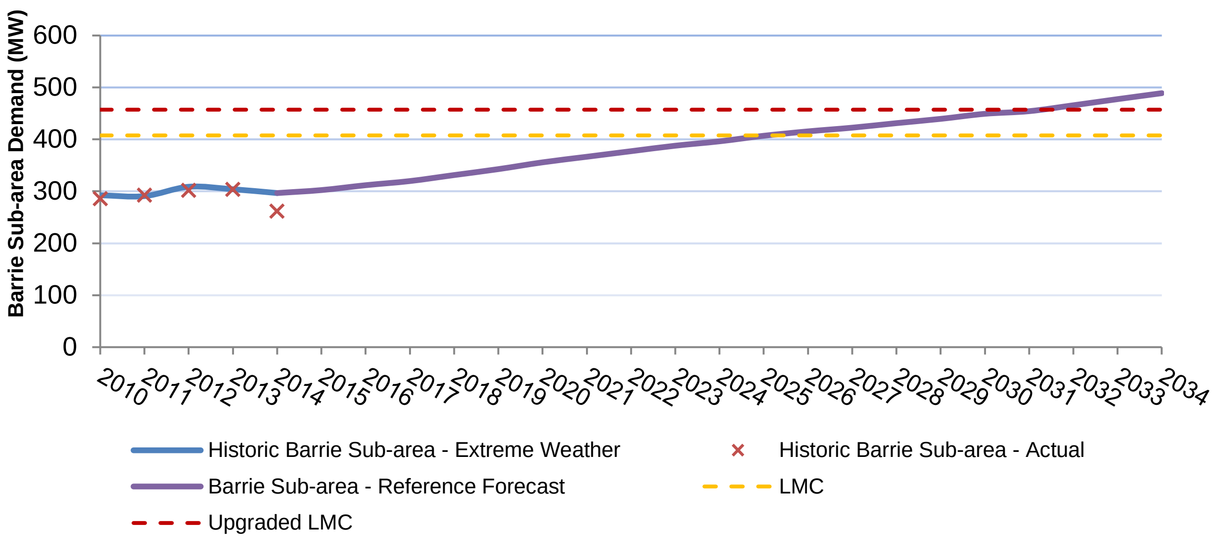


Figure 6-4 shows the forecast load growth in the Barrie Sub-area under assumptions for the reference scenario. Based on the forecasts provided by the LDCs, the Barrie Sub-area will exceed the combined capacity of Midhurst TS and uprated Barrie TS by 2031. By the end of the study period there is approximately 32 MW of forecast capacity need that cannot be supplied in the Barrie Sub-area assuming optimum load sharing between Midhurst TS and Barrie TS.

Barrie / Innisfil Sub-region

The Barrie/Innisfil Sub-region is defined in Section 4.1 as the area supplied by Midhurst TS, Barrie TS, Alliston TS and Everett TS. This area is supplied primarily by the bulk system, via the 500/230 kV autotransformers at Essa TS. Based on the forecast load growth, the region is primarily limited by the combined transformer capacity of Midhurst TS, Barrie TS, Everett TS and Alliston TS. This recognizes the existing ties used for emergency load transfers and the potential to implement permanent load transfers throughout the area.

Figure 6-5: Summer Demand Forecast Barrie/Innisfil Sub-region - Reference Scenario

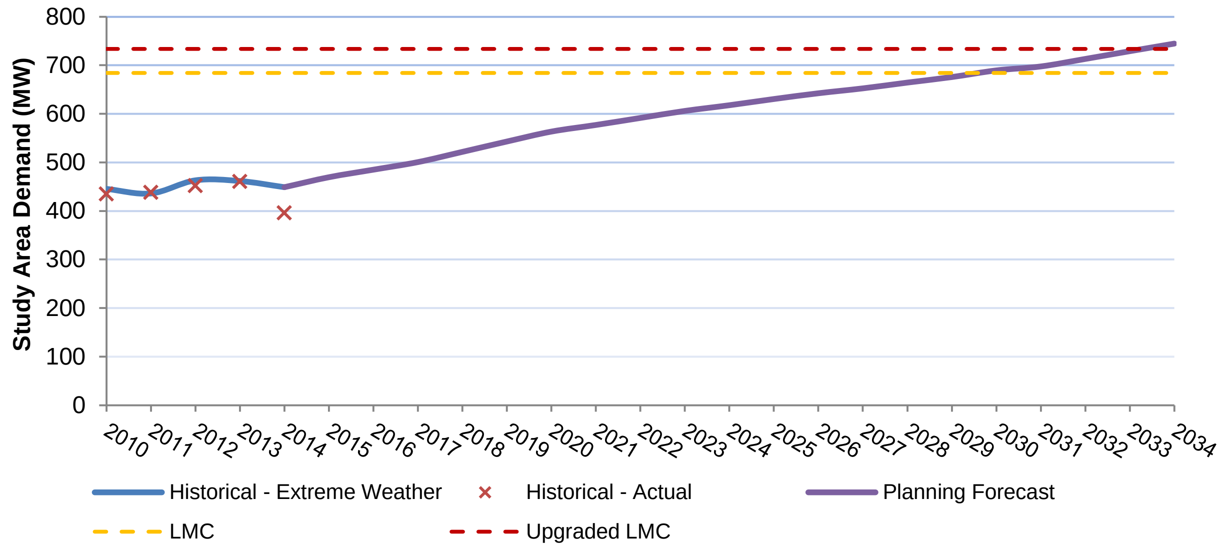


Figure 6-5 shows the forecast load growth in the Barrie/Innisfil Sub-region under assumptions for the reference scenario. Based on the forecasts provided by the LDCs, the Barrie Sub-region will exceed the combined capacity of the transformer stations in the region (accounting for the uprated Barrie TS) by 2034. By the end of the study period there is approximately 14 MW of forecast capacity need that cannot be supplied in the Barrie/Innisfil Sub-region, assuming optimum load sharing between all transformer stations.

The upstream transmission limitation for the sub-region is the 500/230 kV autotransformers at Essa TS. The loading of the autotransformers is also impacted by the load in the Parry Sound/Muskoka Sub-region and, to a certain degree, by the bulk system flow on Ontario's north-south transmission interface. The IESO has studied the impact on the Essa TS autotransformers under different bulk flow conditions and the load forecasts from both the Barrie/Innisfil IRRP and the Parry Sound/Muskoka IRRP. Based on these assumptions, a forecast capacity need, based on the loss of one autotransformer, does not arise until 2034.

In addition to the growth included in the planning demand forecast, the Metrolinx most recent electrification plan has indicated a preference for connecting to the new 230 kV supply extension via the uprated Barrie TS for their traction power station for the Barrie line. This connection could advance the need date for the supply capacity due to the Essa autotransformer limitations. Therefore, this project should be monitored closely by both the IESO (since it has implications for the bulk system) and the Working Group.

6.3 Needs Summary

The majority of needs in the Barrie/Innisfil Sub-region concern various loading limits on Barrie TS, along with the need to address the risk posed by the end-of-life infrastructure at the station.

With the Barrie Area Transmission Reinforcement project, which Hydro One has begun development work for at the request of the IESO and the Working Group, the near-term end-of-life need and the existing capacity need at the station can be addressed. Over the medium and long term, additional capacity needs arise in the area, including InnPower's need for additional 44 kV feeder capacity, additional transformer capacity needs at Everett TS and in the Barrie area, and a need for additional transformer and supply capacity for the sub-region by the end of the study period.

The table below provides a brief summary of needs that will be considered during the development of options for the plan.

Table 6-2: Summary of Needs in Barrie/Innisfil Sub-region

Area	Need	Description	Need Date
Barrie TS	Barrie TS transformer capacity need	There is an existing transformer capacity need at Barrie TS. The incremental capacity provided by the Barrie Area Transmission Reinforcement project should address a large portion of the near- and medium-term capacity need at Barrie TS.	Today
	Barrie TS supply capacity need	The 115 kV circuits currently supplying Barrie TS are forecast to exceed their LMC. By uprating these circuits to 230 kV, the Barrie Area Transmission Reinforcement project addresses this need.	2019

Area	Need	Description	Need Date
	End-of-life for Barrie TS 115/44 kV transformers and station equipment	Significant station components, both at and supplying Barrie TS are nearing end-of-life and require replacement by 2020. The Barrie Area Transmission Reinforcement project should address this need.	2020
	InnPower distribution/feeder supply capacity	Currently InnPower is only allocated one feeder from Barrie TS which is forecast to exceed its normal operating rating in the near to medium term.	2020
	Medium-term transformer capacity need	The uprated Barrie TS is forecast to exceed its new LTR in the medium term, based on the expected load growth in south Barrie and Innisfil.	2022
Everett TS	Everett TS transformer capacity need	Everett TS is forecast to exceed its limited LTR in the long term.	2027
Barrie Sub-area	Transformer capacity need	Load in the Barrie area is forecast to exceed the combined transformer capacity of Midhurst TS and the uprated Barrie TS in the long term, primarily driven by load growth at Barrie TS.	2031

Area	Need	Description	Need Date
Barrie/Innisfil Sub-region	Transformer and supply capacity need	In the long term, the load in the Barrie/Innisfil Sub-region is forecast to exceed both the combined transformer capacity of Barrie TS, Everett TS, Midhurst TS and Alliston TS, and the LMC of the Essa autotransformers.	2034

7. Near- and Medium-Term Plan

The plan to address the near- and medium-term needs identified for the Barrie TS service area is already underway. As described in Section 6.2.1, there are end-of-life and existing station capacity needs at Barrie TS that need to be addressed today. The near-term plan has been developed by the Working Group, with a project to rebuild and uprate Barrie TS (the Barrie Area Transmission Reinforcement project) formally handed off to Hydro One in December 2015. The hand-off letter was issued to ensure that facilities could be in-service in time to meet the identified needs, given the typical lead-time of five to seven years for a transmission project. The rebuild of Barrie TS and E3/4B is currently undergoing the development work (e.g., EA process, Leave to Construct).

This section describes the alternatives considered by the Working Group in developing the near- and medium-term plan for the Barrie/Innisfil Sub-region; provides details of, and rationale for, the recommended plan; and outlines the implementation plan.

7.1 Alternatives for Meeting Near- and Medium-Term Needs

In developing the near- and medium-term plan, the Working Group considered a range of integrated options. The Working Group further considered technical feasibility, cost and consistency with long-term needs and options in the Barrie/Innisfil Sub-region when evaluating alternatives. Solutions that maximize the use of existing infrastructure were given priority.

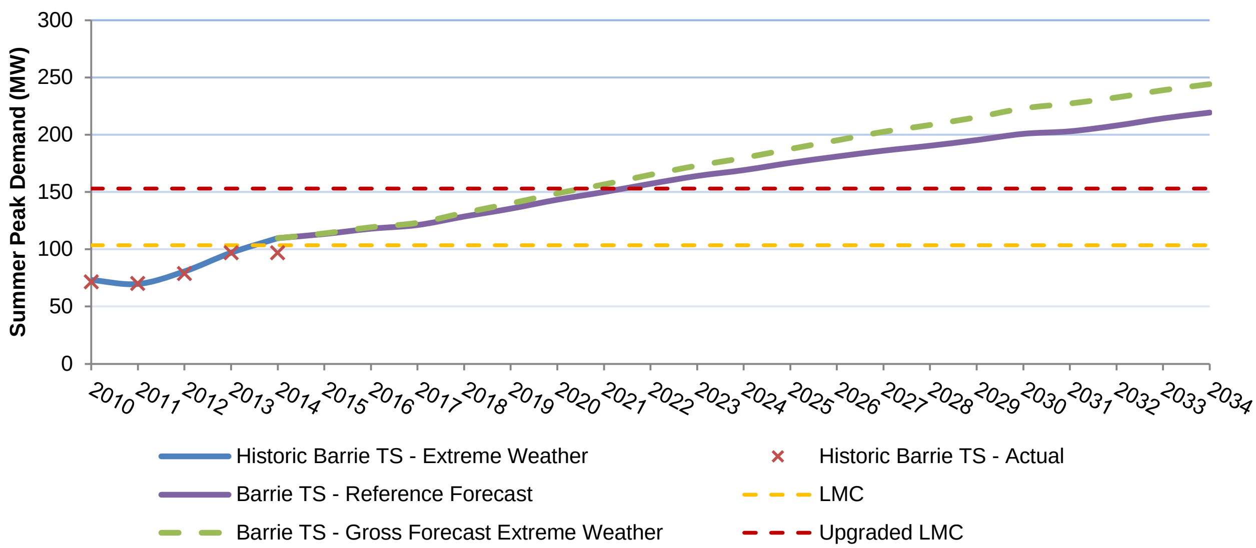
The following sections detail the alternatives considered and evaluates them against the criteria described above. The alternatives are grouped according to three major solution categories: (1) conservation, (2) local generation and (3) transmission and distribution.

7.1.1 Conservation

Conservation was considered as part of the planning forecast, which includes the local peak demand impact of the provincial conservation targets as described in Section 5.4. In the Barrie TS area, the LTEP energy reduction targets account for approximately 10 MW, or 17% of the forecast demand growth during the first 10 years of the study. This is forecast to defer the Barrie TS capacity need by one year from 2021 to 2022.

In Figure 7-1, Barrie TS load is shown under both the gross and net planning (accounts for expected conservation and contracted DG) forecasts. Both forecasts are adjusted for extreme weather conditions.

Figure 7-1: Effect of Conservation Targets on Barrie TS Peak Load



Most conservation targets are energy targets (measured over an entire year). Transmission needs, on the other hand, are triggered based on peak demand (single highest observation of hourly demand in a year). As a result, in order to reduce, defer, or otherwise address needs, conservation programs must have an impact during the hour of peak demand. In the case of the Barrie/Innisfil Sub-region, this typically means late afternoon on the hottest weekdays of summer.

The net planning forecast includes an estimate of how meeting the mostly energy based conservation targets translates into peak demand reductions. There is, however, uncertainty in both meeting energy conservation targets and determining how meeting those targets will translate into peak demand savings. As such, there is a wide range of potential demand impacts that could be experienced (both higher and lower than forecast), while still achieving full conservation targets. Therefore, LDCs are encouraged to focus their Conservation First Framework ("CFF") funding towards measures and programs that can also reduce peak and overall demand–particularly in areas where needs have been identified through regional planning.

As part of the implementation of this plan, the Working Group will annually review actual peak demand, including the impact of conservation. The IESO will support the LDCs in exploring the full potential of conservation for addressing long-term needs, discussed further in the long-term plan in Section 8.

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-term needs in the Barrie/Innisfil Sub-region. This was primarily due to the end-of-life issues at Barrie TS, which must be addressed now and could not be solved using local generation, since approximately 100 MW of existing customer load would be left without supply if the infrastructure was not replaced at end-of-life.

In addition, because local generation contributes to the overall generation capacity for the province, the generation capacity situation at the provincial level must be considered when assessing options for near- and medium-term needs. Currently, Ontario has a surplus of generation capacity and no new capacity is forecast to be needed until the mid-2020s at the earliest. This was an additional consideration in ruling out local generation for meeting the near-term needs.

7.1.3 Transmission and Distribution

A number of transmission and distribution, or "wires," solutions 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 Transmission-based Solution to Address Near-Term Need

To address the end-of-life need at Barrie TS, the Working Group investigated different transmission-based solutions. Based on the assessment of these options along with the system needs, the rebuild and uprating of Barrie TS and E3/4B to 230 kV, with 75/125 MVA transformers was chosen as the preferred option. A description of the alternatives considered by the Working Group can be found in Appendix B.

7.1.3.2 Distribution-based Solutions to Address Medium-Term Need

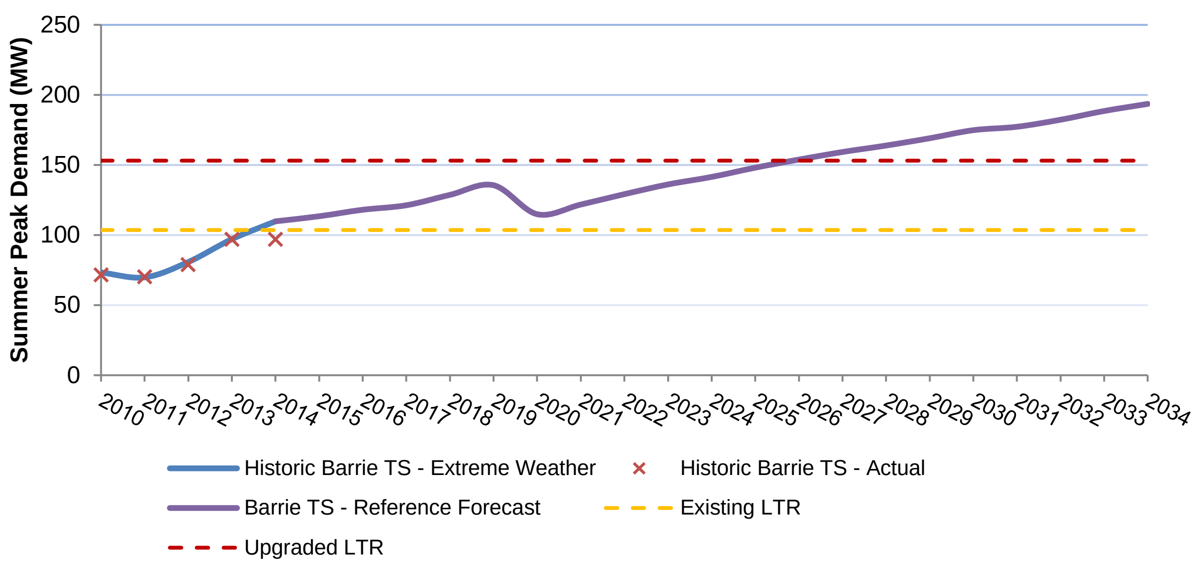
To address the medium-term transformer station and feeder capacity needs at Barrie TS, different distribution-based solutions were investigated. These included load transfers from Barrie TS to Midhurst TS, and new 44 kV feeders from the rebuilt Barrie TS to InnPower's service territory. These are described in more detail below.

Load Transfers

Due to the proximity of Barrie TS and Midhurst TS, and since PowerStream has an existing supply from both stations, load transfers are a feasible option to relieve Barrie TS. By building additional supply feeders from Midhurst TS, PowerStream can transfer up to 27 MW of load from Barrie TS assuming full data center load growth. This load transfer makes use of new feeders PowerStream already planned to construct, primarily due to data center expansion in the area. The available load transfer capacity is based upon normal operating conditions; during feeder outage situations the transfer amount may vary based on the redundancy needs of key customers.

The load transfer defers the capacity need at the uprated Barrie TS from 2022 to 2026 and also provides PowerStream with additional transfer capability between Barrie TS and Midhurst TS during emergency conditions. Figure 7-2 shows the reference scenario demand forecast for Barrie TS accounting for PowerStream's load transfer.

Figure 7-2: Barrie TS Reference Demand Forecast Load with PowerStream 2020 Load Transfer



With PowerStream's load transfer in place, by the end of the study period there is approximately 40 MW of forecast capacity need that cannot be supplied by the uprated Barrie TS.

PowerStream's existing ability to perform temporary load transfers for emergency purposes will also help manage the Barrie TS current capacity need both leading up to the completion of the Barrie Area Reinforcement project and throughout its construction staging. However, depending on Hydro One's contingency plan for the period of construction PowerStream may need to install additional distribution switches to meet their load security requirements during the rebuild of Barrie TS.

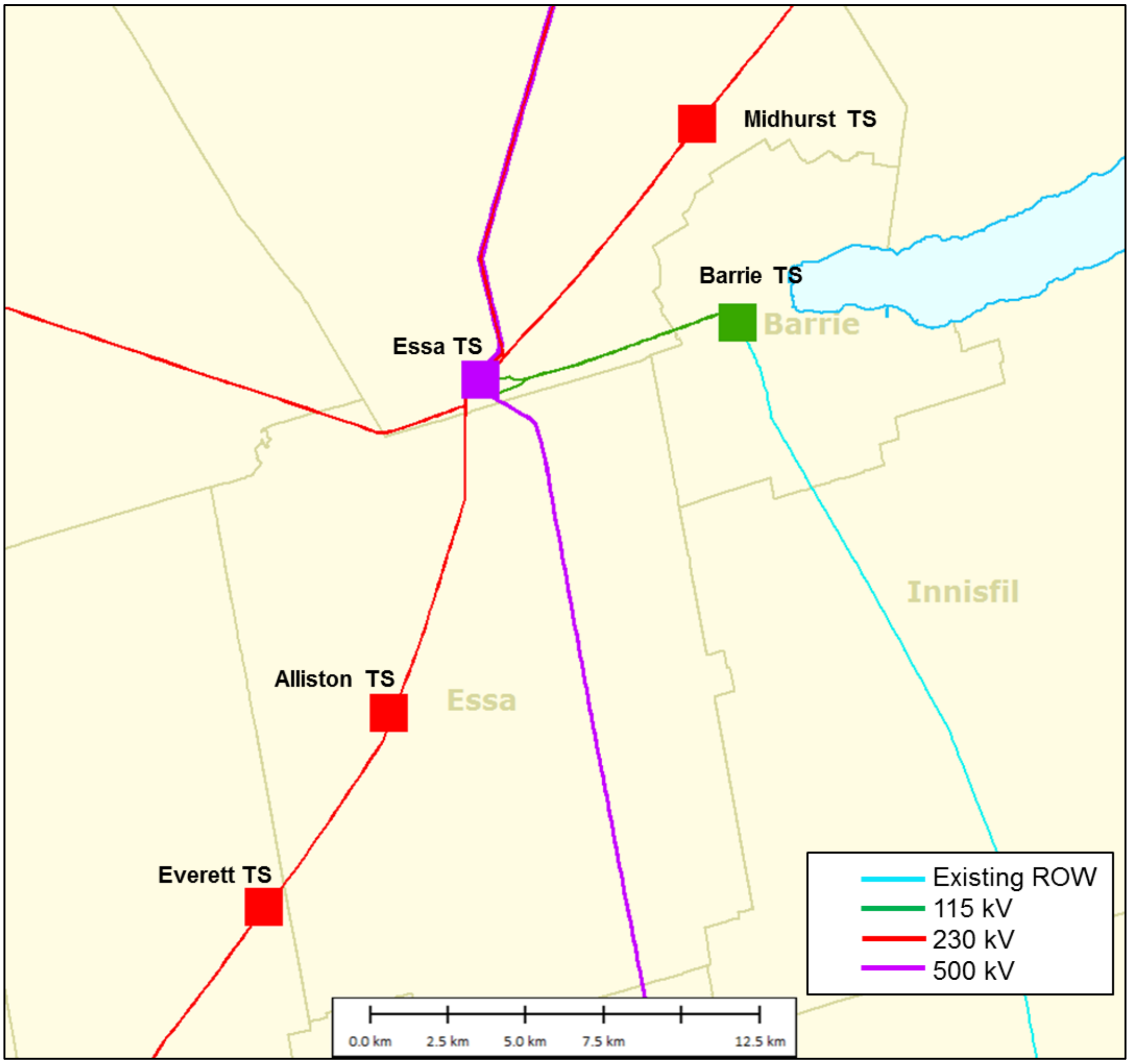
44 kV Feeder Expansion & Relocation

Currently, InnPower is supplied with one feeder from Barrie TS, operated at 44 kV and is considered an embedded customer to Hydro One Distribution. Up until the demarcation point in the Town of Innisfil, the feeder that supplies InnPower, 13M3, is an idle 115 kV line owned by Hydro One Transmission and operated at 44 kV to supply InnPower. The ROW for this 115 kV line extends south, past the existing supply points to InnPower.

This existing feeder can supply approximately 25 MW of capacity, which InnPower is forecast to exceed in 2020. The new Barrie TS will accommodate one additional 44 kV feeder, which can be used by InnPower when their capacity need arises. The additional feeder will require a new route south to Innisfil to service InnPower load.

It is recommended that, when building the new feeder, the line be built as a two circuit 44 kV feeder line and that the 13M3 feeder be relocated to this new line. This will leave the 115 kV ROW idle and will maintain a future option for addressing the long-term capacity needs in the south Barrie and Innisfil areas.

Figure 7-3: Map of the Barrie Area Including the 13M3 115 kV Corridor



Currently, Metrolinx has indicated an interest in utilizing this corridor to extend the 230 kV supply from the uprated Barrie TS to their proposed traction power station site, which sits just south of Barrie TS, adjacent to the ROW. InnPower is also interested in future use of the ROW, recognizing that long-term capacity needs in their service territory may require additional transformer station capacity in the long term.

7.1.3.3 Alternative Transmission Solution to Address Medium-Term Need

To address the need for new transformer station capacity at Barrie TS in 2022 – assuming no PowerStream load transfer – a new station supplied at 230 kV via the 13M3 corridor to south Barrie or Innisfil could provide approximately 150 MW of additional transformer station capacity to the area. This additional capacity would also service the long-term transformer station capacity needs for the Barrie Sub-area and overall Barrie/Innisfil Sub-region.

In this case, the distribution solution (the PowerStream load transfer) is the more cost-effective option and maximizes the use of existing infrastructure, deferring the capacity need to 2026. The lead-time for a new transformer station is five to seven years, so no commitment is needed today to begin development work. The need for new transformer station capacity will be monitored while all options for additional long-term capacity are further explored, as outlined in the long-term plan in Section 8.

7.2 Recommended Near- and Medium-Term Plan

The Working Group recommends the actions described below to meet the near- and medium-term electricity needs of the Barrie/Innisfil Sub-region. Successful implementation of these actions, in addition to achievement of targeted conservation measures, is expected to address the sub-region's electricity needs until the late 2020s /early 2030s.

Rebuild and Uprate Barrie TS and E3/4B to 230 kV

To mitigate challenges posed by both Barrie TS and its 115 kV supply infrastructure reaching end-of-life, and to address the near-term capacity needs at Barrie TS, Hydro One is developing the Barrie Area Transmission Reinforcement project. The project will rebuild the existing Barrie TS and uprate its existing supply from 115 kV to 230 kV, increasing the supply capacity to the area. The existing Barrie TS site is well situated for supplying the near- and medium-term forecast load growth in the south Barrie and Innisfil areas. A Class EA process is currently underway. The targeted in-service date for the project is the end of 2020.

PowerStream Load Transfer – From Barrie TS to Midhurst TS

PowerStream is planning to transfer up to 27 MW of load from Barrie TS to Midhurst TS by 2020 assuming full data centre load growth. This increases the incremental capacity available at Barrie TS, addressing near- and medium-term needs, while providing the reliability benefit of additional transfer points between Barrie TS and Midhurst TS for emergency situations. The PowerStream load transfer allows the need for additional capacity at the uprated Barrie TS to be deferred from 2022 to 2026 under reference case assumptions.

Relocate and Expand InnPower Feeder Supply from Barrie TS

Currently Hydro One Distribution is allocated one feeder from the existing Barrie TS which is used to service InnPower. The capacity of this feeder is forecast to be exceeded in 2020. The rebuilt Barrie TS will include one additional feeder position, which can be used to address this need. Additionally, the existing InnPower supply uses an idle Hydro One Transmission ROW. The use of this ROW for sub-transmission purposes limits future long-term options for additional transmission facilities in the south Barrie and Innisfil areas. It is recommended that Hydro One Distribution and InnPower develop a plan to build a new two circuit 44 kV feeder line to support InnPower's forecast growth and to relocate the InnPower supply to outside of the Hydro One Transmission corridor. The proposed in-service date for these feeders is the end of 2020. The two feeder supply from Barrie TS is forecast to supply InnPower's forecast demand at Barrie TS until 2026 under reference case assumptions.

7.3 Implementation of Near- and Medium-Term Plan

To ensure that the near-term electricity needs of the Barrie/Innisfil Sub-region are addressed, it is important that the plan recommendations be implemented as soon as possible. The specific actions and deliverables are outlined in Table 7-1, along with the recommended timing.

Table 7-1: Summary of Needs and Recommended Actions in Barrie/Innisfil Sub-region

Need	Recommended Action(s)/Deliverable(s)	Lead Responsibility	Timeframe/ Need Date
- Barrie TS is at end-of-life and requires replacement - Barrie TS has reached its firm capacity	Rebuild and upgrade Barrie TS and E3/4B to 230 kV, with 75/125 MVA transformers	Hydro One	In-service by end of 2020
- The uprated Barrie TS has a medium-term capacity need	Transfer up to 27 MW of load from Barrie TS to Midhurst TS assuming full data centre load growth	PowerStream	In-service by 2020 at the latest[10]

[10] PowerStream's 2016-2020 Custom Incentive Rate filing states a proposed in-service date of 2018 based on additional distribution needs their project addresses in the Barrie area. If the project is in-service prior to 2020 it will provide additional ability to mitigate the near-term Barrie TS capacity need until the Barrie Area Transmission Reinforcement project comes in-service.

Need	Recommended Action(s)/Deliverable(s)	Lead Responsibility	Timeframe/ Need Date
- Load growth in south Barrie will require additional feeder capacity for InnPower from Barrie TS - The existing corridor used to supply InnPower is required for future infrastructure development	InnPower will work with Hydro One to relocate out of the 115 kV corridor, constructing two new 44 kV feeders from Barrie TS to Innisfil	InnPower & Hydro One Distribution	Proposed in-service for end of 2020

To implement the recommended near-term actions in a timely manner, a RIP should be initiated for the broader South Georgian Bay/Muskoka planning region upon IRRP completion. This process will allow for detailed design and study of the transmission and distribution infrastructure expansion required to complete the recommended actions. The outcome of the RIP will be a more detailed development plan, including a refined estimate of expected costs and benefits to customers.

8. Long-Term Plan

In the long term, the outlook for the Barrie/Innisfil Sub-region depends on assumptions made in the forecast. Under the low growth scenario, the sub-region has no need for additional transformer station capacity until the end of the study period. Under the reference scenario, the need for new transformer station capacity arises in the mid to late 2020s. With the aggressive load growth assumptions in the high scenario, any new transformer station constructed in the area to address needs throughout the study period would be reaching its LTR by the end of the study period. These three scenarios represent the uncertainty associated with long-term forecasts and are an example of why a different approach is required for long-term versus near- and medium-term planning.

For needs appearing in the long term, there is an opportunity to develop and explore a broader set of options, as specific projects do not need to be committed immediately. This approach is designed to: maintain flexibility; avoid committing ratepayers to investments before they are needed; provide adequate time to assess the success of current and future potential conservation measures in the study area; test emerging technologies; engage with communities and stakeholders; and lay the foundation for informed decisions in the future.

Due to the long-term capacity need forecast for the Barrie and Innisfil areas, PowerStream and InnPower will be undertaking a LAP study for the Barrie TS service area, with support from the IESO's Conservation Fund. This study will help determine the conservation potential, specifically for the Barrie TS area, beyond the LTEP targets already accounted for in the planning demand forecast (e.g., additional incentives and adders to refocus existing CDM programs, new programs, behind-the-meter generation, energy storage, etc.). The study will provide a better understanding of the associated costs and feasibility of CDM measures to address the identified capacity needs in the area, better informing options for the next planning cycle.

PowerStream has also implemented a pilot project in their southern service territory to study the benefits and economics of aggregated customer side generation and storage. The results of this study can be used to inform further discussion and development of non-wires solutions for the long-term needs in the Barrie/Innisfil Sub-region for the next planning cycle.

Broad community and public engagement, including with local Indigenous communities, is essential to develop the long-term plan. It is recommended that engagement involve several phases: addressing public education/awareness of electricity issues, planning, technologies, and regulatory requirements; fostering an understanding of community growth and its relationship to electricity needs; understanding the pros and cons of various alternatives to meeting long-term needs; and obtaining input on community preferences for various approaches to meeting needs.

To provide input and advice on engagement plans for the Barrie/Innisfil Sub-region, the Working Group will establish a LAC consisting of community representatives and stakeholders.

8.1 Recommended Actions and Implementation

A number of alternatives are possible to meet the sub-region's long-term needs. While specific solutions do not need to be committed to today, it is appropriate to begin work now to gather information, monitor developments, engage the community, and develop alternatives to support decision making in the next iteration of the IRRP. The long-term plan sets out the near-term actions required to ensure that options remain available to address future needs if and when they arise.

For some needs, such as the transformer station capacity need at Everett TS, the solution is straightforward (changing the CT ratios) and can be easily implemented by the transmitter when required. For other needs, such as the transformer station capacity needs in the south Barrie and Innisfil areas, the recommended actions focus on monitoring and information gathering, community engagement, and more detailed options development for non-wires solutions prior to the next planning cycle.

The recommended actions and deliverables for the long-term plan are outlined in Table 8-1, along with their recommended timing, and the parties with lead responsibility for implementation.

Table 8-1: Recommended Near-Term Actions for Addressing Long-Term Needs

Recommended Action(s)/Deliverable(s)	Lead Responsibility	Timeframe/ Need Date
Formation of a LAC.	IESO	To be formed early 2017

Recommended Action(s)/Deliverable(s)	Lead Responsibility	Timeframe/ Need Date
Conduct a LAP study to determine cost and feasibility of CDM measures to address capacity needs in the Barrie TS service area.	PowerStream & InnPower	Study to be completed by end of 2017
Coordinate the development work for the Metrolinx traction power station supply to maintain the future supply option for south Barrie and Innisfil utilizing the same corridor.	Hydro One	To be monitored
Change the CT ratios at Everett TS when required.	Hydro One	To be monitored – pre 2027
Monitor, and prepare an annual update to the Working Group, on demand, conservation and DG trends and achievement in the area.	IESO	Annually

The Working Group will work with the local communities to monitor leading indicators for growth in the Barrie/Innisfil Sub-region. This includes monitoring changes to growth targets, the composition and location of specific customer segments (residential, commercial, industrial), and electricity impacts from implementation of community energy plans. If these or other factors affect service reliability or the capacity of the local electricity delivery systems a new IRRP process may be initiated ahead of the five year planning cycle. Examples of developments that could trigger revisiting the plan prior to the next cycle include:

- Critical PowerStream customers reaching 95% of their projected load
- InnPower's expanded feeder supply from Barrie TS reaching 95% of its firm capacity
- Innisfil completing the servicing of their development lands
- Detailed design and development work proceeds for the Metrolinx electrification plans and requires further coordination with the Working Group
- Significant changes to the study area's forecast growth

The Working Group will continue to meet at regular intervals during the implementation phase of this IRRP to monitor developments in the sub-region, progress towards the deliverables in Table 8-1, and developments that would trigger an early return to the IRRP process.

9. Community 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 engagement activities undertaken to date and next steps for the Barrie/Innisfil IRRP.

A phased community engagement approach is being undertaken for the Barrie/Innisfil 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 in 2013 to determine how to improve the regional planning and siting process, and they now guide IRRP outreach with communities and will ensure this dialogue continues as the plan moves forward.

Figure 9-1: Summary of Barrie/Innisfil Community Engagement Process

Creating Transparency:
Creation of IRRP Information Resources

- Dedicated Barrie/Innisfil IRRP web page created on IESO website providing background information, the IRRP Terms of Reference and listing of the Working Group members
- Dedicated web page created on Hydro One website
- Self-subscription service established for the South Georgian Bay/Muskoka planning region for subscribers to receive regional planning updates
- Status: complete

Engaging Early and Often:
Municipal and Indigenous Outreach

- Posting of South Georgian Bay/Muskoka Scoping Assessment Report for feedback (May-June 2015)
- Group and individual meetings held with municipalities from across the planning region in Barrie, Innisfil, Simcoe County and Springwater (August - November 2015); follow-up meetings held to discuss the draft IRRP recommendations prior to posting the IRRP (November 2016)
- Meeting held with Indigenous communities from across the South Georgian Bay/Muskoka planning region.
- Status: initial outreach complete; dialogue continues

Bringing Communities to the Table:
Broader Community Outreach

- Barrie/Innisfil LAC to be formed in early 2017; dedicated Barrie/Innisfil engagement web page to be added to IESO website
- LAC meetings to discuss longer-term needs in the sub-region, and broader community engagement to help inform the next planning cycle
- LAC meetings will be open to the public; materials will be posted to the engagement webpage
- Status: beginning in early 2017; on-going

9.1 Creating Transparency

To start the dialogue on the Barrie/Innisfil IRRP and build transparency in the planning process, a number of information resources were created for the plan. A dedicated Barrie/Innisfil web page[11] was created on the IESO website including information on why an IRRP was being developed for the Barrie/Innisfil Sub-region, the IRRP Terms of Reference and a listing of the organizations involved. A dedicated email subscription service was also established for the broader South Georgian Bay/Muskoka planning region where communities and stakeholders could subscribe to receive email updates about the IRRP.

9.2 Engage Early and Often

Early communication and engagement activities for the Barrie/Innisfil IRRP included posting the South Georgian Bay/Muskoka Region Scoping Assessment document for comment and undertaking meetings with communities in the planning area to discuss the development of the plan and obtain early input and feedback.

9.3 South Georgian Bay/Muskoka Region Scoping Assessment Outcome Report

The draft South Georgian Bay/Muskoka Region Scoping Assessment Outcome Report was posted to the IESO website in May 2015 for comment, and a final version was posted on June 22, 2015. The Scoping Report identified the need for an IRRP for the Barrie/Innisfil Sub-region and presented the Terms of Reference for the development of the plan.

9.4 Municipal Meetings

Meetings with area municipalities are one of the first steps in engagement for all regional plans. In August through November 2015, the Working Group held individual and group municipal meetings in Barrie, Innisfil, Simcoe County, and Springwater to initiate discussions on the IRRP. Key discussion topics included: the regional planning process and findings in the South Georgian Bay/Muskoka Scoping Report, the need for an IRRP for the Barrie/Innisfil area, municipal growth plans and electricity growth forecasts, the identified electricity needs in the area and future engagement activities. Attendees provided insight on updated municipal growth plans, reinforced the importance of community engagement for project/infrastructure siting, and expressed an interest in having a LAC as a forum to bring local municipalities to the table and engage in a singular dialogue.

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[11] http://www.ieso.ca/Pages/Ontario%27s-Power-System/Regional-Planning/South-Georgian-Bay-Muskoka/Barrie/Innisfil.aspx

9.5 Bringing Communities to the Table

To continue the dialogue on regional planning, a LAC[12] will be established for the Barrie/Innisfil Sub-region in early 2017. The role of the LAC will be to provide advice and recommendations on the development of options to meet the longer-term electricity needs in the area, as well as to provide input on broader community engagement. LACs are comprised of municipal, Indigenous, environmental, business, sustainability and community representatives. All LAC meetings are open to the public and meeting information and materials will be posted on the Barrie/Innisfil engagement webpage.

Development of the Barrie/Innisfil LAC will be carried out through a request for nominations process promoted by the following activities: advertisements in local newspapers and digital (website) advertising in communities throughout the planning area; emails sent to municipal representatives across the region; meetings with Indigenous communities for the broader region; and an e-blast sent to the IESO's South Georgian Bay/Muskoka subscribers list. Information will also be posted to the dedicated Barrie/Innisfil IRRP webpage.[13]

Meetings were also held with the area municipalities in November 2016 prior to the posting of the IRRP to discuss the recommendations included in the plan as well as future engagement activities such as the development of a LAC.

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[12] http://www.ieso.ca/Pages/Participate/Regional-Planning/Local-Advisory-Committees.aspx

[13] http://www.ieso.ca/Pages/Ontario%27s-Power-System/Regional-Planning/South-Georgian-Bay-Muskoka/Barrie/Innisfil.aspx

10. Conclusion

This report documents an IRRP that has been carried out for the Barrie/Innisfil area, a sub-region of the OEB's South Georgian Bay/Muskoka planning region. The IRRP identifies electricity needs in the Barrie/Innisfil Sub-region over the 20-year period from 2015-2034, identifies preferred "wires" solutions to address near-term needs, and lays out actions to monitor, defer, and address needs that may arise in the long term.

Implementation of the near-term plan is already underway. Hydro One is developing the Barrie Area Transmission Reinforcement project, and LDCs are continuing to implement their existing CDM plans. PowerStream and InnPower have also initiated a LAP study for the Barrie TS, which will be used to inform the long-term options discussion for the next planning cycle and discussion with the future LAC.

To further refine and implement the preferred near-term "wires" solutions, it is recommended that an RIP be initiated. The RIP for the broader South Georgian Bay/Muskoka Region is to be led by Hydro One Transmission. For recommendations relating to Barrie/Innisfil, the RIP process should include PowerStream and InnPower as working group members. The IESO will continue to provide support throughout the RIP process, and assist with any regulatory matters that may arise during plan implementation.

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

The Barrie/Innisfil Sub-region Working Group will continue to meet at regular intervals to monitor developments in the sub-region and track progress toward the plan deliverables. In particular, the actions and deliverables associated with peak demand reducing initiatives will require annual review of system demand and program achievement to determine whether new initiatives are required. In the event that underlying assumptions change significantly, local plans may be revisited through an amendment, or by initiating a new regional planning cycle sooner than the OEB-mandated 5-year schedule.

BARRIE / INNISFIL SUB-REGION
INTEGRATED REGIONAL RESOURCE PLAN - APPENDICES

Part of the South Georgian Bay/Muskoka Planning Region | December 16, 2016

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Barrie/Innisfil Sub-region IRRP

Appendix A: Demand Forecast

Appendix A: Demand Forecast

A.1 Gross Demand Forecast

Figures A-1 and A-2 show the gross demand forecast in terms of summer peak demand, for both the overall Barrie/Innisfil Sub-region and the individual transformer stations included in the study area. The gross demand forecast reflects existing customer connection requests as well as load projections based on municipal and regional plans for the area. Appendices A.1.1, A.1.2, and A.1.3 describe the LDCs' gross demand forecasting methodologies and assumptions.

The starting points for the forecast were developed by the Working Group. Station summer peak load from 2014 was used as the starting point. Adjustments were made to account for any non-native load in the peak hour (i.e., load transfers). The peak was also adjusted for median weather conditions using Hydro One's 2014 weather correction factor for the Essa zone. All forecasts provided by the LDCs assumed median weather conditions and a power factor of 0.9.[1]

The forecasts for the Barrie/Innisfil IRRP were created prior to the release of the provincial government's Climate Change Action Plan. The plan could have implications for the long-term load growth in the region, particularly the region's classification as summer peaking versus winter peaking (i.e., a change in the time/season of peak demand could occur with a long-term move to electric heat pumps). The magnitude of the region's long-term energy and capacity needs could also vary depending on electric vehicle penetration and operation (i.e., on-peak versus off-peak charging). Potential impacts are not yet well understood at a regional level. As such, future planning cycles will attempt to capture these impacts.

[1] Since Barrie TS and Midhurst TS have low voltage capacitor banks installed the power factor in real time is likely greater than 0.9. The assumed power factor is a conservative assumption used for forecasting and need identification purposes.

Table A-1: Gross Demand Forecast Scenarios 2015-2034 – Barrie/Innisfil Sub-region

Gross Demand Forecast Scenarios (MW)																				
Subsystems	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
Reference Scenario	448	466	482	506	531	553	569	587	605	621	638	654	670	686	702	722	736	751	767	782
High Scenario	452	475	496	527	559	587	613	638	662	687	710	734	758	782	806	830	852	875	898	921
Low Scenario	444	456	468	486	505	520	532	543	554	565	575	585	596	606	616	625	634	643	652	661

Table A-2: LDC Gross Station Peak Forecasts (Reference Scenario)

LDC Gross Station Peak Demand Forecasts (MW)																				
Station	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
Midhurst TS	182	188	193	198	204	210	216	221	227	232	239	244	249	256	261	269	274	281	286	293
Barrie TS	107	112	116	124	132	140	148	156	163	170	177	184	191	197	203	210	214	219	225	230
Everett TS	63	64	67	69	71	73	75	77	79	81	82	85	87	89	91	94	96	99	101	103
Alliston TS	96	101	107	115	123	129	131	133	136	138	139	141	143	145	147	149	151	153	154	156

A.1.1 PowerStream: Gross Forecast Methodology and Assumptions

PowerStream Inc. ("PowerStream") provides service to more than 365,000 customers across eleven Simcoe County and York sub-region communities including Alliston, Aurora, Barrie, Beeton, Bradford West Gwillimbury, Markham, Penetanguishene, Richmond Hill, Thornton, Tottenham and Vaughan. Collingwood, Stayner, Creemore and Thornbury are serviced through a partnership with the Town of Collingwood in the ownership of Collus PowerStream.

PowerStream's service area in Barrie encompasses the City of Barrie boundaries, excluding the annexed lands. PowerStream's primary distribution voltages in Barrie are 44 kV, 13.8 kV and 4.16 kV.

The City of Barrie is supplied by fourteen 44kV feeders from three Hydro One owned transformer stations. These 44 kV feeders supply 25 PowerStream owned Municipal Substations ("MS") that lower the voltage to PowerStream's primary distribution voltage in each respective region; nine 13.8 kV MS's and sixteen 4.16 kV MS's.

Factors that Affect Electricity Demand

The City of Barrie is located within the Greater Golden Horseshoe - a sub-region that accounts for 70% of Ontario's GDP and that has experienced significant population and employment growth over the past 10 years. According to the Watson "City of Barrie Growth Management Strategy Report", Barrie's population is anticipated to reach 210,000 by 2031. This presents an increase in population from 2006 to 2031 of approximately 76,300.

Over the 25-year forecast period, the City's total number of housing units is forecast to increase from 46,505 in 2006 to 78,705 in 2031, a total increase of 32,300 units. Single detached and semidetached housing are expected to represent approximately 58% of total new construction over the forecast period. Medium and high density households are forecast to comprise the remaining 18% and 24% of the new housing stock, respectively. The percentage of new housing by type is expected to gradually shift towards medium and high density housing units.

Barrie is actively encouraging the growth of the transportation and warehousing/wholesale trade sector, as well as manufacturing, construction, professional and scientific services and health services. Barrie has strong assets that serve a regional service function for Simcoe County. Three notable assets include the Royal Victoria Hospital, Georgian College and the SpringBOARD Innovation Centre.

Simcoe County has experienced increased employment in the areas of Health Care and Social Assistance (2,965 new jobs), Public Administration (2,500 new jobs), and Professional and Technical Services (1,335 new jobs). Barrie was forecast to post a total of 73,500 jobs in 2015 with an annual employment growth of 1.4%, resulting in 90,000 jobs by 2031.

A number of projects are currently under construction in the Barrie area including two large commercial developments, as well as three large mixed residential/commercial developments. Numerous industrial subdivisions are identified for potential development in Barrie, including four subdivisions covering approximately 75 hectares. In addition to the future industrial subdivisions, there are four existing data centers that will be implementing their next phase of development, resulting in a significant increase in load.

Forecast Methodology and Assumptions

The following sections describe PowerStream's load forecast methodology for the reference, high and low scenarios.

Reference Scenario

PowerStream's methodology for developing the base load forecast for Barrie consisted of a number of elements, including past system peak performance, statistical trend analysis, and an end-use analysis using the latest information gathered from meetings with the City of Barrie and Simcoe County. During the meetings information was gathered on projected residential and non-residential developments, population and employment growth. The Hemson Report, Watson Report, and the Places to Grow plan were used in conjunction with the information gathered from meetings with the City of Barrie and Simcoe County.

The forecast was based on a coincident system peak for Barrie with a percentage allocation of loading to each respective high voltage transformer station based on historical loading. This approach ensured that any potential load transfers within the boundaries of PowerStream's service territory encompassing the City of Barrie were accounted for during the summer peak.

The reference scenario assumed a conservative load growth forecast for the four large data centers in Barrie based upon the historical loading at each respective facility.

High & Low Scenario

The low growth scenario assumes lower housing and population numbers, as per the City of Barrie Watson Growth Management Strategy Report low growth scenario. This scenario reflects a slow-down in development of residential and commercial units as a reflection of dampened economic activity.

The high growth scenario assumes housing and population numbers achieving the targets outlined in province's Growth Plan for the Greater Golden Horseshoe, 2006, as amended ("Places to Grow"). This scenario also reflects the original load forecast levels and timeline outlined for each of the respective four data centers located in Barrie.

A.1.2 InnPower: Gross Forecast Methodology and Assumptions

InnPower provides service to the Town of Innisfil, as well as lands annexed by the City of Barrie in 2010. InnPower's distribution loads are supplied via 10 distribution stations which are supplied by five 44 kV feeders and four distribution feeders from Hydro One owned distribution stations (i.e., Cookstown DS and Thornton DS); three feeders originating from Alliston TS, one from Barrie TS, and one from Everett TS. InnPower's distribution voltages include 27.6 kV and 8.32 kV.

InnPower is currently a winter peaking utility. When accounting for diversity with the other LDCs at the substation level, however, the stations supplying InnPower are summer peaking. With anticipated growth from new developments and changing demographics, InnPower expects to transition to a summer peak. As such, InnPower has provided a summer peak forecast in-line with the sub-region's peak demand needs.

Factors that Affect Electricity Demand

Growth in the InnPower service territory is influenced primarily by the province's Places to Grow plan. Growth targets for the Town of Innisfil and portions of the City of Barrie have the largest impact on InnPower's future demand.

The Barrie/Innisfil Boundary Adjustment Act came into effect on January 1, 2010, granting the City of Barrie approximately 2,300 hectares of Innisfil lands for development purposes. These lands were to help fulfill the growth targets put forth in the province's Places to Grow plan. While the lands are now part of the City of Barrie they are still serviced by InnPower.

InnPower has potential industrial and commercial growth from proposed development of sites around Highway 400 and the Innisfil Beach Road area. Five commercial development sites exist today, with the potential for over 100 lots to be developed. There is an on-going environmental assessment for the impact of required water and wastewater facilities around the Highway 400 corridor.

There are additional development plans within the Town of Innisfil, including an all-season resort community planned for the development of Big Bay Point. The development has been approved and includes over 1,600 new customers over a 10-year period. Construction began in 2015.

Forecast Methodology and Assumptions

The following sections describe InnPower's load forecast methodology for the reference, high and low scenarios.

Reference Scenario

InnPower's forecast uses an end-use model where the primary input is new dwelling construction activities. This includes a forecast number of homes to be built in each year, based on the population growth targets, existing and proposed subdivision plans, and historical build rates. The reference scenario is generally in-line with the municipal plans and accounts for the latest schedule – at the time of forecast creation – for the servicing of the Highway 400 development lands.

High & Low Scenario

The high scenario assumes the full population and growth targets outlined in the provincial Places to Grow plan are realized. It also assumes the most optimistic forecast for housing construction. The low scenario reflects the low growth scenario, particularly for the Barrie Annexed lands, from the Watson Report – also reference by PowerStream.

A.1.3 Hydro One Distribution: Gross Forecast Methodology and Assumptions

Hydro One Distribution provides electricity service to counties and townships throughout the province. In the Barrie/Innisfil region, their service territory includes townships surrounding Midhurst, Barrie, Innisfil, Alliston and Bradford, as well as the Honda plant in Alliston.

Table A-3 shows the allocation of Hydro One Distribution's provincial load within the study area.

Table A-3: Allocation of Hydro One Distribution Supply by TS

Share of Hydro One Load			
Station	**% of Overall TS Load**	**% of Hydro One Load in the Study Area**	**% of Hydro One Load in Ontario**
Alliston TS	55%	46%	1.6%
Everett TS	21%	11%	0.4%
Midhurst TS	26%	43%	1.5%

Factors that Affect Electricity Demand

Hydro One's load forecast is an econometric forecast. Main drivers in the development of the forecast are provincial economic and demographic factors, such as Ontario GDP and historical and projected housing starts

Forecast Methodology and Assumptions

The following sections describe Hydro One Distribution's load forecast methodology for the reference, high and low scenarios.

Reference Scenario

Load growth in the area, relative to provincial trends was also taken into account. Moreover, as a main local forecast driver, the proposed Honda expansion over the forecast period and its impact on Hydro One's load were taken into account.

For the reference scenario, Table A-4 and Table A-5 show the provincial GDP and housing starts assumption used to create the forecast.

Table A-4: Ontario GDP Growth Assumption for Hydro One Forecast Development

	2015	2016	2017	2018	2019	2020
GDP Growth	2.8%	2.5%	2.5%	2.3%	2.2%	2.0%

Table A-5: Ontario Housing Starts Assumptions for Hydro One Forecast Development

	2015	2016	2017	2018	2019	2020
Ontario Housing Starts (in thousands)	61.8	61.8	65.5	68.9	72.2	69.2

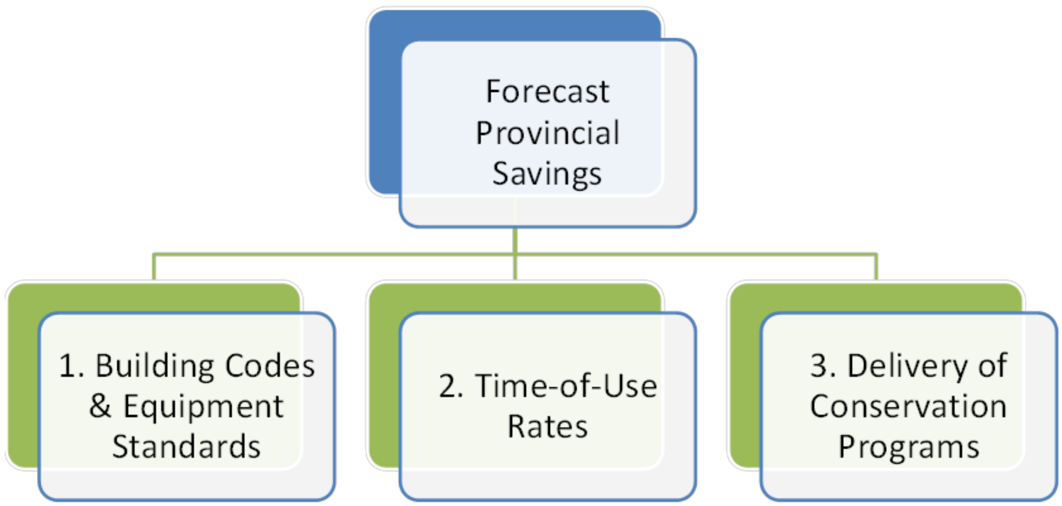
High & Low Scenario

The high and low scenarios were developed using a standard deviation approach. The high and low scenarios represent a standard deviation above and below the reference case, respectively. This approach reflects the inherent variability of load.

A.2 Conservation Forecast in Regional Planning – Barrie/Innisfil IRRP

Conservation savings were separated into the three main categories shown in Figure A-1 below. The impacts of the savings for each category were allocated according to the forecast residential, commercial, and industrial gross demand. This appendix provides additional breakdowns of the conservation savings estimates for the Barrie/Innisfil Sub-region and provides more detail onto how the savings for the three savings categories were developed.

Figure A-1: Conservation Savings Categories



1. *Savings due to Building Codes & Equipment Standards*
2. *Savings due to Time-of-Use Rate structures*
3. *Savings due to the delivery of Conservation Programs*

A.2.1 Estimating Savings from Building Codes and Equipment Standards

Ontario Building codes and equipment standards set minimum efficiency levels through regulations. Under the IESO's current analysis, building codes and equipment standards are forecast to contribute a saving of about 10 TWh by 2032 in Ontario. To estimate the impact on the region, the associated peak demand savings for building codes and equipment standards are estimated and compared with the provincial gross peak demand forecast. From this comparison, annual savings percentages were developed for the purpose of allocating the associated savings to each TS in the sub-region by sector.

Figure A-2: Split of Building Codes & Equipment Standards Savings

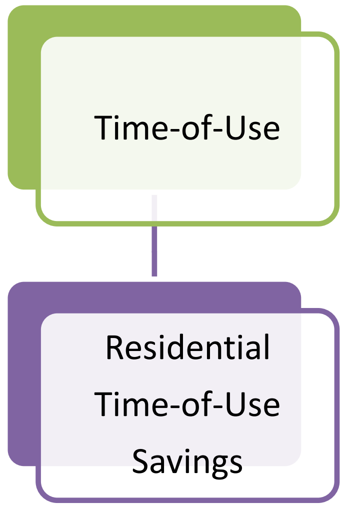
**Savings are projected for Residential & Commercial sectors only*

Annual savings percentages were applied to the forecast sector demand at each TS to develop an estimate of peak demand impacts from codes and standards. By 2032, the residential sector will see about 6.8% peak demand savings through standards, while the commercial sector will see about 6.5% peak demand savings through codes.

A.2.2 Savings from Time-of-Use rates

Almost all residential customers in Ontario have smart meters installed and are on Time-of-Use ("TOU") rates. Small commercial customers, with loads less than 50 kW, are also on TOU rates. Using results from the TOU impact evaluation completed in 2014 and assuming some regional characteristics, an average peak demand reduction of 0.68% was assumed for residential customers who switched to TOU rates. This means a peak reduction of 0.68% across residential customers in the province. This peak reduction factor is assumed to be consistent for residential customers in this sub-region. This percentage impact is assumed to continue, increasing the total forecast peak demand savings as residential sector demand grows. The percentage was applied to the incremental forecast residential load of each TS in the study to estimate the peak reduction. The same impact evaluation found that the peak impact of TOU rates on small commercial customers is minimal. Therefore the commercial sector TOU impact is assumed to be already embedded in the base year and no incremental savings are considered in the forecast.

Figure A-3: Time-of-Use Savings

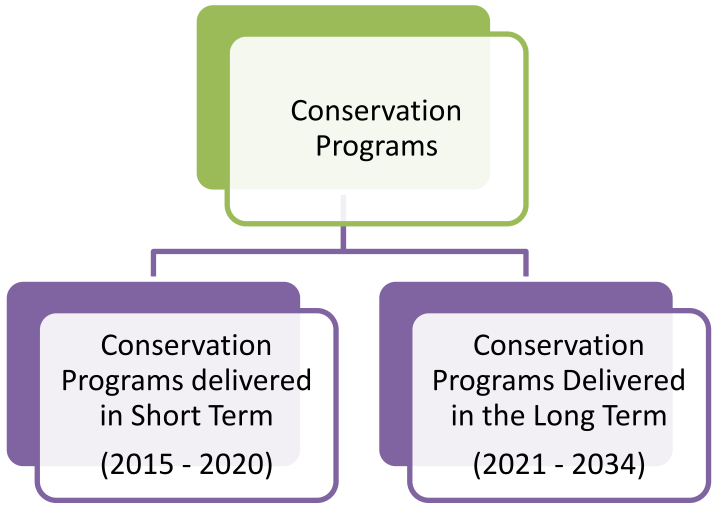


**No incremental savings are assumed for commercial sector*

A.2.3 Savings from the Delivery of Conservation Programs

Conservation programs across the province are forecast to reduce about 20 TWh of energy consumption by 2032. For the short term (2015 – 2020), all LDCs have conservation and demand management ("CDM") plans in place, which includes detailed savings projections from energy efficiency and conservation behind the meter generation. Their plans also indicate how their conservation efforts will integrate with regional planning. As per the Minister's direction for the Conservation First Framework ("CFF"), the IESO is to encourage LDCs to incent measures with persisting savings, peak demand reductions, and those that address local system needs. It is expected that LDCs will meet their CFF conservation targets and provide the estimated benefit that was forecast. The estimated peak impact can be found within the CDM plans; these savings values are used in the demand and conservation forecast for the sub-region. For the long term (2020 – 2034), the achievable potential was estimated in a 2014 study; future programs will be designed to achieve these identified savings. The provincial forecast savings were allocated to the sub-region and transformer stations according to their respective load.

Figure A-4: Timeframes for Conservation Program Savings



Savings from Programs Delivered in the Short Term

CDM plans that were provided by each of the participating LDCs for the CFF contained information that was used to estimate the conservation savings to be considered for short-term program savings. The peak demand savings from Conservation Programs delivered in the short term include all persisting savings till 2034 due to the expected delivery of programs from 2015 – 2020. As a part of the plan, each LDC submitted Cost Effectiveness Calculators that contained estimated energy and demand savings associated with the delivery of programs from 2015 – 2020. The peak demand savings were estimated in the tools for summer demand savings.

For LDCs that only have a portion of their total service territory associated with this IRRP (i.e., PowerStream and Hydro One Distribution), only a portion of their expected savings are estimated to occur in the region. To determine this, the amount of conservation savings in the sub-region is assumed to be proportional to the amount of the LDC's energy within the region, i.e., if 60% of the LDC's energy is served in this region, and then 60% of the expected conservation savings for that LDC are estimated to occur within this sub-region. When the total peak demand savings for the sub-region has been estimated, it is allocated at each TS according to its the relative share of residential, commercial, and industrial gross demand.   For savings due to behind-the-meter generation projects, savings are applied directly to the TS to which the project is expected to connect.

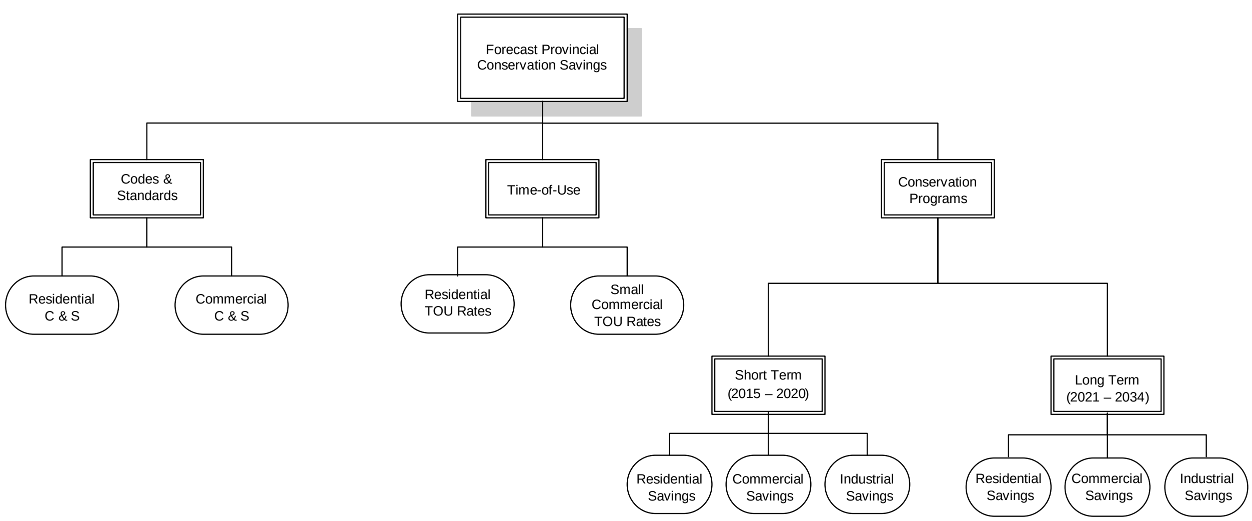
Savings from Programs Delivered in the Long Term

Savings from programs beyond the CFF also were broken down by three sectors, based on the IESO data and analysis. Energy savings were converted to peak reductions using the hourly profile for each sector. These peak reductions were compared with the respective gross peak to derive percentage saving for each year. These percentages were applied to the forecast demand at each TS to develop an estimate of MW peak demand impacts.

In addition to distribution connected customers, planned conservation savings from transmission connected customers were also considered. These customers are eligible for the Industrial Accelerator Program ("IAP") and their peak demand savings were analyzed on a case by case basis. For any transmission connected customers in the study sub-region that have applied for IAP, their expected peak savings were included in the conservation forecast.

As described above, peak demand savings were estimated by sector for each conservation category. They were summed for each TS in the region. The analyses were done under normal weather conditions and can be adjusted to reflect extreme weather conditions. The resulting conservation savings, along with distributed generation resources were applied to the gross demand to determine the net peak demand for further planning analyses.

Figure A-5: Map of Conservation Savings



A.2.4 LDC Load Segmentation Data

In order to generate the CDM forecast, the LDCs provided an allocation of their demand at each station bus for each customer segment. The LDCs' allocation information for 2015 is shown in Table A-6, aggregated to the TS level.

Table A-6: Allocation of Customer Segments at Each TS used for the CDM Forecast

Transformer Station	Sector	% of Total TS Load (2015)
Midhurst TS	Residential	52%
	Commercial	44%
	Industrial	4%
Barrie TS	Residential	51%
	Commercial	42%
	Industrial	7%
Everett TS	Residential	58%
	Commercial	34%
	Industrial	8%
Alliston TS	Residential	34%
	Commercial	20%
	Industrial	46%

A.2.5 Conservation Forecast

The forecast peak demand savings from CDM programs is shown in Table A-7. The savings in Table A-7 are based off the gross forecast accounting for the PowerStream load transfer. Due to the methodology used, there is a slight variance (1 MW over the full study period) of the conservation forecast for the scenarios with and without the load transfer. This comes from the different customer segment allocations at Midhurst TS versus Barrie TS and the difference in savings associated with those segments for the 27 MW of transferred load.

Table A-7: Peak Demand (MW) Savings by TS from 2013 LTEP Conservation Targets

Conservation Forecast (MW)																				
Station	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
Midhurst TS	1	2	3	5	7	8	10	12	15	17	20	23	27	30	32	36	40	40	41	41
Barrie TS	0	1	2	3	5	5	6	7	8	10	11	13	15	16	18	20	21	22	22	22
Alliston TS	0	1	1	2	3	3	4	5	5	6	6	7	8	8	9	10	11	11	11	11
Everett TS	0	1	1	2	2	3	3	4	4	4	5	5	5	6	6	7	7	7	7	8
Total	**2**	**5**	**7**	**12**	**16**	**19**	**23**	**28**	**32**	**37**	**42**	**48**	**55**	**60**	**65**	**73**	**79**	**80**	**81**	**82**

A.3 Expected Peak Demand Contribution of Contracted Distributed Generation

The installed capacity of contracted DG is adjusted to reflect the expected power output at the time of local area peak, based on resource-specific peak capacity contribution values. As of June 2015, there was forecast to be approximately 14.6 MW of additional contracted solar generation connected in the Barrie/Innisfil Sub-region in 2015. Based on analysis of historical solar data for sites in the IESO's Essa zone determining the coincidence of production to the zonal peak, a 22% capacity contribution at peak demand was assumed for solar in the Essa zone for the summer months. Based on this factor, the expected peak demand contribution of contracted DG in the Barrie/Innisfil Sub-region is show in Table A-6. There was an additional 250 kW of pending solar projects, and a 1 MW solar project unassigned to a TS for the Barrie area, with potential 2016 in-service dates. These represent an additional potential 0.28 MW reduction in peak for the study area, but were not included in the forecast since their status was not committed (at the time when this forecast was generated) and the capacity saving could not be allocated to the correct TS. However, this potential additional 0.28 MW reduction was accounted for in decision making for the IRRP.

Table A-6: Expected Peak Demand Contribution from Contracted Distributed Generation

Expected Peak Demand Contribution from Contracted Distributed Generation (MW)																				
Station	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
Midhurst TS	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8
Barrie TS	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
Alliston TS	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14
Everett TS	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22
Total	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2

A.4 Planning Forecast Scenarios

As described in the main report, three planning forecasts were developed for the Barrie/Innisfil IRRP driven by the uncertainties surrounding economic factors influencing residential and commercial growth in the area. The planning forecast takes the gross forecast data provided by the LDCs, accounts for the demand impacts of conservation and DG, outlined in sections A.2 and A.3 respectively, and adjusts for the impact of extreme weather conditions. Extreme weather correction is done using Hydro One's correction factor of 6% between median and extreme weather conditions. Table A-8 shows the planning demand forecasts for the reference, high, and low scenarios respectively. Table A-9 and Table A-10 show the planning demand forecasts for the transformer stations with and without the recommended PowerStream load transfer, respectively.

Table A-8: Peak Demand Planning Forecast for the Barrie/Innisfil Sub-region and the Barrie Sub-area

Planning Demand Forecast Scenarios (MW)																						
Subsystems	**Scenario**	**2014 Historical (Extreme Weather)**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
Barrie Innisfil Sub-region	Reference Scenario	455	469	485	501	522	543	563	577	592	606	618	630	642	652	664	676	689	698	713	729	745
	High Scenario	455	474	495	515	544	573	600	623	645	667	687	707	727	746	766	786	804	821	844	868	892
	Low Scenario	455	465	475	486	500	516	529	537	544	552	559	564	569	573	579	584	587	590	598	607	616
Barrie Sub-area (Portion of the Barrie/Innisfil Sub-region)	Reference Scenario	297	302	312	320	331	343	356	366	377	388	396	407	415	422	431	439	449	454	466	477	489
	High Scenario	297	305	317	328	344	361	378	394	410	425	440	454	467	481	495	509	520	531	547	563	579
	Low Scenario	297	300	305	310	318	326	335	342	348	354	360	365	369	372	377	381	384	386	393	400	407

Table A-9: Reference Case Station Peak Demand Planning Forecasts - *Without* Load Transfer

Planning Station Peak Demand Forecasts (MW)																					
Station	**2014 Historical (Median Weather)**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
Midhurst TS	177	189	194	198	203	207	212	216	220	224	227	232	235	237	241	245	249	252	258	264	270
Barrie TS	104	113	118	121	129	135	143	150	157	164	169	175	181	186	190	195	201	203	208	214	219
Everett TS	61	66	67	70	71	73	75	76	78	80	82	83	85	86	88	90	93	95	97	99	101
Alliston TS	89	101	106	111	119	127	133	135	137	139	140	141	142	144	145	146	148	149	151	153	154

Table A-10: Reference Case Station Peak Demand Planning Forecast - *With* Load Transfer

Planning Station Peak Demand Forecasts (MW)																					
Station	**2014 Historical (Median Weather)**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
Midhurst TS	177	189	194	198	203	207	241	245	248	252	255	259	262	263	267	270	274	277	283	289	295
Barrie TS	104	113	118	121	129	135	115	122	129	136	141	148	154	159	164	169	175	177	182	188	193
Everett TS	61	66	67	70	71	73	75	76	78	80	82	83	85	86	88	90	93	95	97	99	101
Alliston TS	89	101	106	111	119	127	133	135	137	139	140	141	142	144	145	146	148	149	151	153	154

Barrie/Innisfil Sub-region IRRP

Appendix B: Needs Assessment

Appendix B: Needs Assessment

This appendix provides information on the methodology and data used to assess needs and options in the Barrie/Innisfil IRRP.

B.1 Addressing Near-Term/Existing Barrie TS Needs

To address the existing capacity need and the identified end-of-life needs at Barrie TS, different transmission-based solutions were investigated by the Working Group. Based on the assessment of these options along with the system needs, the rebuild and uprating of Barrie TS and E3/4B to 230 kV, with 75/125 MVA transformers was chosen as the preferred option. A description of the alternatives considered by the Working Group is provided below.

B.1.1 Alternatives Considered for the End-of-Life Rebuild of Barrie TS

Rebuild Barrie TS Like-for-Like

Replacing assets like-for-like is standard practice when they reach end-of-life. The existing 115/44 kV transformers at Barrie TS are 55/92 MVA units, which are no longer a Hydro One standard transformer size. To replace the station like-for-like, customized transformers, along with an additional custom spare transformer, would be required. The end-of-life 230/115 kV autotransformer at Essa TS would be replaced with a standard 75/125 MVA unit, and the additional end-of-life 44 kV and 115 kV station equipment at Barrie and Essa TS would be replaced, along with aging conductor and poles along the E3/4B circuits.

The like-for-like replacement option would not result in any incremental capacity being made available at Barrie TS or on the 115 kV supply from Essa TS. With the forecast growth in the south Barrie and Innisfil areas, the like-for-like option means that a significant near-term capacity need would remain in the Barrie TS service area. This option would also limit opportunities for future expansion of the 230 kV to accommodate future capacity increases in the area (i.e., a future TS in south Barrie, or the proposed Metrolinx 230 kV connection) since the 115 kV line cannot meet future capacity needs. This would increase the cost associated with future supply options, which would be needed in the near term since the capacity need in the Barrie area wouldn't be fully addressed by the like-for-like option.

The high level estimated cost of this option is approximately $40 million.

Rebuild Barrie TS to 230 kV Supply

The existing 230/115 kV autotransformers at Essa TS, which are reaching their end-of-life, currently only supply the E3/4B circuits to Barrie TS. With the end-of-life replacement at Barrie TS there is an opportunity to retire the 115 kV switchyard and 230/115 kV autotransformers at Essa TS and supply the rebuilt Barrie TS directly from the 230 kV system.

By converting E3/4B to a 230 kV supply, additional transmission capacity will remain available in the south Barrie and Innisfil area to service the forecast long-term growth in the area. The available capacity on the 230 kV circuits can be used for an additional future TS and for the 230 kV customer connection proposed by Metrolinx.

The transformers at Barrie TS can be replaced with standard 230/44 kV units. Hydro One has two standard transformer sizes which were considered as potential options: 75/125 MVA and 50/83 MVA. The 50/83 MVA units were ruled out since they would result in a decrease in available capacity at Barrie TS and would have required the advancement of additional station capacity in the south Barrie and Innisfil areas. The chosen option of 75/125 MVA units provides an additional 50 MW to meet near- and medium-term needs.

The high level budgetary cost of this option is $80 million.

New DESN at Essa TS & Decommission Barrie TS

The alternative to rebuilding Barrie TS would be to decommission the Barrie TS site and build a new 230/44 kV DESN station at the Essa TS site, with standard 75/125 MVA transformers. From the Essa TS site, 44 kV feeders would utilize the decommissioned E3/4B corridor to re-supply the feeders formerly fed by Barrie TS.

While a new 230/44 kV DESN station at the Essa TS would provide additional capacity in the near term (an additional ~50 MW), it would limit options for future expansion of the 230 kV to accommodate future capacity increases in the area (i.e., future transformer station in south Barrie, or the proposed Metrolinx 230 kV connection).

The high level budgetary cost of this option – not accounting for additional distribution costs to reroute feeders to Essa TS – is $65-70 million.

B.2 Station Capacity Assessment

In order to assess the need for additional TS capacity, planning forecasts were compared to the 10-day limited time rating ("LTR") of the stations in the sub-region. In order to account for the transfer capability between adjacent stations, two groupings of stations were considered:

- **Barrie Sub-area:** Midhurst TS and Barrie TS
- **Barrie/Innisfil Sub-region:** Midhurst TS, Barrie TS, Everett TS, Alliston TS

For each of these station groupings, their combined capacity was compared against their combined planning forecast to determine where new station capacity is most likely to be required. In addition, each station's planning forecast was compared against its LTR.

B.2.1 Reference Case

The needs identified in the Barrie/Innisfil IRRP were based off the reference forecast. Table B-1 shows the reference forecast by area and station, without the recommended PowerStream load transfer. The use of red text indicates transformer capacity at the existing Barrie TS being exceeded until the rebuild is completed in 2020. As stated in the main IRRP document, PowerStream can use their existing emergency load transfer capabilities or other operational measures (e.g., operating with open bus ties) if this load materializes to mitigate risk. Red text along with red shading indicates that the transformer capacity of the station or area is forecast to be exceeded, accounting for the planned Barrie TS rebuild. Cells highlighted in purple indicate to what year needs can be deferred to with the PowerStream load transfer. A revised forecast fully reflecting the transfer is shown in Table B-2.

The need which arises in 2027 at Everett TS can be fully deferred past the end of the study period with the recommended change in CT ratios, allowing the station's full LTR of 117 MVA (or 105 MW) to be utilized.

Table B-1: Reference Planning Station Forecast - *Without* Load Transfer

Transformer Station	Historical Peak (MW) Weather Corrected	Station Peak Planning Forecast (MW)																			
	2014	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
Midhurst TS	177	189	194	198	203	207	212	216	220	224	227	232	235	237	241	245	249	252	258	264	270
Barrie TS	104	113	118	121	129	135	143	150	157	164	169	175	181	186	190	195	201	203	208	214	219
TOTAL BARRIE AREA	**297***	**302**	**312**	**320**	**331**	**343**	**356**	**366**	**377**	**388**	**397**	**407**	**416**	**423**	**432**	**440**	**450**	**455**	**466**	**478**	**490**
Everett TS	61	66	67	70	71	73	75	76	78	80	82	83	85	86	88	90	93	95	97	99	101
Alliston TS	89	101	106	111	119	127	133	135	137	139	140	141	142	144	145	146	148	149	151	153	154
TOTAL STUDY AREA	**455***	**469**	**485**	**501**	**522**	**543**	**563**	**577**	**592**	**606**	**618**	**631**	**643**	**653**	**665**	**677**	**690**	**699**	**714**	**730**	**746**

* Values were adjusted to extreme weather, other historical values shown are only adjusted to median weather; planning forecast assumes extreme weather conditions.

Table B-2: Reference Planning Station Forecast - *With* Load Transfer

Transformer Station	Historical Peak (MW) Weather Corrected	Station Peak Planning Forecast (MW)																			
	2014	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
Midhurst TS	177	189	194	198	203	207	241	245	248	252	255	259	262	263	267	270	274	277	283	289	295
Barrie TS	104	113	118	121	129	135	115	122	129	136	141	148	154	159	164	169	175	177	182	188	193
TOTAL BARRIE AREA	**297***	**302**	**312**	**320**	**331**	**343**	**356**	**366**	**377**	**388**	**396**	**407**	**415**	**422**	**431**	**439**	**449**	**454**	**466**	**477**	**489**
Everett TS	61	66	67	70	71	73	75	76	78	80	82	83	85	86	88	90	93	95	97	99	101
Alliston TS	89	101	106	111	119	127	133	135	137	139	140	141	142	144	145	146	148	149	151	153	154
TOTAL STUDY AREA	**455***	**469**	**485**	**501**	**522**	**543**	**563**	**577**	**592**	**606**	**618**	**630**	**642**	**652**	**664**	**676**	**689**	**698**	**713**	**729**	**745**

* Values were adjusted to extreme weather, other historical values shown are only adjusted to median weather; planning forecast assumes extreme weather conditions.

B.2.2 Low Scenario

Under the low scenario, the recommended near-term actions address the sub-region's needs until the end of the study period.

Table B-3: Low Scenario Planning Station Forecast - *With* Load Transfer

Transformer Station	Historical Peak (MW) Weather Corrected	Station Peak Planning Forecast (MW)																			
	2014	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
Midhurst TS	177	188	190	193	195	197	229	230	231	233	234	235	236	236	237	238	238	238	242	245	249
Barrie TS	104	112	115	118	123	129	106	112	116	121	125	130	133	136	140	143	146	148	151	155	158
TOTAL BARRIE AREA	**297***	**300**	**305**	**310**	**318**	**326**	**335**	**342**	**348**	**354**	**360**	**365**	**369**	**372**	**377**	**381**	**384**	**386**	**393**	**400**	**407**
Everett TS	61	65	67	68	69	70	70	72	73	74	75	76	77	78	79	80	81	82	84	85	87
Alliston TS	89	99	103	107	113	120	123	124	124	124	124	123	123	123	123	122	122	122	122	122	123
TOTAL STUDY AREA	**455***	**465**	**475**	**486**	**500**	**516**	**529**	**537**	**544**	**552**	**559**	**564**	**569**	**573**	**579**	**584**	**587**	**590**	**598**	**607**	**616**

* Values were adjusted to extreme weather, other historical values shown are only adjusted to median weather; planning forecast assumes extreme weather conditions.

B.2.3 High Scenario

Under the high scenario, the recommended near-term actions address the sub-region's needs until the medium term. If load growth is aggressive and aligns with the high growth scenario, the next planning cycle may begin earlier, reflecting the potential need for additional station capacity in Barrie area in the mid-2020s and the typical 5-7 year lead time. The Working Group will continue to monitor load growth, along with CDM and DG uptake. Under the high scenario, capacity needs also arise for Midhurst TS and Alliston TS near the end of the study period.

Table B-4: High Scenario Planning Station Forecast - *With* Load Transfer

Transformer Station	Historical Peak (MW) Weather Corrected	Station Peak Planning Forecast (MW)																			
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Midhurst TS	177	191	197	204	210	216	251	257	262	268	273	278	283	289	294	301	305	311	320	329	338
Barrie TS	104	114	119	124	134	145	127	138	148	158	167	176	184	192	200	208	215	220	227	234	241
TOTAL BARRIE AREA	**297***	**305**	**317**	**328**	**344**	**361**	**378**	**394**	**410**	**425**	**440**	**454**	**467**	**481**	**495**	**509**	**520**	**531**	**547**	**563**	**579**
Everett TS	61	67	69	72	74	76	78	81	83	86	88	91	93	95	98	101	103	106	109	112	115
Alliston TS	89	102	109	116	126	136	144	148	152	156	159	163	166	170	173	177	180	184	188	193	197
TOTAL STUDY AREA	**455***	**474**	**495**	**515**	**544**	**573**	**600**	**623**	**645**	**667**	**687**	**707**	**727**	**746**	**766**	**786**	**804**	**821**	**844**	**868**	**892**

* Values were adjusted to extreme weather, other historical values shown are only adjusted to median weather; planning forecast assumes extreme weather conditions.

B.2.4 LTR Reference Table

The 10-day limited time ratings ("LTR") used for the station capacity analyses are shown in Table B-5. A power factor of 0.9 was used for the conversion to MWs, consistent with the load forecast.

Table B-5: 10-Day Limited Time Ratings for Station Transformers in the Barrie/Innisfil Sub-region

Station/Bus	Existing LTR (MVA)	Existing LTR (MW)	LTR with Recommended Plan (MVA)	LTR with Recommended Plan (MW)
Midhurst TS	337	304	337	304
Barrie TS	115	103	168	151
Everett TS	95	86	117	105
Alliston TS	211	190	211	190

B.3 Essa Bulk Study

B.3.1 Application of Planning Criteria

In accordance with the Ontario Resource and Transmission Assessment Criteria ("ORTAC"), the system must be designed to provide continuous supply to a local area, under specific transmission and generation outage scenarios summarized in Table B-6. Voltage and thermal limitations should be respected under these outage conditions.

Table B-6: ORTAC Criteria - Transmission and Generation Outage Scenarios

Pre-contingency		Contingency[1]	Thermal Rating	Maximum Permissible Load Rejection
All transmission elements in-service	Local generation in-service	N-0	Continuous	None
		N-1	LTE[2]	None
		N-2	LTE[2]	150 MW
	Local generation out-of-service	N-0	Continuous	None
		N-1	LTE[2]	150 MW[3]
		N-2	LTE[2]	>150 MW[3] (600 MW total)

1. N-0 refers to all elements in-service; N-1 refers to one element (a circuit or transformer) out-of-service; N-2 refers to two elements out-of-service (for example, loss of two adjacent circuits on same tower, breaker failure or overlapping transformer outage); N-G refers to local generation not available (for example, out-of-service due to planned maintenance).
2. LTE: Long-term emergency rating (50-hr rating for circuits, 10-day rating for transformers).
3. Only to account for the capacity of the local generating unit out-of-service.

ORTAC Load Security and Restoration

With respect to supply interruptions, ORTAC requires that the transmission system be designed to minimize the impact to customers of major outages, such as a contingency on a double-circuit tower line resulting in the loss of both circuits, in two ways: by limiting the amount of customer load affected; and by restoring power to those affected within a reasonable timeframe.

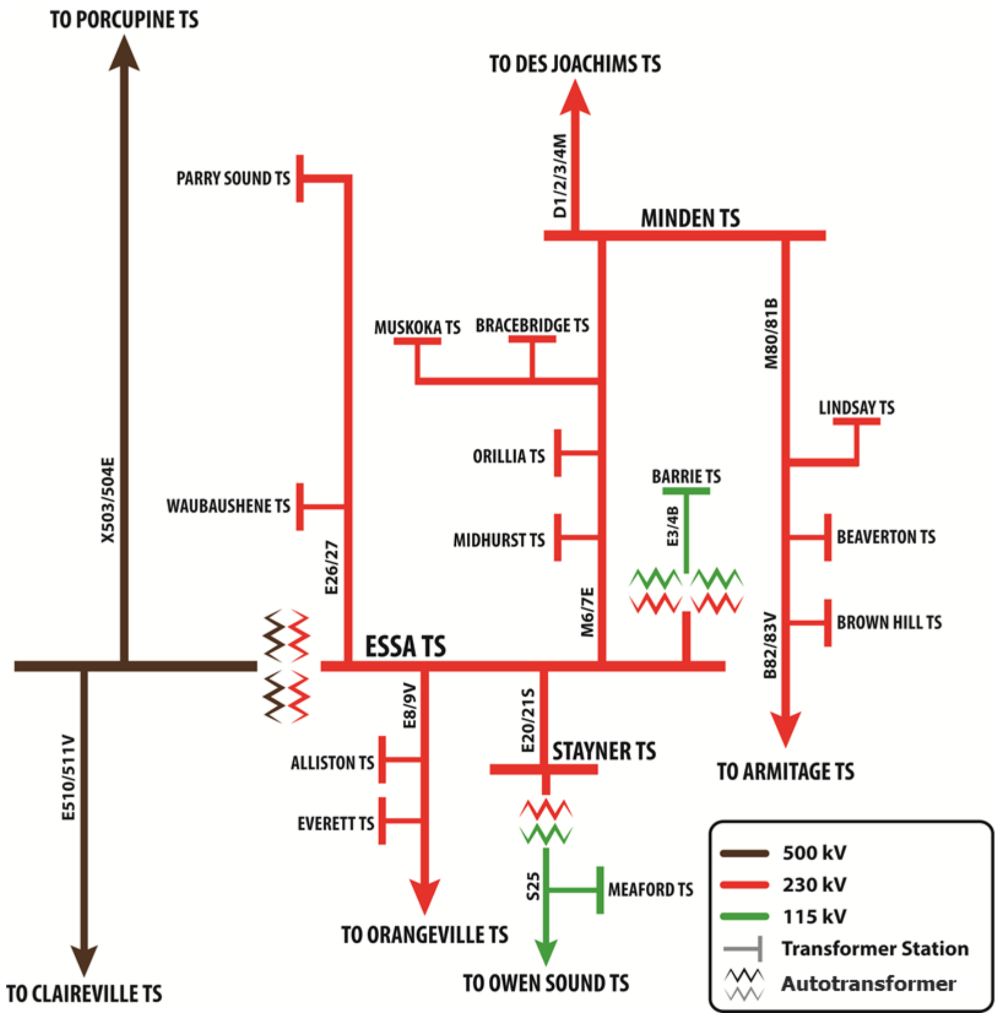
Specifically, ORTAC requires that no more than 600 MW of load be interrupted in the event of a major outage involving two elements. Further, load lost during a major outage is to be restored within the following timeframes:

- All load lost in excess of 250 MW must be restored within 30 minutes;
- All load lost in excess of 150 MW must be restored within four hours; and
- All load lost must be restored within eight hours.

B.3.2 Study Assumptions

Planning criteria were applied to assess supply capacity and reliability needs in the broader sub-region impacting the Essa autotransformers, including the Barrie/Innisfil and Parry Sound-Muskoka Sub-regions.

Figure B-1: Single Line Diagram for the Essa Bulk Study



The scope of the study included the following transmission elements:

- Essa 500/230 kV autotransformers T3 and T4
- Transmission circuits:
  - 500 kV: X503/504E, E510/511V
  - 230 kV: E8/9V, E20/21S, E26/27, M6/7E, M80/81B
  - 115 kV: E3/4B *(to be upgraded to 230 kV within the study period)*

- Transformer stations: Essa, Barrie, Stayner, Everett, Alliston, Waubaushene, Parry Sound, Midhurst, Orillia, Bracebridge, Muskoka, Minden, Lindsay, and Beaverton

The study considers the following contingencies:

- All single and double circuit outages in study scope
- Outages of one or both Essa 500/230 kV autotransformers
- Breaker failure contingencies at Essa, Minden, and in-line at Brown Hill
- Loss of generation at Des Joachims

PSS/E Base Case and Bulk System Conditions

The broader South Georgian Bay/Muskoka area was assessed using PSS/E Power System Simulation software. The PSS/E base case for the planning study was adapted from the 2016 PSS/E base case produced by the IESO.

Demand Forecast

The study was conducted for both winter and summer peak conditions. The IRRP forecasts for the Barrie/Innisfil and Parry Sound–Muskoka Sub-regions were used as the basis of the forecast. For stations not included in the scope of these studies, or for winter peaking information for the Barrie/Innisfil area, the Hydro One Needs Assessment forecast was used as a basis and extrapolated for the last 10 years of the study period.

North South Interface Flow Sensitivity

The Flow South conditions outlined in Table B-7 were tested to examine the impact of the North South interface on the timing of any identified needs.

Table B-7: Flow South Conditions Used to Examine Sensitivity

Base Case	Flow South
Summer Peak – Reference	1200 MW
Winter Peak – Reference	520 MW
Summer Peak – Extreme Flow South	1900 MW
Summer Peak – Flow North	-440 MW

Equipment Ratings

Transmission line and transformer ratings are as per transmitter records, assuming 35°C ratings for summer and 10°C ratings for winter. A wind speed of 4 km/h was respected for both the summer and the winter case.

Barrie/Innisfil Sub-region IRRP

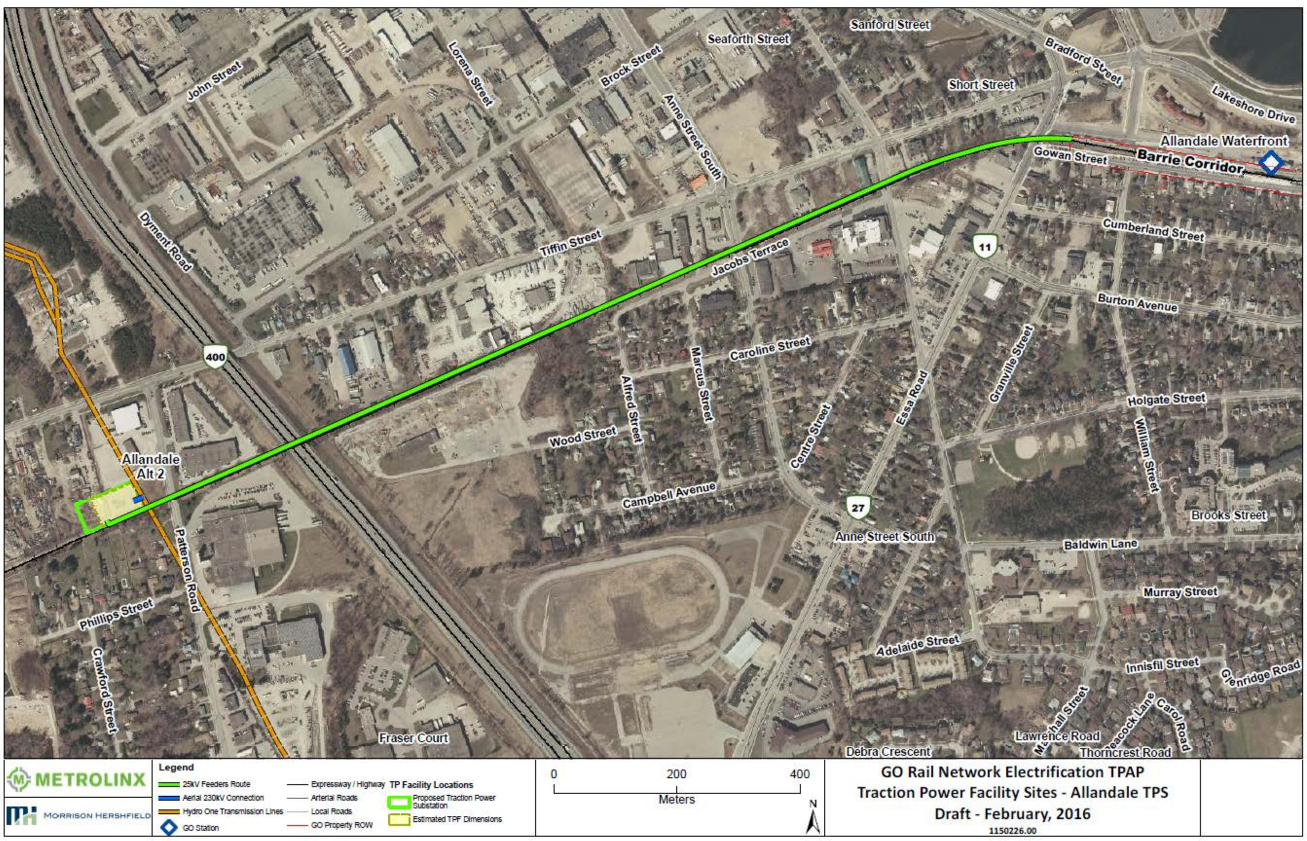
Appendix C: Other Planning Considerations

Appendix C: Other Planning Considerations

C.1 Metrolinx Electrification Plans – Barrie Area

Metrolinx is currently planning to install a traction power station ("TPS") for the Barrie line in the study area. The proposed location for the TPS is south of the existing Barrie TS. The TPS will be supplied by a short line-tap that will connect to the new Essa/Barrie 230 kV double-circuit line. Metrolinx is currently in the feasibility study phase of the project and more information will be available once it is complete. The map Metrolinx is currently using in their public consultation[2] has been included below, Figure C-1.

Figure C-1: Metrolinx Proposed Traction Power Station for the Barrie Line



[2] https://www.metrolinxengage.com/en/content/Barrie/corridor
https://www.metrolinxengage.com/sites/default/files/documents/go_electrification_public_meeting.pdf

PARRY SOUND / MUSKOKA SUB-REGION
INTEGRATED REGIONAL RESOURCE PLAN

Part of the South Georgian Bay/Muskoka Planning Region | December 16, 2016

ieso
Connecting Today. Powering Tomorrow.

Integrated Regional Resource Plan

Parry Sound/Muskoka

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

This IRRP was prepared on behalf of the Parry Sound/Muskoka Sub-region Working Group (the "Working Group"), which included the following members:

- Independent Electricity System Operator
- Hydro One Networks Inc. (Distribution)
- Hydro One Networks Inc. (Transmission)
- Lakeland Power Distribution Ltd.
- Midland Power Utility Corporation
- Newmarket-Tay Power Distribution Ltd.
- Orillia Power Distribution Corporation
- PowerStream Inc.
- Veridian Connections Inc.

The Working Group assessed the reliability of electricity supply to customers in the Parry Sound/Muskoka 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 Parry Sound/Muskoka Sub-region; and developed recommended actions, while maintaining flexibility in order to accommodate changes in key assumptions over time.

The Working Group members agree with the IRRP's recommendations and support implementation of the plan, subject to obtaining necessary regulatory approvals and appropriate community consultations.

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List of Abbreviations

Abbreviations	Descriptions
CCAP	Climate Change Action Plan
CDM or Conservation	Conservation and Demand Management
CEP	Community Energy Plans
CFF	Conservation First Framework
CHP	Combined Heat and Power
DG	Distributed Generation
DR	Demand Response
FIT	Feed-in Tariff
GHG	Greenhouse Gas
Hydro One	Hydro One Networks Inc. (Distribution and Transmission)
IAP	Industrial Accelerator Program
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
LAC	Local Advisory Committee
Lakeland Power	Lakeland Power Distribution Ltd.
LDC	Local Distribution Company
LMC	Load Meeting Capability
LTEP	(2013) Long-Term Energy Plan
LTR	Limited Time Rating
Midland PUC	Midland Power Utility Corporation
MW	Megawatt
Newmarket-Tay Power	Newmarket-Tay Power Distribution Ltd.
OEB or Board	Ontario Energy Board
OPA	Ontario Power Authority
Orillia Power	Orillia Power Distribution Corporation

Abbreviations	Descriptions
ORTAC	Ontario Resource and Transmission Assessment Criteria
OWA	Ontario Waterpower Association
PowerStream	PowerStream Inc.
PPWG	Planning Process Working Group
PPWG Report	Planning Process Working Group Report to the Board
RIP	Regional Infrastructure Plan
TOU	Time-of-Use
TS	Transformer Station
TWh	Terawatt-Hours
Veridian Connections	Veridian Connections Inc.
Working Group	Technical Working Group for Parry Sound/Muskoka Sub-region IRRP

1. Introduction

This Integrated Regional Resource Plan ("IRRP") for the Parry Sound/Muskoka Sub-region addresses the electricity needs for the sub-region over the next 20 years from 2015 to 2034 ("study period"). The IRRP was prepared by the Independent Electricity System Operator ("IESO") on behalf of the Technical Working Group (the "Working Group") for the Parry Sound/Muskoka Sub-region composed of the IESO, Hydro One Distribution and Hydro One Transmission[1], Lakeland Power Distribution Ltd. ("Lakeland Power"), Midland Power Utility Corporation ("Midland PUC"), Newmarket-Tay Power Distribution Ltd. ("Newmarket-Tay Power"), Orillia Power Distribution Corporation ("Orillia Power"), PowerStream Inc. ("PowerStream") and Veridian Connections Inc. ("Veridian Connections").

The area covered by the Parry Sound/Muskoka IRRP is a Sub-region of the South Georgian Bay/ Muskoka Region identified through the Ontario Energy Board ("OEB" or "Board") regional planning process. This sub-region roughly encompasses the Districts of Muskoka and Parry Sound and the northern part of Simcoe County. This sub-region is characterized by:

- **Diverse communities**: In addition to the "unorganized areas"[2] in the Parry Sound District, there are eight First Nation communities and 35 municipalities located in this sub-region, all of which are listed in Section 4.1. The communities have different local priorities and electricity needs. Some communities are engaging in community energy planning activities.

- **Large geographical area:** A mix of long and expansive 230 kilovolt ("kV") transmission, 44 kV sub-transmission and low-voltage distribution infrastructure are required to deliver electricity supply to the various communities and customers across this sub-region. The geography and sparsely populated areas make it challenging and costly to develop and maintain infrastructure.

- **Use of Electric Space and Water Heating:** Due to limited access to natural gas infrastructure in this sub-region, many communities rely on electric space and water heating, especially during the winter season. In addition to electricity, some customers also rely on other fuel types, such as wood, to meet their heating requirements.

[1] For the purpose of this report, "Hydro One Transmission" and "Hydro One Distribution" are used to differentiate the transmission and distribution accountabilities of Hydro One Networks Inc. ("Hydro One"), respectively.
[2] Unorganized areas are parts of the province where there is no municipal level of government. Services in these unorganized districts are typically administered by local services boards.

- **Modest Growth:** While relatively slower growth is expected in the manufacturing sector, growing First Nation communities, developments in the tourism and retail sector, and potential local economic development could contribute to higher electricity demand in the sub-region. Seasonal population driven by tourism and recreational activities may also increase electricity requirements over the longer term.

This IRRP fulfills the requirements for the sub-region as required by the IESO's OEB electricity licence. IRRPs are required to be reviewed on a 5-year cycle so that plans can be updated to reflect the changing electricity outlook. This IRRP will be revisited in 2021, or earlier if significant changes occur relative to the current forecast.

This IRRP report is organized as follows:

- A summary of the recommended plan for the Parry Sound/Muskoka Sub-region is provided in Section 2;
- The process used to develop the plan is discussed in Section 3;
- The context for electricity planning in the Parry Sound/Muskoka Sub-region and the study scope are discussed in Section 4;
- Demand forecast and conservation and demand management ("CDM" or "conservation") and distributed generation ("DG") assumptions are described in Section 5;
- Needs in the Parry Sound/Muskoka Sub-region are presented in Section 6;
- Options to address regional and local needs are addressed in Section 7;
- Recommended actions are set out in Section 8;
- A summary of community, Indigenous and stakeholder engagement to date is provided in Section 9; and
- A conclusion is provided in Section 10.

2. The Integrated Regional Resource Plan

The Parry Sound/Muskoka IRRP addresses the sub-region's electricity needs over the next 20 years, based on application of the IESO's Ontario Resource and Transmission Assessment Criteria ("ORTAC"). The IRRP was developed in consideration of a number of factors, including reliability, cost, technical feasibility, flexibility and also the diverse needs and unique characteristics of the sub-region.

The needs and recommended actions are summarized below.

2.1 Need to Minimize the Frequency and Duration of Power Outages

Customers and communities in the Parry Sound/Muskoka Sub-region experience more frequent and prolonged power outages relative to other communities and electricity customers in the province. Any outage along the 230 kV transmission, 44 kV sub-transmission and low-voltage distribution lines can interrupt the electricity supply to the communities and customers. Results from the service reliability performance assessment show that a number of 44 kV sub-transmission systems in this sub-region are performing below provincial average[3] in terms of frequency and duration of outages. Long 44 kV sub-transmission lines and off-road facilities are the main causes for frequent and prolonged outages for this sub-region. Lengthy distribution lines also typically exhibit lower levels of reliability because of increased exposure to trees and wildlife, and they sustain more damage from poor weather. Limited access to off-road facilities makes it difficult for repair crews to detect early signs of equipment failures, do preventative maintenance and restore power in a timely manner.

While major 230 kV transmission outages have been relatively infrequent in the Parry Sound/Muskoka Sub-region, the existing 230 kV transmission system has limited ability to restore power in a timely manner and minimize the number of customers impacted in the event of a major 230 kV transmission outage and does meet Ontario's planning criteria.

The Working Group has recommended a set of actions to minimize the frequency and duration of 44 kV related power outages and to bring the 230 kV transmission system in compliance with Ontario's planning standards.

[3] On average, customers being supplied from a typical 44 kV sub-transmission line in Ontario experience outages about two times a year with outages typically lasting 5 hours or less.

Recommended Actions

1. **Inform communities and Local Advisory Committee ("LAC")[4] members of the 44 kV sub-transmission system service reliability performance and the on-going maintenance and improvement initiatives in the Parry Sound/Muskoka Sub-region.**

   Hydro One Distribution will examine options to improve the reliability performance on the 44 kV sub-transmission system as part of their planning process. Hydro One Distribution will provide an update on measures to improve 44 kV sub-transmission system service reliability performance including any proposed capital plans. This update will be provided by end of 2017.

   The ability to implement any proposed capital investment plans will be contingent on the outcome of Hydro One Distribution's 2018-2022 rate filing application with the OEB.

2. **Examine the cost benefit and cost responsibility of options to resupply customers in Bracebridge, Gravenhurst, Muskoka Lakes and surrounding areas from alternate transformer station**

   Hydro One Distribution, Lakeland Power and Veridian Connections will examine various options to improve service reliability performance of the 44 kV sub-transmission system supplying the Bracebridge/Gravenhurst/Muskoka Lakes and surrounding areas, including the option to resupply customers in Bracebridge, Gravenhurst, Muskoka Lakes and surrounding areas from an alternate transformer station. The cost-benefit and cost responsibility of these options will be considered. The affected LDCs will discuss their assessment and decision with the Working Group through the regional planning process. This action is expected to be completed by the end of 2017. The results will be shared with LAC members and affected communities.

[4] A LAC for the Parry Sound/Muskoka Sub-region was established to allow community representatives to provide input on the status of local growth and developments, local planning priorities, energy planning activities (e.g., community energy planning), and opportunities to implement community-based energy solutions.

3. **Install two 230 kV motorized switches at Orillia TS**

   To restore power to customers in a timely manner in the event of a major outage on the Muskoka-Orillia 230 kV sub-system, the Working Group recommends proceeding with the installation of two 230 kV motorized switches at the Orillia Transformer Station ("TS"). The IESO will provide a letter to Hydro One Transmission to initiate project development work for the two 230 kV motorized switches at Orillia TS in 2017. Based on typical development timeline of switching facilities, the project is expected to be in-service by the end of 2020.

4. **Explore opportunities to improve resilience and service reliability at the community level**

   Some communities are engaged in community energy planning activities and interested in developing distributed energy resources. The IESO can facilitate discussions with First Nation communities, municipalities and LAC members on the opportunities to improve system resilience and service reliability through community energy planning and distributed energy resources and the cost-benefit of these opportunities.

2.2 Need to Provide Adequate Supply to Support Growth

Despite the relatively slow growth in this sub-region, the transformers supplying the Parry Sound and Waubaushene areas are approaching their maximum capacity in the near term. Additionally, the electricity demand on the 230 kV transmission system supplying the Orillia and Muskoka area may exceed capacity over the longer term.

Actions need to be taken to ensure that the regional electricity system has adequate supply to support growth in this sub-region over the planning period.

Recommended Actions

1. **Resupply some customers in the Parry Sound and Waubaushene areas from neighbouring transformer stations using existing and new distribution facilities to maximize the use of the existing system**

   The electricity demand at the Parry Sound TS has already exceeded the transformers' capacity. To manage the near-term demand growth in the area, about 6 Megawatts ("MW") at Parry Sound TS will be resupplied from Muskoka TS. To facilitate the transfer of load from Parry Sound TS to Muskoka TS, it is recommended that Hydro One Distribution seek approval to construct 44 kV feeder tie between the Muskoka TS M5 and M1 feeders. The siting and routing of these facilities will be determined as part of the project development process. Based on the typical project development timeline for 44 kV sub-transmission reinforcements, the project is expected to be in-service by 2020.

The electricity demand at Waubaushene TS is approaching it's transformer's capacity limits. To manage the near-term demand growth in the area, about 4 MW at Waubaushene TS will be resupplied from Orillia TS by 2020. If required, another 7 MW at Waubaushene TS can be resupplied from Midhurst TS upon completion of Barrie Area Transmission Reinforcement in the early 2020s. This can be done using existing distribution system and no new facilities will be required.

Midhurst TS is a major transformer station supplying the Barrie/Innisfil Sub-region. Resupplying some of the customers in the Waubaushene area from Midhurst TS could impact the timing and need for a new transformer station in the Barrie/Innisfil Sub-region over the longer term. As such, the Working Group will need to coordinate with the Barrie/Innisfil IRRP Working Group to monitor and manage the demand growth in the Waubaushene and Barrie/Innisfil Sub-region.

2. **Determine the cost and feasibility of using distributed energy resources and local conservation and demand management options to defer major capital investments in the Parry Sound/Muskoka Sub-region**

   With the relatively slow electricity demand growth forecast for this sub-region, there is an opportunity to use targeted local conservation and demand management, distribution-connected generation and/or other distributed energy resources to defer major capital investments that might otherwise be required (e.g., transformer upgrades at Parry Sound TS and Waubaushene TS, reinforcements on the Muskoka-Orillia Sub-system).

   The Working Group will initiate a local achievable potential study in the Parry Sound/Muskoka Sub-region to determine the cost and feasibility of using distributed energy resources and local demand management options to defer those major capital investments. A range of distributed energy resources and local demand management options may be suitable, including focused marketing and/or incentive adders to existing conservation programs, new conservation and demand management programs, local demand response, behind-the-meter generation and energy storage. These options will be considered as part of the study. This study will be initiated in early 2017 by the LDCs. The IESO will assist and provide funding for the study.

The Working Group will also work closely with communities to leverage local knowledge and community energy planning activities and to identify opportunities for targeted conservation and energy efficiency programs in First Nation communities and municipalities.

3. **Determine whether it is cost effective to advance the end-of-life replacement and to replace the aging assets with upgraded/upsized facilities at Parry Sound TS and Waubaushene TS**

   The transformers at Parry Sound TS and Waubaushene TS were installed in the early 1970's and therefore these transformers could be reaching end-of-life in the early 2030s. On an annual basis, Hydro One Transmission will provide updated information on the condition of aging equipment at the Parry Sound TS and Waubaushene TS. This information will be shared with the LAC and the Working Group. The IESO will continue to monitor the demand growth at Parry Sound TS and Waubaushene TS to determine whether it is cost effective to advance the end-of-life replacement and to replace aging assets with upgraded/upsized facilities. This need will be revisited in the next iteration of the plan.

4. **Monitor electricity demand growth closely to determine the timing of any investment decisions relating to the Muskoka-Orillia 230 kV sub-system**

   On an annual basis, the IESO will review electricity demand growth on the Muskoka-Orillia 230 kV sub-system with the Working Group and members of the LAC. This information will be used to determine if and when an investment decision for the Muskoka-Orillia 230 kV is required. This need will be revisited in the next iteration of the plan.

3. Development of the Integrated Regional Resource Plan

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 former Ontario Power Authority ("OPA") carried out 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 the fall of 2012, the Board convened a 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, and in May 2013, the PPWG released its report to the Board[5] ("PPWG Report"), setting out the new regional planning process. Twenty-one electricity planning regions were identified in the PPWG Report, and a phased schedule for completion was outlined. The Board endorsed the PPWG 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's licence changes required it to lead a number of aspects of regional planning. After the merger of the IESO and the OPA on January 1, 2015, the regional planning roles identified in the OPA's licence were to become the responsibility of the new IESO.

The regional planning process begins with a Needs Screening 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

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[5] http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2011-0043/PPWG_Regional_Planning_Report_to_the_Board_App.pdf

distribution solutions, or whether a more limited "wires" solution is the only option such that a transmission and distribution focused Regional Infrastructure Plan ("RIP") can be undertaken instead. The Scoping Assessment assesses what type of planning is required for each region. There may also be regions where infrastructure investments do not require regional coordination and so 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 and a preliminary Terms of Reference. If an IRRP is the identified outcome, the IESO is required to complete the IRRP within 18 months. If an RIP is the identified outcome, the transmitter takes the lead and has six months to complete it. It should be noted that a RIP may be initiated after the Scoping Assessment or after the completion of all IRRPs within a planning region; the transmitter may also initiate and produce a RIP report for every region. Both RIPs and IRRPs are to be updated at least every five years. The draft Scoping Assessment Outcome Report is posted to the IESO's website for a 2-week comment period prior to finalization.

The final IRRPs and RIPs are posted on the IESO's and relevant transmitter's websites, and may be referenced and submitted to the Board as supporting evidence in rate or "Leave to Construct" applications for specific infrastructure investments. These documents are also useful for municipalities, First Nation communities and Métis for planning, conservation and energy management purposes, as information for individual large customers that may be involved in the region, and for other parties seeking an understanding of local electricity growth, CDM and infrastructure requirements. Regional planning is not the only type of electricity planning that is undertaken in Ontario. As shown in Figure 3-1, there are three levels of planning that are carried out for the electricity system in Ontario:

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

Planning at the bulk system level typically considers the 230 kV and 500 kV network and examines province-wide system issues. Bulk system planning considers not only the major transmission facilities or "wires", but it also assesses the resources needed to adequately supply the province. This type of planning is typically carried out by the IESO pursuant to government policy. Distribution planning, which is carried out by Local Distribution Companies ("LDCs"), considers specific investments in an LDC's territory at distribution level voltages.

Regional planning can overlap with bulk system planning. For example, overlaps can occur at interface points where there may be regional resource options to address a bulk system issue. Similarly, regional planning can overlap with the distribution planning of LDCs. For example, overlaps can occur when a distribution solution addresses the needs of the broader local area or region. Therefore, it is important for regional planning to be coordinated with both bulk and distribution system planning as it is the link between all levels of planning.

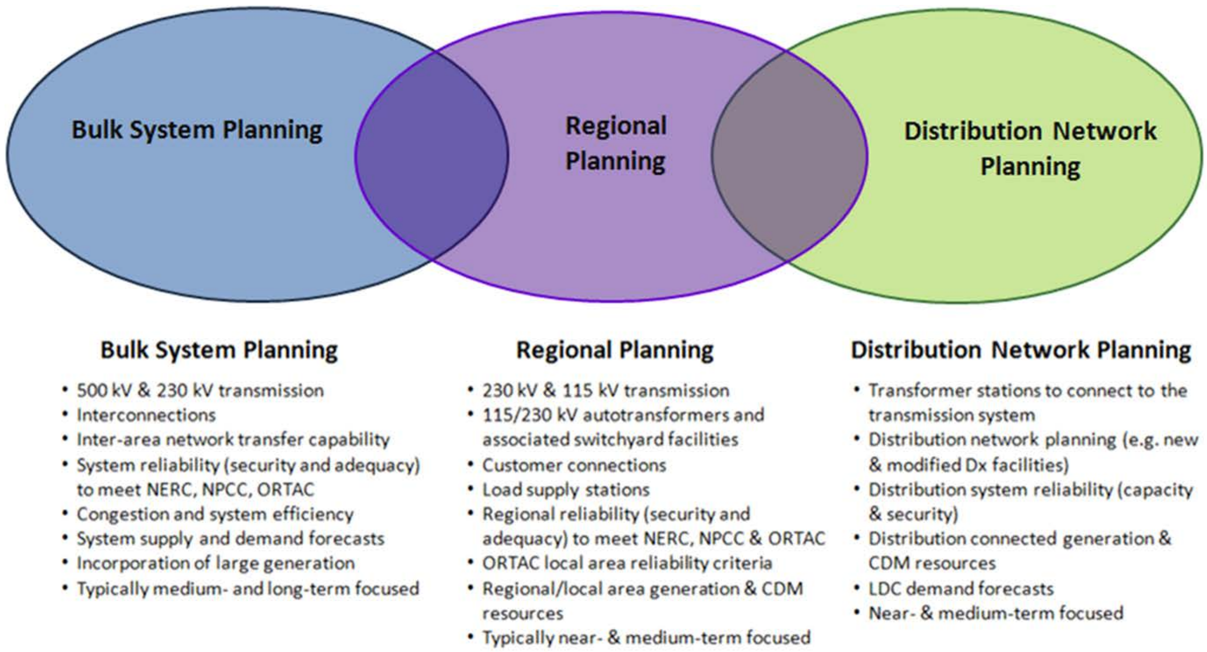


Figure 3-1: Levels of Electricity System Planning

By recognizing the linkages with bulk and distribution system planning, and coordinating multiple needs identified within a region over the long term, the regional planning process provides a comprehensive assessment of a region's electricity needs. Regional planning aligns near- and long-term solutions and puts specific investments and recommendations coming out of the plan in perspective. Furthermore, regional planning optimizes ratepayer interests by avoiding piecemeal planning and asset duplication, and allows Ontario ratepayer interests to be represented along with the interests of LDC ratepayers, and individual large customers. IRRPs evaluate the multiple options that are available to meet the 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.

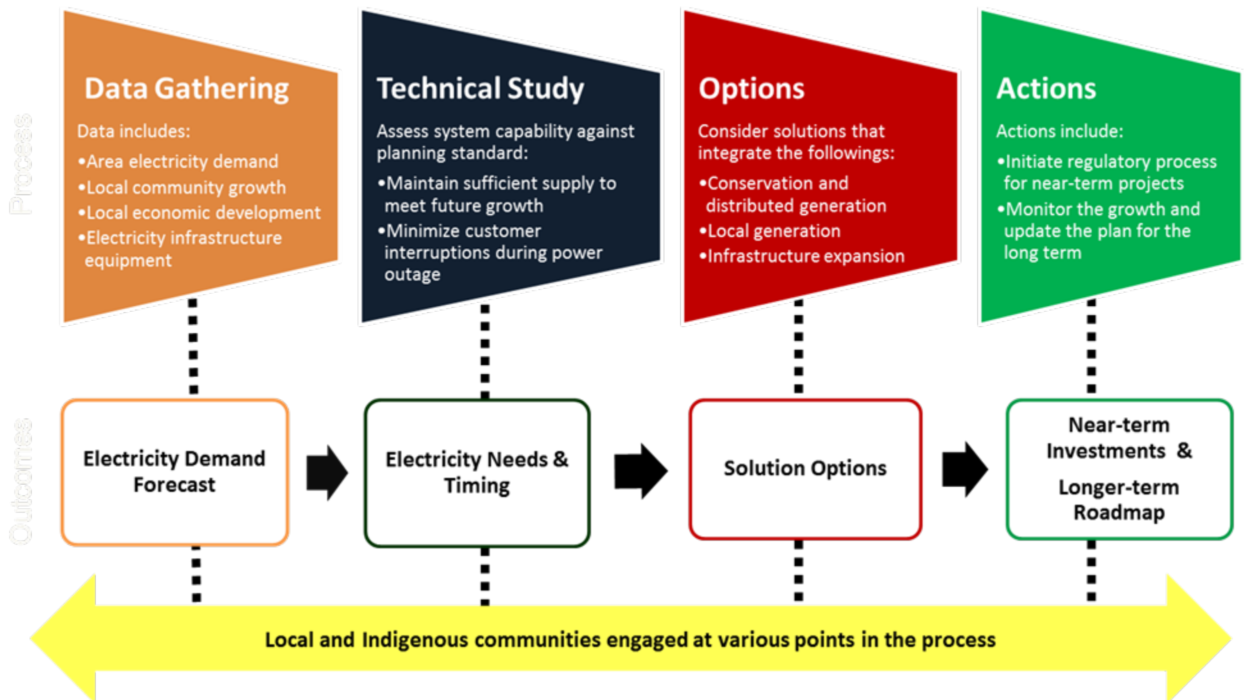
3.2 The IESO's Approach to Integrated Regional Resource Planning

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

The IRRP describes the Working Group's recommendations for system enhancements based on different scenarios. The Working Group also recommends staging options to mitigate reliability and cost risks related to demand forecast uncertainty associated with large individual customers. The IRRP seeks to ensure flexibility is maintained such that changing long-term conditions may be accommodated.

In developing this IRRP, the Working Group followed a number of steps. These steps included: data gathering, including development of electricity demand forecasts; technical studies to determine electricity needs and the timing of these needs; the development of potential options; and, preparation of a recommended plan including actions for the near and longer term. Throughout this process, engagement was carried out with local municipalities, First Nation communities, Métis community councils and local stakeholders. These steps are illustrated in Figure 3-2 below.

Figure 3-2: Steps in the IRRP Process



This IRRP documents the inputs, findings, and recommendations developed through the process described above, and provides recommended actions for the various entities responsible for plan implementation.

3.3 Parry Sound / Muskoka Sub-region Working Group and IRRP Development

In 2014, the lead transmitter – Hydro One Transmission – initiated a Needs Screening process for the South Georgian Bay/Muskoka planning region. The South Georgian Bay/Muskoka Needs Screening study team determined that there was a need for coordinated regional planning, resulting in the initiation of the Scoping Assessment process.

The South Georgian Bay/Muskoka Scoping Assessment Outcome Report [6] was finalized on June 22, 2015 and identified two sub-regions for coordinated regional planning: Parry Sound/Muskoka and Barrie/Innisfil. The two sub-regions are shown in Figure 3-3.

[6] South Georgian Bay/Muskoka Region Scoping Assessment Outcomes report (see IESO website: whttp://www.iemo.com/Documents/Regional-Planning/South-Georgian-Bay-Muskoka/SGBM-Scoping-Process-Outcome-Report-Final-20150622.pdf)

Figure 3-3: South Georgian Bay/Muskoka Region and Sub-regions

Subsequently, the Working Groups were formed to carry out the IRRP for the Parry Sound/Muskoka and Barrie/Innisfil Sub-regions. According to the OEB regional planning process, the Working Groups had 18 months to develop the IRRP.

In addition to the formation of the Working Groups, a LAC for the Parry Sound/Muskoka was established to allow community representatives to provide input on the status of local growth and developments, local planning priorities, energy planning activities (e.g., community energy planning), and opportunities to implement community-based energy solutions. Further detail regarding community and stakeholder engagement activities is provided in Section 9.

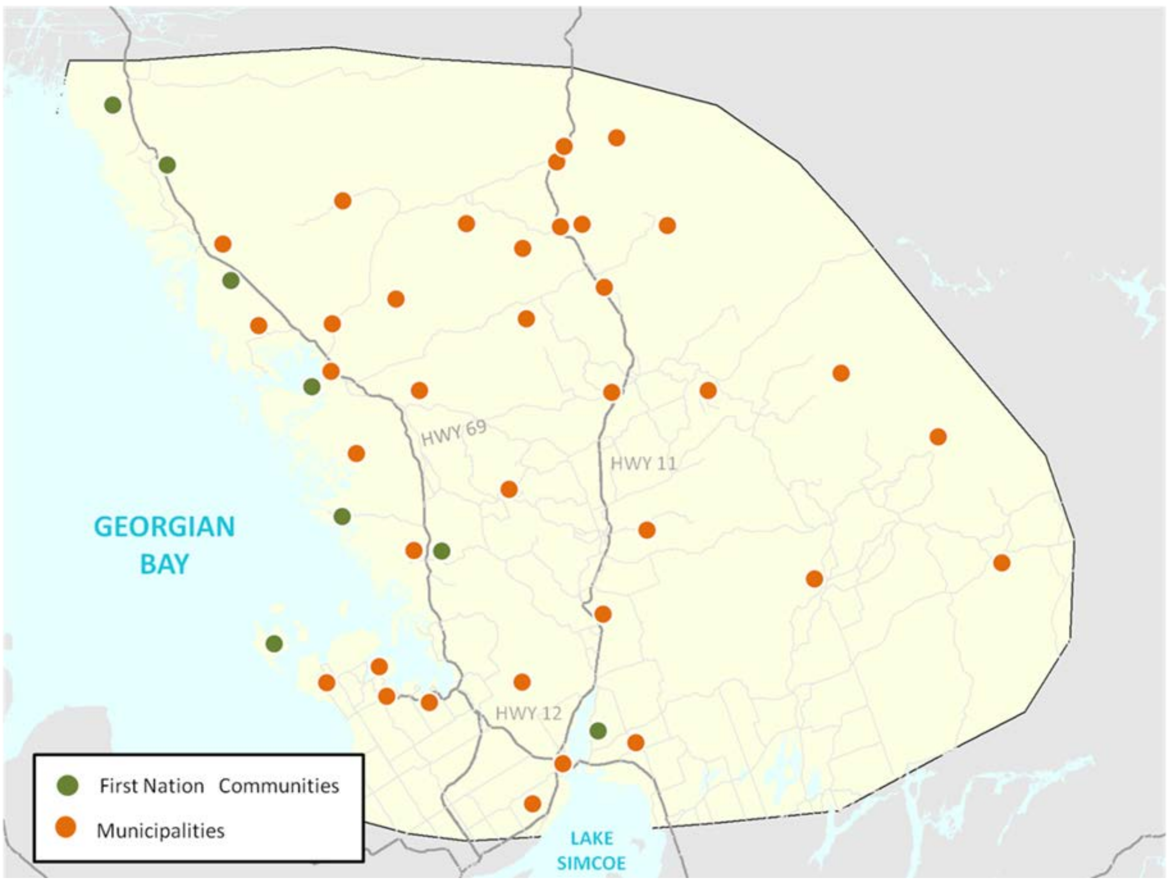
4. Background and Study Scope

The study scope of the IRRP is described in Section 4.1. Section 4.2 describes the electricity system supplying the Parry Sound/Muskoka Sub-region.

4.1 Parry Sound / Muskoka - Study Scope

The Parry Sound/Muskoka Sub-region roughly encompasses the Districts of Muskoka and Parry Sound and the northern part of Simcoe County. The approximate geographical boundaries of the sub-region are shown in Figure 4-1.

Figure 4-1: Geographical Boundaries of the Parry Sound/Muskoka Sub-region



The Parry Sound/Muskoka Sub-region includes the following First Nation communities:

- Henvey Inlet
- Magnetawan
- Shawanaga
- Wasauksing
- Moose Deer Point
- Beausoleil
- Wahta Mohawks
- Chippewas of Rama

The sub-region also includes the following municipalities:

- City of Orillia
- Municipality of Highlands East
- Municipality of Magnetawan
- Municipality of McDougall
- Municipality of Whitestone
- Town of Bracebridge
- Town of Gravenhurst
- Town of Huntsville
- Town of Kearney
- Town of Midland
- Town of Parry Sound
- Town of Penetanguishene
- Township of Algonquin Highlands
- Township of Armour
- Township of Carling
- Township of Georgian Bay
- Township of Joly
- Township of Lake of Bays
- Township of McKellar
- Township of McMurrich-Monteith
- Township of Minden Hills
- Township of Muskoka Lakes
- Township of Oro-Medonte
- Township of Perry
- Township of Ramara
- Township of Ryerson
- Township of Seguin

- Township of Severn
- Township of Strong
- Township of Tay
- Township of the Archipelago
- Township of Tiny
- United Townships of Dysart, Dudley, Harcourt, Guilford, Harburn, Bruton, Havelock, Eyre and Clyde
- Village of Burk's Falls
- Village of Sundridge

In addition, there are a number of unorganized areas in the District of Parry Sound.

The Parry Sound/Muskoka IRRP assesses the reliability and adequacy of the regional electricity system supplying the Parry Sound/Muskoka Sub-region and identifies integrated solutions for the 20-year period from 2015 to 2034. The electricity system supplying the Parry Sound/Muskoka Sub-region is described in more detail in Section 4.2.

It is important to note that connection assessments of generation resources procured under programs, such as the Feed-in-Tariff, are beyond the scope of this IRRP. Generation projects participating in procurement programs will be assessed according to the rules and specifications of those programs. However, the peak demand contribution from generation resources already contracted through such programs are taken into account in the demand forecast as described in Section 5.3.3.

4.2 Electricity System Supplying Parry Sound/Muskoka Sub-region

The electricity system supplying the Parry Sound/Muskoka Sub-region consists of local generation resources, 230 kV regional transmission, 44 kV sub-transmission and low voltage distribution networks. Local generation resources provide important sources of electricity supply to the communities and customers in this sub-region. However, local generation sources are not sufficient and are supplemented with power delivered to the sub-region from the rest of the province through the 230 kV transmission system. From the 230 kV transmission system power is delivered to communities and customers through the 44 kV sub-transmission and low-voltage distribution networks. The following sub-sections discuss these components in more detail.

4.2.1 Local Generation Resources

Local generation in the Parry Sound/Muskoka Sub-region is primarily hydroelectric and solar. The total installed capacity of local generation is approximately 126 MW comprised of approximately 28 MW hydroelectric, 97 MW solar, and 1 MW combined heat and power ("CHP").

In Ontario, the electricity system is designed to meet regional coincident peak demand – i.e., the one-hour period each year when total demand for electricity in the region is the highest. While hydroelectric and solar resources are potential sources of energy, only a portion of their generation capacity can be relied upon at the time of peak due to the variable nature of these resources. In the Parry Sound/Muskoka Sub-region, electricity demand typically peaks during the evening in the winter season. For the purpose of infrastructure planning, the installed capacity of distributed and variable generation is accordingly adjusted to reflect the reliable power output at the time of the local winter peak.

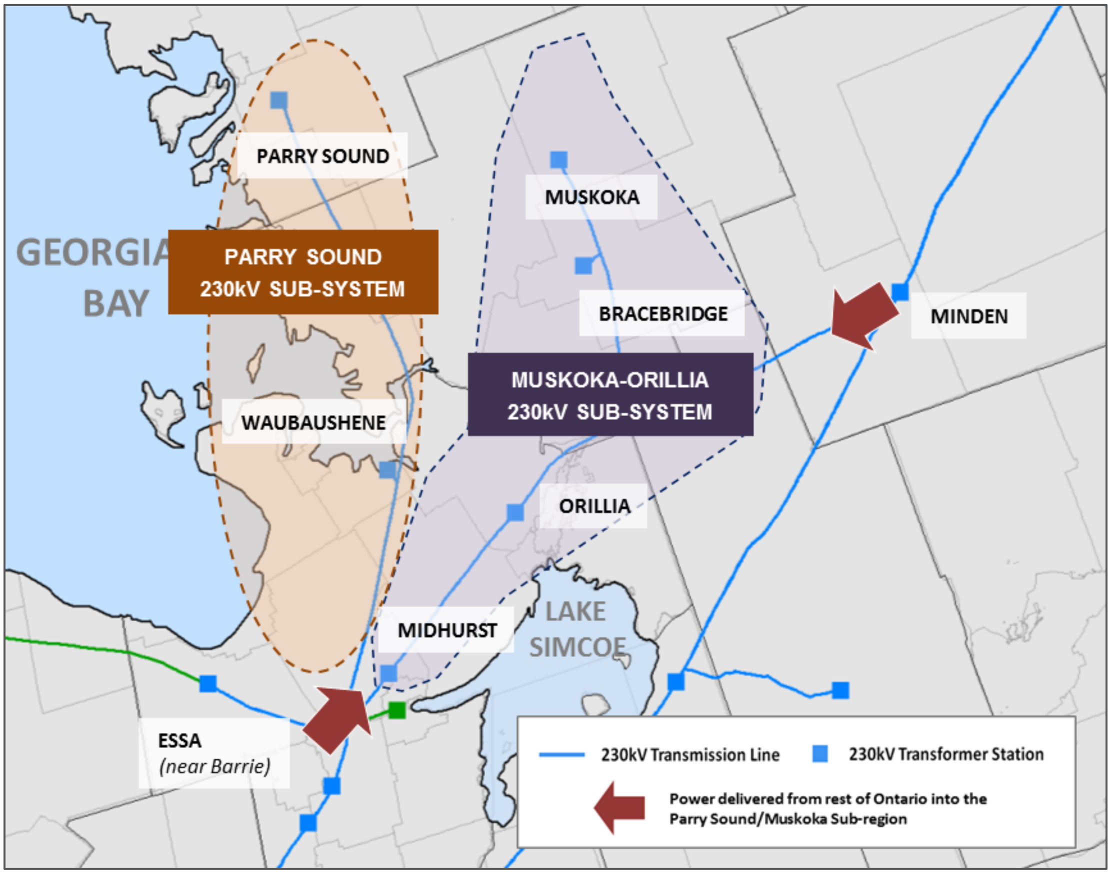
Hydroelectric facilities in the area are relatively small, generally less than 2 MW, however there are a couple facilities as large as 10 MW. The output of these facilities also depends on the availability of water resources and the operation of the facilities. To determine the dependable level of output at the time of peak, historical performance data of the hydroelectric generation facilities in the sub-region were used. The results are an assumed 34% capacity contribution from these resources.

Similarly, the solar facilities in the sub-region are also relatively small, with most being less than 0.5 MW, however there are a couple facilities as large as 10 MW. While the installed capacity of solar is high in the region, there is limited availability of solar power during the time of local peak, which occurs during the evening in the winter. It is assumed that solar would not provide any capacity at the time of local peak.

4.2.2 230 kV Transmission System

Power is delivered from the rest of the province into the Sub-region through the 230 kV transmission system at Essa (near Barrie) and Minden. As shown in Figure 4-2, the 230 kV transmission system supplies seven customers and utility-owned transformer stations. For the purpose of regional planning, the sub-region is further sub-divided into two regional 230 kV sub-systems: Muskoka-Orillia 230 kV sub-system and Parry Sound 230 kV sub-system.

Figure 4-2: Parry Sound/Muskoka Sub-region – 230 kV Transmission System

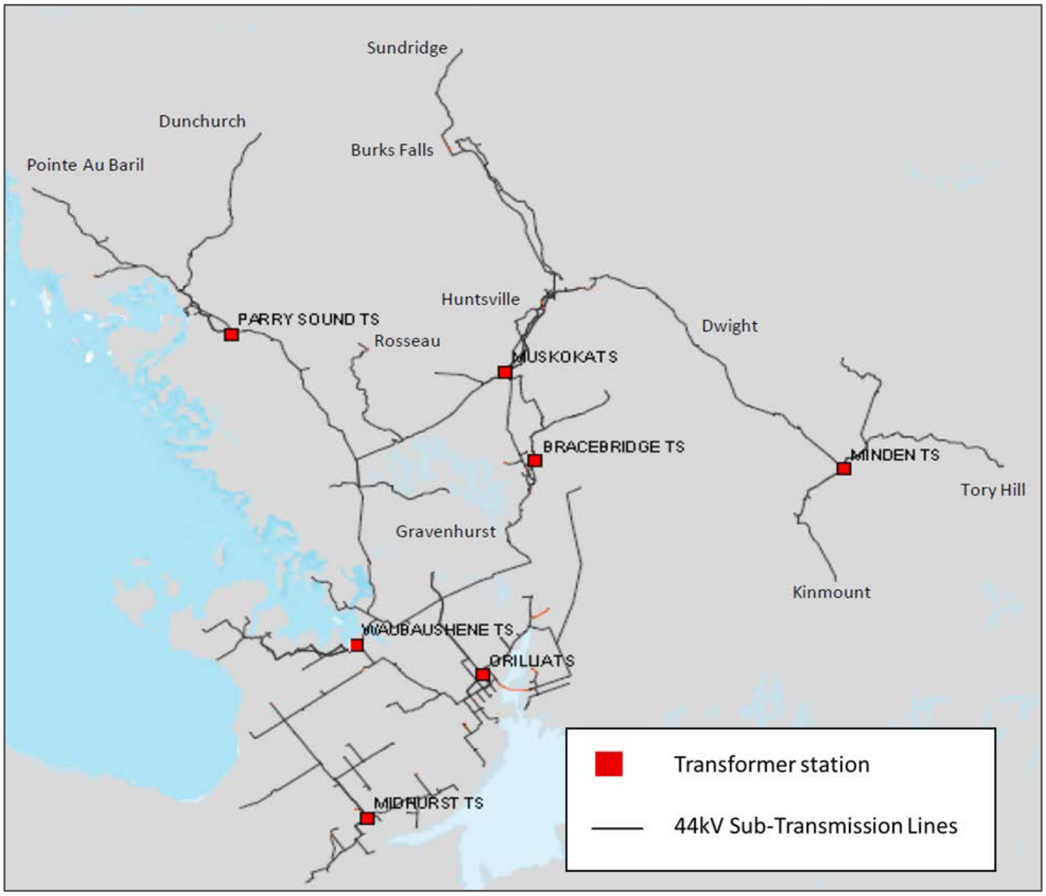


Since Midhurst TS primarily supplies the customers in the Barrie/Innisfil Sub-region, it is considered within the scope of the Barrie/Innisfil IRRP. However, Midhurst TS is supplied by the Muskoka-Orillia 230 kV sub-system and could impact the electricity supply to the Parry Sound/Muskoka Sub-region. Therefore, when assessing the reliability and adequacy of the Muskoka-Orillia 230 kV sub-system, the electricity demand growth at Midhurst TS needs to be considered in this IRRP.

4.2.3 44 kV Sub-transmission and Low-Voltage Distribution System

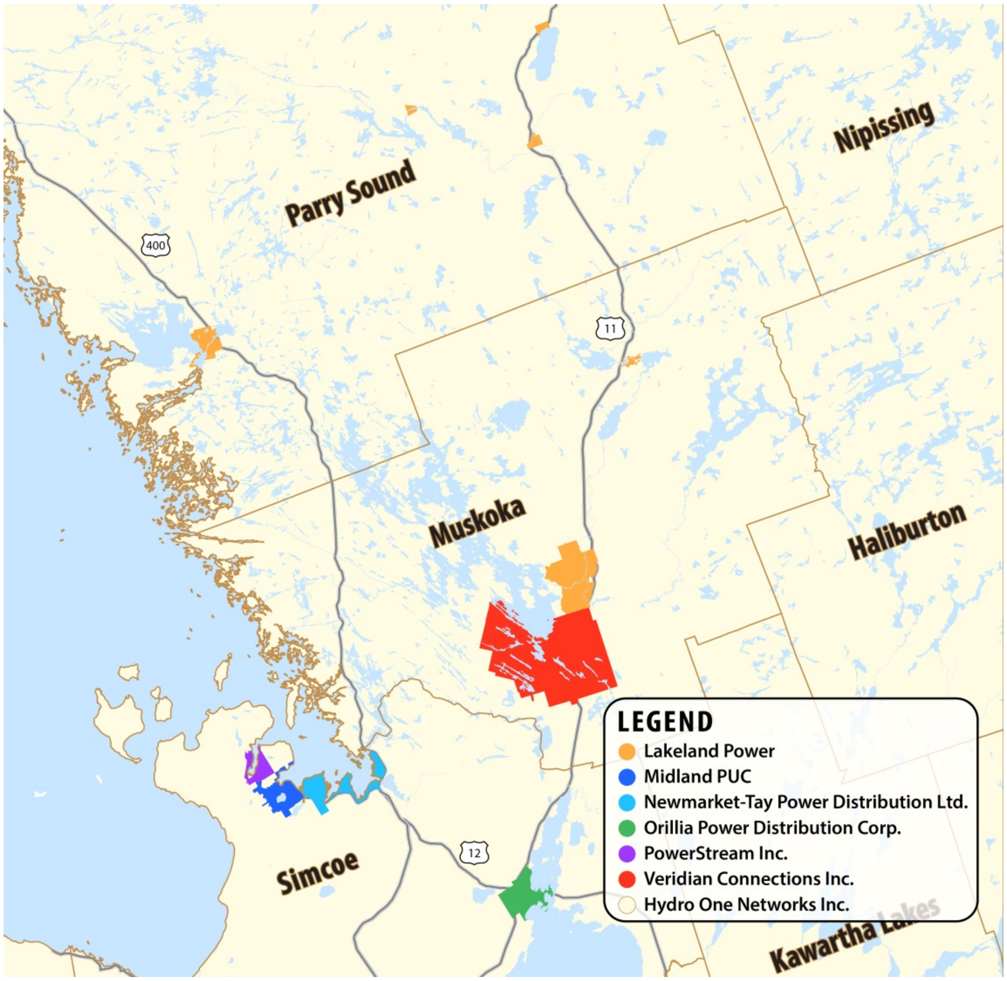
From the 230 kV sub-systems, power is delivered through transformer stations to the 44 kV sub-transmission system majority of which is operated by Hydro One Distribution in the Parry Sound/Muskoka Sub-region. As illustrated in Figure 4-3, given the large geography and sparsely populated areas, many communities and customers in this Sub-region are supplied by long 44 kV sub-transmission lines and a single source of supply.

Figure 4-3: 44 kV Sub-transmission System in the Parry Sound/Muskoka Sub-region



From the 44 kV sub-transmission system, power is delivered to the low voltage distribution network, which supplies various communities across the sub-region. The low-voltage distribution system is managed and operated by seven LDCs: Lakeland Power, Midland PUC, Newmarket-Tay Power, Orillia Power, PowerStream, Veridian Connections, and Hydro One Distribution, as shown in Figure 4-4.

Figure 4-4: Local Distribution Companies Service Areas



Distribution system planning is beyond the scope of the regional planning process. Issues related to the distribution system may be discussed in this IRRP for context, but will be addressed through the local distribution planning process led by the Local Distribution Companies ("LDCs").

Details regarding the characteristics of the LDC service areas can be found in Appendix A.

5. Demand Forecast

Regional electricity systems in Ontario are designed to meet regional coincident peak demand – the one-hour period each year when total regional demand for electricity is the highest.

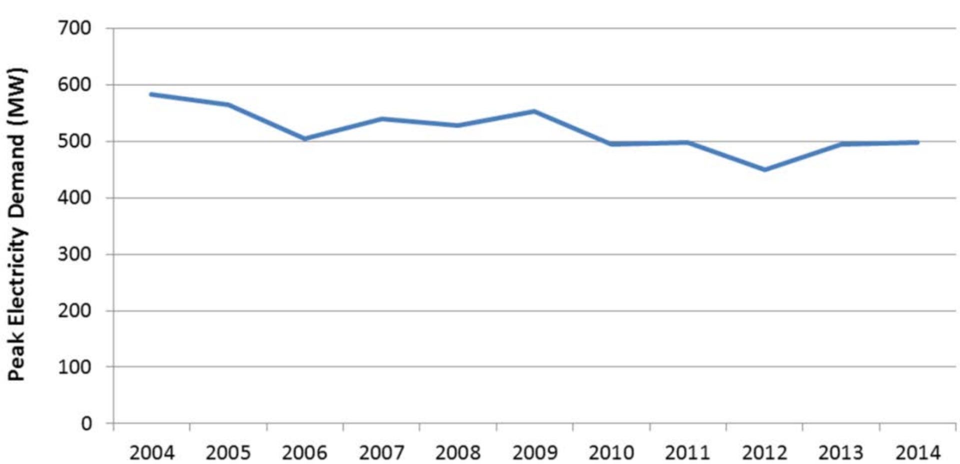
This section describes the development of the regional electricity demand forecast for the Parry Sound/Muskoka Sub-region. Section 5.1 describes historical electricity demand trends in the sub-region from 2004 to 2014. Section 5.2 provides an overview of the demand forecast methodology used in this study, and Section 5.3 summarizes the planning forecast for the sub-region.

5.1 Historical Electricity Demand 2004-2014

Electricity demand in this sub-region is primarily driven by residential and commercial customers. Due to limited access to natural gas infrastructure in this sub-region, many communities rely on electric space and water heating, especially during the winter season. As such, the electricity demand in this sub-region typically peaks during the winter months. This sub-region also supports a mix of economic activities including tourism, retail, healthcare and manufacturing industries. Seasonal population driven by tourism and recreation activities also contributes to the electricity demand requirements in this sub-region.

Demand has declined slightly between 2004 and 2010 but has been relatively stable since then at around 500 MW, as shown in Figure 5-1. The historical demand shown below was adjusted to account for weather-related impacts.

Figure 5-1: Historical Peak Demand - Parry Sound/Muskoka Sub-region (2004-2014)



5.2 Methodology for Establishing Planning Forecast

A planning forecast was developed to assess reliability of the Parry Sound/Muskoka Sub-region electricity system over the planning period (2015 to 2034). For the purpose of regional planning, the planning forecast considers the following components:

- Gross winter demand forecast scenarios for distribution-connected and transmission-connected customers,
- Estimated peak demand savings from meeting provincial energy conservation targets, and
- Expected peak demand capacity contribution from DG.

The gross demand forecast was developed based on the expected peak demand projections for distribution-connected and transmission-connected customers in the Parry Sound/Muskoka Sub-region. To develop the planning forecast, the gross demand forecast was modified to reflect the estimated peak demand savings from meeting provincial energy conservation targets and from existing and contracted DG.

Using a planning forecast that is net of provincial conservation targets is consistent with the province's Conservation First policy. However, this assumes that the targets will be met and that the targets, which are energy-based, will produce the expected local peak demand impacts. An important aspect of plan implementation will be monitoring the actual peak demand impacts of conservation programs delivered by the LDCs and, adapting the plan accordingly.

The methodology and assumptions used for the development of the planning forecast are described in detail in Appendix A.

5.3 Development of Planning Forecast

5.3.1 Gross Demand Forecast

The gross demand forecast was provided by the seven LDCs in this sub-region, based on customer connection requests, local economic development and growth assumptions outlined in Ontario's *Places to Grow Act, 2005*, which are reflected in municipal and regional plans.

A modest increase in electricity demand is forecast in this sub-region over the next 20 years. While slower growth is expected in the sub-region's manufacturing sector, growing Indigenous communities, new residential and commercial developments, seasonal population and potential local economic development such as the Parry Sound Airport Development and

Rama Road Corridor Economic Employment District, will contribute to growing electricity demand in the sub-region. Electric space and water heating requirements from communities, and aforementioned new residential and commercial developments will continue to be a major driver of peak electricity demand in this sub-region. Based on the information provided by the LDCs, gross demand is expected to grow 1.1% annually over the planning period.

Given the diverse communities and geography of this sub-region, electricity demand growth is not uniformly distributed across the sub-region. Only a small increase in electricity demand is expected in the northern Simcoe County, Minden and Parry Sound. Most of the electricity growth is forecast to be concentrated in Muskoka, Orillia and surrounding areas. For example, in Orillia, additional planned developments, including condominium and waterfront development and new retail, commercial, industrial and institutional customers may materialize within the 20-year planning period resulting in as much as an additional 20-22 MW of peak demand. For the purpose of regional planning, this potential load was considered as part of the sensitivity analysis.

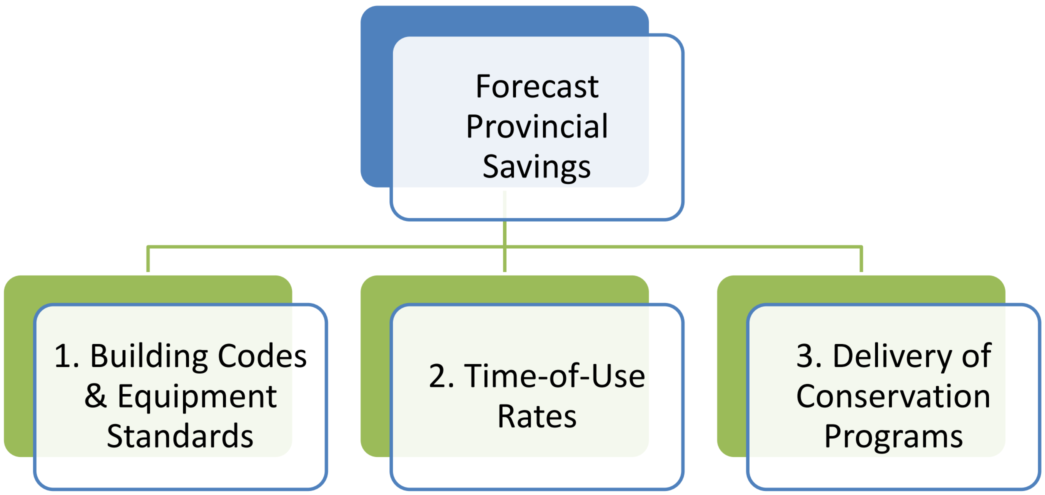
The specific forecasting methodology and assumptions for the gross demand forecast can be found in Appendix A.

5.3.2 Expected Peak Demand Savings from Provincial Conservation Targets

Conservation is incented and achieved through a mix of program-related activities, rate structures, and mandated efficiencies from building codes and equipment standards. Conservation plays a key role in maximizing the utilization of existing infrastructure and maintaining reliable supply by keeping demand within equipment capability. The conservation savings forecast for the Parry Sound/Muskoka Sub-region have been applied to the gross peak demand forecast, along with DG resources (described in Section 5.2), to determine the planning forecast in this sub-region.

In December 2013 the Ministry of Energy released a revised Long-Term Energy Plan ("LTEP") that outlined a provincial conservation target of 30 terawatt-hours ("TWh") of energy savings by 2032. The expected peak demand savings from meeting this target were estimated for the Parry Sound/Muskoka Sub-region. To estimate the impact of the conservation savings in the sub-region, the forecast provincial savings were divided into three main categories, as illustrated in Figure 5-2.

Figure 5-2: Categories of Conservation Savings



1. *Savings due to Building Codes & Equipment Standards*
2. *Savings due to Time-of-Use Rate structures*
3. *Savings due to the delivery of Conservation Programs*

The impact of estimated savings for each category was further broken down for the Parry Sound/Muskoka Sub-region by the residential, commercial and industrial customer sectors. The IESO worked together with the LDCs to establish a methodology to estimate the electrical demand impacts of the energy targets by the three customer sectors. This provides a better resolution of forecast conservation, as conservation potential estimates vary by sector due to different energy consumption characteristics and applicable measures.

For the Parry Sound/Muskoka Sub-region, LDCs were requested to provide breakdowns of their gross demand forecast, and electrical demand by sector for the forecast at each transformer station. For each transformer station where the LDC could not provide gross load segmentation, the IESO and the LDC worked together using best available information and assumptions to derive sectoral gross demand. For example, LDC information found in the OEB's Yearbook of Electricity Distributors was used to help estimate the breakdown of demand. Once sectoral gross demand at each transformer station was estimated, the next step was to estimate peak demand savings for each conservation category: building codes and equipment standards, time-of-use rates, and delivery of conservation programs. The estimates for each of the three savings groups were done separately due to their unique characteristics and available data. The final estimated conservation peak demand reduction, 35 MW by 2034, was then applied to the gross demand to create the planning forecast.

Additional conservation forecast details are provided in Appendix A.

5.3.3 Expected Peak Demand Contribution of Existing and Contracted Distributed Generation

As of 2015, about 123 MW of DG was contracted and/or existing in the Parry Sound/Muskoka Sub-region. The majority of the contracted and installed capacity is solar projects. The sub-region also has several hydroelectric power facilities and one CHP facility.

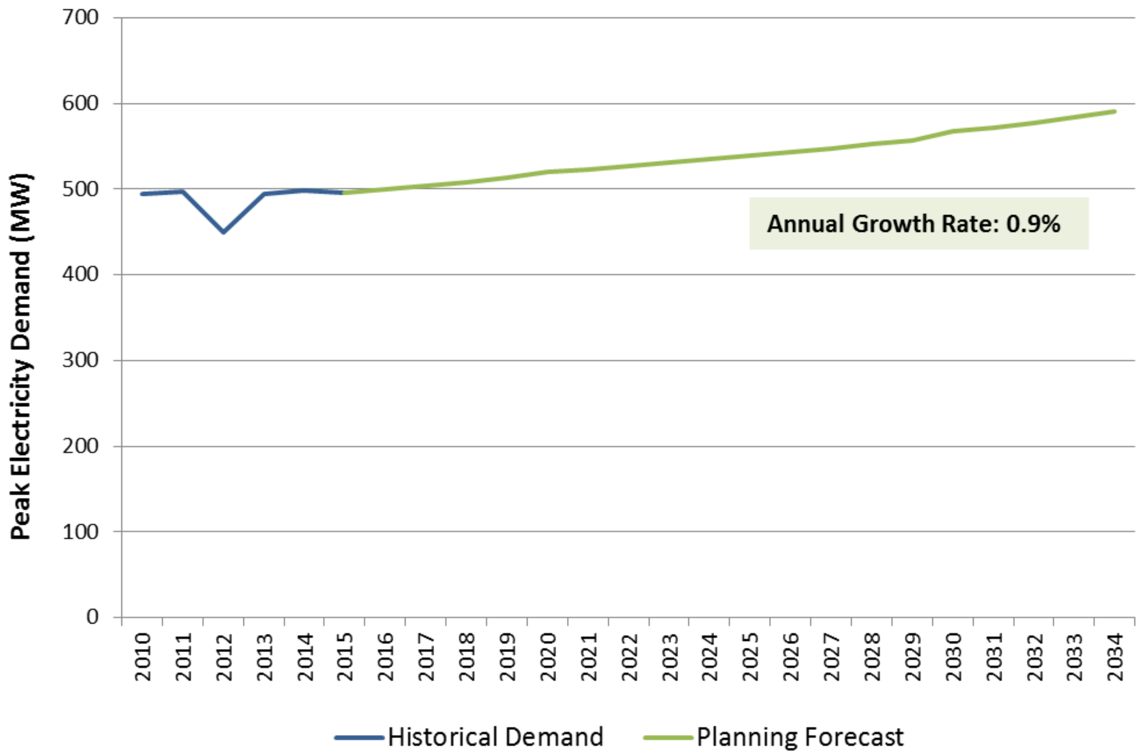
As the peak for the sub-region tends to occur during the winter evening hours, solar resources do not provide capacity contribution, however the other DG resources do have an impact on the peak. For the purpose of developing the planning forecast, contracted DG is expected to reduce the regional peak demand by as much as 11 MW over the next 20 years. Future DG uptake was, as noted, not included in the planning forecast and is instead considered as an option for meeting identified needs.

The expected annual peak demand contribution of contracted DG in the Parry Sound/Muskoka Sub-region can be found in Appendix A.

5.3.4 Planning Forecast

Figure 5-3 shows the planning forecast for the Parry Sound/Muskoka Sub-region for the planning period from 2015 to 2034 (using a base year of 2014). The planning forecast takes into consideration the gross demand forecast scenarios, estimated peak demand savings from provincial energy conservation targets, and existing and contracted DG. Based on the planning forecast, the electricity demand in the sub-region is expected to grow 0.9% annually, with an incremental peak demand growth of 100 MW over the planning period.

Figure 5-3: Parry Sound/Muskoka Sub-region Planning Forecast (2015-2034)



As discussed in Section 4.2.2, Midhurst TS primarily supplies the customers in the Barrie/Innisfil Sub-region. As a result, the Parry Sound/Muskoka Sub-region demand forecast shown above does not include electricity demand from Midhurst TS.

Further details related to the demand forecast scenarios can be found in Appendix A.

6. Needs

This section outlines the needs assessment methodology and identifies regional electricity supply and reliability needs over the 20-year planning period.

6.1 Needs Assessment Methodology

The IESO's ORTAC,[7] the provincial standard for assessing the reliability of the transmission system, was applied to assess supply capacity and reliability needs. ORTAC includes criteria related to the assessment of the bulk transmission system, as well as the assessment of local or regional reliability (see Appendix B for more details).

Through the application of these criteria, three broad categories of needs can be identified:

- **Transformer Station Capacity** is the electricity system's ability to deliver power to the local distribution network through the regional transformer stations. This is limited by the load meeting capability ("LMC") of the step-down transformer stations in the local area, which is the maximum demand that can be supplied from the transformer stations based on equipment rating and outage conditions.
- **Supply Capacity** is the electricity system's ability to provide continuous supply to a local area. This is limited by the LMC of the transmission line or sub-system, which is the maximum demand that can be supplied on a transmission line or sub-system under applicable transmission and generation outage scenarios as prescribed by ORTAC; it is determined through power system simulations analysis (See Appendix B for more details). Supply capacity needs are identified when peak demand on a transmission line or sub-system exceeds its LMC.
- **Load Security and Restoration** is the electricity system's ability to minimize the impact of potential supply interruptions to customers in the event of a major transmission outage, such as an outage on a double-circuit tower line resulting in the loss of both circuits. Load security describes the total amount of electricity supply that would be interrupted in the event of a major transmission outage. Load restoration describes the electricity system's ability to restore power to those affected by a major transmission outage within reasonable timeframes. The specific load security and restoration requirements prescribed by ORTAC are described in Appendix B.

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

In addition, the needs assessment may also identify needs related to service reliability performance, equipment end-of-life and planned sustainment activities. Service reliability and performance is measured based on customers' exposure to power outages on the distribution and transmission system, and is expressed in terms of frequency (i.e., number of outages a year) and duration (e.g., length of time before the power is restored). Equipment reaching the end of its life and planned sustainment activities may impact the needs assessment and options development. Transmission assets reaching end-of-life are typically replaced with assets of equivalent capacity and specification. The need to replace aging transmission assets may present opportunities to better align investments with evolving power system priorities. This may involve up-sizing equipment in areas with capacity needs, or downsizing or even removing equipment that is no longer considered useful. Such instances may also present opportunities to enhance or reconfigure assets for infrastructure hardening to improve system resilience.

6.2 Regional and Local Electricity Reliability Needs

Through the needs assessments, the Working Group has identified the need: (1) to minimize the frequency and duration of power outages and (2) to provide adequate supply to support growth in the Parry Sound/Muskoka Sub-region. The following sections further describe these needs.

6.2.1 Need to Minimize the Frequency and Duration of Power Outages

As discussed in Section 4.2, while there is local generation in this sub-region, communities and customers primarily rely on the 230 kV transmission, 44 kV sub-transmission and low-voltage distribution lines to deliver power from the rest of the province into the Parry Sound/Muskoka Sub-region. Outages along any of these lines (i.e., 230 kV, 44 kV, low voltage distribution lines) could interrupt the electricity supply to communities and customers in the Parry Sound/Muskoka Sub-region.

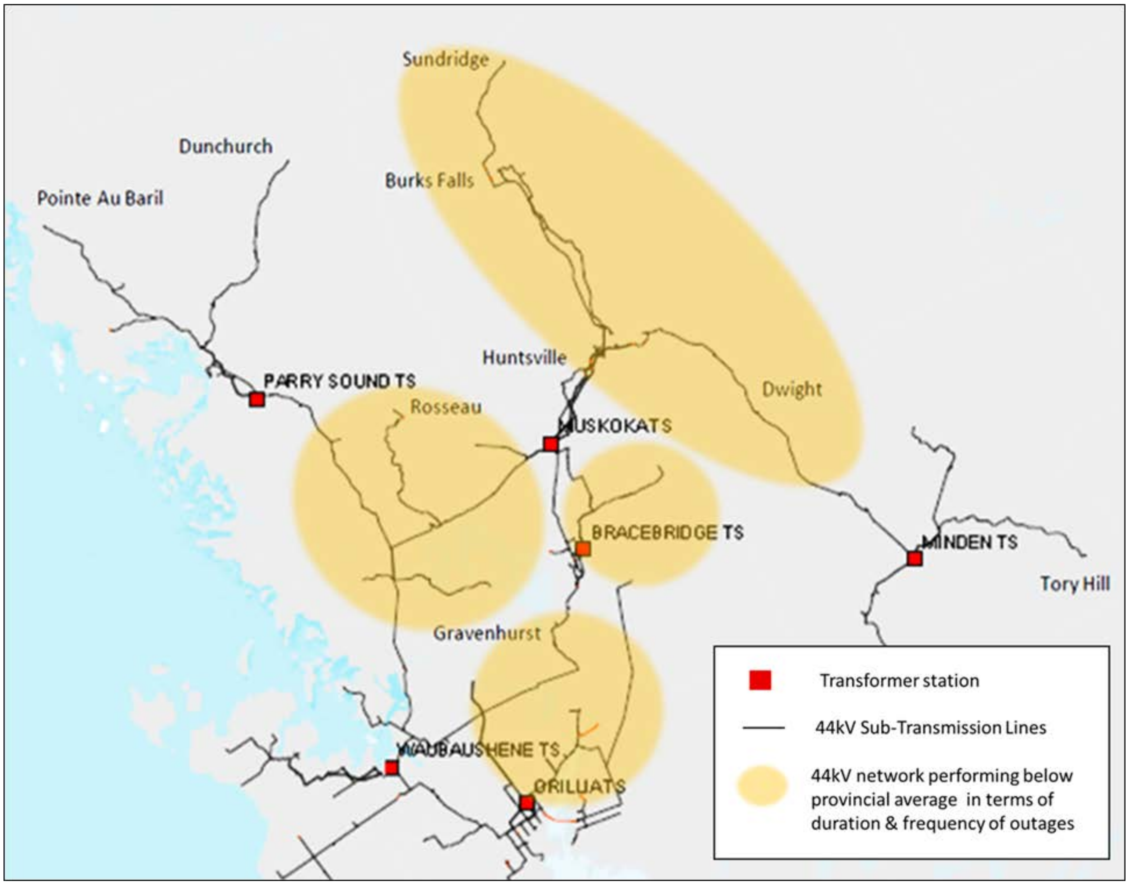
In this sub-region, customers and communities experience more frequent and prolonged power outages in comparison to customers and communities in other areas of the province. The consequences of extended power outages can have impacts for customers and society at large. For example, the Working Group has heard from communities and customers in this sub-region that below-average reliability is an impediment to economic development.

To better understand the causes of these power outages, the Working Group examined the service reliability and performance of the 44 kV sub-transmission system, and the load restoration capability and security of the 230 kV transmission line supplying the Parry Sound/Muskoka Sub-region. The results from the needs assessments are summarized below.

44 kV Sub-Transmission Service Reliability and Performance

In response to community and customers' concerns regarding power outages in this sub-region, the Working Group examined historical service reliability and performance of the 44 kV sub-transmission system over the last five years. Results from the assessment show that a number of 44 kV sub-transmission systems in this sub-region are performing below average in terms of frequency and duration of outages (as shown in Figure 6-1). On average, customers being supplied from a typical 44 kV sub-transmission line in Ontario experience outages about two times a year with outages typically lasting 5 hours or less. Based on the historical service reliability and performance data over the last five years, the outages for many of the 44 kV sub-transmission system in the Parry Sound/Muskoka Sub-region are almost double the provincial average in terms of frequency and duration.

Figure 6-1: 44 kV sub-transmission systems that are performing below provincial average in terms of frequency and duration of outages in the Parry Sound/Muskoka Sub-region



The service reliability and performance of the 44 kV sub-transmission system is impacted by a number of factors, including a facility's exposure to various elements, age and maintenance of equipment, length and configuration of the network, and the repair crew's accessibility to facilities. Lengthy 44 kV sub-transmission lines and off-road facilities are the main reasons for frequent and prolonged outages in the Parry Sound/Muskoka Sub-region.

- **Lengthy 44 kV sub-transmission lines:** As a large and sparsely populated geographical area, this sub-region is supplied by 44 kV sub-transmission lines that are typically longer than other 44 kV sub-transmission lines in Ontario. The average length of a 44 kV sub-transmission line in Ontario is about 45 km. Most of the 44 kV sub-transmission systems in the Parry Sound/Muskoka Sub-region range from 40 to 100 km in length. Long sub-transmission lines typically exhibit lower levels of reliability because of increased exposure to trees and wildlife. Tree contact has been identified as one of the major causes of 44 kV sub-transmission outages in this sub-region. Furthermore, with longer

44 kV sub-transmission lines, repair crews require additional time to identify and isolate causes of any outages.

- **Off-Road Facilities:** Many of the 44 kV sub-transmission systems are located off-roads. Due to limited access to off-road facilities, repair crews have difficulty detecting early signs of equipment failure, performing preventative maintenance and restoring power in a timely manner.

The detailed summary of the reliability performances of these 44 kV sub-transmission systems can be found in Appendix C.

Load Restoration and Security on the 230 kV Transmission System

Outage statistics from Hydro One Transmission indicate that have been three major outages involving the loss of both 230 kV transmission circuits in the sub-region since 1990. These outages lasted no more than 2-3 hours. While major 230 kV transmission outages have been relatively infrequent and short in duration in the Parry Sound/Muskoka Sub-region, the existing 230 kV transmission system supplying the Orillia and Muskoka area has limited ability to restore power in a timely manner and minimize the number of customers interrupted in the event of a major 230 kV transmission outage. As discussed in Section 6.1, the 230 kV transmission system should be designed in accordance with the load restoration and security criteria outlined in ORTAC (see Appendix B).

Based on the needs assessment, the Muskoka-Orillia 230 kV sub-system does not meet the ORTAC load restoration criteria and may violate the load security criteria over the longer term depending on the electricity demand growth in the area. The Muskoka-Orillia 230 kV sub-system is a 171 km double-circuit 230 kV transmission line (M6/7E) between Barrie and Minden. This system currently supplies four transformer stations and supplies about 465 MW of peak demand.[8] In the event of a major outage involving the loss of both transmission circuits on the Muskoka-Orillia 230 kV sub-system, all customers supplied by this transmission line would be interrupted. The existing system cannot restore any power to customers within 30 minutes. As

[8] Muskoka-Orillia 230 kV sub-system includes the electricity demand at Orillia TS, Muskoka TS, Midhurst TS, and Bracebridge TS. Although Midhurst is part of Barrie/Innisfil IRRP, it is supplied by the Muskoka-Orillia 230 kV sub-system and could have an impact on the electricity supply to the Parry Sound/Muskoka Sub-region.

a result, the Muskoka-Orillia 230 kV sub-system does not meet the ORTAC 30 minute load restoration criteria.

Based on the planning forecast, the winter demand on the Muskoka-Orillia 230 kV sub-system is expected to increase to 621 MW by 2034. According to ORTAC load security criteria, no more than 600 MW of electricity supply can be interrupted following a major outage. Depending on the electricity demand growth, the Muskoka-Orillia 230 kV sub-system may violate the load security criteria over the longer term.

Action is required to improve the load restoration and security for the Muskoka-Orillia 230 kV sub-system and to bring the 230 kV transmission system in compliance with Ontario's planning standards.

6.2.2 Need to Provide Adequate Supply to Support Growth

To ensure there is an adequate and reliable source of electricity supply for the customers and communities in the Parry Sound/Muskoka Sub-region, the electricity system will need to have sufficient supply to support forecast electricity demand growth and to comply with ORTAC. Results from the needs assessment indicate that transformers at Waubaushene TS and Parry Sound TS are at, or nearing capacity and will be in violation of ORTAC in the near term. Over the longer term, electricity demand growth could also exceed the supply capability of the Muskoka-Orillia 230 kV sub-system. The following sections further discuss these near- and longer-term supply capacity needs.

<u>Demand Exceeds Capability at Parry Sound TS and Waubaushene TS in the Near-Term</u>

The transformers supplying the Town of Parry Sound and surrounding areas can supply up to 52 MW at the time of local peak (Parry Sound TS LMC = 52 MW). The electricity demand in the area has already exceeded the capability of these transformers over the last couple of years. For example, during the winter of 2015, these transformers supplied up to 61 MW at the time of local peak, exceeding the LMC of Parry Sound TS by about 9 MW. Near-term action is required to ensure that the electricity system in the area has adequate supply to support growth. Over the planning period, the electricity demand supplied by Parry Sound TS is forecast to grow less than 1 MW per year so that by 2034 Parry Sound TS would need to supply about 74 MW.

Similarly, Waubaushene TS, supplying Waubaushene and the surrounding area can supply up to 99 MW at the time of local peak (Waubaushene TS LMC = 99 MW). Today, Waubaushene TS supplies about 96 MW of electricity demand. The transformers at this station are nearing capacity and electricity demand growth is expected to exceed capability by 2017. Near-term action is required to ensure that the electricity system has adequate supply to support future growth. The electricity demand supplied by Waubaushene TS is expected grow modestly at less than 1 MW per year. Based on the planning forecast, Waubaushene TS is expected to supply about 111 MW of electricity demand by 2034.

Demand may exceed the capability of Muskoka-Orillia 230 kV sub-system over the longer term

The Muskoka-Orillia 230 kV sub-system can supply up to 600 MW at the time of peak (Muskoka-Orillia 230 kV sub-system LMC = 600 MW). Today, the Muskoka-Orillia 230 kV sub-system supplies up to 454 MW.[9] Given the modest electricity demand growth in this area, electricity demand is not expected to exceed its capability until the early 2030s based on the planning forecast.

Given the uncertainty associated with the long-term electricity demand forecast, it is sufficient to monitor demand growth before proceeding with an investment decision. Section 7.2.2 provides a high-level discussion of options to address this potential need over the longer term.

6.3 Other Electricity Needs and Considerations

In addition to the regional and local electricity reliability needs outlined in Section 6.2, the Working Group identified other electricity needs and considerations that could impact the regional electricity supply. These issues are discussed in more detail below.

6.3.1 End-of-Life Replacements and Sustainment Activities

The Minden 230/44 kV transformers are scheduled for end-of-life replacements within the next five years. Hydro One is preparing a plan to replace all the aging equipment at Minden TS in the next few years. The aging 25/42 MVA transformers are to be replaced with 50/83 MVA transformers to address the capacity needs at the station. This sustainment decision was made prior to the initiation of this IRRP.

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[9] Muskoka-Orillia 230 kV sub-system includes the electricity demand at Orillia TS, Muskoka TS, Midhurst TS, and Bracebridge TS. Although Midhurst TS is considered as part of Barrie/Innisfil IRRP, it is supplied by the Muskoka-Orillia 230 kV sub-system and has an impact on the electricity supply to the Parry Sound/Muskoka Sub-region.

In addition to the near-term sustainment activities, the Working Group also identified potential assets that could be reaching end-of-life over the planning period. The expected service life of a transformer is about 60 years. The transformers at Parry Sound TS and Waubaushene TS were installed in the early 1970s and therefore these transformers could be reaching end-of-life in the early 2030s. There may be opportunities to align end-of-life facility replacements with solutions to address longer-term needs in the sub-region.

6.3.2 Community Energy Planning

A number of communities in the sub-region are in the process of developing community energy plans ("CEP(s)"). At the time of this report, seven of the eight First Nation communities have received funding from the IESO through the Aboriginal Community Energy Plan program to develop CEPs. The Municipal Energy Plan Program[10] administrated by the provincial government supports municipalities in their efforts to develop CEPs.

Through community energy planning activities, communities will have a better understanding of their local energy needs and emissions footprint, be able to identify opportunities for energy efficiency and emissions reduction, and develop plans to meet their goals in consideration of local economic development. These CEPs examine broader energy needs, such as transportation, natural gas and electricity, and consider other objectives including net zero energy, electrification, and emissions reductions.

On June 8, 2016, the Ontario government released Ontario's Climate Change Action Plan ("CCAP"), which outlines policy to reduce the use of fossil fuel and to encourage the move toward a low carbon economy. In response to this policy direction, a CEP may include recommendations to promote electrification and other forms of fuel switching, such as shifting from natural gas to electric-power heat pumps and from gasoline to electric vehicles, to achieve a goal of reducing greenhouse gas ("GHG") emissions. As such, the outcomes from CEPs may drive additional requirements on the electricity system and should be monitored closely through the regional planning process. Furthermore, with the increased access to distributed energy resources, CEPs may identify opportunities for community-based energy solutions, such as district energy, CHP, or microgrids. Depending on the timing, location and magnitude of the

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[10] For more information on the Ministry of Energy MEP Program:
http://www.energy.gov.on.ca/en/municipal-energy/

needs, community-based energy solutions can be considered as potential options to address regional electricity needs.

6.3.3 Power Quality

A large customer in the sub-region is experiencing issues related to power quality. Power quality issues are defined as disturbances to the customer's electricity supply as a result of voltage. Voltage issues can be caused by customers' equipment and/or system voltage performance. The solutions and cost responsibility of investments to address power quality issues may vary depending on the root causes of the problem. The Working Group agreed that power quality issues need to be better understood and should be examined on a case-by-case basis by the area LDCs, transmitter and customers.

6.4 Needs Summary

Table 6-1 provides a summary of the regional supply and reliability needs in the Parry Sound/Muskoka Sub-region.

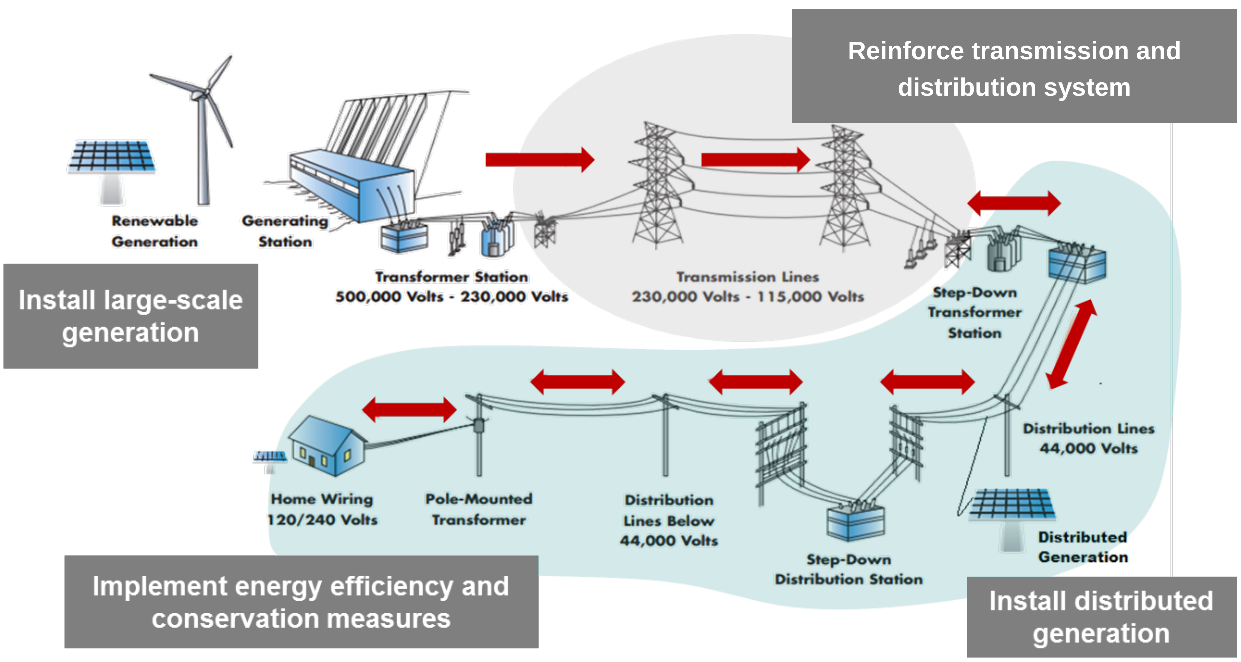
Table 6-1: Summary of Regional and Local Reliability Needs

Local and Regional Electricity Reliability Needs	Components	Status
Need to Minimize the Frequency and Duration of Power Outages	44 kV sub-transmission systems	Performing below provincial average in terms of frequency and duration of 44 kV sub-transmission outages
	Muskoka-Orillia 230 kV sub-system	Limited ability to restore power to customers in a timely manner in the event of a 230 kV transmission outage involving the loss of both transmission circuits. The sub-system does not meet the ORTAC load restoration criteria
		Electricity demand growth may exceed 600 MW and could violate the ORTAC load security criteria in the early 2030s
Provide Adequate Supply to Support Growth	Parry Sound TS	Electricity demand growth already exceeds system capability today
	Waubaushene TS	Electricity demand growth forecast to exceed system capability in 2017
	Muskoka-Orillia 230 kV sub-system	Electricity demand growth could exceed system capability in the early 2030s

7. Options to Address Regional and Local Electricity Needs

As shown in Figure 7-1, traditionally power has been generated from large, centralized generation sources. To provide electricity supply to the various communities across Ontario, power has been delivered through transmission and distribution infrastructure. To address regional and local electricity needs, one approach is therefore to reinforce the transmission and distribution infrastructure supplying the local area. However, in recent years, communities and customers have been exploring opportunities to reduce their reliance on the provincial electricity system by meeting their electricity needs with local, distributed energy resources and community-based solutions. This approach includes a combination of emerging technologies and conservation programs, such as targeted DR and conservation programs, DG and advanced storage technologies, micro-grid and smart-grid technologies, and more efficient and integrated process systems combining heat and power.

Figure 7-1: Options to Address Electricity Needs



Options Evaluation

When evaluating alternatives, the Working Group considered a number of factors, including technical feasibility, cost, flexibility, alignment with planning policies and priorities and consistency with long-term needs and options. Solutions that maximized the use of existing infrastructure were given priority.

Investing in new electricity infrastructure, such as a new transmission line or a generation facility requires substantial capital investment, has environmental/land-use impacts and has a long-service life. As such, it is important to take into the consideration the longer-term cost implications, value and potential risks (e.g., stranded or underutilized assets) when recommending an investment. Furthermore, these facilities typically require long lead times to obtain approvals and complete construction. For these reasons, decisions on new facilities must take into account these considerations and be made with sufficient lead time to ensure they are available when needed.

When assessing the need for infrastructure investments, it is important to strike a balance between overbuilding infrastructure (e.g., committing to infrastructure when there is insufficient demand to justify the investment) and under-investing (e.g., avoiding or deferring investment despite insufficient infrastructure to support growth in the region). Typically, demand management and energy efficiency programs can be implemented within six months, or up to two years for larger projects, whereas transmission and distribution facilities can take five to seven years to come into service. The lead time for generation development is typically two to three years, but could be longer depending on the size and technology type.

Finally, the issue of how much is appropriate to invest and who pays needs to be addressed. In regional planning, depending on the type and classification of assets, the costs may be shared by all provincial ratepayers or recovered only by the specific customers they serve (e.g., LDC, industrial customers). In some cases, a combination of cost-sharing may occur when there are both provincial and local benefits. Notably, the Working Group has heard concerns from communities about affordability. Given the high cost of electricity, it is important consider how investments impact local ratepayers.

<u>Near-Term Actions and Long-Term Planning Considerations</u>

For the near and medium term, the IRRP identifies specific actions and investments for immediate implementation. This ensures that necessary resources will be in-service in time to address more pressing needs. For the long term, the IRRP identifies potential options to meet needs that may arise in 10-20 years. It is not necessary to recommend specific projects at this time (nor would it be prudent given forecast uncertainty and the potential for technological change). Instead, the long-term plan focuses on developing and maintaining the viability of long-term options, engaging with communities, and gathering information to lay the groundwork for making decisions on future options.

As discussed in Section 6, actions need to be taken to (1) minimize the frequency and duration of power outages, and (2) ensure that the regional electricity system has adequate supply to support growth. In developing the 20-year plan, the Working Group examined a wide range of integrated solutions to address these local and regional needs. These options are discussed in the following section.

7.1 Minimize the Frequency and Duration of Power Outages

To minimize the frequency and duration of power outages, the Working Group examined options to improve service reliability and performance on the 44 kV sub-transmission system and to address load restoration and security needs on the 230 kV transmission system.

7.1.1 Options to Improve Service Reliability and Performance on the 44 kV Sub-transmission System

44 kV Sub-Transmission Maintenance and Outage Mitigation Initiatives

Hydro One Distribution owns and operates the 44 kV sub-transmission system in the Parry Sound/Muskoka Sub-region. Currently, Hydro One Distribution has a number of on-going maintenance and outage mitigation initiatives, including vegetation management, line patrols and grid modernization, to help reduce the frequency and duration of outages on the 44 kV sub-transmission system. These initiatives are summarized in Table 7-1.

Table 7-1: Status of Current Maintenance and Outage Mitigation Initiatives in the Parry Sound/Muskoka Sub-region

Initiatives	Status
Vegetation Management Program	▪ Vegetation management was last completed in these areas in 2015/2016 ▪ Full clearing for these areas is planned for 2021/2022 ▪ Hydro One has committed $20 million in 2016 in the districts of Muskoka and Parry Sound to reduce tree-related outages for its customers
Line Patrols	▪ Data is collected to help identify and prioritize the need to replace distribution poles and/or potentially defective equipment ▪ Last line patrolling cycle for these priorities areas occurred between 2010-2012 ▪ The next line patrolling cycle is scheduled for 2016 to 2021

Mid-cycle Hazard Tree Program	▪ Visual inspection to identify potential risk of tree-related contact ▪ This program will be conducted in this sub-region in 2018/2019
Distribution Management System & Grid Modernization	▪ Distribution management system will be implemented in this sub-region by the end of 2016 and will enable operators to have greater grid visibility and to respond to outages in a timely manner ▪ A broader grid modernization initiative is underway to identify opportunities for distribution automation (e.g., remote fault indicators, automated switches), which can help operators diagnose the sources of the outages and respond in a timely manner

In addition to these on-going maintenance programs and initiatives, Hydro One Distribution may take additional measures to further improve service reliability and performance on the 44 kV sub-transmission systems. These include:

- Install distribution automation and fast-acting switching devices to restore power in a timely manner
- Relocate "Off-Road" 44 kV sub-transmission system lines to roadside to facilitate access for maintenance crews
- Strengthen ties within the 44 kV sub-transmission system to allow adjacent 44 kV lines to serve as a back-up supply in the event of an outage

The cost, feasibility and effectiveness of these measures depend on the solution type, geography and nature of the 44 kV sub-transmission system and will need to be examined on a case-by-case basis. Hydro One Distribution will assess these options through the distribution planning process and will provide an update to the communities and LACs on plans to improve 44 kV sub-transmission system service reliability performance, including any proposed capital plans, by the end of 2017. The ability to implement any proposed capital investment plans will be contingent on the outcome of Hydro One Distribution's 2018-2022 rate filing application with the OEB.

<u>Option to Resupply Customers from Bracebridge TS</u>

Currently, the Town of Bracebridge, the Town of Gravenhurst, the Township of Muskoka Lakes, and the Township of Seguin are supplied by lengthy 44 kV sub-transmission system lines (60-100 km in length) from Muskoka TS and Orillia TS. To reduce 44 kV sub-transmission line exposure, new 44 kV sub-transmission lines can be built (~ up to 15 km) to resupply these areas from Bracebridge TS. These new 44 kV sub-transmission lines to Bracebridge TS cost about $3 to $6 million.

Today, Bracebridge TS supplies one industrial customer. The electricity demand from this industrial customer has decreased significantly over several years. Over the longer term, there should be sufficient capacity at Bracebridge TS to supply some of the customers in the Town of Bracebridge, the Town of Gravenhurst, the Township of Muskoka Lakes, and surrounding areas.

As discussed in Section 6.2.1, outages on the transmission system or transformer stations are relatively infrequent in this sub-region. However, due to the current system configuration at Bracebridge TS,[11] all power being supplied by the Bracebridge TS will be interrupted in the event of an outage at the TS or on the 230 kV transmission line.

Operational measures could help mitigate customers' exposure to outages on the 230 kV transmission system supplying Bracebridge TS. In the event of an outage on the 230 kV system, customers could rely on the Muskoka TS or Orillia TS as a backup supply and vice versa. In addition, a second TS and/or a combination of switching facilities could be installed to minimize the impact of potential 230 kV transmission system outages. The cost of these transmission reinforcements could range from $5 to $30 million.

Going forward, Hydro One Transmission, Hydro One Distribution, Lakeland Power and Veridian Connections will examine the cost-benefit and cost-responsibility of options to improve the service reliability performance of the 44 kV sub-transmission system supplying the Bracebridge/Gravenhurst/Muskoka Lakes and surrounding areas and will discuss these findings with the Working Group through the regional planning process. This action is expected to be completed by the end of 2017. The results from these discussions will be shared with LAC members and affected communities.

[11] In Ontario, most transformer stations are designed to have two transformers to provide redundancy during outages on the transmission system. In the event that one transformer is out-of-service, the remaining TS could still provide a continuous supply to the customers. Because Bracebridge TS was originally designed to serve the needs of the specific industrial customer, the station only has a single transformer.

7.1.2 Options to Improve Load Restoration and Security on the Muskoka-Orillia 230 kV Transmission System

Distribution Option

One option to restore electricity supply to customers following a major outage on the Muskoka-Orillia 230 kV sub-system is to resupply these customers from neighbouring 230 kV transmission system (e.g., Parry Sound 230 kV sub-system) using the distribution network. The extent to which these customers can be resupplied through the distribution network is highly variable and depends on various factors such as load level at neighbouring stations, distance between stations, voltage of neighbouring distribution systems, time of day and operating procedures in place on the distribution system. Based on information provided by the LDCs, only about 20 to 30 MW can be resupplied from neighbouring stations within 30 minutes following a major outage on the Muskoka-Orillia 230 kV sub-system. In order to meet the ORTAC load restoration at today's demand level, the system will need to restore at least 200 MW within 30 minutes following the transmission outage. As such, this option is not sufficient to meet the ORTAC load restoration criteria.

Transmission Option

In the event of a 230 kV transmission outage, fast-acting isolating devices can be installed to minimize the impact of supply interruption to customers. There are two types of fast-acting isolating devices: (1) motorized switches and (2) breakers.

Motorized switches can be used to isolate sections of the transmission line within 30 minutes following a major transmission outage and would enable power to be restored to customers in a timely manner. This is particularly important in remote areas, where repair crew may have limited access to the infrastructure. Grid operators can operate these switches remotely to isolate sections affected by an outage in a timely manner. The cost of these switches ranges from $5 to $7 million.

As an alternative solution, breakers can immediately isolate sections of the transmission line that are not directly impacted by the outage. Since breakers can reduce the total number of customers that would be affected by a transmission outage, it can be an effective solution to address the longer-term load security needs on Muskoka-Orillia 230 kV sub-system. Since additional infrastructure and protection and control systems are required for breakers, the cost of breakers is usually 3-4 times more than for motorized switches ($20 to $25 million). Given the uncertainty of the demand forecast over the longer term and the substantial cost of installing breakers, the Working Group agreed that installing breakers on the Muskoka-Orillia 230 kV sub-system is not required at this time. A summary of options to improve load restoration and load security on Muskoka-Orillia 230 kV sub-system can be found in Appendix E.

In consideration of the cost-benefit of these options, the Working Group recommends proceeding with the installation of two 230 kV motorized switches at Orillia TS. With these switches, about 50% of the electricity supply to customers on the Muskoka-Orillia 230 kV sub-system could be restored within 30 minutes in the event of an outage on the 230 kV transmission system, meeting the ORTAC 30 minute load restoration criteria.

To bring the 230 kV transmission system in compliance with Ontario's planning standard, the IESO will provide a letter to Hydro One Transmission to initiate project development work for the two 230 kV motorized switches at Orillia TS. Based on project development timeline for switching facilities, the project is expected to be in-service by the end of 2020.

7.1.3 Opportunities to Use Community-Based Solutions to Improve Resilience and Service Reliability

In addition to the transmission and distribution options discussed above, there may be opportunities to improve system resilience and service reliability at the community level using distributed energy resources and emerging technologies, such as residential solar-storage technology, micro-grids and on-site generation. Many of the community-based solutions are still in the early stages of development. The Working Group needs to better understand the cost and feasibility of these options. Depending on the interest from First Nation communities, municipalities and the LAC, the Working Group can facilitate discussions on the cost-benefit of opportunities to improve system resilience and the service reliability through community-based solutions. A good opportunity for these discussions may be through community energy planning activities.

7.2 Provide Adequate Supply to Support Growth

To ensure that the regional electricity system has adequate supply to support growth, the Working Group examined options to address the near-term needs at Parry Sound TS and Waubaushene TS and the longer-term supply capacity needs on the Muskoka-Orillia 230 kV sub-system.

The following section discusses these options in more detail.

7.2.1 Options to Provide Additional Transformer Station Capacity at Parry Sound TS and Waubaushene TS

Distribution Option

To free up supply capacity at Parry Sound TS and Waubaushene TS, some customers in the Parry Sound and Waubaushene areas can be resupplied from neighbouring transformer stations using existing and/or new 44 kV sub-transmission facilities.

To manage the near-term demand growth in the area, about 4 MW at Waubaushene TS can be resupplied from Orillia TS using the existing 44 kV sub-transmission infrastructure by 2020. If required, another 7 MW at Waubaushene TS can be resupplied from Midhurst TS upon completion of Barrie Area Transmission Reinforcement in the early 2020s. This can be done using existing distribution system and no new facilities will be required. This option would address the needs at Waubaushene TS over the planning period at minimal cost and would maximize the use of existing facilities. Midhurst TS is a major transformer station supplying the Barrie/Innisfil Sub-region. Resupplying some of the customers in Waubaushene from Midhurst TS could have an impact on the timing and need for a new TS in the Barrie/Innisfil Sub-region over the longer term. As such, the Working Group will need to coordinate with the Barrie/Innisfil IRRP Working Group to monitor and manage the demand growth in the Waubaushene and Barrie/Innisfil areas.

Similarly, to manage the near-term growth in the area, about 6 MW at the Parry Sound TS can be resupplied from Muskoka TS. There is sufficient capacity at Muskoka TS to supply these customers over the planning period. To facilitate the transfer of load from Parry Sound TS to Muskoka TS, Hydro One will need to seek approval to construct 44 kV feeder tie between the Muskoka TS M5 and M1 feeders (estimated cost of about $7 million). The siting and routing of these facilities will be determined as part of the project development process. Based on the typical project development timeline for 44 kV sub-transmission reinforcements, the project is expected to be in-service by 2020. These reinforcements would substantially address the near-term supply needs at Parry Sound TS and would also improve service reliability for the Townships of Muskoka Lakes and Seguin.

In the near term, the Working Group recommends resupplying some customers in the Parry Sound and Waubaushene areas from neighbouring transformer stations. This option will fully address the supply needs at Waubaushene TS over the planning period and will help manage near-term demand at Parry Sound TS at a minimal cost. Even after implementing these near-term measures, about 16 MW of additional supply will still be required to address the supply needs at Parry Sound TS over the planning period. As such, other options will need to be considered to address the supply needs at Parry Sound TS over the planning period.

Transmission Option

Transformers at the existing Parry Sound TS and Waubaushene TS can be upgraded to enable more power to be delivered to the Parry Sound and Waubaushene areas. This option costs about $25 to $30 million for each transformer station upgrade.

Transmission-Connected Generation Facilities

Since the need is at the transformer station level, transmission-connected generation facilities would not address the need. The Working Group therefore did not consider it.

Community-Based Solution: Local Demand Management and Distributed Energy Resources

With the relatively slow electricity demand growth forecast for this sub-region, there is an opportunity to use targeted conservation and local demand management, distribution-connected generation and/or other distributed energy resources to defer the transformer upgrade at Parry Sound TS and Waubaushene TS. In order to defer the transformer upgrades, LDCs would need to reduce the electricity demand by about 1 MW annually at each of these transformer stations. Based on economic analysis, the LDCs can save about $2 million for every year of deferred capital. More details related to the capital deferral analysis can be found in Appendix D.

Through discussions with the LDCs and communities, the Working Group has identified a number of potential community-based solutions to address supply needs in the Parry Sound and Waubaushene areas. For example:

- **Heating efficiency:** As discussed in Section 5.1, the electricity demand peak in this sub-region is driven by electric space and water heating. There may be opportunities to reduce the peak demand by improving heating efficiency in the area.

  While a large portion of the communities in this sub-region rely on electric heating, some customers also rely on other fuel types, such as wood, to meet their heating requirements. In some cases, communities may have some access to natural gas infrastructure. Through initiatives, such as home energy audits, retrofit programs and community energy planning activities, the Working Group can work with communities to better understand the heating requirements and energy baseline (e.g., heating fuel, housing insulation) and identify opportunities to improve heating efficiencies in the Parry Sound/Muskoka Sub-region.

- **Local hydroelectric potential:** Based on information provided by the Ontario Waterpower Association ("OWA"), there is about 38 MW of hydroelectric potential in the Parry Sound District. As discussed in Section 4.2.1, many of the hydroelectric resources are run-of-the-river facilities with limited storage capability. As such, only a portion of their installed capacity can be relied upon at the time of local peak. Furthermore, much of these potential hydroelectric resources are located far from existing transmission and distribution infrastructure. To access this potential, additional transmission and distribution infrastructure may be required. More details related to these hydroelectric potential can be found in Appendix F.

- **Pilots and emerging technologies:** Many LDCs are engaging in pilots and studies to better understand the costs and feasibility of community based solutions and **e**merging technologies, such as residential solar-storage technology, microgrids, and thermal energy storage. These emerging technologies can potentially help reduce a community's reliance on the provincial grid during the time of local peak.

At this time, the Working Group has limited information on the cost and feasibility of distributed energy resources and local demand management. More work is needed to determine whether it is cost effective and feasible to rely on these solutions to address the local need. To better understand the cost and feasibility of implementing distributed energy solutions and demand management in the Parry Sound/Muskoka Sub-region, the Working Group recommends initiating a local achievable potential ("LAP") study for the Parry Sound/Muskoka Sub-region in early 2017. The study will examine the cost and feasibility of a range of distributed energy resources and local demand management options including incentive adders to existing conservation programs, new conservation and demand management programs, local demand response, behind-the-meter generation and energy storage. The study may also examine options to manage new demand from increased electrification that may result from Ontario's CCAP. This study will be initiated in early 2017 by the LDCs. The IESO will assist and provide funding for the LAP study.

As well, the Working Group will work closely with communities to leverage local knowledge and community energy planning activities and to identify opportunities for targeted conservation and energy efficiency opportunities in First Nation communities and municipalities.

End-of-Life Replacement Considerations

As discussed in Section 6.3.1, transformers at Parry Sound TS and Waubaushene TS could be reaching their end-of-life in the early 2030s. Depending on the electricity demand growth, it may be cost effective to advance the end-of-life replacement of these aging assets with upgraded/upsized facilities.

To determine if there is an opportunity to align the end-of-life facility replacement with solutions to address supply need at Parry Sound TS and Waubaushene TS, the Working Group will actively monitor and assess the conditions of these transformers and electricity demand growth. The Working Group will revisit this need in the next iteration of the plan.

7.2.2 Options to Provide Additional Supply Capacity on Muskoka-Orillia 230 kV sub-system over the Longer Term

As discussed in Section 6.2.2, about 20 MW of additional supply capacity will be required on the Muskoka-Orillia 230 kV sub-system in the early 2030s. Given the uncertainty with the demand growth and the fact that the need does not arise until late in the planning period, early development work for major electricity infrastructure projects is not required at this time. However, it is important to continue to monitor demand closely to determine if and when an investment decision for the Muskoka-Orillia 230 kV sub-system is required. To lay the ground work for the next planning cycle, the Working Group has explored potential options to address the longer-term needs on Muskoka-Orillia 230 kV sub-system.

Distribution Option

To free up supply capacity on the Muskoka-Orillia 230 kV sub-system, one option is to supply some of customers on the Muskoka-Orillia 230 kV sub-system from the transformer stations on the Parry Sound 230 kV sub-system using existing and/or new 44 kV sub-transmission facilities. However, as discussed in Section 6.2.2 , electricity demand at Parry Sound TS and Waubaushene TS has already exceeded the TS capacity and would not have sufficient capacity to supply additional customers. This option was therefore ruled out by the Working Group.

Transmission Options

Installing switching facilities or upgrading sections of the transmission lines can enable more power to be delivered into the Muskoka-Orillia 230 kV sub-system. These enhancements may be subject to regulatory approvals, such as a Class Environmental Assessment and utilities' rate filings. The lead time to develop these facilities is typically three to five years.

The costs of these transmission reinforcements range from $20 to $30 million depending on the reinforcements requirements. Cost responsibility for the transmission reinforcements would be determined as part of the regulatory application review process.

This option should be considered and revisited in the next iteration of the plan.

Transmission-Connected Generation Option

Siting transmission-connected generation facilities can be effective for addressing supply capacity on Muskoka-Orillia 230 kV sub-system. A 20 MW generation facility connected to Muskoka-Orillia 230 kV sub-system can address the potential supply capacity needs arising in the early 2030s.

There are a number of factors that need to be considered when siting localized generation, and any decisions would need to align with the recommendations found in the August 2013 report entitled "Engaging Local Communities in Ontario's Electricity Planning Continuum"[12] prepared for the Minister of Energy by the former OPA and the IESO.

As the requirements in the Parry Sound/Muskoka Sub-region are for additional capacity during times of peak demand, a large, transmission-connected generation solution would need to be capable of being dispatched when needed, and operate at an appropriate capacity factor. In some cases, additional transmission reinforcements may also be required.

The cost of a large, localized generation resource depends on the size, fuel type, technology and the degree to which it can contribute to the local and provincial system capacity or energy needs. The fuel availability will also need to be taken into consideration. The lead time for generation development is typically two to three years, but it could be longer depending on the size and technology type.

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[12] http://www.ieso.ca/Pages/Participate/Regional-Planning/Local-Advisory-Committees.aspx

This option should be considered and revisited in the next iteration of the plan.

<u>Community-Based Solutions: Local Demand Management and Distributed Energy Resources</u>

With the modest electricity demand growth in this sub-region, there is an opportunity to use targeted local demand management, distribution-connected generation and/or other distributed energy resources to manage demand on the Muskoka-Orillia 230 kV sub-system and to defer major capital investments and infrastructure development over the longer term. As discussed in Section 7.2.1, the Working Group will initiate a LAP study to determine the cost and feasibility of using distributed energy resources and local demand management options to defer major capital investments (e.g., transmission reinforcements). In conjunction with the study, the Working Group will continue to work closely with communities to coordinate community-energy planning activities and to identify opportunities for targeted CDM opportunities in First Nation communities and municipalities.

This option should be considered and revisited in the next iteration of the plan.

8. Recommended Actions

The recommended actions to minimize the frequency and duration of power outages and to provide adequate supply to support growth in the Parry Sound/Muskoka Sub-region over the planning period are outlined in Tables 8-1 and 8-2, along with the proposed timing and the parties that will lead the implementation.

The Working Group will continue to meet regularly during the implementation phase of this IRRP to monitor developments in the sub-region and to track progress toward these deliverables and this information will be shared and discussed with the LAC.

Table 8-1: Recommended Actions to Minimize Frequency and Duration of Power Outages

Recommendations		Action(s)/Deliverable(s)	Lead Responsibility	Timeframe
1	**Inform communities and LAC members of the 44 kV sub-transmission service reliability performance and the on-going maintenance and improvement initiatives in the Parry Sound/Muskoka Sub-region**	Provide an update to communities and LAC members on the 44 kV sub-transmission service reliability performance improvements including any proposed capital plans The ability to implement any proposed capital investment plans will be contingent on the outcome of Hydro One Distribution's 2018-2022 rate filing application with the OEB.	Hydro One Distribution	End of year 2017
2	**Examine the cost benefit and cost responsibility of options to resupply customers in Bracebridge, Gravenhurst, Muskoka Lakes and surrounding areas from alternate transformer station**	Discuss findings and decision with the Working Group through the regional planning process Share the results with LAC members and affected communities	Hydro One Distribution, Lakeland Power and Veridian Connections	To be completed by Q4 2017

3	**Install two 230 kV motorized switches at Orillia TS to restore power to customers in timely manner in the event of a major outage on the Muskoka-Orillia 230 kV sub-system**	Prepare a letter to Hydro One Transmission to initiate project development work	IESO	Early 2017
		Design, develop and construct two 230 kV motorized switches	Hydro One Transmission	In-service by end of 2020
4	**Explore opportunities to improve resilience and service reliability at the community level**	Facilitate discussions with First Nation communities, municipalities and LAC members on the cost-benefit and opportunities to improve system resilience and service reliability through community energy planning	IESO	On-going

Table 8-2: Recommended Actions to Provide Adequate Supply to Support Growth

Recommendations		Action(s)/Deliverable(s)	Lead Responsibility	Timeframe
1	**Resupply some customers in the Parry Sound and Waubaushene areas from neighbouring transformer stations using existing and new distribution facilities to maximize the use of the existing system**	Seek approval to construct 44 kV feeder tie between the Muskoka TS M5 and M1 feeders to facilitate the transfer of load from Parry Sound TS to Muskoka TS	Hydro One Distribution	In-service by 2020
		Transfer up to 4 MW from Waubaushene TS to Orillia TS Transfer up to 6 MW from Parry Sound TS to Muskoka TS	Hydro One Distribution	Prior to 2020
		Transfer up to 7 MW from Waubaushene TS to Midhurst TS (if required)	Hydro One Distribution	Early 2020s upon completion of

				Barrie Area Transmission Reinforcement
		Coordinate with the Barrie/Innisfil IRRP Working Group to monitor and manage demand growth in the Waubaushene and Barrie/Innisfil areas	IESO	On-going
2	**Determine the cost and feasibility of using distributed energy resources and local CDM options to defer major capital investments in the Parry Sound/Muskoka Sub-region**	Initiate a LAP study to determine the cost and feasibility of using distributed energy resources and local conservation and demand management options to defer major capital investments (e.g., transmission reinforcements)	IESO to assist and provide funding LDCs to carry out the study	Initiate study in early 2017
		Work closely with communities to leverage local knowledge and community energy planning activities and to identify opportunities for targeted conservation and demand management opportunities in First Nation communities and municipalities.	IESO	On-going
3	**Determine whether it is cost effective to advance the end-of-life replacement and to replace the aging assets with upgraded/upsized facilities at Parry Sound TS and Waubaushene TS**	Review electricity demand growth at Parry Sound TS and Waubaushene TS with LAC members	IESO	Annually
		Monitor and provide updated information on the condition of aging equipment at Waubaushene TS and Parry Sound TS to the LAC and the Working Group	Hydro One Transmission	Annually

		Determine whether it is cost effective to advance the end-of-life replacement and to replace the aging assets with upgraded/upsized facilities.	IESO	Annually
4	**Monitor electricity demand growth closely to determine if and when an investment decision on the Muskoka-Orillia 230 kV sub-system is required**	Review electricity demand growth on the Muskoka-Orillia 230 kV sub-system with LAC members	IESO	Annually

9. Community 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 engagement activities undertaken to date and next steps for the Parry Sound/Muskoka IRRP.

A phased community engagement approach was undertaken for the Parry Sound/Muskoka 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 in 2013 to determine how to improve the regional planning and siting process, and they now guide IRRP outreach with communities and will ensure this dialogue continues as the plan moves forward.

Figure 9-1: Summary of the Parry Sound/Muskoka Community Engagement Process

Creating Transparency: ***Creation of Parry Sound/Muskoka IRRP Information Resources***	• Dedicated Parry Sound/Muskoka IRRP web page created on IESO website providing background information, the IRRP Terms of Reference and listing of the Working Group members • Dedicated web page created on Hydro One website • Self-subscription service established for the South Georgian Bay/Muskoka planning region for subscribers to receive regional planning updates • Status: complete
Engaging Early and Often: ***Municipal and Indigenous Outreach***	• Early engagement on regional planning and the South Georgian Bay/Muskoka Scoping Assessment Report (September 2015) • Group meetings held with municipalities from across the planning region held in Huntsville and Parry Sound (September 2015) • Meetings held with First Nation communities in Rama (September 2015) • Status: initial outreach complete; dialogue continues
Bringing Communities to the Table: ***Broader Community Outreach***	• Parry Sound/Muskoka LAC formed in spring 2016; dedicated Parry Sound/Muskoka engagement web page added to IESO website • Two LAC meetings held in June and September 2016 to discuss and obtain feedback on the development of the IRRP and draft recommendations • LAC meetings are open to the public; materials are posted to the engagement webpage • Status: begun in spring 2016; on-going

9.1 Creating Transparency

To start the dialogue on the Parry Sound/Muskoka IRRP and build transparency in the planning process, a number of information resources were created for the plan. A dedicated web page was created on the IESO website including a map of the regional planning area, information on why an IRRP was being developed for the Parry Sound/Muskoka Sub-region, the IRRP terms of reference and a listing of the organizations involved. A dedicated email subscription service was also established for the broader South Georgian Bay/Muskoka planning region where communities and stakeholders could subscribe to receive email updates about the IRRP.

9.2 Engage Early and Often

Early communication and engagement activities for the Parry Sound/Muskoka IRRP were initiated in September 2015 as part of a series of meetings with communities and stakeholders to discuss electricity planning initiatives across the Parry Sound/Muskoka Sub-region. The main objective of the meetings from a regional planning perspective was to introduce attendees to the regional planning process. This included the South Georgian Bay/Muskoka Scoping Assessment process for the regional planning studies being initiated in the area, as well as discussions of upcoming engagement activities. Various meetings were held with a broad range of attendees including municipal representatives, First Nation community members, and local industrial customers.

9.2.1 South Georgian Bay/Muskoka Region Scoping Assessment Outcome Report

The draft South Georgian Bay/Muskoka Region Scoping Report was posted to the IESO website in May 2015 for comment, and a final version was posted on June, 22, 2015. The report was led by the IESO, and developed in collaboration with regional participants, including Hydro One Networks, Lakeland Power, Midland PUC, Newmarket-Tay Power, Orillia Power, PowerStream, and Veridian Connections.

9.2.2 First Nation Community Meetings

On September 24, 2015 the IESO met with Chief Denise Restoule and Councillor Roger Restoule of Dokis First Nation, Chief Barron King of Moose Deer Point First Nation, Chief Warren Tabobondung of Wasauksing First Nation and community representatives. The feedback received focused on the concern that any necessary future infrastructure be planned so that environmental disturbance is minimized and traditional land and space considerations for each community be respected during the planning process. Community members also expressed the preference to have meetings with communities and municipalities at the same time to ensure that everyone is engaged in the same dialogue. Feedback was also shared that communities would like distributed generation proponents to have the same strong relationship with First Nation communities as they do with municipalities to provide communities with a firsthand opportunity to present and protect their needs.

The IESO remains open to additional meetings to support further engagement of the IRRP.

9.2.3 Municipal Meetings

Meetings with area municipalities are one of the first steps in engagement for all regional plans. In September 2015, the Working Group held municipal meetings in Huntsville and Parry Sound to discuss findings for the South Georgian Bay/Muskoka Region and next steps in the process, including identifying potential options to strengthen reliability in the area, increase supply capacity and replaced aging electricity infrastructure nearing end-of-life. Attendees provided insight on population forecasting, challenges with reliability in the area, and the importance of public and community engagement as the planning process develops. It was also indicated that there was a preference for a LAC for each of the two sub-regions instead of one committee for the larger South Georgian Bay/Muskoka Region.

9.3 Bringing Communities to the Table

To continue the dialogue on regional planning, a LAC was established for the Parry Sound/Muskoka Sub-region in spring 2016. The role of the LAC is to provide advice and recommendations on the development of the regional plan as well as to provide input on broader community engagement. LACs are comprised of municipal, Indigenous, environmental, business, sustainability and community representatives. There is currently one general LAC in the planning area, which includes First Nation and Métis representation. The possibility of also forming a First Nation LAC, comprised of representatives from the First Nation communities in the planning area remains, should First Nation communities request an additional forum for community discussions. All general LAC meetings are open to the public and meeting information is posted on the dedicated engagement webpage, which in this case is the IESO's Parry Sound/Muskoka engagement webpage.[13]

Development of the Parry Sound/Muskoka LAC was completed through a request for nominations process promoted by the following activities: advertisements in nine local newspapers across the planning area; digital (website) advertising in communities throughout the planning area; emails sent to municipal representatives across the region; letters to the Chiefs of the First Nation communities in the area inviting them to appoint a representative to the LAC, and an e-blast sent to the IESO's South Georgian Bay/Muskoka subscribers list.

On June 20, 2016, the Working Group held the inaugural LAC meeting in the Town of Gravenhurst. The focus of the meeting was to introduce the regional planning process to the newly formed LAC, provide an overview of the electricity infrastructure supplying the area, and touch upon key electricity needs and issues in the Parry Sound/ Muskoka Sub-region to be discussed in greater detail at subsequent LAC meetings.

The second LAC meeting was held on September 26, 2016 in the Town of Dwight. LAC members were presented with the draft IRRP recommendations, and had the opportunity to provide their feedback following the meeting to help inform the final report. Materials from both meetings can be accessed online on the IESO's website.[14]

Copies of the meeting summaries from the Parry Sound/Muskoka LAC meetings can be found in Appendix G.

At the September 2016 meeting, the members of the Parry Sound/Muskoka LAC expressed their interest in continuing to meet on a regular basis following the posting of the IRRP. As a result, the LAC will continue to meet until the start of the next planning cycle in 2018. Information about LAC meetings will continue to be posted on the IESO Parry Sound/Muskoka Sub-region engagement webpage and email notifications of meetings will continue to be sent to the broader South Georgian Bay/Muskoka email subscriber list.

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[13] http://www.ieso.ca/Pages/Participate/Regional-Planning/South-Georgian-Bay-Muskoka/Parry-Sound-Muskoka-sub-region.aspx

[14] http://www.ieso.ca/Pages/Participate/Regional-Planning/South-Georgian-Bay-Muskoka/Parry-Sound-Muskoka-sub-region.aspx

10. Conclusion

This report documents the regional planning process that has been carried out for the Parry Sound/Muskoka Sub-region and fulfills the OEB's regional planning requirement for the sub-region. The IRRP identifies electricity needs in this sub-region over the 20-year period from 2015 to 2034 and recommends a set of actions to minimize the frequency and duration of power outages and to ensure that the regional electricity system has adequate supply to support growth.

The Parry Sound/Muskoka Sub-region Working Group will continue to meet regularly throughout the implementation of the plan to monitor progress and developments in the sub-region, and will produce annual updates that will be posted on the IESO website[15]. To support development of the plan, a number of actions have been identified to develop alternatives, engage with communities, and monitor growth in the area. Responsibility has been assigned to appropriate members of the Working Group for these actions. Information gathered and lessons learned from these activities will inform development of the next iteration of the IRRP for the Parry Sound/Muskoka Sub-region. The plan will be revisited according to the OEB-mandated 5-year schedule.

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[15] IESO website (http://www.iemo.com/Pages/Ontario%27s-Power-System/Regional-Planning/South-Georgian-Bay-Muskoka/default.aspx)

PARRY SOUND / MUSKOKA SUB-REGION
INTEGRATED REGIONAL RESOURCE PLAN - APPENDICES

Part of the South Georgian Bay/Muskoka Planning Region | December 16, 2016

Connecting Today. Powering Tomorrow.

Parry Sound/Muskoka IRRP

Appendix A: Demand Forecast – Methodology and Assumptions

A.1 Gross Demand Forecast

Tables A-1 shows the gross demand forecast scenarios developed for the Parry Sound/Muskoka Sub-region. The gross demand forecast reflects the regional peak demand and was developed based on the growth projections developed by the Local Distribution Companies.
Appendices A.1.1 through A.1.6 describe the LDCs' gross demand forecasting methodologies and assumptions. The gross demand also includes expected peak demand consumption from various existing and potential transmission connected customers in the West of Thunder Bay Sub-region. Appendix A.1.6 describes how these assumptions were developed.

Table A-1: Winter Gross Demand Forecast 2015-2034 – Parry Sound/Muskoka Sub-region

Winter Gross Demand Forecast (MW)																				
Transformer Station	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
Orillia TS[1]	127.0	128.9	131.1	133.5	136.0	138.3	139.8	141.6	143.2	144.8	146.4	148.2	149.9	151.7	153.4	155.2	156.9	158.6	160.4	162.1
Parry Sound TS	61.2	62.1	62.7	63.4	64.5	65.5	66.3	67.1	67.9	68.6	69.4	70.2	71.1	71.9	72.8	73.6	74.5	75.3	76.2	77.1
Bracebridge TS[2]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Minden TS	58.8	59.5	59.8	60.3	61.2	62.0	62.5	62.9	63.3	63.7	64.1	64.5	64.9	65.4	65.8	66.2	66.6	67.0	67.4	67.8
Waubaushene TS	99.2	99.2	100.2	101.1	102.5	103.8	104.6	105.6	106.6	107.5	108.5	109.3	110.3	111.3	112.2	113.2	114.2	115.0	115.9	116.8
Muskoka TS	160.6	163.0	164.7	166.9	169.8	172.7	175.0	177.2	179.4	181.6	183.9	186.2	188.7	191.2	193.7	196.0	198.5	201.0	203.5	205.9
Midhurst TS[3]	173.4	178.3	182.8	188.4	194.5	219.5	224.1	229.8	235.4	239.9	245.5	251.1	255.8	261.5	267.1	272.8	278.4	284.0	289.6	295.2
Muskoka-Orillia 230 kV sub-system[4]	461.0	470.1	478.6	488.8	500.3	530.5	539.0	548.5	558.0	566.4	575.8	585.6	594.4	604.4	614.2	624.0	633.8	643.6	653.5	663.2
Parry Sound 230 kV sub-system[5]	160.4	161.3	162.9	164.6	167.0	169.3	170.9	172.7	174.4	176.1	177.9	179.5	181.4	183.2	185.0	186.9	188.7	190.3	192.1	193.8
TOTAL Parry Sound/Muskoka Sub-region	506.8	512.7	518.5	525.2	534.0	542.3	548.3	554.4	560.3	566.2	572.3	578.4	584.9	591.5	597.9	604.3	610.7	616.9	623.4	629.7

[1] Note that the high demand forecast could result in an additional 30 MW at Orillia TS by 2034.
[2] Bracebridge demand is assumed to be 0 MW at time of area coincident peak due to the intermittent nature of the customer connected at the station and historical demand at this station at times of area peak.
[3] Although Midhurst is part of Barrie/Innisfil IRRP, it is supplied by the Muskoka-Orillia 230 kV sub-system and could have an impact on the electricity supply to the Parry Sound/Muskoka Sub-region. The demand has been included in the Muskoka-Orillia 230 kV sub-system forecast for the purposes of establishing needs for this sub-system.
[4] Includes demand at Midhurst TS, Orillia TS, Bracebridge TS, and Muskoka TS.
[5] Includes demand at Waubaushene TS and Parry Sound TS.

A.1.1 Hydro One Distribution: Gross Forecast Methodology and Assumptions

Hydro One Distribution provides service to counties and townships in the Muskoka – Parry Sound region including those surrounding Parry Sound, Waubaushene, Orillia, Bracebridge, Muskoka, and Minden. Hydro One Distribution also provides service to 8 First Nation communities, Henvey Inlet, Magnetawan, Shawanaga, Wasauksing, Moose Deer Point, Beausoleil, Wahta Mohawks and Chippewas of Rama.

Hydro One Distribution serves 124,971 customers in the Sub-region of which 93% are residential, 6.6% commercial, and 0.4% industrial customers. In terms of energy usage, residential share is 61%, commercial 22%, and industrial 17%.

Factors that Affect Electricity Demand

Hydro One Distribution serves mostly the rural areas outside the major communities in the region. The demand growth in the Hydro One Distribution service area is largely driven by the economic activities in these large communities and is expected to be modest as the population moves from the urban centers to the rural areas.

Nonetheless, the demand for electricity in the study area as a whole and, therefore, in Hydro One Distribution territory is affected by provincial economic and demographic factors, as detailed in the following section.

Forecast Methodology and Assumptions

An econometric method was used to perform the forecast. The reference level forecast is developed using macro-economic analysis, which takes into account the growth of demographic and economic factors, as follow.

Ontario GDP growth assumption used in developing the forecast::

2015	2016	2017	2018	2019	2020
2.8%	2.5%	2.5%	2.3%	2.2%	2.0%

Ontario Housing Starts (in thousands)

2015	2016	2017	2018	2019	2020
61.8	61.8	65.5	68.9	72.2	69.2

The forecast corresponds to the expected weather impact on peak load under average peak-time weather conditions, known as weather-normality. Furthermore, the forecast is unbiased such that there is an equal chance of the actual peak load being above or below the forecast. In addition, local knowledge and information regarding the loading in the area within the next two to three years, is utilized to make minor adjustments to the forecast on an ongoing basis.

A.1.2 Lakeland Power: Gross Forecast Methodology and Assumptions

Lakeland Power Distribution Ltd. (LPDL) is a small Local Distribution Company (LDC) that distributes electricity to approximately 13,500 customers across its service area. LPDL is comprised of six separate, rural communities and is completely embedded within Hydro One's system. This non-contiguous service area encompasses: Town of Parry Sound, Town of Huntsville, Town of Bracebridge, Municipality of Magnetawan, Village of Burk's Falls and Village of Sundridge

Due to the diversity of the six, distinctly separate communities, LPDL's distribution system consists of widely varying ages of overhead and underground assets, station capacities and system voltages (4.16 kV, 12.5 kV, 27.6 kV and 44 kV).

Forecast Methodology and Assumptions

LPDL has a strong residential customer base (town, rural and island customers) mixed with various commercial and industrial loads. LPDL has experienced minimal growth over the past number of years. LPDL's six service areas are completely embedded within Hydro One's territory thus limiting room for expansion. Lakeland Power's load forecast is developed in a multi -step process. This includes weather normalized load forecast, customer/connection forecast, past system peak performance, past customer growth rate and CDM targets.

A.1.3 Midland Power Utility Corporation: Gross Forecast Methodology and Assumptions

Midland Power Utility Corporation (MPUC) is a small Local Distribution Company (LDC) that delivers electricity to over 7000 customers in the Town of Midland. Midland PUC is completely embedded within Hydro One's distribution system and is fed from four 44 KV feeders from Waubaushene TS. Midland PUC continues to be the most northern summer peaking LDC, this is likely due to our industrial customers and the large marinas located inside our service territory.

Forecast Methodology and Assumptions

Midland PUC has a strong Industrial customer base that accounts for half of our Electricity Load and Demand. Residential and commercial loads account for the remaining half. With very slow growth in the community partnered with an aggressive conservation initiative, Midland PUC has taken several factors into consideration. These factors include coincident peak data from 2015, weather normalized load forecast, and potential Residential and Industrial growth within the Town of Midland. Using current base load along with future forecast growth plans we expect a very modest 1% increase in the Town of Midland.

A.1.4 Newmarket-Tay Power Distribution Ltd.: Gross Forecast Methodology and Assumptions

Newmarket-Tay Power Distribution Ltd (a merger of Newmarket Hydro and Tay Hydro) owns and operates the electricity system servicing the three communities of Port McNicoll, Victoria harbor & Waubaushene within Tay Township.

Forecast of Municipal Growth Rate as Basis of Load Forecast

In developing the forecast, NT Power relied upon a combination of past historical growth, as well information obtained through the County of Simcoe long-term growth information. For the current load forecast the coincident peak data from 2015 has been used as the base for load growth. In developing the load forecast several factors must be considered and evaluated to determine potential growth within the study area. The electric load forecast is one the key drivers of NT Power's planning activities at both the distribution planning level and overall supply requirements from the bulk wholesale transmission system.

Base Forecast; Trend and End Use Analysis

Trend Analysis uses historical consumption of electricity demand to predict future requirements. A combination of timeframes (5, 10, 15 years) is used to determine potential demand increases as compared to forecast growth. Regular updating and review is completed on an annual basis.

A second analysis is completed based on customer end use. As stated above Tay Township is a community in transition with future growth focused within the urban areas. The end-use methodology considers that the demand for electricity is dependent on what it is used for. An analysis is completed on end-use and the demand is subsequently allocated between residential and industrial/commercial/institutional type of demand. Using standard historical usage data per end-use customer provides a basis to forecast expected demand with load growth across the communities.

A.1.5 Orillia Power Distribution Corporation: Gross Forecast Methodology and Assumptions

Orillia Power Distribution Corporation ("Orillia Power") owns and operates the electricity distribution system within the City of Orillia, with a licensed territory of 27 square kilometers. Orillia Power services approximately 13,400 customers, of which 88% are residential, 11% are general service <50 kW, and 1% are general service >50 kW.

Orillia Power's distribution system is fed by four 44 kV lines from Hydro One Networks' Orillia TS. Nine distribution substations within the city step this voltage down to 13.8 kV (five stations) and 4.16 kV (four stations), before power is delivered to customers

Factors that Affect Electricity Demand

The primary drivers of electricity demand growth in Orillia are new residential and commercial developments. In addition to condos and townhouse projects spread throughout the city, the most substantial growth can be seen in Orillia's west end (west of HWY 11) where a number of new subdivision developments are being constructed in the area around the West Orillia Sports Complex and Lakehead University's campus. Potential future expansion of this campus presents an opportunity for growth as well.

Also in this segment of the city is the Horne Business Park, which currently has over 40 acres of fully serviced employment lands available for development. There has been significant interest in the land that could result into future business development which could be a significant impact on system load. One major retailer has started construction which could lead to additional spinoff growth in the area. Additionally, a new major service center development is planned for the park in the near future.

Approximately 4,500kW of installed solar generation through the FIT and MicroFIT programs help to offset the system's peak demand, and several smaller CDM initiatives including a proposed CHP generator will contribute to a lesser extent as well.

Looking into the future, the potential for more widespread adoption of electric vehicles could place substantial additional demand on Orillia's distribution system. The timeline for how this will progress is currently unclear, however the utility has begun to receive inquiries around installing charging stations in the downtown core.

Forecast Methodology and Assumptions

Orillia Power's forecast methodology is based on historical load growth trends, as well as estimated loading for planned developments in the near term. Building on an average of the system peaks for 2010-2014, Orillia Power assumed a base load growth of 0.5% per year. Forecasting as far out as 2021 takes into account anticipated additional load from residential subdivisions, condos, and commercial developments for which plans have been received. Looking beyond 2021, an allotment of 0.55 MW was added each year to account for possible future developments that are in addition to the base 0.5% growth.

The municipality also updates Orillia Power with planned developments and timing. Additional planned developments in Orillia, including condo and waterfront development and new retail, commercial, industrial and institutional customers may materialize within the 20-year planning period resulting in as much as an additional 20-22 MW of peak demand in the sub-region. These planned developments are considered as a sensitivity scenario to the forecast developed as described above.

A.1.6 PowerStream Inc.: Gross Forecast Methodology and Assumptions

PowerStream Inc. ("PowerStream") provides service to more than 365,000 customers across eleven Simcoe County and York Region communities including Alliston, Aurora, Barrie, Beeton, Bradford West Gwillimbury, Markham, Penetanguishene, Richmond Hill, Thornton, Tottenham and Vaughan. Collingwood, Stayner, Creemore and Thornbury are serviced through a partnership with the Town of Collingwood in the ownership of Collus PowerStream.

PowerStream's service area in Penetanguishene encompasses the urban boundaries of the Town of Penetanguishene. PowerStream's primary distribution voltages in Penetanguishene are 44 kV and 4.16 kV.

The Town of Penetanguishene is supplied by two 44 kV feeders from one Hydro One owned transformer station. These 44 kV feeders supply four PowerStream owned Municipal Substations that lower the voltage to PowerStream's primary 4.16 kV distribution voltage in the supply region.

Factors that Affect Electricity Demand

The Town of Penetanguishene is located in north-west Simcoe County. According to the Hemson Simcoe Area Growth Plan Report, Penetanguishene's population is anticipated to reach 12,700 by 2031. This presents an increase in population from 2006 to 2031 of approximately 2,600.

Penetanguishene is forecast to post 7,000 jobs by 2031, an increase of approximately 1,800 jobs relative to the 2006 employment census. Employment is predicted to concentrate around health care, social assistance, manufacturing, and tourism.

Penetanguishene's total number of housing units is forecast to increase from 3,626 units in 2006 to 5,142 in 2031, a total increase of 1,516 units. Single detached and semidetached housing is expected to represent the majority of housing stock, with row-houses and apartments representing the remaining balance of units.

Numerous residential subdivisions comprised of detached homes represent the projects currently under construction. A new sewage treatment plant was completed in 2016 to address future growth in the area. The Town of Penetanguishene has identified approximately 47 hectares of vacant land available for employment, however, there are currently no plans identified to provide services to the identified parcels.

Forecast Methodology and Assumptions

PowerStream's methodology for developing the base load forecast for Penetanguishene consisted of a number of elements including past system peak performance and statistical trend analysis, as well as an end-use analysis using the latest information gathered from meetings with the Town.

During the meetings information was gathered on projected residential and non-residential developments, population and employment growth. The Hemson Simcoe Area Growth Plan Report and the Ontario Places to Grow Report were used in conjunction with the information gathered from meetings with the Town of Penetanguishene.

A.1.6 Veridian Connections: Gross Forecast Methodology and Assumptions

Veridian Connections supplies over 120,000 customers in all of its geographically diverse service areas. Included in that number are over 5,500 customers in and around the Town of Gravenhurst. Approximately 60% of these customers are in urban Gravenhurst, with the remaining being located in the rural lands, and islands, around the town. In Gravenhurst, Veridian receives its power from Hydro One Networks Inc. through two (2) 44 kV feeders-one from Orillia TS, one from Muskoka TS. These feeders supply three local Veridian owned distribution stations. Additionally, Veridian customers are embedded on a number of Hydro One 12.47 kV feeders from local Hydro One owned and operated distribution stations. Veridian's distribution system in the Gravenhurst area consists of overhead, underground and submarine assets operating at a number of system voltages (4.16 kV, 12.47 kV and 44 kV). Installed Distributed Generators total approximately 424kW (nameplate capacity).

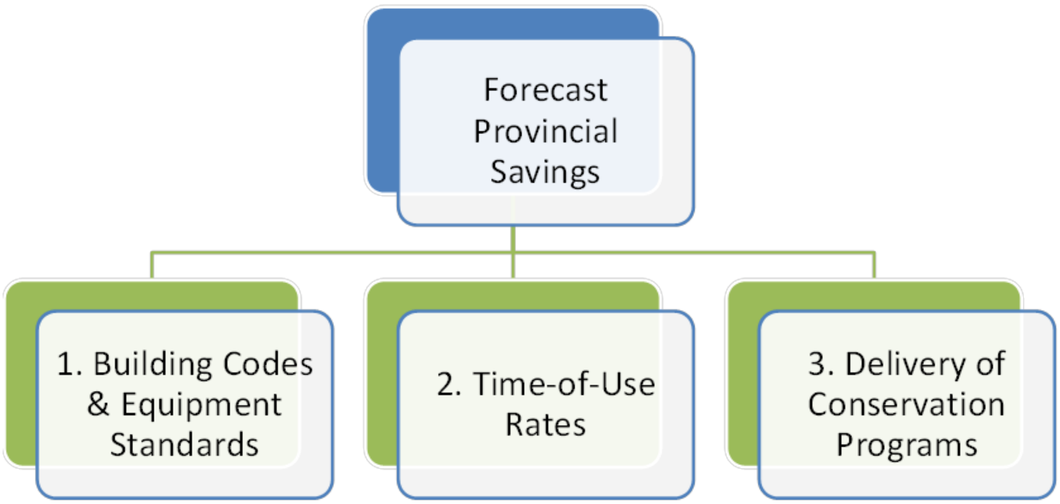
Forecast Methodology and Assumptions

Veridian relies primarily on the relationship between population and typical load per customer type to generate its demand forecasts. Average load per customer type comes from analysis of Veridian's own customer data as well as incorporating the impacts of mandated CDM targets. This average load is also reviewed against changing trends in consumption to incorporate changes such as the charging of electric cars, or the penetration of DG with net metering. Veridian's loads in the Gravenhurst area are expected to remain essentially flat over the coming years. Any modest load growth is expected to be offset by CDM and DG projects.

A.2 Estimated Peak Demand Savings from Provincial Energy Conservation Targets

Conservation savings were separated into the three main categories shown in Figure A-1 below. The impacts of the savings for each category were allocated according to the residential, commercial and industrial gross demand. This appendix provides additional breakdowns for the conservation savings estimates for the Parry Sound/Muskoka Sub-Region and provides more detail onto how the savings for the three savings categories were developed.

Figure A-1 – Conservation Savings Categories



1. *Savings due to Building Codes & Equipment Standards*
2. *Savings due to Time-of-Use Rate structures*
3. *Savings due to the delivery of Conservation Programs*

Estimating Savings from Building Codes and Equipment Standards

Ontario Building codes and equipment standards set minimum efficiency level through regulations. Under IESO's current analysis, building codes and equipment standards are forecast to contribute a saving of about 10 TWh by 2032 in Ontario. To estimate the impact on the region, the associated peak demand savings for building codes and equipment standards are estimated and compared with the provincial gross peak demand forecast. From this comparison, annual savings percentages were developed for the purpose of allocating the associated savings to each TS in the region by sector.

Figure A-2 – Split of Building Codes & Equipment Standards Savings

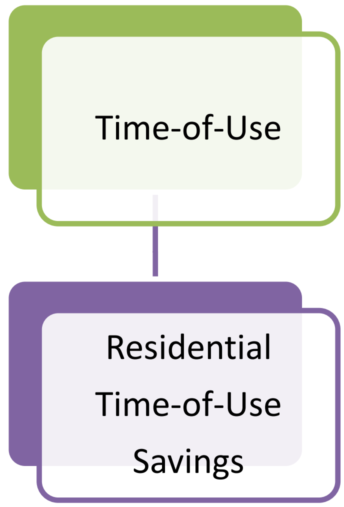
**Savings are projected for Residential & Commercial sectors only*

Annual savings percentages were applied to the forecast sector demand at each TS to develop an estimate of peak demand impacts from codes and standards. By 2032, the residential sector will see about 5.5% peak demand savings through standards and commercial sector will see about 5.3% peak demand savings through codes.

Savings from Time-of-Use Rates

Almost all residential customers in Ontario have smart meters installed and are on Time-of-Use ("TOU") rates. Small commercial customers, with loads less than 50kW, are also on TOU rates. Using results from the TOU impact evaluation completed in 2014 and assuming some regional characteristics, an average peak demand reduction of 0.55% was assumed for residential customers who switched to TOU rates. This means a peak reduction of 0.55% across residential customers in the province. This peak reduction factor is assumed to be consistent for residential customers in this sub-region. This percentage impact is assumed to continue, increasing the total forecast peak demand savings as residential sector demand grows. The percentage was applied to the incremental forecast residential load of each TS in the study to estimate the peak reduction. The same impact evaluation found that the peak impact of TOU rates on small commercial customers is minimal. Therefore the commercial sector TOU impact is assumed to be already embedded in the base year and no incremental savings are considered in the forecast.

Figure A-3 – Time-of-Use Savings

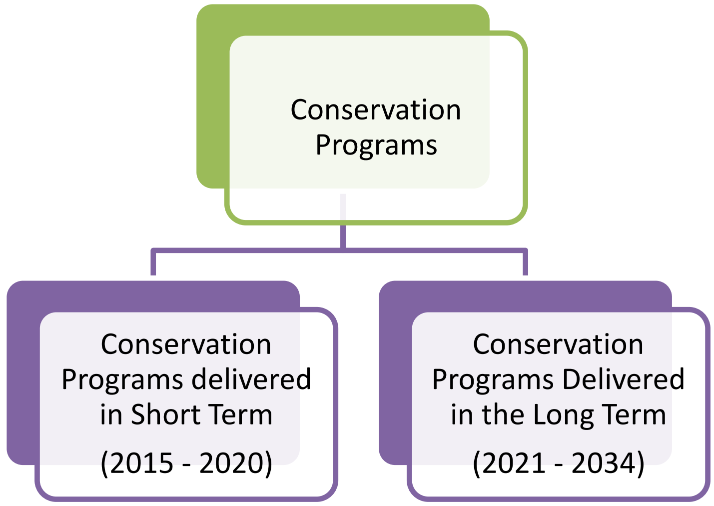


**No incremental savings are assumed for commercial sector*

Savings from the Delivery of Conservation Programs

Conservation programs across the province are forecast to reduce about 20 TWh energy consumption by 2032. For the short term (2015 to 2020), all LDCs have conservation and demand management ("CDM") plans in place, which includes detailed savings projections through energy efficiency, conservation, and behind the meter generation, and indicate how their conservation efforts will integrate with regional planning. As per the Minister's direction for the Conservation First Framework ("CFF"), the IESO is to encourage LDCs to incent measures with persisting savings, peak demand reductions, and those that address local system needs. It is expected that LDCs will meet their CFF conservation targets and provide the estimated benefit that was forecast. The estimated peak impact can be found within the CDM plans; these savings values are used in the demand and conservation forecast for the region. For the long term (2021 to 2034), the achievable potential was estimated in a 2014 study; future programs will be designed to achieve these identified savings. The provincial forecast savings were allocated to the region and TSs according to their respective load.

Figure A-4 – Timeframes for Conservation Program Savings



Savings from Programs Delivered in the Short Term

CDM plans that were provided by each of the participating LDCs for the CFF contained information that was used to estimate the conservation savings to be considered for short-term program savings. The peak demand savings from Conservation Programs delivered in the short term include all persisting savings until 2034 due to the expected delivery of programs from 2015 to 2020. As a part of the plan, each LDC submitted Cost Effectiveness Calculators that contains estimated energy and demand savings associated with the delivery of programs from 2015 to 2020. The peak demand savings are estimated in the tools for summer demand savings. A conversion factor of 81% was used to correlate between the summer and winter peak demand savings. This factor was derived from the conservation profile for the provincial conservation forecast comparing the gross summer and winter peak demand impact for the Essa region.

For LDCs that only have a portion of their total service territory associated with this IRRP (i.e. PowerStream, Newmarket-Tay Power Distribution, and Hydro One Distribution), only a portion of their expected savings are estimated to occur in the region. To determine this, the amount of conservation savings in the region is assumed to be proportional to the amount of the LDC's energy within the region, i.e. if 60% of the LDC's energy is served in this region, and then 60% of the expected conservation savings for that LDC are estimated to occur within this Sub-region. When the total peak demand savings for the region has been estimated, it is allocated at each TS according to its relative share of residential, commercial, and industrial gross demand.

Savings from Programs Delivered in the Long Term

Savings from programs beyond the CFF also were broken down by three sectors, based on the IESO data and analysis. Energy savings were converted to peak reductions using the hourly profile for each sector. These peak reductions were compared with the respective gross peak to derive percentage saving for each year. These percentages were applied to the forecast demand at each TS to develop an estimate of MW peak demand impacts.

In addition to distribution connected customers, planned conservation savings from transmission connected customers were also considered. These customers are eligible for the Industrial Accelerator Program ("IAP") and their peak demand savings were analyzed on a case by case basis. For any transmission connected customers in the study region that have applied for IAP, their expected peak savings were included in the conservation forecast.

As described above, peak demand savings were estimated by sector for each conservation category. They were summed for each TS in the region. The analyses were done under normal weather conditions and can be adjusted to reflect extreme weather conditions. The resulting conservation savings, along with distributed generation resources were applied to the gross demand to determine the net peak demand for further planning analyses.

Figure A-5 – Map of Conservation Savings

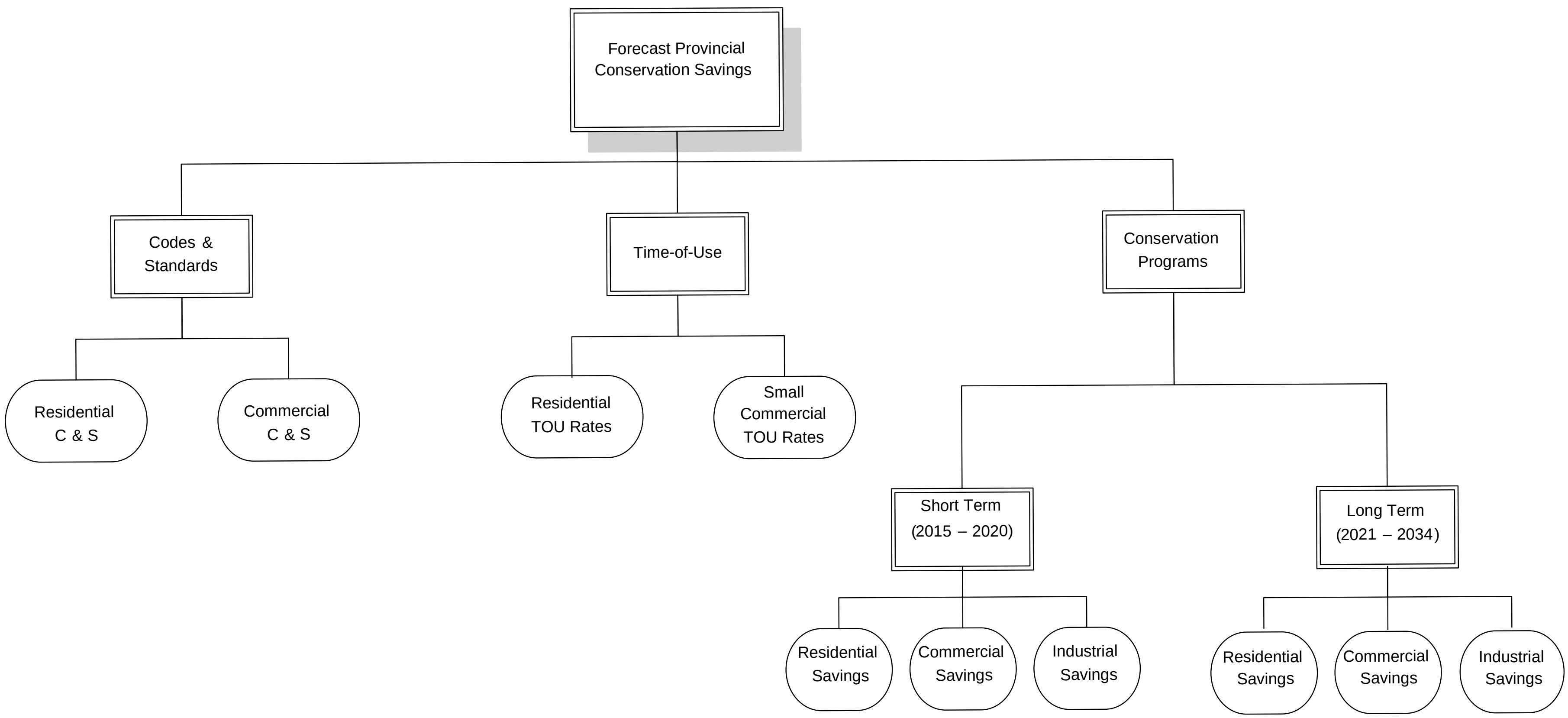


Table A-2: Estimated Peak Demand Savings from Provincial Energy Targets in the Parry Sound/Muskoka Sub-region - 2015-2034

Estimated Peak Demand Savings from Provincial Energy Conservation Targets (MW)																				
Transformer Station	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
Orillia TS	0.5	1.1	1.4	2.0	2.7	3.1	3.8	4.4	5.0	5.7	6.4	7.1	7.9	8.5	9.1	10.1	10.8	10.8	10.8	10.8
Parry Sound TS	0.2	0.4	0.5	0.7	0.9	1.1	1.3	1.6	1.8	2.0	2.2	2.5	2.7	2.9	3.2	3.5	3.7	3.7	3.7	3.7
Bracebridge TS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Minden TS	0.1	0.3	0.4	0.5	0.6	0.7	0.9	1.0	1.2	1.4	1.6	1.7	1.9	2.1	2.3	2.6	2.7	2.7	2.7	2.7
Muskoka TS	0.5	1.1	1.5	2.2	2.9	3.5	4.2	4.8	5.4	6.0	6.7	7.2	7.8	8.3	8.9	9.7	10.2	10.2	10.2	10.1
Waubaushene TS	0.2	0.4	0.5	0.8	1.0	1.2	1.7	2.3	2.8	3.4	4.0	4.6	5.1	5.6	6.1	6.7	7.2	7.2	7.3	7.3
Midhurst TS[6]	0.8	1.8	2.5	4.0	5.4	6.2	7.6	9.5	11.1	13.0	15.1	17.4	19.6	21.7	23.7	26.6	29.0	29.5	29.8	30.2
Muskoka-Orillia 230 kV subsystem	1.8	4.1	5.5	8.2	11.0	12.8	15.6	18.8	21.5	24.7	28.1	31.7	35.2	38.5	41.8	46.4	50.0	50.6	50.8	51.1
Parry Sound 230 kV subsystem	0.4	0.8	1.0	1.5	2.0	2.3	3.1	3.9	4.5	5.4	6.3	7.1	7.8	8.6	9.3	10.2	10.9	10.9	11.0	10.9
TOTAL Parry Sound/Muskoka Sub-region	1.5	3.3	4.3	6.2	8.2	9.5	11.8	14.2	16.1	18.4	20.8	23.1	25.4	27.5	29.6	32.6	34.6	34.7	34.7	34.5

[6] Although Midhurst is part of Barrie/Innisfil IRRP, it is supplied by the Muskoka-Orillia 230 kV sub-system and could have an impact on the electricity supply to the Parry Sound/Muskoka Sub-region. The demand has been included in the Muskoka-Orillia 230 kV sub-system forecast for the purposes of establishing needs for this sub-system.

A.3 Expected Peak Demand Contribution of Contracted Distributed Generation

The installed capacity of contracted DG is adjusted to reflect the expected power output at the time of local area peak, based on resource-specific peak capacity contribution values. The expected peak demand contribution of contracted DG in the Parry Sound/Muskoka Sub-region is show in Table A-3. The total installed capacity of contracted DG in the Parry Sound/Muskoka Sub-region can be found in Appendix A.3.1. The effective DG capacity captured below includes solar and hydro-electric projects. The expected winter peak demand contribution factor is 0% for solar and 34% for hydro-electric. This factor was applied to the installed capacity to reflect the expected power output from DG at the time of local area peak.

Table A-3: Expected Peak Demand Contribution from Contracted Distributed Generation

Expected Peak Contribution of Distributed Generation Resources (MW)																				
Transformer Station	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
Orillia TS	3.7	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	0.5	0.5	0.5	0.5	0.5
Parry Sound TS	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	-	-	-	-	-
Bracebridge TS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Minden TS	1.6	1.6	1.6	1.6	1.6	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8
Muskoka TS	3.4	3.4	3.4	3.4	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	4.6	4.6	2.1	2.1	2.1	2.1	2.0
Waubaushene TS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Midhurst TS[7]	-	0.2	0.8	16.3	24.8	36.8	37.7	37.7	37.7	37.7	37.7	37.7	37.7	37.7	37.7	37.7	37.7	37.7	37.7	37.7
Muskoka-Orillia 230 kV sub-system	7.1	7.6	7.6	7.6	9.3	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	8.8	8.8	2.3	2.3	2.3	2.3	2.3
Parry Sound 230 kV sub-system	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	-	-	-	-	-
Total Parry Sound/Muskoka Sub-region	9.1	9.6	9.6	9.6	11.3	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.0	11.0	4.4	4.4	4.4	4.4	4.3

A.3.1 Installed Capacity of Contracted Distributed Generation

Table A-4 shows the installed capacity of contracted DG in the Parry Sound/Muskoka Sub-region, which was active as of October 2015.

Table A-4: Installed Capacity of Distributed Generation

Installed Capacity of Distributed Generation in the Parry Sound/Muskoka Sub-region (MW)																				
Transformer Station	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
Orillia TS	42.3	44.3	44.8	45.3	45.3	45.3	45.3	45.3	45.3	45.3	45.3	45.3	45.3	45.3	45.3	34.4	34.2	33.9	33.2	5.5
Parry Sound TS	1.4	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	0.4	0.4	0.4	0.4	0.4
Bracebridge TS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

[7] Although Midhurst is part of Barrie/Innisfil IRRP, it is supplied by the Muskoka-Orillia 230 kV sub-system and could have an impact on the electricity supply to the Parry Sound/Muskoka Sub-region. The demand has been included in the Muskoka-Orillia 230 kV sub-system forecast for the purposes of establishing needs for this sub-system.

Installed Capacity of Distributed Generation in the Parry Sound/Muskoka Sub-region (MW)																				
Minden TS	4.9	4.9	7.4	7.9	7.9	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.2
Muskoka TS	30.9	31.3	32.3	33.8	38.8	38.9	38.9	38.9	38.9	38.9	38.9	38.9	38.9	37.4	37.4	30.0	30.0	30.0	19.7	9.2
Waubaushene TS	42.5	42.8	42.8	42.8	42.8	42.8	42.8	42.8	42.8	42.8	42.8	42.8	42.8	42.8	42.8	42.8	42.8	42.3	20.8	10.2
Midhurst TS[8]	-	0.2	0.8	16.3	24.8	36.8	37.7	37.7	37.7	37.7	37.7	37.7	37.7	37.7	37.7	37.7	37.7	37.7	37.7	37.7
Muskoka-Orillia 230 kV sub-system	73.2	75.7	77.8	95.3	108.9	121.0	121.9	121.9	121.9	121.9	121.9	121.9	121.9	120.4	120.4	102.2	101.8	101.6	90.6	52.5
Parry Sound 230 kV sub-system	44.0	44.4	44.4	44.4	44.4	44.4	44.4	44.4	44.4	44.4	44.4	44.4	44.4	44.4	44.4	44.2	44.2	42.7	21.2	10.6
Total Parry Sound/Muskoka Sub-region	9.1	9.6	9.6	9.6	11.3	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.0	11.0	4.4	4.4	4.4	4.4	4.3

A.4 Planning Forecast

As described in the main report, a planning forecast was developed for the Parry Sound/Muskoka IRRP. The Working Group also considered a sensitivity scenario including additional growth in Orillia due additional planned developments, including condo and waterfront development and new retail, commercial, industrial and institutional customers could materialize, resulting in an additional 30 MW of peak demand requirement in the Sub-region within the 20-year planning period. Tables A-5 shows the Planning Demand Forecasts for the Reference and sensitivity scenarios respectively. Note that diagrams in the Integrated Regional Resource Plan report do not include forecast demand at Midhurst TS.

Table A-5: Planning Demand Forecast 2015-2034 – Parry Sound/Muskoka Sub-region

Planning Demand Forecast (MW)																				
Transformer Station	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
Orillia TS[9]	122.7	123.5	125.3	127.0	128.8	130.6	131.5	132.6	133.6	134.6	135.5	136.5	137.5	138.7	139.7	144.2	145.2	146.9	148.7	150.5
Parry Sound TS	60.6	61.2	61.6	62.0	62.8	63.7	64.2	64.7	65.3	65.9	66.4	67.1	67.7	68.4	69.1	70.0	70.7	71.5	72.4	73.3
Bracebridge TS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Minden TS	57.0	57.5	57.6	58.0	58.7	59.2	59.5	59.8	60.0	60.3	60.5	60.8	61.0	61.3	61.6	61.7	62.0	62.4	62.8	63.2
Muskoka TS	156.7	158.5	159.9	161.3	161.9	164.2	165.8	167.3	169.0	170.6	172.2	174.0	175.9	178.4	180.3	184.4	186.4	188.9	191.4	194.1
Waubaushene TS	99.0	98.7	99.5	100.0	101.0	101.9	102.3	102.8	103.2	103.6	104.0	104.3	104.8	105.4	105.9	106.5	107.0	107.8	108.7	109.6
Midhurst TS[10]	172.7	176.4	180.2	184.5	189.1	213.3	216.5	220.3	224.3	226.9	230.4	233.8	236.2	239.8	243.4	246.1	249.4	254.5	259.8	265.0
Muskoka-Orillia 230 kV sub-system	452	458	465	473	480	508	514	520	527	532	538	544	550	557	563	575	581	590	600	610
Parry Sound 230 kV sub-system	160	160	161	162	164	166	167	168	169	169	170	171	173	174	175	176	178	179	181	183
Total Parry Sound/Muskoka Sub-region	496	499	504	508	513	520	523	527	531	535	539	543	547	552	557	567	571	578	584	591

[8] Although Midhurst is part of Barrie/Innisfil IRRP, it is supplied by the Muskoka-Orillia 230 kV sub-system and could have an impact on the electricity supply to the Parry Sound/Muskoka Sub-region. The demand has been included in the Muskoka-Orillia 230 kV sub-system forecast for the purposes of establishing needs for this sub-system.

[9] Note that the high demand forecast could result in an additional 30 MW at Orillia TS by 2034.

[10] Although Midhurst is part of Barrie/Innisfil IRRP, it is supplied by the Muskoka-Orillia 230 kV sub-system and could have an impact on the electricity supply to the Parry Sound/Muskoka Sub-region. The demand has been included in the Muskoka-Orillia 230 kV sub-system forecast for the purposes of establishing needs for this sub-system.

Parry Sound-Muskoka IRRP

Appendix B: Needs Assessment

Appendix B: Needs Assessment

B.1 Application of Ontario Resource and Transmission Assessment Criteria (ORTAC)

In accordance with Ontario Resources and Transmission Assessment Criteria ("ORTAC"), the system must be designed to provide continuous supply to a local area, under specific transmission and generation outage scenarios summarized in Table B-1. Voltage and thermal limitations should be respected under these outage conditions.

Table B-1: ORTAC Criteria – Transmission and Generation Outage Scenarios

Pre-contingency		Contingency[1]	Thermal Rating	Maximum Permissible Load Rejection
All transmission elements in-service	Local generation in-service	N-0	Continuous	None
		N-1	LTE[2]	None
		N-2	LTE[2]	150 MW
	Local generation out-of-service	N-0	Continuous	None
		N-1	LTE[2]	150 MW[3]
		N-2	LTE[2]	>150 MW[3] (600 MW total)

1. N-0 refers to all elements in-service; N-1 refers to one element (a circuit or transformer) out of service; N-2 refers to two elements out of service (for example, loss of two adjacent circuits on same tower, breaker failure or overlapping transformer outage); N-G refers to local generation not available (for example, out of service due to planned maintenance).
2. LTE: Long-term emergency rating (50-hr rating for circuits, 10-day rating for transformers).
3. Only to account for the capacity of the local generating unit out of service.

ORTAC Load Security and Restoration

With respect to supply interruptions, ORTAC requires that the transmission system be designed to minimize the impact to customers of major outages, such as a contingency on a double-circuit tower line resulting in the loss of both circuits, in two ways: by limiting the amount of customer load affected; and by restoring power to those affected within a reasonable timeframe.

Specifically, ORTAC requires that no more than 600 MW of load be interrupted in the event of a major outage involving two elements. Further, load lost during a major outage is to be restored within the following timeframes:

- All load lost in excess of 250 MW must be restored within 30 minutes;
- All load lost in excess of 150 MW must be restored within four hours; and
- All load lost must be restored within eight hours.

B.2 Study Assumptions

Planning criteria was applied to assess supply capacity and reliability needs of the West of Thunder Bay transmission system.

PSS/E Base case and Bulk System Conditions

The Parry Sound/Muskoka transmission system was assessed using PSS/E Power System Simulation software. The PSS/E base case for the planning study was adapted from the 2015 base case that was produced by the IESO.

Hydraulic Generation Assumptions

Most of the Hydraulic generation in the Sub-region is produced on the distribution side and is considered as a reduction to local peak. There are also larger hydraulic generators just outside of the Sub-region that impact the flow of electricity on the Sub-regional transmission system. For these larger generators, the total capacity was assumed to be 70 MW.

Equipment Rating

For transmission facilities, continuous and limited time ratings based on an ambient temperature of 30°C and a wind speed of 4 km/hour were respected.

Demand Forecast

The West of Thunder Bay transmission system is assessed under the reference, high and low planning forecast scenarios provided in Appendix A.4.

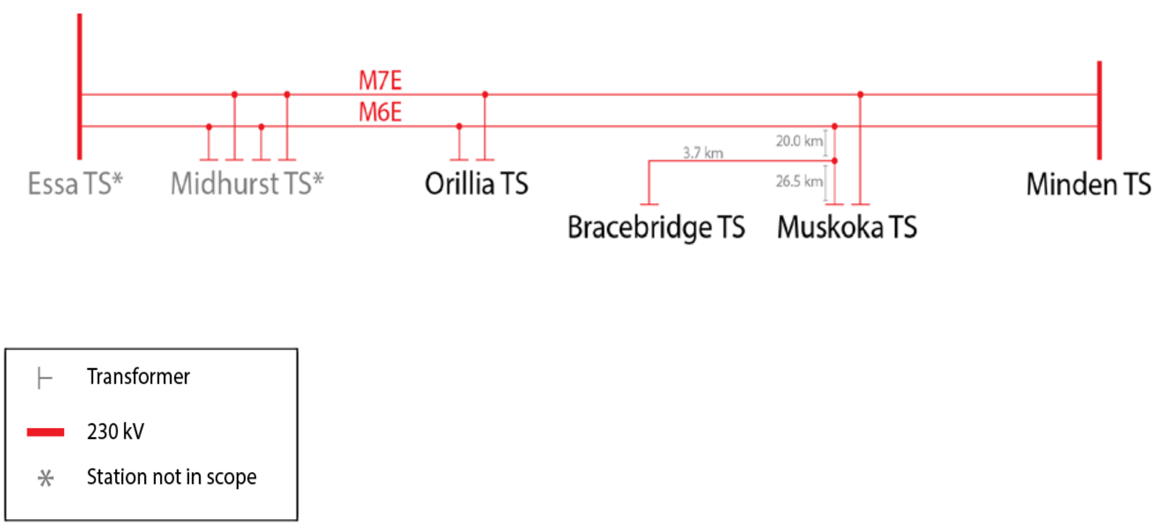
B.3 Summary of Needs Assessment Results

The following sections outline the results of the needs assessment undertaken for the Parry Sound/Muskoka Sub-region.

B.3.1 Muskoka-Orillia 230 kV Sub-system Capacity Assessment

The Muskoka-Orillia 230 kV sub-system (M6/7E) is a 230 kV double circuit transmission line supplying Midhurst TS, Orillia TS, Bracebridge TS, and Muskoka TS, and extending between Essa TS in the Barrie area and Minden TS.

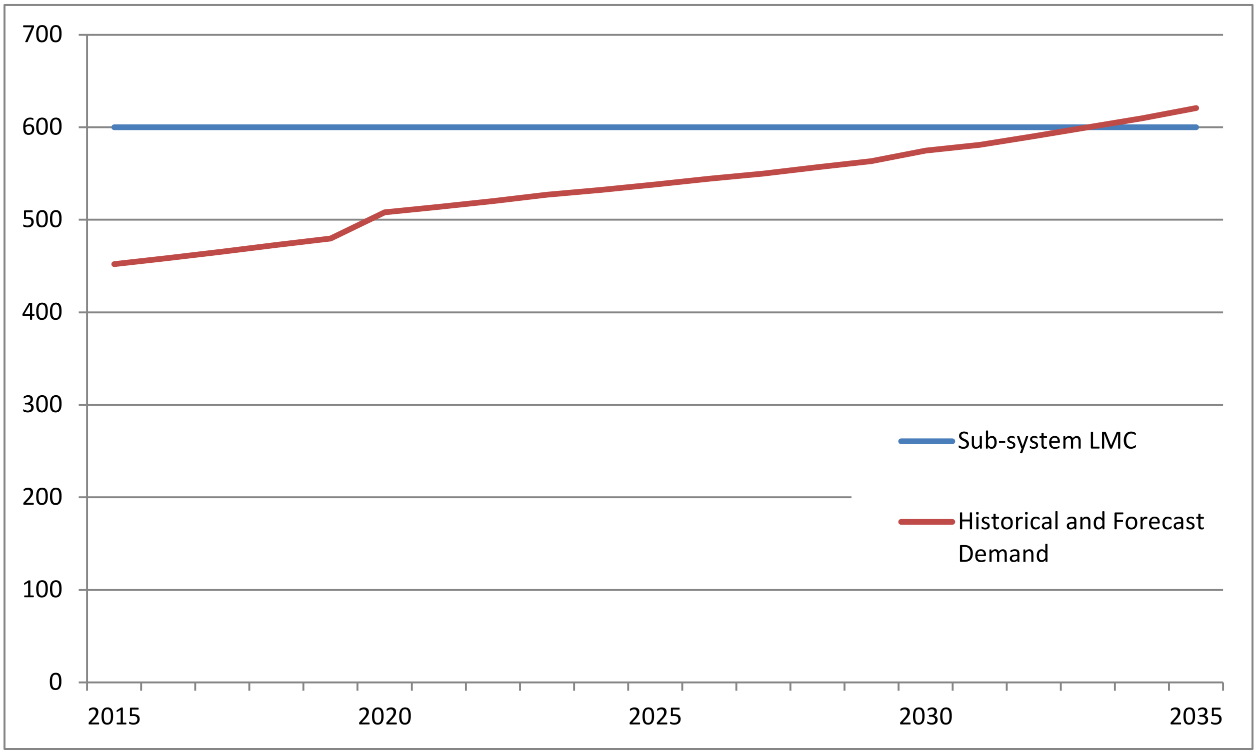
Figure B-1: Muskoka-Orillia 230 kV Sub-system



Based on the application of ORTAC criteria, this subsystem has an LMC of approximately 600 MW. This is based on the thermal rating of the section between Essa TS and Midhurst TS following an outage on either circuit M6E or M7E. The planning forecast for the area indicates that this need could arise near the end of the planning period.

Figure B-2 illustrates the need using the winter planning forecast.

Figure B-2: Muskoka-Orillia 230 kV Sub-system Capacity Need, Winter Planning Forecast



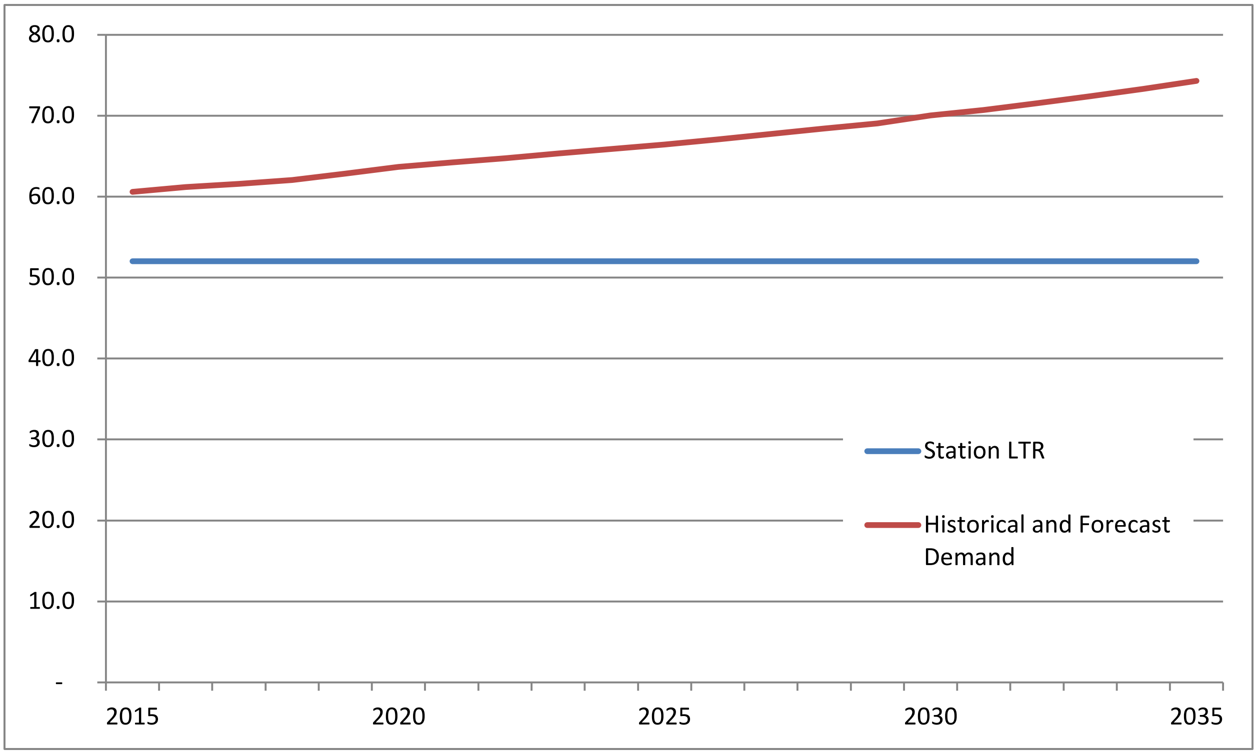
B.3.2 Transformer Station Capacity Assessment

In the planning period, three transformer stations are either forecast to exceed or already exceeding the 10-day Limited Time Rating ("LTR") of the transformers: Minden TS, Parry Sound TS, and Waubaushene TS. The LTR at these transformers is limited by the capability for the smallest transformer at the station to supply load when the larger transformer is unavailable, due to an unplanned or scheduled outage.

At the time of this plan, the transformers at Minden TS were scheduled to be replaced with uprated facilities as part of Hydro One's sustainment activities. This would meet the need at Minden TS for the rest of the planning period.

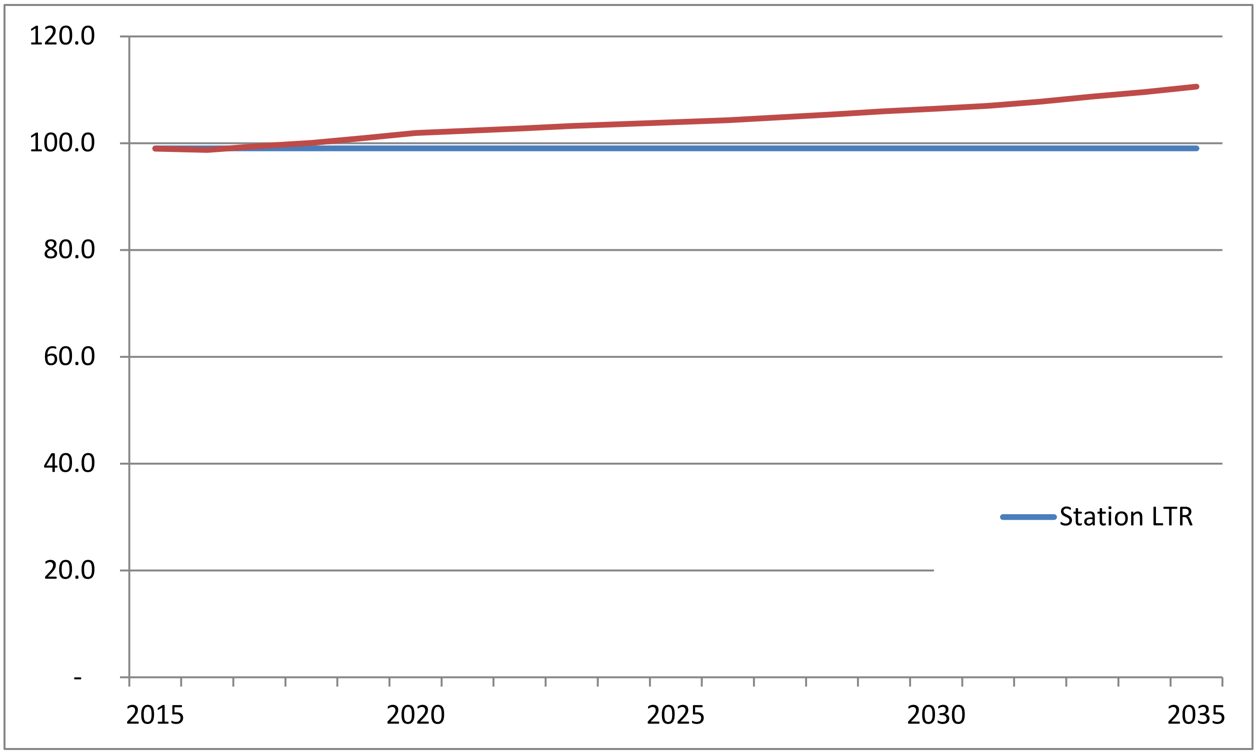
The LMC at Parry Sound TS is currently about 52 MW in the winter. In 2014, the winter peak demand was about 61 MW. The Parry Sound area is forecast to grow by just under 1 MW per year during the planning period, which would continue to exceed the rating of the station.

Figure B-3: Forecast for Parry Sound TS Compared to Station LTR



The LMC at Waubausheme TS is currently about 99 MW in the winter. In 2014, the winter peak demand was about 96 MW. The Waubaushene area is forecast to grow by just under 1 MW per year during the planning period, which would result in the demand exceeding the rating in 2017.

Figure B-4: Forecast for Waubaushene TS Compared to Station LTR



Parry Sound-Muskoka IRRP

Appendix C: 44 kV Service Reliability Performance

Table C-1: Summary of Sub-Transmission Historical Outages Statistics

Sub-Transmission Feeder	Communities Served	5-Year Average Outage Frequency Per Customer (count)	5-Year Average Outage Duration Per Customer (hours)
Muskoka M1	Township of Muskoka Lakes, Township of Seguin	4.3	10.4
Parry Sound M2	Township of Seguin, Wahta Mohawk First Nation	2.9	6.0
Muskoka M7	Town of Bracebridge	4.1	8.5
Muskoka M3	Town of Bracebridge, Town of Gravenhurst	4.0	10.4
Orillia M6	Town of Gravenhurst	3.0	6.0
Orillia M2	Township of Severn	3.6	8.0
Muskoka M2	Municipality of Magnetawan, Township of Armour, Township of Joly, Township of McMurrich Monteith, Township of Perry, Township of Strong, Village of Burks Falls, Village of Sundridge, Township of Ryerson	2.8	11.0
Muskoka M4	Town of Huntsville, Township of Alogonquin Highlands, Township of Lake of Bays	2.0	6.7

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Appendix D: Estimated Value of Deferring Transformer Upgrade at Parry Sound TS and Waubaushene TS

Table D-1: Estimated Value of Deferring Transformer Upgrade at Parry Sound TS and Waubaushene TS

Option	Capital Cost ($2016 Millions)	Annual Deferral Value ($2016 Millions)[11]
Upgrade Parry Sound Transformers to 50/83 MVA	30	2.2
Upgrade Waubaushene Transformers to 75/125 MVA	35	3.6

[11] Note that deferral value assumes a social discount rate of 4%, an annual cost of O&M equal to 1% of initial capital cost, and a facility life of 60 years.

Parry Sound-Muskoka IRRP

Appendix E: Muskoka-Orillia 230 kV sub-system load restoration options

Table E-1 Summary of Muskoka-Orillia 230 kV sub-system load restoration options following a double circuit contingency on M6E and M7E (Winter, 2016)

			Initial Load Interrupted		Restorable Load	
Option #	Option Specifics (Sectionalization Facilities)	Option Cost ($Million)	Fault West of the Sectionalization Facility	Fault East of the Sectionalization Facility	Fault West of the Sectionalization Facility	Fault East of the Sectionalization Facility
--	Existing Midhurst to Minden 230 kV subsystem	N/A	All Load 458 MW	All Load 458 MW	0	0
1	230 kV in-line **switches** on M6/7E at **Cooper's Falls Junction**	7	All Load 458 MW	All Load 458 MW	Muskoka TS, Bracebridge TS 159 MW[12]	Midhurst TS, Orillia TS 300 MW
2	230 kV in-line **breakers** on M6/7E at **Cooper's Falls Junction**	20	Midhurst TS, Orillia TS 300 MW	Muskoka TS, Bracebridge TS 159 MW	Muskoka TS, Bracebridge TS 159 MW	Midhurst TS, Orillia TS 300 MW
3	230 kV in-line **switches** on M6/7E at **Orillia TS**	7	All Load 458 MW	All Load 458 MW	Muskoka TS, Bracebridge TS, Orillia TS 282 MW	Midhurst TS, Orillia TS 300 MW
4	230 kV in-line **breakers** on M6/7E at **Orillia TS**	20	Midhurst TS 176 MW	Muskoka TS, Bracebridge TS 159 MW	Muskoka TS, Bracebridge TS, Orillia TS 282 MW	Midhurst TS, Orillia TS 300 MW

[12] Note that for options where sectionalization facilities are installed at Coopers Falls Junction, the restorable load following a double circuit fault on the west side would not be sufficient to meet ORTAC.

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Appendix F: Hydroelectric Potential in the Parry Sound/Muskoka Sub-region

Parry Sound/Muskoka IESO Regional Plan: Waterpower Analysis Report

Existing & Potential Waterpower Infrastructure

Table of Contents

1.0 Introduction

The Independent Electricity System Operator (IESO) has developed the Integrated Regional Resource Planning (IRRP) process to encourage municipalities and other stakeholders to provide their input into the planning to meet regional electricity needs. Regional system planning contributes to supplying a reliable source of electricity to those who live within the regions. The province has been separated into three (3) Groups and twenty-one (21) zones for regional planning. This report focuses on a sub-region of Group 2, the Parry Sound/Muskoka Area.

As described by the ISEO, The Parry Sound/Muskoka sub-region roughly encompasses the Districts of Muskoka and Parry Sound, and the northern part of Simcoe County. This sub-region also includes eight First Nation communities: Beausoleil, Chippewas of Rama, Henvey Inlet, Magnetawan, Moose Deer Point, Shawanaga, Wahta Mohawks and Wasauksing.

The electricity demand in this sub-region is primarily driven by residential and commercial uses, especially electric heating during the winter season. This region also supports a mix of economic activities including tourism, retail, health care and manufacturing industries. Electricity demand in this area typically peaks during the winter months, with historic peak demands ranging from around 470-530 MW.

A modest increase in the electricity is forecasted over the next 20-year for the area. While slower growth is expected in the region's manufacturing sector, growing Aboriginal communities, developments in the tourism and retail sector, and potential economic development such as the Parry Sound Airport Development and Rama Road Corridor Economic Employment District, will contribute to the electricity demand requirements for the region.

Given the large geographical area, many communities in the Parry Sound/Muskoka sub-region are supplied by long transmission and distribution networks and rely on single supply sources. Regional planning will examine the reliability performances of the transmission and distribution infrastructure and where appropriate, examine options to mitigate the potential impact of power outages to communities and businesses in the area. Given the forecasted demand growth in this sub-region, there may be opportunities for communities to manage growth through the development of community-based solutions, including energy efficiency measures, distributed generation, demand response programs and other innovative technologies.

This report has been prepared to support the development of a Regional Plan for the area and focuses on the identification of the existing and potential contribution of waterpower generation to help meet regional needs. Within this sub-region there are approximately 60 potential sites with the technical capacity to support waterpower development. These are potential sites that do not reside within provincial or federal protected lands. The accumulative potential generating capacity of all these sites is approximately 61.10 MW. There are 36 potential sites found in the Parry Sound District alone that have a total potential generating capacity of 38.60 MW. Within the Muskoka District Municipality there are 14 potential sites for waterpower development with a total potential generating capacity of 19.11 MW. Finally, for Simcoe County there are 10 potential sites for waterpower development that equal to a total potential generating capacity of 3.39 MW.

There are 24 existing waterpower facilities within the sub-region that possess an accumulative installed capacity of 92.82 MW. Of the 24 existing stations, 10 of them are found within the Parry Sound District, 13 within the Muskoka District Municipality and one within Simcoe County. The total installed capacity for each area is 22.06 MW for Parry Sound District, 69.06 MW for Muskoka District Municipality and 1.7 MW for Simcoe County.

2.0 Method of Analysis

The initial step of this geographical analysis was determining and obtaining the necessary data layers that would be utilized in the final map-based product. Using ArcGIS 10.4, the following list of data layers were manipulated in order to undertake the analysis:

- Towns/Cities
- Existing Waterpower Facilities
- Potential Waterpower Sites
- Existing Transmission Lines
- National Parks
- Provincial Parks
- Upper Tier Municipalities
- First Nations Reserves
- Waterbodies
- Province of Ontario Base Layer

Once a proper overlay was completed of these layers the potential waterpower sites were then queried in order to remove any potential sites that possessed a potential capacity of less than 0.05 MW as this would not be a viable development choice economically speaking. The remaining potential sites were then categorized through another querying process to differentiate the sites by their potential energy capacity (MW). The three categories were FIT (<0.5 MW), LRP (0.5-9.9 MW), and if applicable LRP (>10 MW). There is no significance in separating the LRP facilities into two categories aside from depicting an emphasis on the map of the generating capacity of these sites. There is significance in creating both Feed-In-Tariff (FIT) and Large Renewable Procurement (LRP) categories though, as they will fall under different application processes as set out by the IESO.

Further querying was also completed in order to isolate the potential sites that resided within Provincial Parks so that the potential generating capacity the sites possessed was not included in the overall capacity calculations for the entire study area.

After the generating capacity querying was completed it was possible to retrieve all the non-spatial data that corresponded to the sites of interests which could then be populated into an excel file. Certain data standards were utilized in populating the excel file such as MNRF site code, site name/location, watershed, waterbody name, generating capacity (MW).

Recognition of the source data utilized in order to generate these maps as well as provide the non-spatial attribute data necessary to complete the geographical analysis is due to the Ontario Waterpower Association (OWA) being a member of Land Information Ontario (LIO) where the raw data layers were made available.

3.0 Analysis Map

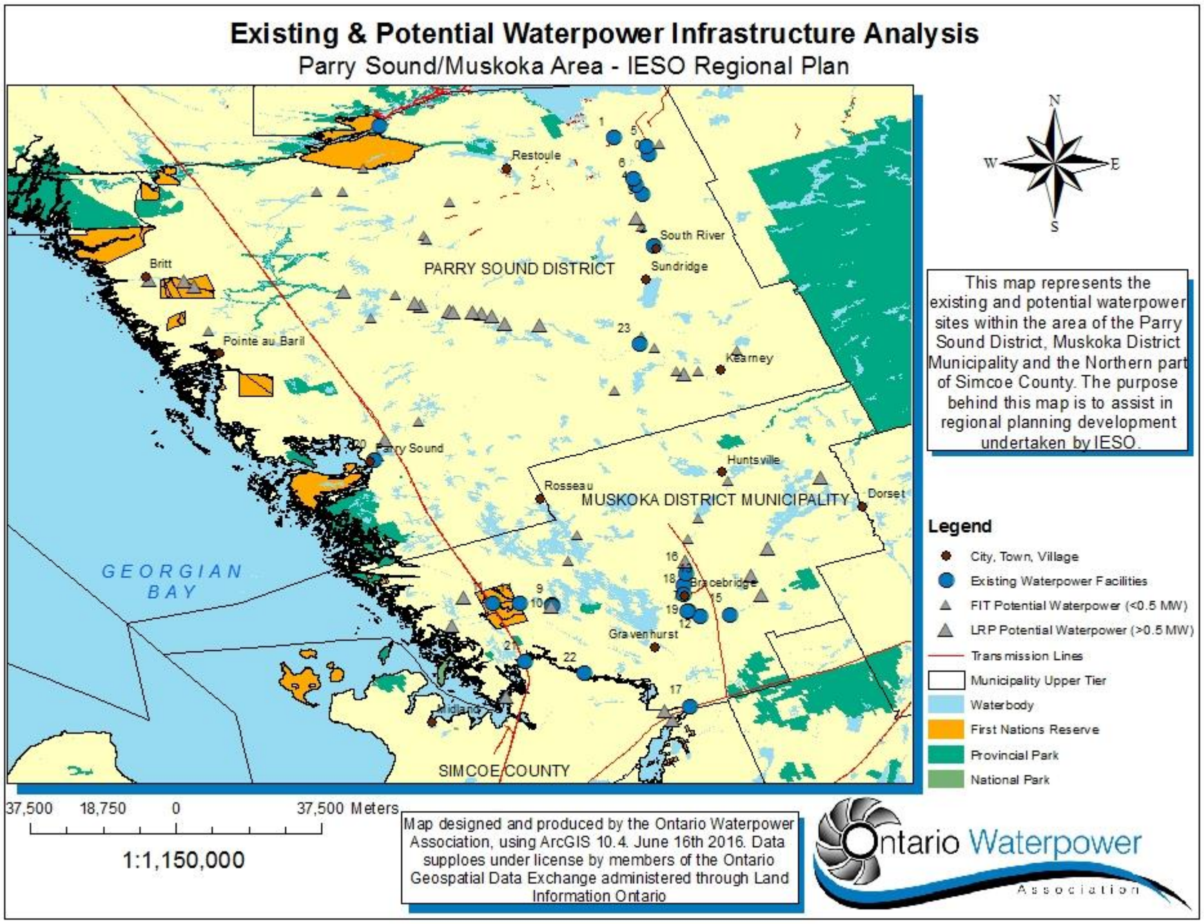

Figure 1. Generated map displaying the potential and existing waterpower infrastructure within the Parry Sound/ Muskoka sub-region of the South Georgian Bay/Muskoka regional planning area. A Larger image of this map can be found in Appendix A.

4.0 Results

4.1 Existing Waterpower Facilities Within Sub-Region

There is a total of 24 existing waterpower facilities within the Parry Sound/ Muskoka sub-region. The facilities are as follows with the respective waterbody they reside on, their installed capacity (MW) as well as the municipality they fall within:

- Elliot Chute GS, South River, 2 MW, Parry Sound District
- Nipissing GS, South River, 1.8 MW, Parry Sound District
- South River GS, South River, 0.8 MW, Parry Sound District
- Truisler Chute GS, South River, 0.6 MW, Parry Sound District
- Geisler Chute GS, South River, 2.25 MW, Parry Sound District
- Bingham Chute GS, South River, 1 MW, Parry Sound District
- Corkery Chute GS, South River, 1.31 MW, Parry Sound District
- Okikendawt Hydroelectric GS, French River, 10 MW, Parry Sound District
- Cascade Street GS, Seguin River, 3.1 MW, Parry Sound District (to be commissioned in 2017)
- Burks' Fall's GS, Magnetawan River, 1.12 MW, Parry Sound District
- Hanna Chute GS, South Muskoka River, 1.46 MW, Muskoka District Municipality
- Burgess GS, Muskoka River, 0.13 MW, Muskoka District Municipality
- Bala Dam GS, Muskoka River, 4.45 MW, Muskoka District Municipality (to be commissioned in 2020)
- Big Eddy GS, Musquash River, 8 MW, Muskoka District Municipality
- Trethewey Falls GS, South Muskoka River, 2 MW, Muskoka District Municipality
- Wilson's Fall's GS, North Muskoka River, 2.9 MW, Muskoka District Municipality
- Ragged Rapids GS, Musquash River, 8 MW, Muskoka District Municipality
- Matthias GS, South Muskoka River, 2.95 MW, Muskoka District Municipality
- High Falls GS, North Muskoka River, 2.6 MW, Muskoka District Municipality
- Bracebridge Falls GS #1, North Muskoka River, 2.6 MW, Muskoka District Municipality
- South Falls GS, South Muskoka River, 5 MW, Muskoka District Municipality
- Big Chute GS, Severn River, 10 MW, Muskoka District Municipality
- Swift Rapids, Severn River, 7.9 MW, Muskoka District Municipality
- Wasdell's Falls Dam, Severn River, 1.7 MW, Simcoe County

Accumulatively there is approximately 83.67 MW of installed waterpower capacity within the sub-region. In Appendix B of this report the excel data table can be found that includes further information such as the watershed the facility falls within, and the year it was built.

4.2 Potential Waterpower Sites: Parry Sound District

Within the Parry Sound District there are a total of 36 potential sites. When looking at the FIT category (<0.5MW) there are 19 potential sites within this area and the remaining 17 sites all qualify for the LRP category (>0.5 MW). In Appendix C at the end of the report the complete data table can be viewed which describes the location, watershed, waterbody name, potential generating capacity (MW) and capacity category for each site (LRP/FIT). Below is a list of the waterbodies with their accumulative potential capacity (MW) that has been generated from the sum of all the potential sites on each one:

Waterbody Name	Capacity (MW)	# of Potential Sites
Genesee Creek	0.07	1
Wolf	0.19	2
Gooseneck Creek	0.05	1
Memesagamesing River	0.07	1
Manitouwabgin River	0.21	1
Magnetawan River	26.65	19
Beggsboro Creek	0.07	1
Naiscoot River	0.08	1
South River	1.54	2
Pickerel River	0.86	3
North Magnetawan River	0.34	1
Seguin	1.53	2
French River	6.94	1
Total	38.6	36

Accumulatively for all the potential sites there is approximately 38.60 MW of potential waterpower generating capacity.

4.3 Potential Waterpower Sites: Muskoka District Municipality

Within the Muskoka District Municipality area there was a total of 14 potential. When looking at the FIT category (<0.5MW) there are 5 potential sites within this area and the remaining 9 sites all qualify for the LRP category (>0.5 MW). In Appendix D at the end of the report the complete data table can be viewed which describes the location, watershed, waterbody name, potential generating capacity (MW) and capacity category for each site (LRP/FIT). Below is a list of the waterbodies with the accumulative potential capacity (MW) that has been generated from the sum of all the potential sites on each one:

Waterbody Name	Capacity (MW)	# of Sites
Dee River	0.16	1
Indian River	0.24	1
North Muskoka River	1.99	4
Severn River	1.33	1
Oxtongue River	0.54	1
South Muskoka River	4.36	3
Musquash River	6.49	2
Muskoka River	4.00	1
Total	19.11	14

Accumulatively for all the potential sites there is approximately 19.11 MW of potential waterpower generating capacity.

4.4 Potential Waterpower Sites: Simcoe County

Within the Simcoe County area there was a total of 10 potential sites. When looking at the FIT category (<0.5MW) there are 8 potential sites within this area and the remaining 2 sites both qualify for the LRP category (>0.5 MW). In Appendix E at the end of the report the complete data table can be viewed which describes the location, watershed, waterbody name, potential generating capacity (MW) and capacity category for each site (LRP/FIT). Below is a list of the waterbodies with the accumulative potential capacity (MW) that has been generated from the sum of all the potential sites on each one:

Waterbody Name	Capacity (MW)	#of Sites
Mad River	0.38	4
Boyne River	0.14	2
Nottawasaga River	0.54	2
Severn River - MID	2.33	2
Total	3.39	10

Accumulatively for all the potential sites there is approximately 3.39 MW of potential waterpower generating capacity.

5.0 Analysis Conclusion

After completion of the Parry Sound/Muskoka sub-region waterpower analysis, it is evident that there is a significant amount of potential waterpower within the planning area.

Within the sub-region there are 24 existing waterpower facilities with an accumulative installed generating capacity of 83.67 MW. When looking at potential waterpower infrastructure increase there are 60 potential waterpower sites that could be developed. There are 32 of those potential sites that would qualify for the FIT category as their potential generating capacity falls below 0.5 MW and the remaining 28 potential sites would qualify for the LRP category as their potential generating capacities have been calculated to exceed 0.5 MW.

When looking at the individual upper tier municipalities there is approximately 38.60 MW of potential generating capacity for the Parry Sound District, 19.11 MW for the Muskoka District Municipality and 3.39 MW for Simcoe County. Accumulatively, the potential generating capacity of undeveloped waterpower sites within the entire sub-region is approximately 61.10 MW. On an individual municipality scale, within the Parry Sound District there are 19 potential FIT sites and 17 potential LRP sites. The Muskoka District Municipality possesses 5 potential FIT sites and 9 potential LRP sites and for Simcoe County there are 8 potential FIT sites and 2 potential LRP sites. It is important to note that these numbers account for all the potential sites that did not reside within Provincial/Federal Park boundaries and the information pertaining to those that did reside in such boundaries have been excluded from the report.

Overall, the total capacity of potential waterpower sites within the sub-region of Parry Sound/Muskoka represents a significant supply of distributed renewable energy that should be considered among the options to meet regional requirements.

6.0 Appendices

Appendix A – Analysis Map

Appendix B – Existing Waterpower Facilities Data Table

Appendix C –Potential Waterpower Sites: Parry Sound District Data Table

Appendix D –Potential Waterpower Sites: Muskoka District Municipality Data Table

Appendix E –Potential Waterpower Sites: Simcoe County Data Table

Appendix A – Analysis Map

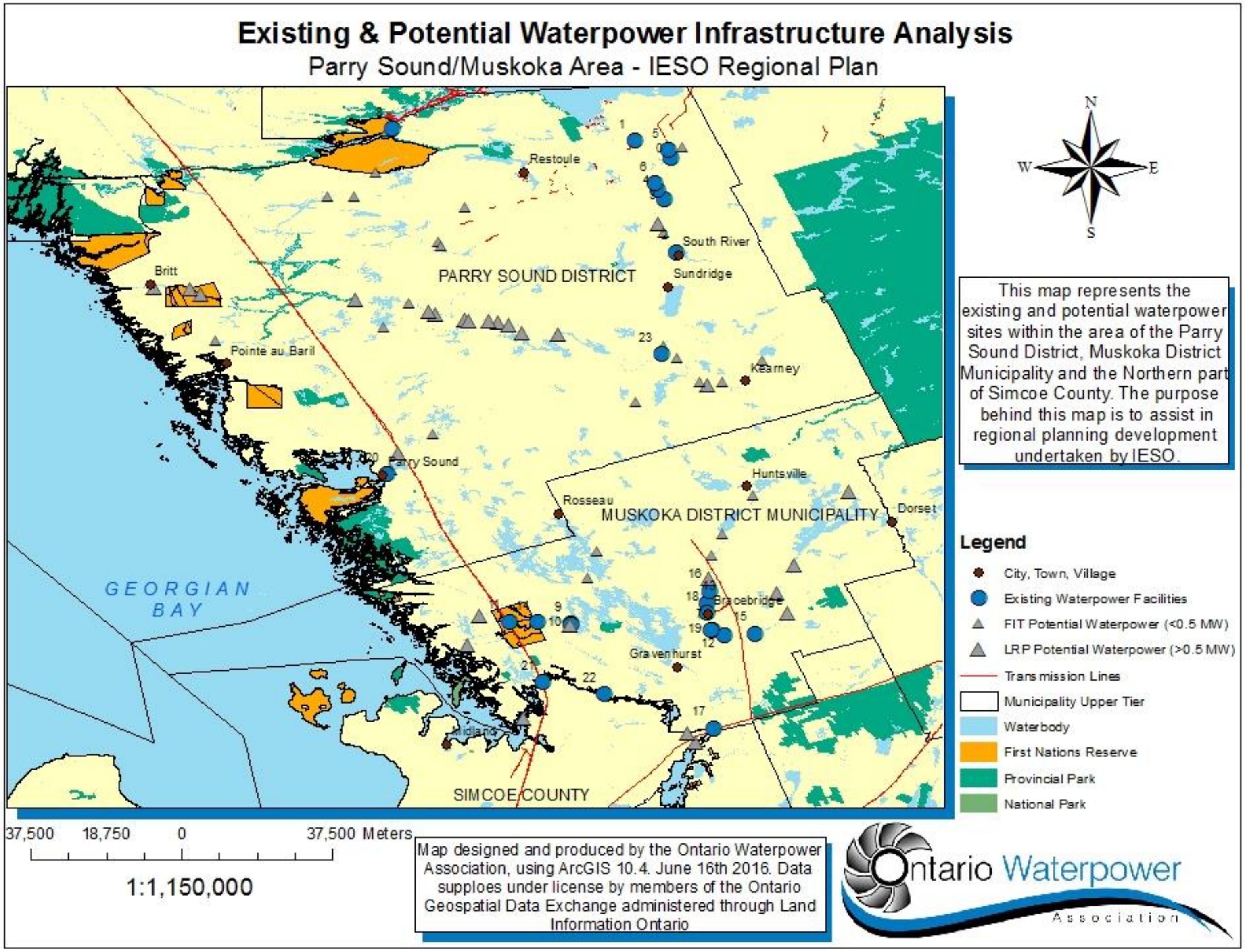

Figure 1. Generated map displaying the potential and existing waterpower infrastructure within the Parry Sound/ Muskoka sub-region of the South Georgian Bay/Muskoka regional planning area. The existing waterpower facilities have been labelled with the FID numbers that correspond with the data table in Appendix B.

Appendix B – Existing Waterpower Facilities Within Sub-Region

FID	Site Identifier (MNRF)	Facility Name	Waterbody Name	Watershed	Year Built	Capacity (MW)
0	2DD17	Elliot Chute GS	South River	Wanipitai and French	1929	2
1	2DD34	Nippising GS	South River	Wanipitai and French	1909	1.8
2	2DD16	South RiverGS	South River	Wanipitai and French	2009	0.8
3	2DD05	Truisler Chute GS	South River	Wanipitai and French	1990	0.6
4	2DD06	Geisler Chute GS	South River	Wanipitai and French	1990	2.25
5	2DD33	Bingham Chute GS	South River	Wanipitai and French	1923	1
6	2DD07	Corkery Chute GS	South River	Wanipitai and French	1990	1.31
7	2EB42	Hanna Chute GS	South Muskoka River	Eastern Georgian Bay	1926	1.46
8	2DD37	Okikendawt Hydroelectric GS	French River	Wanipitai and French	2014	10
9	2EB04	Burgess GS	Muskoka River	Eastern Georgian Bay	1989	0.13
10	2EB57	Bala Dam GS	Muskoka River	Eastern Georgian Bay	2020	4.45
11	2EB18	Big Eddy GS	Musquash River	Eastern Georgian Bay	1941	8
12	2EB15	Trethewey Falls GS	South Muskoka River	Eastern Georgian Bay	1929	2
13	2EB03	Wilson's Fall's GS	North Muskoka River	Eastern Georgian Bay	2012	2.9
14	2EB17	Ragged Rapids GS	Musquash River	Eastern Georgian Bay	1938	8
15	2EB43	Matthias GS	South Muskoka River	Eastern Georgian Bay	1948	2.95
16	2EB22	High Falls GS	North Muskoka River	Eastern Georgian Bay	1947	2.6
17	2EC31	Wasdell's Falls Dam	Severn River- MID	Eastern Georgian Bay	1914	1.7
18	2EB07	Bracebridge Falls GS #1	North Muskoka River	Eastern Georgian Bay	2012	2.6
19	2EB08	South Falls GS	South Muskoka River	Eastern Georgian Bay	1916	5
20	2EA50	Cascade Street GS	Seguin River	Eastern Georgian Bay	2017	3.1
21	2EC24	Big Chute GS	Severn River	Eastern Georgian Bay	1919	10
22	2EC17	Swift Rapids	Severn River	Eastern Georgian Bay	1917	7.9
23	2EA29	Burk's Fall's GS	Magnetawan River	Eastern Georgian Bay	1986	1.12

Appendix C – Potential Waterpower Sites: Parry Sound District

Site Identifier (MNRF)	Site Name / Location	Waterbody Name	Watershed	Capacity (MW)	FIT/LRP
2DD9	Powassan	Genesee Creek	Wanipitai and French	0.07	FIT
2DD32	Pine Lake Dam	Wolf	Wanipitai and French	0.13	FIT
2EA34	Gooseneck Lake Dam	Gooseneck Creek	Eastern Georgian Bay	0.05	FIT
2DD13	Memesagamesing Lake Dam	Memesagamesing River	Wanipitai and French	0.07	FIT
2EA24	Hurdville Dam	Manitouwabgin River	Eastern Georgian Bay	0.21	FIT
2EA3	1.6 km Below Sand Lake	Magnetawan River	Eastern Georgian Bay	0.09	FIT
2EA28	Watts Dam	Magnetawan River	Eastern Georgian Bay	0.11	FIT
2EA4	4 km Below Perry Lake	Magnetawan River	Eastern Georgian Bay	0.26	FIT
2EA20	Head of Wawashkesh Lake	Magnetawan River	Eastern Georgian Bay	0.32	FIT
2EA31	Sprucedale	Beggsboro Creek	Eastern Georgian Bay	0.07	FIT
2EA6	8 km Below Perry Lake	Magnetawan River	Eastern Georgian Bay	0.39	FIT
2DD31	Arthur's Lake Dam	Wolf	Wanipitai and French	0.06	FIT
2EA54	Naiscoot River Dam	Naiscoot River	Eastern Georgian Bay	0.08	FIT
2DD8	Gimball's Chute	South River	Wanipitai and French	0.49	FIT
2DD28	Dollars Dam	Pickerel River	Wanipitai and French	0.45	FIT
2DD27	Dutchman Dam	Pickerel River	Wanipitai and French	0.22	FIT
2DD35	Le Groux Dam	Pickerel River	Wanipitai and French	0.19	FIT
2EA42	Mill Lake Dam	Seguin	Eastern Georgian Bay	0.40	FIT
2EA2	Burks Falls	North Magnetawan River	Eastern Georgian Bay	0.34	FIT
2DD4	Cox's Including Davidson's Chute	South River	Wanipitai and French	1.05	LRP
2EA1	High Falls (Mountain Chute)	Seguin	Eastern Georgian Bay	1.13	LRP
2EA11	Upper Burnt Chute	Magnetawan River	Eastern Georgian Bay	1.70	LRP
2EA17	Above Bying Inlet	Magnetawan River	Eastern Georgian Bay	2.21	LRP
2EA18	Above Bying Inlet	Magnetawan River	Eastern Georgian Bay	1.70	LRP
2EA12	Lower Burnt Chute	Magnetawan River	Eastern Georgian Bay	3.15	LRP
2EA55	Bying Inlet	Magnetawan River	Eastern Georgian Bay	4.40	LRP
2EA5	6.4 km Below Perry Lake	Magnetawan River	Eastern Georgian Bay	1.49	LRP
2EA21	Wawashkesh Lake Dam	Magnetawan River	Eastern Georgian Bay	0.60	LRP
2EA26	Ahmic(Knoefli) Lake Dam and Kneopple's Rapids	Magnetawan River	Eastern Georgian Bay	1.78	LRP
2EA19	Porter's Rapids	Magnetawan River	Eastern Georgian Bay	0.55	LRP
2EA10	Cody's Rapids	Magnetawan River	Eastern Georgian Bay	1.98	LRP
2EA8	Elbow Rapids	Magnetawan River	Eastern Georgian Bay	1.85	LRP
2DD1	Chaudière Dam	French River	Wanipitai and French	6.94	LRP
2EA7	Below Poverty Bay	Magnetawan River	Eastern Georgian Bay	2.46	LRP
2EA9	Ross's Rapids	Magnetawan River	Eastern Georgian Bay	0.70	LRP
2EA30	Magnetawan (Cecebe) Dam	Magnetawan River	Eastern Georgian Bay	0.91	LRP

Appendix D – Potential Waterpower Sites: Muskoka District Municipality

Site Identifier (MNRF)	Site Name / Location	Waterbody Name	Watershed	Capacity (MW)	FIT/LRP
2EB26	Windermere Dam	Dee River	Eastern Georgian Bay	0.16	FIT
2EB38	Port Carling Dam	Indian River	Eastern Georgian Bay	0.24	FIT
2EB23	Fairy Lake Dam	North Muskoka River	Eastern Georgian Bay	0.42	FIT
2EB1	6.4 km Below Mary Lake	North Muskoka River	Eastern Georgian Bay	0.46	FIT
2EB6	Mary Lake Dam	North Muskoka River	Eastern Georgian Bay	0.44	FIT
2EC25	Port Severn	Severn River	Eastern Georgian Bay	1.33	LRP
2EB21	Marsh Falls	Oxtongue River	Eastern Georgian Bay	0.54	LRP
2EB14	Crozier Chute	South Muskoka River	Eastern Georgian Bay	2.40	LRP
2EB13	Slaters Chute	South Muskoka River	Eastern Georgian Bay	1.43	LRP
2EB31	Baysville Dam	South Muskoka River	Eastern Georgian Bay	0.53	LRP
2EB12	Go Home Lake Dam	Musquash River	Eastern Georgian Bay	6.49	LRP
2EB2	Duck Chute	North Muskoka River	Eastern Georgian Bay	0.67	LRP
2EB11	Gray Rapids	Musquash River	Eastern Georgian Bay	5.34	LRP
2EB57	Bala Dam	Muskoka River	Eastern Georgian Bay	4.00	LRP

Appendix E – Potential Waterpower Sites: Simcoe County

Site Identifier (MNRF)	Site Name / Location	Waterbody Name	Watershed	Capacity (MW)	FIT/LRP
2ED4	Glencairn	Mad River	Eastern Georgian Bay	0.13	FIT
2ED1	Avening	Mad River	Eastern Georgian Bay	0.07	FIT
2ED26	Singhampton	Mad River	Eastern Georgian Bay	0.12	FIT
2ED22	2.4 km Above Creemore (Websterville)	Mad River	Eastern Georgian Bay	0.06	FIT
2ED3	1.6 km from Alliston	Boyne River	Eastern Georgian Bay	0.09	FIT
2ED2	4 km West of Ivy	Nottawasaga River	Eastern Georgian Bay	0.31	FIT
2ED29	Nicolston Dam	Nottawasaga River	Eastern Georgian Bay	0.23	FIT
2ED20	4 km below Alliston	Boyne River	Eastern Georgian Bay	0.05	FIT
2EC21	Washago Dams	Severn River - MID	Eastern Georgian Bay	0.94	LRP
2EC42	Couchiching Lock 42	Severn River - MID	Eastern Georgian Bay	1.39	LRP

Parry Sound-Muskoka IRRP

Appendix G: Local Advisory Committee Meeting Summaries

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Meeting Summary

Engagement Information	
Date:	June 20, 2016
Location:	Muskoka Discovery Centre - Gravenhurst
Subject:	**Parry Sound/Muskoka Local Advisory Committee Inaugural Meeting**
Attendees:	**Committee Members** Adam Pawis Andrew Farnsworth Mayor Bob Young Brent Devolin Forrest Pengra Geoff Ross Jeff Gilbert Joan Pajunen Larry Ferris Melinda Zytaruk Michael Duben Chief Wayne Pamajewon **Hydro One** Alexander Constantinescu Gaurav Behal Matthew Bell **Lakeland Power** Brian Elliot **Midland PUC** Roy Rogers **Newmarket-Tay Power** Larry Herod **Orillia Power** Chris Burrell **PowerStream** Michael Swift Riaz Shaikh **Veridian Connections** Ed Johnston **IESO** Bob Chow Chuck Farmer Amanda Flude Bernice Chan Stephanie Aldersley Humphrey Tse Jeffrey Schnuerer
Meeting Materials	http://www.ieso.ca/Pages/Participate/Regional-Planning/South-Georgian-Bay-Muskoka/Parry-Sound-Muskoka-sub-region.aspx *A copy of all presentations are available at the LAC Meeting Materials Link above.*

	Key Themes	* Follow up Actions
1	**Role of the Local Advisory Committee** • To provide input on planning initiatives and local priorities (economic, development, intensification, community energy plans, etc.) • To share information on local electricity supply preferences • Provide input into the local engagement process relating to regional electricity planning • Help to inform the development of the electricity plan **Meetings are an Information Sharing Forum**	

- The Working Group will provide updates on progress and results on electricity planning initiatives in the Parry Sound/Muskoka area
- Will be an opportunity for a broader energy dialogue between communities and the electricity sector, and serve as a bridge between regional planning cycles for the area

Regional Planning Process

- A formal process of identifying and meeting electricity needs for a region; consistent in all 21 electrically-defined regions across the province
- Carried out by the Technical Working Group; comprised of local utilities, the transmitter and the IESO
- Serves as a link between provincial and local planning.
- Key outcome is an Integrated Regional Resource Plan (IRRP), providing a 20-year forecasted outlook at the area's electricity needs and where applicable, outlining recommendations for solutions to immediate needs, and the long-term approach to address needs forecasted for the future.
- Considers an integrated approach of conservation, generation, transmission and distribution, and innovative resources.
- Project-related considerations and planning are beyond the scope of regional planning. Projects identified in the IRRP or regional planning process will still need to consider project-level details such as siting and routing, approval processes such as environmental assessments and regulatory approvals, project-level stakeholder and community engagement, consultation with Indigenous peoples, and project funding and cost allocation.
- A Scoping Assessment Report has been completed for the South Georgian Bay/Muskoka Region; with the final IRRP report being posted for the sub-region of Parry Sound/Muskoka by the end of December 2016. The LAC will have the opportunity to review and discuss draft recommendations made in the draft report prior to the report being finalized.

Electricity Planning in the Parry Sound/Muskoka Area

- Local generation includes a number of small-scale hydroelectric generation sites providing 27 MW of installed capacity, 95 MW of solar and Combined Heat and Power, with increasing local interest in further distributed generation, and the potential for large-scale wind development.
- The area is served by seven local distribution companies: PowerStream, Orillia Power, Newmarket-Tay Power, Lakeland Power, Veridian Connections, Hydro One, and Midland PUC.
- A full list of municipalities and communities in this sub-region can be found in the South Georgian Bay/Muskoka Region Scoping Assessment Outcome Report

Summary of Local Electricity Needs

- Reliability of service and overall performance of the system; challenging for many communities in the area relying on a single source and being supplied by long transmission and distribution networks.
- Communities are concerned about the potential impact of service interruptions; both frequency and duration.
- Many of the 44kV sub-transmission lines supplying the area are not performing well relative to the provincial service reliability performance expectations.
- There is a limited supply capacity remaining on the two transformer stations supplying the Parry Sound area (Parry Sound TS, Waubaushene TS). Based on electricity demand forecasts, an additional 30 MW of capacity will be required in the Parry Sound area by 2035. Given the modest growth, there may be opportunity for targeted demand management and conservation activities to defer

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the need for major system infrastructure reinforcements.

- In the event of a major outage on the 230kV system for Orillia and Muskoka, all loads would be interrupted and the ability to restore the supply in a timely manner is limited. The Working Group will examine opportunities to improve load restoration by installing switching facilities in consideration of cost benefits.
- Other considerations:
    - End of life replacement of a transformer station at Minden within the next five years
    - Additional supply may be required on the Orillia-Muskoka 230kV system over the longer term (beyond 2030s)
    - Concerns regarding voltage and power quality

Next Steps

- The Working Group will seek input from the LAC on the following topics as committee meetings continue:
    1. **Service reliability and performance**
        - Cost and impact of supply interruptions to customers and communities
        - Discussing opportunities to improve the 44kV sub-transmission reliability
        - Building awareness of considerations of cost-benefit and cost-responsibility regarding system performance improvement
    2. **Limited supply capacity on transformer stations supplying the Parry Sound area**
        - Explore opportunities to manage growth and defer the need for system reinforcements using community-based energy solutions

    The LAC will be kept informed of activities and results related to load restoration, end of life replacements, voltage and power quality, and long-terms needs.

- The LAC will meet again in September to discuss options to meet the need, and draft recommendations being proposed for the draft report if available. A follow up meeting may be required in October/November to initiate the discussion on the draft recommendations before the report is finalized at the end of 2016.
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- The Working Group will inform and discuss the outcome of the analysis with the LAC.
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Summary of Feedback/Discussion Items from the LAC:

- **Cost**
- Ensure that the impact of infrastructure upgrades on the local ratepayer is considered during the planning process, as costs are already high.

- **Demand Forecasting**
- Should take into account the number of people that are trying to move away from utilizing the electricity grid due to costs.
- Interest in knowing what forecasting looks like for industry vs. residential; tourism and recreation is a large factor in the local economy.

- **Reliability**
- Consider the need for reliable power to attract knowledge-based industry.
- Further statistical information on frequency of outages in specific areas would be of interest.

- **Distributed Generation**
- Interest in more information on feasibility and costing of various options.
- Examples of community-based programs that are working in other regions would be appreciated. i.e. Net-zero homes, micro grids, Power.House, etc.
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- **Community Focus**
  - Greater voice from First Nation needs to be represented in the discussion, as do businesses.
  - Municipal and community resources are limited for Community Energy Plans, but there is strong interest in moving forward with those.
  - The Township of Minden Hills has an Alternative Energy Task Force; so focus is shifting.
  - Should be engaging the broader community in the process when it comes to any project-level detail, including land use impacts

- **Other**
  - Would like to see stronger involvement from the Ministry of Energy at the community level.
  - Stronger dialogue would be beneficial in some areas between municipalities and LDCs.
  - Interest in an ‘Electricity Bill 101’ session for the LAC as an educational opportunity that they could further share with constituents.
  - More information on the Climate Change Action Plan would be helpful; provincial direction, current incentives, and the role/opportunities that municipalities have.

Collective meeting ended at 2:30 pm; discussion with Working Group and First Nation communities followed.

Next meeting – September; further details will follow from the IESO.

Meeting Summary

Meeting Information	
Date:	September 26, 2016
Location:	Dwight Community Centre, Dwight, ON
Subject:	**Parry Sound/Muskoka Local Advisory Committee Meeting**
Attendees:	**Committee Members** Mayor Bob Young Brent Devolin Forrest Pengra Geoff Ross Jeff Gilbert Joan Pajunen Melinda Zytaruk **Regrets** Andrew Farnsworth Larry Ferris Michael Duben **Hydro One** Alexander Constantinescu Gaurav Behal Richard Shannon **Lakeland Power** Brian Elliott **Midland PUC** Roy Rogers **Orillia Power** Chris Burrell **PowerStream** Michael Swift Riaz Shaikh **Veridian Connections** Ed Johnston **IESO** Amanda Flude Luisa Da Rocha Bernice Chan Stephanie Aldersley Jeffrey Schnuerer Kim Veeneman
Meeting Materials	http://www.ieso.ca/Pages/Participate/Regional-Planning/South-Georgian-Bay-Muskoka/Parry-Sound-Muskoka-sub-region.aspx *Copies of all presentations are available at the LAC Meeting Materials Link above.*

	Key Themes	Follow-up Actions
1	**Opening Remarks/Introductions** • Bob Young, Mayor, Township of Lake of Bays opened the meeting and welcomed everyone. • Amanda Flude, Senior Advisor, Regional and Community Engagement, IESO provided a welcome to the group and roundtable introduction were done.	
2	**Review of Minutes from LAC Meeting #1** • Amanda Flude provided a high level review of the draft meeting summary from the previous meeting. LAC members are asked to provide any final comments or feedback before the end of the following day.	▪ Follow-up to be undertaken with committee for any additional feedback on the previous meeting summary.

3	**Recap: Electricity Needs in the Parry Sound/Muskoka Area**
	
	Presentation Summary: Bernice Chan, Planner, IESO provided a recap of the electricity needs in the Parry Sound/Muskoka area and reviewed the key areas of focus identified at the last meeting. Also discussed were the impacts of power outages in this area, both in terms of frequency and duration, and the growth pockets in this region where forecasted growth is expected to exceed the capability of the system. A key focus of the meeting is to discuss the local needs and options the Working Group is using or looking into to address the needs. The Working Group will also be seeking input from the committee on the draft recommendations that will be included in the Parry Sound/Muskoka Integrated Regional Resource Plan (IRRP) that will be published in December.
	
	Questions and Feedback from the LAC Members:
	
	• Is 95 MW of installed solar and combined heat of power correct? That number seems really high.
	    o Yes, this is correct. That is the current total for contracts for the whole Parry Sound/Muskoka area. Hydro is an additional 27 MW.
	• Has any sensitivity analysis been done with demand growth numbers in case they don't turn out like we estimate?
	    • Yes, the Working Group monitors this regularly.	

4	**44kV Service Reliability Performances - Outages and Causes** *Presentation Summary: Gaurav Behal, Hydro One, provided a recap of the performance and reliability of the 44 kV networks in this region, outlining how some of them are performing below provincial average in terms of frequency and durations of outages. The reliability analysis was based on two metrics - the frequency and duration of the outages. The provincial average for 44 kV feeders for the past five years is approximately two outages per year with a total annual outage time of about five hours. Following are the statistics for the feeders identified for line M2 and those in the yellow zone on slide 12:* • *Muskoka M2 (85 km in length): 3 outages/year; 11 hours* • *Huntsville area: 4 outages/year, 10 hours* • *Bracebridge area: 4 outages/year, 8.5 hours* • *Rosseau area: 4.5 outages/year, 11 hours* • *Orillia/Waubaushene: 3 outages/year, 6 hours* *The main causes for these outages are: tree-related incidents; equipment failure and aging equipment; long length of 44 kV feeders, which increases exposure to these incidents; as well as distribution facilities being located off-road, which results in higher restoration times. For example, Muskoka M1 is about 102 km long; more than twice the provincial average.* *In order to reduce the customer impact resulting from outages, Hydro One has a variety of maintenance programs, which are run on a cyclical basis. These include programs for vegetation management, line patrols and addressing hazard trees mid-cycle, and tools focusing on distribution system management and grid modernization. These vegetation management programs are typically run on six year cycles, with the next cycle for the Parry Sound-Muskoka area scheduled to take place in 2021. Hydro One recently announced $20M in funding for initiatives to reduce all tree-related outages, which are the cause of about 40-45% of all outages in this area.* *Richard Shannon, Hydro One, continued the discussion on outages and provided an overview of the different opportunities and actions that would help to improve local reliability issues. These include increased vegetation management, installing distribution automation and fast-acting switching devices to restore power, relocating "off-road" 44 kV lines to the roadside to*	

allow crews better access, and strengthening ties within other 44 kV lines to serve as a back-up supply in the event of an outage. There are about 450 km of 44 kV circuits that are fed from Muskoka TS, and after examination, Hydro One has identified approximately 80 km of line that can be relocated to roadside. Hydro One is also looking at approximately 35-40 km of potential new feeder construction to strengthen the ties within the network to enable switching to alternate lines when there is an outage.

Also discussed was the potential for an upgrade to the Gravenhurst and Bracebridge area to reduce the exposure of local feeders to outages. This area is currently supplied by Muskoka TS and Orillia TS via a total of three 44 kV feeders, which includes some underperforming feeders. Currently, there is a transformer station in Bracebridge that only supplies one large industrial customer and has spare capacity due to decreased customer need since it came into service. This spare capacity could be used to supply about 75% of the load in the Bracebridge/Gravenhurst area. There are options for resupply of these communities from Bracebridge TS, which include new feeder lines at a cost of approximately $3-6M, and a second transformer or a combination of switching facilities can be installed at a cost of approximately $5-30M to minimize the impact of potential transmission outages.

Questions and Feedback from the LAC Members:

- Do you have any data from Dwight North for these underperforming feeders?
    - The Dwight area is serviced by the Muskoka M4 and it has about two outages per year. The duration is about six hours.
- Does Hydro One have the capacity to track the frequency and duration of every outage for each area?
    - Yes, the last five years of data was reviewed.
- How long is the M4 feeder?
    - The M4 is 44 km long, which is around the provincial average.
- Is the $20 million included in the total that Hydro One is already spending in 2016?
    - Yes.
- Has a cost analysis been done on burying these lines? What about the life cycle costs?
    - A formal life cycle analysis has not been done, but it is about 3-5 times more costly upfront to bury these lines. The North American accepted practice is to go with overhead wires because of the lower costs. There are also other challenges with burying lines such as repair costs, and technical issues like the granite base in Muskoka.
- Is there a formal analysis of this cost comparison?
    - Hydro One is not aware of any formal analysis done and will follow up on this.
- What's the current status of vegetation management and how is it carried out, i.e. spraying versus manual clearing of trees?
    - This is looked after by Hydro One's Forestry group. This question will be taken back and the information will be passed along.
- What is the timeline on implementation of grid modernization?
    - Five years. Grid modernization is proposed in the rate filing for 2018. It is an on-going program.
- When you do your cost-benefit analysis are you just analysing the forgone revenues to Hydro One, or is there any consideration on the losses incurred by those outages by private companies?
    - There is no consideration of lost revenue to Hydro One or others and no real revenue consideration to societal costs. Our commitment is to maintain reliability at historical levels; levels that have been accepted by customers in the past and to target the areas where reliability is not meeting customer expectations. The target for grid modernization is industrial and commercial customers as these are the segments most impacted by outages.

- Hydro One to provide numbers from the reliability analysis done for the underperforming 44 kV sub transmission feeders.
- Hydro One to follow-up on cost comparisons.
- Hydro One will take the question back to the Forestry Group and report back to the LAC.

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What communication infrastructure is used?
Third party cellular providers.
Is it possible to get a list of the 80 km of off-road 44 kV lines that have been identified as able to be relocated to roadside over the five year period?
This list will be provided.
Does Hydro One discuss road and highway projects with municipalities and counties in order to ensure that things are done in a mutually beneficial manner?
If there is a lot of activity in a municipality, then yes, however this usually occurs when municipalities reaching out to Hydro One to discuss a utility pole relocation.
When a municipality initiates a pole relocation with Hydro One how is this costed? If Hydro One was going to relocate the pole anyway, does the municipality still have to pay?
There is a general agreement that municipalities pay 50% of labour costs as well as any additional costs for specialized equipment for working on an off-road location. In the case where poles were going to be relocated anyway, it is still 50% as it is hard to determine incremental costs.
Anything planned for the Waubaushene/Parry Sound line?
No.
What is the timing of the study (local planning study for work on the TS improvements in the Muskoka area)?
3-6 months; the LAC will be kept informed

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Hydro One will provide a listing of the 80 km of off-road lines that have been identified as being able to be relocated to roadside.
The Working Group to provide LAC with an update on local planning study for work on the local TS improvements as they become available.

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Transformer Station Capacity in the Parry Sound and Waubaushene Areas
Presentation Summary: Bernice discussed the limited supply capacity of the two transformer stations currently supplying Parry Sound, Waubaushene and the surrounding areas. Electricity demand at the Parry Sound and Waubaushene TS is expected to grow at a rate of 1-2 MW per year over the planning period. By 2035, an additional 23 MW of capacity will be required at Parry Sound TS and 11 MW at Waubaushene TS. Potential options include resupplying some customers in the Parry Sound and Waubaushene areas from other adjacent stations using existing and new distribution facilities. Another option is to upgrade the transformers at the existing Parry Sound and Waubaushene stations at a cost of $25-30M per transformer upgrade. A third option is to defer the costs of the transformer upgrades for as long as possible by using targeted demand management and distributed energy resources. Given the modest growth in this area, there is a value of approximately $2M a year in deferring the TS upgrades, but there are also costs related to implementing community based solutions.
Community based solutions in Parry Sound/Muskoka can include local distributed generation, such as hydroelectric facilities, opportunities to improve heating efficiency, and pilots for emerging technologies such as thermal energy storage and microgrids. With limited information on the cost and feasibility of distributed energy resources and demand management, more work needs to be done to determine whether it is cost-effective and feasible to rely on these solutions to address local needs. The draft recommendations from the Working Group are to manage near-term growth, to better understand the cost and feasibility of implementing distributed energy and demand management options in the Parry Sound and Waubaushene areas, and to determine if there is an opportunity to align the end-of-life replacement with transformer station capacity needs.
Questions and Feedback from the LAC Members:

Have there been any conversations with Energy Efficiency Organizations?
Not yet. Suggestions from the LAC on local organizations to speak with are welcome.
A LAC member noted that they are on the boards of some energy efficiency

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LAC members to provide the Working Group with any suggestions for local organizations that should be included

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	companies and can assist with this.
	• Why is hydro being considered and not solar?
	  o Historically, the area has been winter peaking in the evening and during this time solar does not provide sufficient capacity.
	• Has there been any analysis done when looking at the $25-30M transformer upgrades and do we know what it's costing to maintain service to the consumers that are currently on those lines regarding outages or regular repair work etc.?
	  o No, not on this particular analysis as we were more focused on capacity.
	• Are you speaking with the provincial Climate Change Action Plan and Cap and Trade folks? There are four or five dominant elements linked together and these groups need to be at the table so discussions can happen at the same time. Municipalities need to refine their Official Plans and these groups need to inform the LAC as to their activities.
	  o We will try to bring this to the table.
	• Pricing policies are forcing people to shed load because they can't afford it. This is going to affect demand and the social structure. Wood has become very expense and to ask people to put in baseboard heaters is also an expensive option since most people can't afford to change the source of heat in their homes.
	  o Our next step is to understand what type of opportunities there are in the community. Affordability is going to be a big factor.
	• Water power is not really reliable in this area because of droughts in the summer and draining the lakes because of tourism.
	  o IESO is working with local hydroelectric operators to understand the capability of local facilities during peak.
	• While the hydro potential may be there, NIMBYism is big in this area (i.e. Bala Falls).
	• Regarding the energy efficiency option, is there an ability to identify individuals that have baseboard heating through smart metres? Can aggregate data be used?
	  o With smart metres, it is possible to see habits in a household, however privacy laws regulate the use of this data. In terms of the aggregate data, information can likely be obtained at the feeder level and IESO is working with the local distribution companies to determine what data is available. From this data, the LDCs may be able to identify who has electric heating and find out what the penetration is.
	• There is a socio-economic factor – any solution that says that consumers need to buy anything is ludicrous. People are having a hard time paying their bills, so this will be a tough sell.
	• There is a problem when there is a difference between the accrued costs and the realized savings.
		in the discussion on potential energy efficiency opportunities for the area.
		
		▪ The Working Group to look into including future speakers on the Climate Change Action Plan and Cap and Trade at future meetings.

6	**Load Restoration on 230kV Orillia-Muskoka Transmission System** *Presentation Summary: There is a 230 kV transmission line from Essa TS to Minden TS and north to Muskoka that currently supplies 450 MW of peak load. If there is a fault anywhere on this line then all customers supplied by the line would be affected. This 450 MW loss is not meeting the IESO's planning criteria and needs to be addressed. There are two options for isolating devices to address this - motorized switches and breakers which are more expensive but they allow the side not on the fault to not experience an interruption. Based on this, the Working Group is recommending that switches be installed at the Orillia TS, which would allow for up to 350 MW of load to be restored within 30 minutes following a major event on this line. Another option is as follows: the transformer station at Minden is planned for end-of-life replacement and will undergo a small upgrade at that time, within the next five years. In the longer term, additional supply may be required on the Orillia-Muskoka 230 kV transmission system, and the Working Group has heard of voltage and power quality concerns.*	

	Questions and Feedback from the LAC Members:
	
	• Where are the motorized switches going and are they operated manually?
	  o The switches would be at the Orillia, staggered on either side. The proposed configuration will provide restoration capability at Orillia TS in the case of an outage on the 230 kV line. Switches allow service to customers to be restored in 30 minutes, therefore meeting the IESO's restoration criteria. The motorized switches are remotely controlled from a control centre. If there is a fault, the breakers at Essa and Minden would automatically open and then an operator would open the switches and close the breakers at either Minden or Essa depending on where the fault occurred. The operator manages this remotely.
	• With distributed generation (e.g. biomass), are there other features and benefits that can be added other than just increased capacity?
	  o This hasn't been considered in this plan. This is a good recommendation for consideration of distributed generation in the future studies for this area.
	• What is being done with the end-of-life replacements so that it is best for the community?
	  o This is being more actively monitored and there are considerations of local capacity needs as part of the process.
	• Are some end-of-life assets being replaced with different technologies? Is this policy? Who is determining the minimum requirements for today?
	  o Yes, for example, upgrades to two-way power flows instead of one-way. Decisions are made based on strategic alignment with plans, and they meet industry standards and are done in conjunction with the IESO.
	• How are people aware of what is happening locally? There are lots of gaps.
	• Socio-economic growth is not your area of interest, but it's ours. We need to have reliable transmission and instead of looking for ways to reduce 11 hours of outage, we need to be looking at ways of getting people back on instantaneously. The plan is looking at a $5-7M investment that gives a 30 minute downtime verses spending $25M that would get businesses back up instantly. Municipal councils need to be part of this discussion as this would be valuable to promote for economic development.
	  o The transmission system only has about one outage per year – previous statistics were for the 44 kV system. The recommended upgrades are consistent with ORTAC, which are the planning criteria used by IESO. We are open to discussions with communities about their desire for reliability beyond the ORTAC criteria.	

7	**Parry Sound-Muskoka Technical Working Groups priorities:** The following Working Group priorities were presented to the LAC members: • Seek LAC input on the draft recommendations • Better understand the potential, cost and feasibility of demand management and distributed energy resources in the area • Keep LAC members and communities informed of the status of the IRRP recommendations • Keep LAC members and communities informed of demand growth and conservation activities • Coordinate regional and community energy planning activities	
8	**Discussion around the LAC meeting priorities and scheduling:** A LAC roadmap document was reviewed with the committee members, identifying the Working Group's priorities until the end of 2018. A brainstorming session was conducted	▪ The draft list of LAC priorities discussed at the meeting to be provided to the

	with members regarding their priorities for future LAC meetings. At future meetings, the LAC members will collectively discuss the agenda for the subsequent meeting before the meeting concludes. A full list of the LAC member priorities will be circulated to the LAC members for review. **Questions and Feedback from the LAC members:** • Meeting once per year is not enough – there are many provincial changes that will impact the plans With respect to the frequency of LAC meeting following the posting of the plan in December, the committee members decided on a frequency of three meetings per year.	committee for further review and comment.

9	**Public Questions:**
	
	• What is the province's stand on fossil fuels? My perception of what's happening is "let's take everyone off natural gas and put them on electric and we will be ok".
	   o The government is about to embark upon a province-wide consultation on the development of the next Long-Term Energy Plan and this will set the policy direction for the province for the next 20 years. The IESO released the Ontario Planning Outlook on September 1st which is a technical analysis for the Minister in preparation for the LTEP consultations. A fuel sector report will also be released in the next few weeks as another foundational document for the Ministry for those consultations.
	• I'm a microFIT customer and the rules say that I have to sell generation back to the IESO, but I would like to put what I produce into batteries for my use first, and then sell back any excess to the IESO. I don't know where the technology is on that aspect.
	   o Net metering is still under development. This may be considered as part of this program.	

10	**Closing Remarks:** A recap was provided on the immediate next steps which are to provide a copy of the meeting summary from the previous meeting to all members for further comment or feedback, remind members of the October 15th deadline to provide comments or feedback on the draft recommendations for the IRRP that were presented today, and finally to provide the list of brainstorming items discussed at this meeting.	
11	**Meeting adjourned at 2:30 pm.** **Next meeting** – Will be held in late winter/early spring 2017. Details will follow from the IESO.	

Hydro One Networks Inc.
483 Bay Street
Toronto, Ontario
M5G 2P5

NEEDS ASSESSMENT REPORT

GTA North Region

Date: March 20, 2018

Prepared by: GTA North Region Study Team

Disclaimer

This Needs Assessment Report was prepared for the purpose of identifying potential needs in the GTA North Region and to recommend which needs may require further assessment and/or regional coordination to develop a preferred plan. The results reported in this Needs Assessment are based on the input and information provided by the Study Team.

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Executive Summary

REGION	GTA North		
LEAD	Hydro One Networks Inc. ("HONI")		
START DATE	December 1, 2017	**END DATE**	March 20, 2018

1. INTRODUCTION

The first cycle of the Regional Planning process for the GTA North Region was initiated in Q2 2014 and completed with the publication of the Regional Infrastructure Plan ("RIP") in February 2016. The RIP provided a description of needs and recommendations of preferred wires plans to address near-term needs. The RIP also identified some mid- and long-term needs that will be reviewed during this planning cycle.

The purpose of this Needs Assessment is to identify any new needs and reaffirm needs identified in the previous GTA North Region RIP.

2. REGIONAL ISSUE/TRIGGER

In accordance with the Regional Planning process, the regional planning cycle should be triggered at least every five years. Due to the timing of the mid-term needs identified in the previous Integrated Regional Resource Plan ("IRRP") and RIP reports as well as new needs in the GTA North Region, the NA was triggered in advance of the regular 5-year review schedule.

3. SCOPE OF NEEDS ASSESSMENT

The scope of this NA covers the GTA North Region and includes:

- New needs identified by Study Team members; and,
- Review and reaffirm needs/plans identified in the previous RIP

The Study Team may also identify additional needs during the next phases of the planning process, namely Scoping Assessment ("SA"), IRRP and RIP, based on updated information available at that time.

4. INPUTS/DATA

The Study Team representatives from Local Distribution Companies ("LDC"), the Independent Electricity System Operator ("IESO"), and Hydro One provided input and relevant information for the GTA North Region regarding capacity needs, system reliability, operational issues, and major assets/facilities approaching end-of-life ("EOL").

5. ASSESSMENT METHODOLOGY

The assessment's primary objective is to identify the electrical infrastructure needs in the Region over the study period. The assessment reviewed available information including load forecasts, conservation and demand management (CDM) and distributed generation (DG) forecasts, system reliability and operation issues, and major high voltage equipment identified to be at or near the end of their useful life and requiring replacement/refurbishment.

A technical assessment of needs was undertaken based on:

- Station capacity and transmission adequacy;
- System reliability and operation; and,
- Major high voltage equipment reaching the end of its useful life with respect to replacing it with similar type equipment versus other options to determine the most technically feasible, resilient, and cost effective outcome.

6. RESULTS

I. Aging Infrastructure

In the GTA North Region, high voltage equipment at Woodbridge TS (T5 transformer) was identified to be approaching the end of its useful life and requires replacement in the near-term. Refer to section 7.1.1 for more details.

II. 230kV Connection Capacity

- A transformation capacity need for the Vaughan area was reaffirmed. Based on current extreme summer weather non-coincident peak net load forecast, the need for additional transformation capacity is beyond 2027. If CDM savings are not achieved as forecasted, the need date may be as early as 2027. Refer to section 7.2.3 for more details.

- A transformation capacity need for the Northern York Area was reaffirmed. Based on current extreme summer weather non-coincident peak net load forecast, the need for additional transformation capacity is beyond 2027. If CDM savings are not achieved as forecasted, the need date may be as early as 2024. Refer to section 7.2.6 for more details.

III. 230kV Transmission Supply Capacity

Transmission Supply Capacity needs were reaffirmed to connect new transformation capacity in Vaughan and Northern York Areas in the long term. Refer to sections 7.2.3 and 7.2.6 for more details.

IV. System Reliability & Operation

- A load restoration need for the loss of circuits V43+V44 (supplies Woodbridge TS, Vaughan #3 MTS, and Kleinburg TS), was identified during the previous NA for the GTA North Western Sub-Region and the Northwest GTA IRRP. The study team reaffirmed this need. Refer to section 7.2.1 for more details.
- A load restoration need for the loss of circuits, P45+P46 (supplies Buttonville TS, Markham #4 MTS, and future Markham #5 MTS), has been identified in the near term. Refer to section 7.1.2 for more details.
- A load security need was previously identified on the Parkway to Claireville corridor and was reassessed during this NA. The load on this corridor is slightly lower than it was when the previous assessment was completed, although it continues to exceed the 600MW limit. Refer to section 7.2.2 for more details.

V. Station Service Supply to York Energy Centre

A need for addressing station service supply to York Energy Centre was reaffirmed for the near to medium term. Refer to section 7.2.5 for more details.

7. RECOMMENDATIONS

The Study Team's recommendations are as follows:

a) Further regional coordination is not required to address the following needs:
   - EOL Woodbridge TS T5 transformer (discussed in section 7.1.1). The study team recommends that this EOL need be addressed by Hydro One and affected LDCs to coordinate the replacement plan. Hydro One will keep the study team informed of the status of the plan if any major changes occur.

b) As per the IESO's letter of support in April 2017, Hydro One will proceed with development and estimate work to connect a new 230/27.6kV DESN in the Markham-Richmond Hill area in coordination with Alectra (discussed in section 7.2.4). Further updates will be included in the next IRRP and RIP.

c) Further assessment and regional coordination is required in the IRRP and/or RIP, to develop a preferred plan for the following needs:
   - Load Restoration – P45+P46 (discussed in Section 7.1.2)
   - Load Restoration – V43+V44 (discussed in Section 7.2.1)
   - Load Security on V71P/V75P – Parkway to Claireville (discussed in Section 7.2.2)
   - Vaughan Transformation Capacity (discussed in Section 7.2.3)
   - Station Service Supply to York Energy Centre (discussed in Section 7.2.5)
   - Northern York Area Transformation Capacity (discussed in Section 7.2.6)
   - Transmission Supply Capacity in Vaughan and Northern York Area in long term (discussed in sections 7.2.3 and 7.2.6)

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List of Tables and Figures

1 INTRODUCTION

The first cycle of the Regional Planning process for the GTA North Region was completed in February 2016 with the publication of the Regional Infrastructure Plan (“RIP”). The RIP provided a description of needs and recommendations of preferred wires plans to address near and medium term needs. Additional medium and long term needs were recommended for further review during the next regional planning cycle.

The purpose of this Needs Assessment (“NA”) is to identify new needs and reconfirm the needs identified in the previous GTA North regional planning cycle. Since the first regional planning cycle, some new needs in the region have been identified.

This report was prepared by the GTA North Region Study Team (“Study Team”), led by Hydro One Networks Inc. Participants of the Study Team are listed below in Table 1. The report captures the results of the assessment based on information provided by the lead transmitter, Local Distribution Companies (“LDC”) and the Independent Electricity System Operator (“IESO”).

Table 1: GTA North Region Study Team Participants

Company
Alectra Utilities Corporation (formerly Enersource Hydro Mississauga, PowerStream Inc., Hydro One Brampton)
Hydro One Networks Inc. (Distribution)
Hydro One Networks Inc. (Lead Transmitter)
Independent Electricity System Operator (“IESO”)
Newmarket-Tay Power Distribution Ltd. (“Newmarket-Tay”)
Toronto Hydro-Electric System Limited (“THESL”)
Veridian Connections Inc. (“Veridian”)

2 REGIONAL ISSUE/TRIGGER

In accordance with the Regional Planning process, the Regional Planning cycle should be triggered at least every five years. Due to the timing of the mid-term needs identified in the previous IRRP and RIP reports as well as new needs in the GTA North Region, the study team recommended to trigger the next cycle in advance of the regular 5-year review schedule.

3 SCOPE OF NEEDS ASSESSMENT

The scope of this NA covers the GTA North Region and includes:

- Identification of new needs based on latest information provided by the Study Team; and,
- Confirmation/updates of existing needs and/or plans identified in the previous planning cycle.

The Study Team may identify additional needs during the next phases of the planning process, namely Scoping Assessment (“SA”), Local Planning (“LP”), IRRP, and/or RIP.

4 REGIONAL DESCRIPTION AND CONNECTION CONFIGURATION

The GTA North Region is approximately bounded by the Regional Municipality of York, and also includes parts of the City of Toronto, Brampton, and Mississauga. The region is divided into two sub-regions:

- York Sub-Region: This area includes Southern York area (the Municipalities of Vaughan, Markham, and Richmond Hill) and Northern York area (the Municipalities of Aurora, Newmarket, King, East Gwillimbury, Whitchurch-Stouffville, Georgina, and some parts of Durham and Simcoe regions are supplied from the same electricity infrastructure).
- Western Sub-Region: This area comprises the western portion of the City of Vaughan.

Electrical supply to the GTA North Region is primarily provided from three major 500/230 kV autotransformer stations, namely Claireville TS, Parkway TS, and Cherrywood TS, and a 230 kV transmission network supplying the various step-down transformation stations in the region. Local generation in the Region consists of the 393 MW York Energy Centre connected to the 230 kV circuits B82V/B83V in King Township.

Please see Figure 1 and Figure 2 for a map and single line diagram of the Sub-Region facilities.

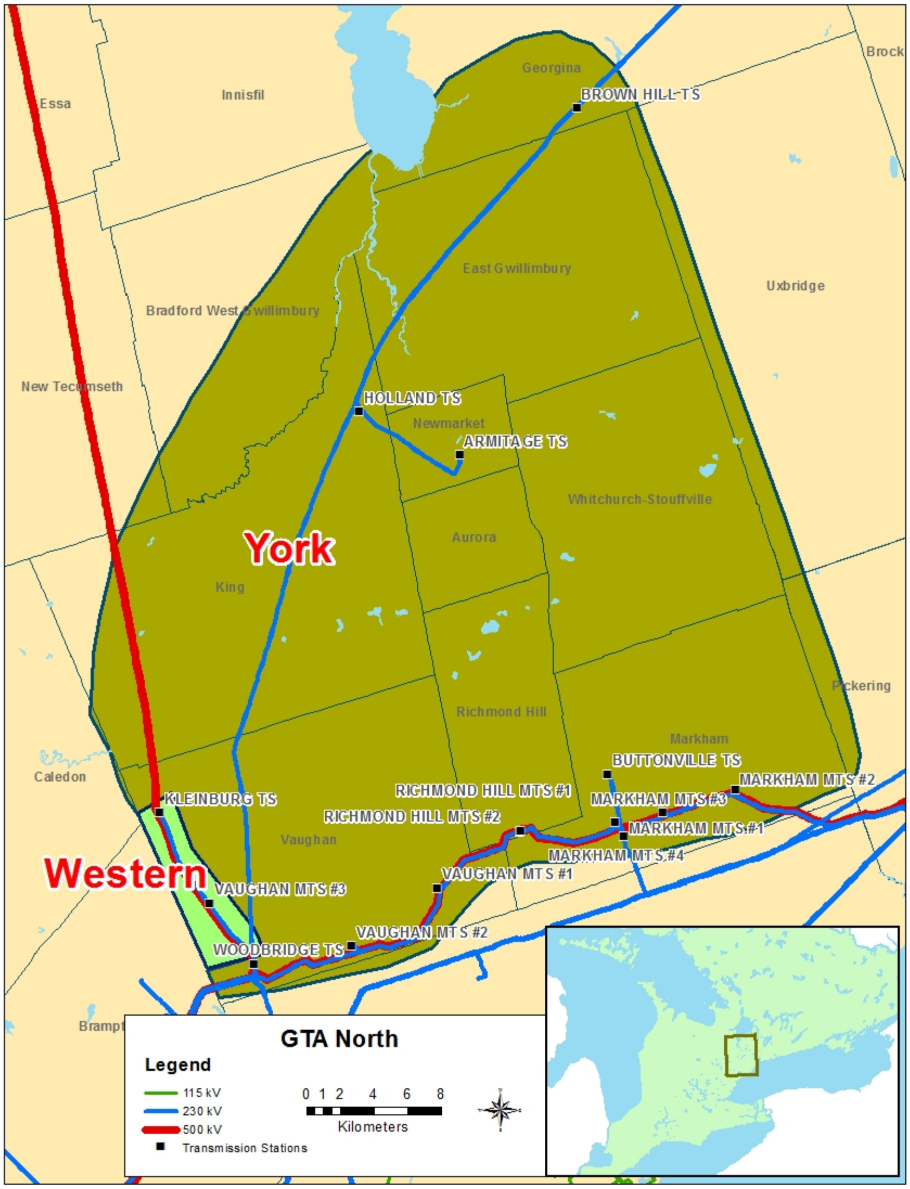

Figure 1: GTA North Region – Supply Areas

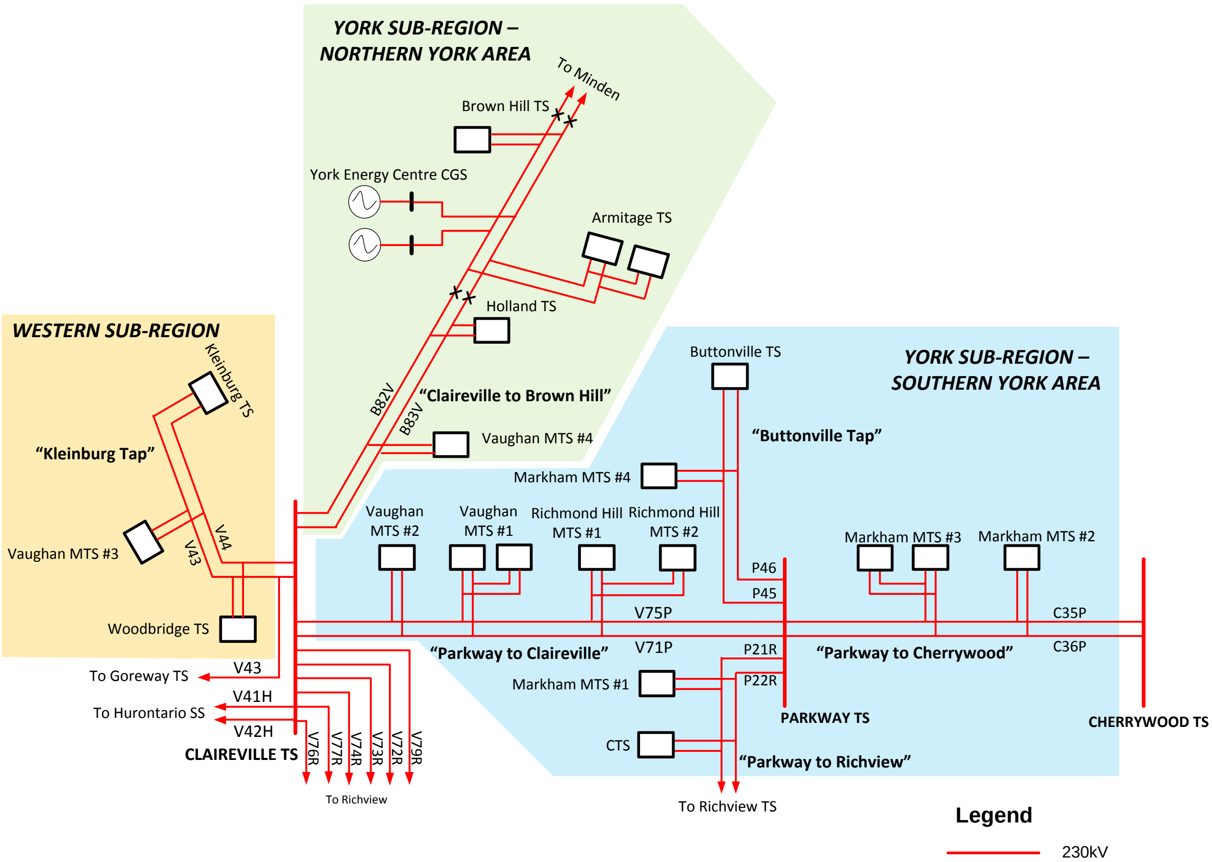

Figure 2: GTA North Transmission Single Line Diagram

5 Inputs and Data

Study Team participants, including representatives from LDCs, IESO, and Hydro One provided information and input for the GTA North Region NA. The information provided includes the following:

- Load Forecast;
- Known capacity and reliability needs, operating issues, and/or major assets approaching the end of their useful life ("EOL"); and,
- Planned/foreseen transmission and distribution investments that are relevant to regional planning for the GTA North Region

6 Assessment Methodology

The following methodology and assumptions are made in this Needs Assessment:

Information gathering included:

i. Load forecast: The LDCs provided a load forecast for the region. The IESO provided a simplified Conservation and Demand Management ("CDM") and Distributed Generation ("DG") assumptions to determine their high-level impact on needs in the region. A GTA North Region extreme summer weather coincident peak gross load forecast was produced by translating the LDC load forecast into load growth rates and applying onto the 2017 actual summer station coincident peak load, adjusted for extreme weather conditions (according to Hydro One's methodology). The CDM and DG assumptions were applied to this gross forecast to produce the net forecast. The extreme summer weather coincident peak net load forecast for the individual stations in the GTA North Region is given in Appendix A. A similar approach was used to develop the GTA North Region extreme summer weather non-coincident peak gross and net load forecast. It should be noted that the actual versus forecasted year to year demand can vary due to factors such as weather, economic development, etc.

ii. Relevant information regarding system reliability and operational issues in the region;

iii. List of major HV transmission equipment planned and/or identified to be refurbished and/or replaced due to the end of their useful life which is relevant for regional planning purposes. This includes HV transformers, autotransformers, HV Breakers, HV underground cables and overhead lines.

Technical assessment of needs was based on:

i. Station capacity and Transmission Adequacy assessment

ii. System reliability and operation assessment

iii. End-of-life equipment: Major high voltage equipment reaching the end of its useful life with respect to replacing it with similar type equipment versus other options to determine the most optimal, resilient, and economic outcome.

Note that the Region is summer peaking so the assessment is based on summer peak loads.

7 NEEDS

This section describes emerging needs that have been identified in the GTA North Region since the previous regional planning cycle and reaffirms the near, mid, and long-term needs already identified in the previous RIP and IRRP. The needs are summarized in Tables 2 and 3 below:

Table 2: New Needs

New Needs	Discussed in Section
End-of-Life Equipment – Woodbridge TS T5 transformer	7.1.1
Load Restoration – P45+P46 ("Buttonville Tap")	7.1.2

Table 3: Needs Identified in Previous RIP and IRRP(1)

Needs Identified in Previous RIP and IRRP	Discussed in Section	RIP Report Section
Load Restoration – V43+V44 ("Kleinburg Tap")	7.2.1	7.3.1
Load Security on V71P/V75P – Parkway to Claireville	7.2.2	7.1.2
Vaughan Transformation Capacity	7.2.3	7.1.3
Markham Transformation Capacity	7.2.4	7.1.4
Station Service Supply to York Energy Centre (YEC)	7.2.5	7.2.1
Northern York Area Transformation Capacity	7.2.6	7.2.2

(1) Includes needs identified in the previous RIP and IRRP that do not have final plans underway yet

7.1 New Needs

7.1.1 End-Of-Life (EOL) Equipment Needs

Hydro One has identified the following major high voltage equipment to be reaching the end of their useful life over the next 10 years. Based on the equipment condition assessment, this asset has been identified to be in poor condition and approaching the end of its useful life.

Table 4: End-of-Life Equipment – GTA North Region

EOL Equipment(1)	Replacement Timing(2)
Woodbridge TS: T5 Transformer	2022-2023

(1) No other major HV station equipment or lines in the GTA North region have been identified for replacement/refurbishment at this time
(2) The replacement/refurbishment timing and prioritization are subject to change

The end-of-life equipment assessment for the above asset considered the following options:

1. Maintaining the status quo
2. Replacing equipment with similar equipment with *lower* ratings and built to current standards
3. Replacing equipment with similar equipment with *lower* ratings and built to current standards by transferring some load to other existing facilities
4. Eliminating equipment by transferring all of the load to other existing facilities
5. Replacing equipment with similar equipment and built to current standards (i.e., "like-for-like" replacement)
6. Replacing equipment with *higher* ratings and built to current standards

Woodbridge TS

Woodbridge TS comprises one DESN unit, T3/T5 (75/125 MVA), with two secondary winding voltages at 44 kV and 28 kV, each with a summer 10-Day LTR of 80 MW. The station's 2017 actual non-coincident summer peak load (adjusted for extreme weather) was 156 MW. Transformer T5 is currently about 45 years old and has been identified to be at its EOL. The companion DESN transformer, T3, is about 29 years old and is not at its EOL. Woodbridge TS supplies both Alectra and THESL.

The 44kV and 28kV load at Woodbridge TS is forecasted to be over 80% and 90% of their respective LTRs in the near and medium term. The closest station is Vaughan MTS #3 (owned by Alectra) and its load is forecasted to be over 95% of its LTR in the medium term. Therefore, downsizing T5 and consolidating load within the station and/or with area stations is not a prudent or viable option given medium term load growth at these stations and based on its historical loading. It is also important to note that the station is configured as a dual secondary yard (230/44-28kV) and the standard lower rated unit has only one secondary. Consequently, replacing T5 with a lower rated unit would result in significant re-configuration of the station and greater cost compared to replacing the EOL transformer with a similar unit of same ratings. Moreover, downsizing capacity today and then later upgrading within the lifetime of the transformer due to eventual load growth will also be significantly more costly. For example it may cost an additional $5-$10 million for the replacement of the transformer plus the incremental cost for the LDC to reconfigure feeders at a later stage. It should also be noted that maintaining capacity, as opposed to downsizing, is a more resilient option as it provides additional flexibility during emergency conditions through load transfers.

With respect to maintaining status quo, the T5 transformer is in poor condition so this is not an option due to the risk of equipment failure, customer outages, increased maintenance cost, and environmental impact. Upgrading T5 is also not an option since it's already at the maximum size.

Based on the above, the study team recommends that this need be addressed by Hydro One and affected LDCs to coordinate the replacement plan. Hydro One will keep the study team informed of the status of the plan if any major changes occur. The timing of replacement for the EOL equipment is 2022-2023.

7.1.2 Load Restoration – P45+P46 ("Buttonville Tap")

This load restoration need is based on the ORTAC load restoration criteria that requires any load loss exceeding 250 MW to be restorable within 30 minutes. Based on the extreme summer weather coincident peak net load forecast, for the loss of 230kV circuits, P45 and P46 (stations connected are Buttonville TS and Markham #4 MTS), the load interrupted by configuration is expected to exceed 250 MW beginning in 2021 and restoration within 30 minutes needs to be assessed.

It should also be noted that a new station, Markham #5 MTS, is being planned for connection to circuits P45 and P46, with a projected need date in the 2025-2026[1] timeframe and an initial load of 26 MW based on the extreme summer weather coincident peak net load forecast (see Section 7.2.4 for more details). This load should also be taken into account for the load restoration need analysis.

The study team recommends that further assessment and regional coordination in the IRRP and RIP phase is required to review options and identify a preferred restoration plan.

7.2 Needs Identified in Previous RIP and/or IRRP

The following section summarizes the needs identified in the previous 2016 GTA North RIP report and 2015 York Region IRRP that do not have final plans underway yet. The Study Team reaffirms these needs and an update is provided below.

7.2.1 Load Restoration – V43+V44 ("Kleinburg Tap")

The load restoration need for 230 kV radial circuits, V43 and V44 (supplying Woodbridge TS, Vaughan #3 MTS, and Kleinburg TS), was identified during the previous NA for the GTA North Western Sub-Region and also in the Northwest GTA IRRP as load restoration times as per the ORTAC may not be met

[1] The need date will be further refined by Hydro One and Alectra through the project development process. Refer to section 7.2.4 for more details.

for the loss of V43 and V44. The study team recommended that this need be addressed in IESO's GTA West bulk system planning initiative.

The subsequent GTA West bulk system study did not address the restoration need. As a result, the study team recommends that the need be revisited as part of the next GTA North IRRP.

7.2.2 Load Security on V71P/V75P – Parkway to Claireville

In the previous York Region IRRP, the study team recommended the installation of inline switches at the Vaughan MTS #1 junction in order to improve the capability of the system to restore load in the event that both 230 kV circuits V71P/V75P are lost. While the installation of these switches will improve the load restoration capabilities and overall reliability on the Parkway to Claireville corridor, it does not address the load security need on V71P/V75P.

Since the previous GTA North RIP, the IESO completed an addendum to its expedited SIA for the in-line switches at Grainger Junction project. The addendum indicated that an exemption for this project with respect to the 600 MW load security limit would not be required. However, it advised that the load security issue on the Parkway to Claireville corridor must be re-assessed as part of the next regional planning cycle.

The Study Team reassessed the load security issue during this regional planning cycle. Based on the extreme summer weather coincident peak net load forecast, the load on the Parkway to Claireville corridor is around 695 MW, which is lower than the previous RIP forecast (refer to RIP report, Appendix D), however continues to exceed the 600 MW limit. As a result, the study team reaffirms this need and recommends further assessment and regional coordination in the next IRRP and RIP phase to review options and develop a preferred plan.

7.2.3 Vaughan Transformation Capacity

In the previous RIP, the study team recommended that the need for additional transformation capacity in Vaughan, along with associated transmission capacity[2], be further assessed in the next regional planning cycle and to refine the need timing as Alectra advised they were updating their load forecast and the need date may change (for more details, refer to section 7.1.3 of the RIP report). Based on the current extreme summer weather non-coincident peak net load forecast, the need for additional transformation capacity is beyond 2027. If CDM savings are not achieved as forecasted, then the need date can be as early as 2027.

The Study Team reaffirms this need and recommends further assessment and regional coordination in the IRRP and RIP phase to review options and develop a preferred plan.

7.2.4 Markham Transformation Capacity

[2] There are long-term transmission supply needs associated with new transformation capacity

In the previous RIP, the study team recommended to continue the assessment of wires and non-wires options to address the need for additional transformation capacity in the Markham-Richmond Hill area and to refine the need timing. During the RIP, Alectra advised that they were updating their load forecast and the need date may change (for more details, refer to section 7.1.4 of the RIP report). In April 2017, the IESO issued a letter of support to Hydro One Transmission and Alectra to proceed with wires planning for a new 230/27.6kV DESN and the associated distribution and/or transmission lines to connect the new transformer station. In the hand-off letter, the IESO concluded that it is not feasible to rely entirely on distributed energy resources to defer the near-term supply need in the area and that a new station and associated connection lines would be required by 2023 to meet the growth projections in the Markham-Richmond Hill area. Based on the current extreme summer weather non-coincident peak net load forecast, the need for additional transformation capacity is projected to be in the 2025-2026[3] timeframe. If CDM savings are not achieved as forecasted, then the need date can be as early as 2024.

The Study Team reaffirms this need and Hydro One and Alectra are currently in the process of selecting a preferred location to connect to 230 kV circuits P45/P46. Following this, Hydro One will proceed with development and estimate work to meet the need date. Further updates will be included in the next IRRP and RIP.

7.2.5 Station Service Supply to York Energy Centre

In the previous RIP, a need for addressing station service supply to York Energy Centre (currently supplied from Holland TS) in the event of a (i) low-voltage breaker failure at Holland TS or (ii) double circuit 230 kV contingency was identified (for more details, refer to section 7.2.1 of the RIP report). These events can result in an interruption to the station service supply to York Energy Centre and therefore the loss of all generation output until the station service can be restored from the alternate source.

Since the RIP, the IESO completed a System Impact Assessment (SIA) for the new 230 kV in-line breakers at Holland TS and it found that the use of load rejection will no longer be a suitable means to address (i) and (ii) in the near to medium term as the amount of load rejection required to address overloads and voltage collapse will exceed the permissible amount of 150 MW allowed by ORTAC load security criteria.

The Study Team reaffirms this need and recommends further assessment and regional coordination in the IRRP and RIP phase to review options and develop a preferred plan.

7.2.6 Northern York Area Transformation Capacity

In the previous RIP, the study team recommended that the need for additional transformation capacity in the Northern York Area, along with associated transmission capacity[4], be further assessed in the next regional planning cycle (for more details, refer to section 7.2.2 of the RIP report). Based on the current

[3] The need date will be further refined by Hydro One and Alectra through the project development process
[4] There are long-term transmission supply needs associated with new transformation capacity

extreme summer weather non-coincident peak net load forecast, the combined loading on Armitage TS and Holland TS will not exceed their combined summer 10-Day LTR during the study period (combined load is over 97% of its combined LTR in 2027). There is 44 kV transfer capability between these stations on the distribution system so the timing of the need is based on the combined capability of both stations. However, if CDM savings are not achieved as forecasted, then the need date may be as early as 2024.

The Study Team reaffirms this need and recommends further assessment and regional coordination in the IRRP and RIP phase to review options and develop a preferred plan.

8 RECOMMENDATIONS

The Study Team's recommendations to address the needs identified are as follows:

a) Further regional coordination is not required to address the EOL Woodbridge TS T5 transformer (discussed in sections 7.1.1). From a cost, loading, station configuration, and customer connection needs perspective, this asset should not be eliminated or have its capacity reduced. The study team recommends that this EOL need be addressed by Hydro One and affected LDCs to coordinate the replacement plan. Hydro One will keep the study team informed of the status of the plan if any major changes occur.

b) As per the IESO's letter of support in April 2017, Alectra and Hydro One will continue to develop a new 230/27.6kV DESN in the Markham-Richmond Hill area (discussed in section 7.2.4). Further updates will be included in the next IRRP and RIP.

c) Further assessment and regional coordination is required in the IRRP and/or RIP, to develop a preferred plan for the following needs:

- Load Restoration – P45+P46 (discussed in Section 7.1.2)
- Load Restoration – V43+V44 (discussed in Section 7.2.1)
- Load Security on V71P/V75P – Parkway to Claireville (discussed in Section 7.2.2)
- Vaughan Transformation Capacity (discussed in Section 7.2.3)
- Station Service Supply to York Energy Centre (discussed in Section 7.2.5)
- Northern York Area Transformation Capacity (discussed in Section 7.2.6)
- Transmission Supply Capacity in Vaughan and Northern York Area in long term (discussed in sections 7.2.3 and 7.2.6)

The table below summarizes the above recommendations.

Table 5: Summary of Recommendations

Further Regional Coordination Not Required	Further Regional Coordination Required
EOL Station Equipment: • Woodbridge TS: T5	**Load Restoration:** • P45+P46 (Buttonville TS, Markham #4 MTS,

Further Regional Coordination Not Required	Further Regional Coordination Required
IESO Letter of Support: • Markham Transformation Capacity (Markham #5 MTS)	and future Markham #5 MTS) • V43+V44 (Woodbridge TS, Vaughan #3 MTS, and Kleinburg TS) **Load Security:** • V71P/V75P (Parkway to Claireville) **Transformation Capacity:** • Vaughan #5 MTS • Northern York Area **Station Service Supply:** • York Energy Centre **Transmission Supply Capacity (long term)** • Vaughan #5 MTS • Northern York Area

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Appendix A: GTA North Region Load Forecast (2017 to 2027)

Stations Net Coincident Peak Load Forecast (MW)

Station Name	LTR*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Kleinburg TS (28kV)	97	55	51	52	52	52	52	52	52	52	52	51
Kleinburg TS (44kV)	99	87	83	83	84	84	84	85	84	84	84	83
Vaughan MTS #3 (28kV)	153	162	124	140	147	147	146	146	145	144	142	147
Woodbridge TS (44kV)	80	45	46	47	47	47	47	47	47	46	46	45
Woodbridge TS (28kV)	80	85	71	70	69	69	69	70	69	68	68	67
Holland TS (44kV)	168	126	123	128	132	136	137	139	140	141	140	141
Armitage TS (44kV)	317	265	262	266	270	274	278	282	285	287	288	291
Brown Hill TS (44kV)	184	49	47	47	48	48	49	50	50	50	50	50
Richmond Hill MTS (28kV)	254	256	232	229	236	244	243	242	249	254	254	254
Vaughan MTS #1 (28kV)	306	302	257	254	253	270	276	291	289	287	284	294
Vaughan MTS #2 (28kV)	153	113	124	131	139	147	146	146	145	144	142	147
Vaughan MTS #4 (28kV)	153	0	44	52	69	78	110	127	145	144	142	147
Vaughan MTS #5 (28kV)**	153	0	0	0	0	0	0	0	0	0	0	0
Buttonville TS (28kV)	166	126	123	136	136	141	141	140	139	138	137	136
Markham MTS #1 (28kV)	81	78	80	79	78	78	78	77	80	81	81	81
Markham MTS #2 (28kV)	101	114	92	98	97	97	96	96	99	101	101	101
Markham MTS #3 (28kV)	202	154	197	196	194	193	193	192	198	202	202	202
Markham MTS #4 (28kV)	153	70	89	91	104	112	129	146	150	153	153	153
Markham MTS #5 (28kV)	153	0	0	0	0	0	0	0	0	26	86	77

* LTR based on 0.9 power factor

** Based on the non-coincident net forecast, the need date for Vaughan MTS #5 is beyond 2027.

Stations Net Non-Coincident Peak Load Forecast (MW)

Station Name	LTR*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Kleinburg TS (28kV)	97	62	59	59	59	59	59	59	59	59	59	58
Kleinburg TS (44kV)	99	87	83	83	84	84	84	85	84	84	84	83
Vaughan MTS #3 (28kV)	153	162	124	140	147	147	146	146	145	144	142	147
Woodbridge TS (44kV)	80	64	66	68	67	67	67	67	66	66	65	65
Woodbridge TS (28kV)	80	92	77	76	75	75	75	76	75	74	74	73
Holland TS (44kV)	168	132	128	134	138	142	144	145	146	147	147	147
Armitage TS (44kV)	317	295	291	296	300	304	309	313	316	318	319	323
Brown Hill TS (44kV)	184	78	75	75	77	77	78	80	80	80	80	80
Richmond Hill MTS (28kV)	254	256	232	229	236	244	243	242	249	254	254	254
Vaughan MTS #1 (28kV)	306	302	257	254	253	270	276	291	289	287	284	294
Vaughan MTS #2 (28kV)	153	113	124	131	139	147	146	146	145	144	142	147
Vaughan MTS #4 (28kV)	153	0	44	52	69	78	110	127	145	144	142	147
Vaughan MTS #5 (28kV)**	153	0	0	0	0	0	0	0	0	0	0	0
Buttonville TS (28kV)	166	135	132	146	146	152	151	151	150	148	147	145
Markham MTS #1 (28kV)	81	78	80	79	78	78	78	77	80	81	81	81
Markham MTS #2 (28kV)	101	114	92	98	97	97	96	96	99	101	101	101
Markham MTS #3 (28kV)	202	154	197	196	194	193	193	192	198	202	202	202
Markham MTS #4 (28kV)	153	70	89	91	104	112	129	146	150	153	153	153
Markham MTS #5 (28kV)	153	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	26	86	77

* LTR based on 0.9 power factor
** Based on the non-coincident net forecast, the need date for Vaughan MTS #5 is beyond 2027.

Appendix B: Acronyms

Acronym	Description
A	Ampere
BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
CIA	Customer Impact Assessment
CGS	Customer Generating Station
CSS	Customer Switching Station
CTS	Customer Transformer Station
DCF	Discounted Cash Flow
DESN	Dual Element Spot Network
DG	Distributed Generation
DSC	Distribution System Code
GATR	Guelph Area Transmission Reinforcement
GS	Generating Station
GTA	Greater Toronto Area
HV	High Voltage
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
LDC	Local Distribution Company
LP	Local Plan
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low Voltage
MTS	Municipal Transformer Station
MW	Megawatt
MVA	Mega Volt-Ampere
MVAR	Mega Volt-Ampere Reactive
NA	Needs Assessment
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.
NUG	Non-Utility Generator
OEB	Ontario Energy Board
OPA	Ontario Power Authority
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Plan
ROW	Right-of-Way
SA	Scoping Assessment
SIA	System Impact Assessment
SPS	Special Protection Scheme
SS	Switching Station
STG	Steam Turbine Generator
TPS	Traction Power Station
TS	Transformer Station
TSC	Transmission System Code
UFLS	Under Frequency Load Shedding
ULTC	Under Load Tap Changer
UVLS	Under Voltage Load Rejection Scheme
YEC	York Energy Centre

YORK REGION
INTEGRATED REGIONAL RESOURCE PLAN

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

ieso
Independent Electricity System Operator

Integrated Regional Resource Plan

York 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 York Region Working Group, which included the following members:

- Independent Electricity System Operator
- Newmarket-Tay Power Distribution Ltd.
- PowerStream Inc.
- Hydro One Networks Inc. (Distribution) and
- Hydro One Networks Inc. (Transmission)

The York Region Working Group assessed the adequacy of electricity supply to customers in the York 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 York Region; and developed an implementation plan for the recommended options, while maintaining flexibility in order to accommodate changes in key assumptions over time.

York Region Working Group members agree with the IRRP's recommendations and support implementation of the plan through the recommended actions. York Region 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
C&S	Codes and Standards
CDM	Conservation and Demand Management
CEP	Community Energy Plan
CHP	Combined Heat and Power
CHPSOP	Combined Heat and Power Standard Offer Program
DG	Distributed Generation
DR	Demand Response
EE	Energy Efficiency
EA	Environmental Assessment
EM&V	Evaluation, Measurement and Verification
EMS	Energy Management Systems
EV	Electric Vehicle
FIT	Feed-in Tariff
GHG	Greenhouse Gas
GS	Generating Station
GTA	Greater Toronto Area
IESO	Independent Electricity System Operator
ICI	Industrial/Commercial/Institutional
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
L/R	Load Rejection
LAC	Local Advisory Committee
LDC	Local Distribution Company
LTEP	(2013) Long-Term Energy Plan
LTR	Limited Time Rating
LMC	Load Meeting Capability
MCOD	Maximum Commercial Operation Date

Abbreviation	Description
MW	Megawatt
MEP	Municipal Energy Plan
MEP/CEP	Municipal or Community Energy Planning
MTO	Ministry of Transportation
MTS	Municipal Transformer Station
NT Power	Newmarket-Tay Power Distribution Ltd.
NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council
OEB or Board	Ontario Energy Board
OPA	Ontario Power Authority
ORTAC	Ontario Resource and Transmission Assessment Criteria
PPS	(Ontario's) Provincial Policy Statement
PPWG	Planning Process Working Group
PV	Photovoltaic
Region	York Region
RIP	Regional Infrastructure Plan
SCGT	Simple-Cycle Gas Turbine
SCC	Solar Capacity Contribution
SPS	Special Protection System
TOU	Time-of-Use
TS	Transformer Station
Working Group	Technical Working Group for York Region IRRP
YEC	York Energy Centre

1. Introduction

This Integrated Regional Resource Plan ("IRRP") addresses the electricity needs of York Region ("York Region" or the "Region") 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, Newmarket-Tay Power, PowerStream, Hydro One Distribution and Hydro One Transmission (the "Working Group").

The Region encompasses the municipalities of Vaughan, Richmond Hill, Markham, Aurora, Newmarket, King, East Gwillimbury, Whitchurch-Stouffville and Georgina, and is one of the fastest growing regions in Ontario. Extensive urbanization in the Region has resulted in electricity demand growth greater than the provincial average. With a current population of over 1 million, York Region's electricity infrastructure currently supplies almost 2,000 megawatts ("MW") of demand. Under the province's "Places to Grow" policy, York Region is expected to host substantial continued population growth in the coming decades. There is therefore a strong need for integrated regional electricity planning to ensure that the electricity system can support the pace of development in the long term.

The area covered by the York Region IRRP is a sub-region of the Greater Toronto Area ("GTA") North Region identified through the Ontario Energy Board ("OEB" or "Board") regional planning process. A second sub-region, located in the southwest corner of the GTA North Region, was defined that contains the Claireville-to-Kleinburg transmission line. As a substantial portion of the customer loads supplied from this transmission line are located in the GTA West Region, the second sub-region is being studied as part of the GTA West Region and is not included in the scope of this IRRP.

This IRRP for York Region identifies and coordinates the many different options to meet customer needs in the Region over the next 20 years. Specifically, this IRRP identifies investments for immediate implementation necessary to meet near-term needs in the Region. This IRRP also identifies a number of options to meet medium- and longer-term needs, but given forecast uncertainty, the longer development lead time and the potential for technological change, the plan maintains flexibility for longer-term options and does not recommend 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 of these actions can inform a decision should one be needed at that time.

This report is organized as follows:

- A summary of the recommended plan for York Region is provided in Section 2;
- The process used to develop the plan is discussed in Section 3;
- The context for electricity planning in York Region and the study scope are discussed in Section 4;
- Demand forecast scenarios, and conservation and distributed generation ("DG") assumptions, are described in Section 5;
- Near, medium, and long-term electricity needs in York Region are presented in Section 6;
- Alternatives and recommendations for meeting near-term needs are addressed in Section 7;
- Options for meeting medium- and 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, and moving forward in developing this IRRP is provided in Section 9; and
- A conclusion is provided in Section 10.

2. The Integrated Regional Resource Plan

The York Region IRRP addresses the Region's electricity needs over the next 20 years, based on the application of the IESO's Ontario Resource and Transmission Assessment Criteria ("ORTAC"). The IRRP identifies needs that are forecast to arise in the near term (0-5 years), medium term (5-10 years) and long term (10-20 years). These planning horizons are distinguished in the IRRP to reflect the different level of commitment required over these time horizons. The plans to address these 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.

For the near term, the IRRP identifies specific investments that need to be immediately implemented or that are already being 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 medium and long term, the IRRP identifies a number of alternatives to meet needs. However, as these needs are forecast to arise 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 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 so that their results can inform a decision at that time.

The needs and recommended actions are summarized below.

2.1 The Near-Term Plan

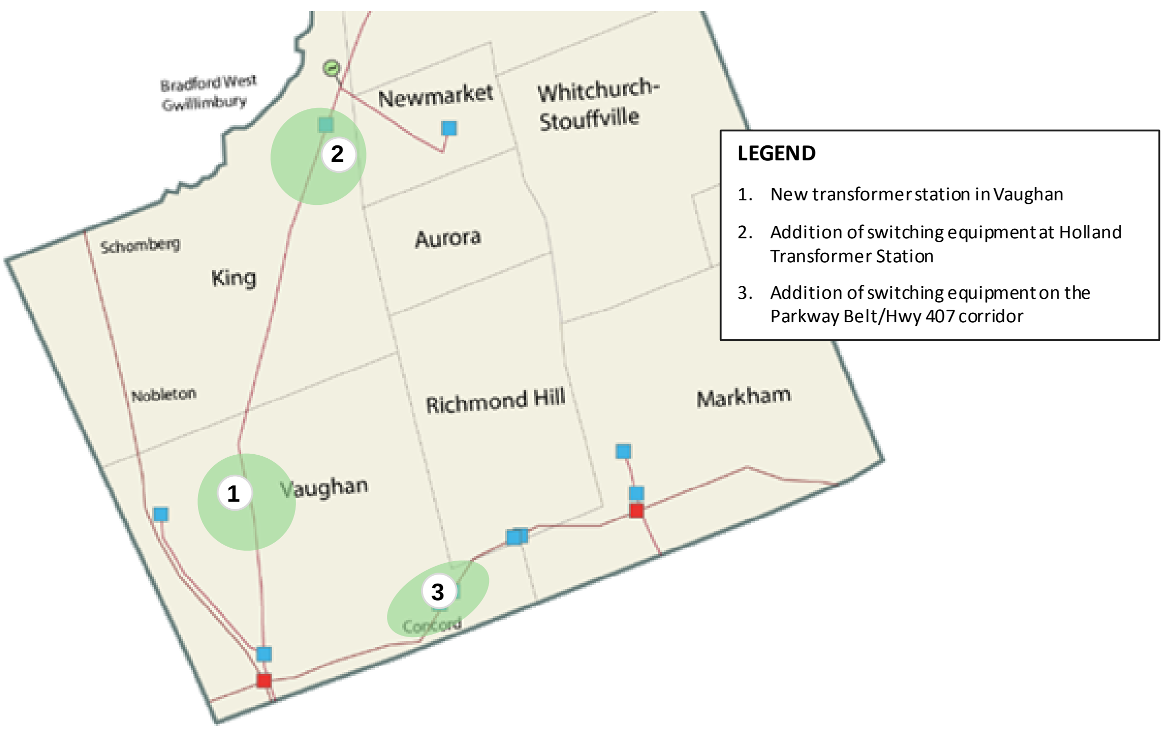
The plan to meet the near-term needs of electricity customers in York Region (see sidebar on the next page) was developed based on consideration of planning criteria, including reliability, cost, feasibility, and maximizing the use of the existing electricity system. The near-term plan was also developed to be consistent with the long-term development of the Region's electricity system.

The first element of the near-term plan is implementation of targeted conservation and DG. To address near-term reliability needs and to supply residual load growth in Vaughan, three transmission projects are also recommended. The development of these "wires" projects is currently underway, in accordance with 2012 and 2013 letters from the former OPA[1] addressed to Hydro One and PowerStream.[2] These transmission projects will also become part of a Regional Infrastructure Planning ("RIP")[3] process to be initiated by Hydro One as an outcome of this IRRP. These projects are described below with their locations indicated in Figure 2-1.

Near-Term Needs

- Meet load security criteria in Northern York Region – **Today**
- Meet load security criteria for stations connected to the Parkway Belt in Richmond Hill and Vaughan – **Today**
- Provide additional transformer station supply capability in Vaughan to meet forecast demand growth – **2017**
- Increase transmission system capability to supply a new station in Vaughan – **2017**

Figure 2-1: Transmission Projects Included in the York Region Near-Term Plan



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

[2] OPA Letter to PowerStream re: Siting Vaughan #4 MTS: http://www.ieso.ca/Documents/Regional-Planning/GTA_North/Vaughan4%20MTS%20Letter%20-2012-12-14.pdf
OPA Letter to Hydro One - York Region: http://www.ieso.ca/Documents/Regional-Planning/GTA_North/OPA-Letter-Hydro-One-York-Subregion.pdf

[3] See Section 3.1 for a description of the IRRP and RIP processes.

Recommended Actions

1. Implement Conservation and Distributed Generation

The implementation of provincial conservation targets established in the 2013 Long-Term Energy Plan ("LTEP") is a key component of the near-term plan for York Region. In developing the demand forecast, peak-demand impacts associated with meeting the provincial targets were assumed before identifying any residual needs; this is consistent with the provincial Conservation First[4] policy. This conservation amounts to approximately 170 MW, or 32% of the forecast demand growth, during the first 10 years of the study.

To ensure that these savings materialize, it is recommended that the local distribution companies ("LDC") conservation efforts be focused as much as possible on measures that will balance the needs for energy savings to meet the Conservation First targets while maximizing peak-demand reductions. Monitoring of conservation success, including evaluation, measurement and verification ("EM&V") of peak demand savings, is an important element of the near-term plan. It will lay the foundation for the long-term plan by evaluating the performance of specific conservation measures in the Region and assessing potential for further conservation.

Provincial programs that encourage the development of DG, such as the Feed-in Tariff ("FIT"), microFIT, and Combined Heat and Power Standard Offer ("CHPSOP") programs, can also contribute to reducing peak demand in the Region; these will, in part, depend 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. Develop New Station in Vaughan

To supply forecast demand growth in Vaughan in the near term, PowerStream is developing a new station, "Vaughan Municipal Transformer Station ("MTS") #4." A class Environmental Assessment ("EA") process is complete and PowerStream is proceeding with the design and construction of the station. Located in northern Vaughan, the station is well situated to supply growth due to urbanization, which is forecast to be concentrated toward the northern boundary of the City of Vaughan. The station will connect to the Claireville-to-Minden transmission line.

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[4] Conservation First: A Renewed Vision for Energy Conservation in Ontario: http://www.energy.gov.on.ca/en/conservation-first/

PowerStream will continue to develop this project toward a targeted completion date of spring 2017.

3. Add Switching Facilities at the Holland Station Site

To enable load security criteria to be substantially met in Northern York Region and to complete the integration of local peaking generation at York Energy Centre ("YEC"), Hydro One is developing switching facilities at the Holland station site. This project has the added benefit of increasing the load meeting capability ("LMC") of the Claireville-to-Minden transmission system and enabling the connection of the new Vaughan #4 MTS (recommendation #2 above) without major new transmission expansion. Hydro One will continue to develop this project toward a targeted completion date of spring 2017.

4. Install In-Line Circuit Switchers on Parkway 230 kV Transmission Line

To enable load security criteria to be substantially met for five stations in Richmond Hill and Vaughan supplying 700 MW of customer demand during peak conditions, Hydro One will develop switching facilities along the Parkway Belt (Highway 407) transmission corridor. This project may also involve enhancements to PowerStream's distribution system to facilitate load transfers between stations once the switching facilities are in place. Hydro One will develop this project toward a completion date of spring 2018.

2.2 The Medium- and Long-Term Plan

In the medium and long term, York Region's electricity system is expected to reach its capacity to supply growth. This is based on forecast projections consistent with municipal growth plans and the province's *Places to Grow Act, 2005*. Beginning in the early to mid 2020s, if actual demand growth is as forecast, there will be a need for major new supply in the Region (see sidebar).

The capacity of the Region's transformer stations ("TS") is expected to be exceeded in the early to mid-2020s. With continued demand growth, the transmission system supplying these stations is also expected to reach its limits by the end of that decade. Planning to address the station capacity needs must be coordinated with the plan to address the long-term transmission system needs, as they are interrelated.

A number of alternatives are possible to meet the Region's long-term needs. While specific solutions do not need to be committed today, it is appropriate to begin work now to gather information, monitor developments, engage the community, and develop alternatives, to support decision-making in the next iteration of the IRRP. This IRRP sets out near-term actions required to ensure that options remain available to address future needs if and when they arise.

Medium- and Long-Term Needs

Based on current planning forecasts, and considering the system reinforcements included in the near-term plan, the capability to supply continued electricity demand growth in the following three areas will be exceeded in the long term:

	Transformer station capability exceeded	Transmission system supply capability exceeded*
Markham	2021-2022	2027-2028 (Parkway-to-Buttonville)
Northern York Region	2023-2024	2029-2030 (Claireville-to-Minden)
Vaughan	2023-2024	

* Needs may arise sooner, depending on location of new stations

Recommended Actions

1. Undertake Community Engagement

Broad community and public engagement, including with local First Nation communities, is essential to development of the long-term plan. It is recommended that engagement involve several phases addressing: public education/awareness of electricity issues, planning, technologies and regulatory requirements; fostering understanding of community growth and its relationship to electricity needs; understanding the pros and cons of various alternatives to meeting long-term needs; and obtaining input on community preferences for various approaches to meeting needs.

To provide input and advice on engagement plans for York Region, the Working Group will establish a Local Advisory Committee ("LAC") consisting of community representatives and stakeholders.

The LDCs will lead engagement activities in their communities, with support from the IESO, beginning in mid-2015 and extending over the next 2-3 years as necessary.

2. Develop Community-Based Solutions

There is the potential for emerging technologies and innovative solutions to address the medium- and long-term needs in York Region. These could include combinations of conservation, district heating, local generation, storage, off-grid solutions, and other emerging technologies. However, before such options can be relied upon to address regional capacity needs, it is necessary to identify potential opportunities in the Region, to test the performance of emerging technologies, and to demonstrate how combinations of community-based solutions can be integrated, or "bundled," to provide firm capacity resources at a local level. In addition, cost responsibility and payment mechanisms for solutions that are more costly than traditional supply options will need to be assessed. PowerStream and Newmarket-Tay Power will implement pilot projects to test a variety of innovative solutions in the next 2-3 years (see Section 8.1.3 for examples). The results of these pilots will be an important input to the medium/long-term plan for York Region and will be considered in the next iteration of the York Region IRRP.

3. Continue Ongoing Work to Establish Joint-use Transmission/Transportation Corridor through Peel, Halton Hills, and Northern Vaughan

The Ministry of Transportation ("MTO") recently began Phase 2 of an EA process to establish a new 400-series highway corridor running from the Highway 401/407 junction near Milton to Highway 400 in northern Vaughan. The IESO and Hydro One have been working with MTO and municipal government staff to establish a future transmission corridor in the general vicinity of this highway, consistent with direction on coordinated and efficient use of land, resources, infrastructure and public service facilities in Ontario communities, outlined in the Provincial Policy Statement ("PPS").

In addition, the transmission corridor would be well situated to provide long-term supply capacity for northern Halton, northern Peel, and York Region in the long term, and also enhance the capability of the West GTA Region bulk supply system.

To ensure the viability of this option, the IESO will continue to work with Hydro One and relevant municipal, regional and provincial entities to plan this long-term strategic asset.

4. Monitor Demand Growth, Conservation Achievement and Distributed Generation Uptake

On an annual basis, the IESO, with the Working Group, will review conservation and demand management ("CDM") achievement, the uptake of provincial distributed generation projects, and actual demand growth in York Region. This information will be used to track the expected timing of long-term needs to determine when decisions on the long-term plan are required. Information on conservation and DG performance will also provide useful input into the ongoing development of these options as potential long-term solutions.

5. Initiate the Next Regional Planning Cycle Early, if Needed

Based on current forecasts and CDM assumptions, and considering the lead time necessary to develop options for meeting needs, it is anticipated that the next medium- and long-term supply plan for York Region may need to be developed by 2018. If so, it will be necessary to initiate the next iteration of the regional planning process for York Region as early as 2017. However, if monitoring activities indicate that actual net load growth has slowed to the extent that planning decisions can be deferred, then the next cycle can be started later, possibly up to the usual 5-year IRRP review timeframe.

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 communities and 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 of regional planning 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 became responsibilities of the new IESO.

The regional planning process begins with a Needs Assessment process performed by the transmitter, which determines whether there are electricity needs requiring regional coordination. If regional planning is required, the IESO then conducts a Scoping Assessment process to determine whether a comprehensive IRRP is required, which considers conservation, generation, transmission, and distribution solutions, or whether a straightforward "wires" solution is the only option. If the latter applies, then a transmission and distribution focused Regional Infrastructure Plan is required. 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 Scoping Assessment 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 is required to complete the plan within six months. 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, conservation opportunities, and infrastructure requirements.

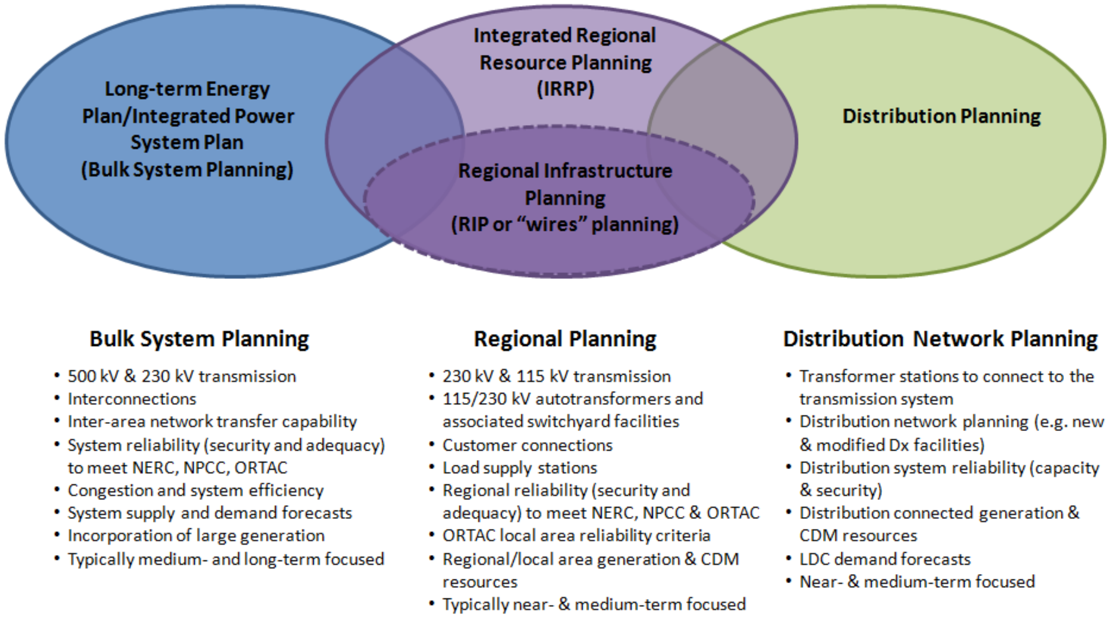
Regional planning, as shown in Figure 3-1, is just one form of electricity planning that is undertaken in Ontario. There are three types of electricity planning in Ontario:

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

Planning at the bulk system level typically considers the 230 kilovolt ("kV") and 500 kV transmission network. Bulk system planning considers the major transmission facilities and assesses the resources needed to adequately supply the province. Bulk system planning is carried out by the IESO. Distribution planning, which is carried out by LDCs, 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.

Figure 3-1: Levels of Electricity 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.

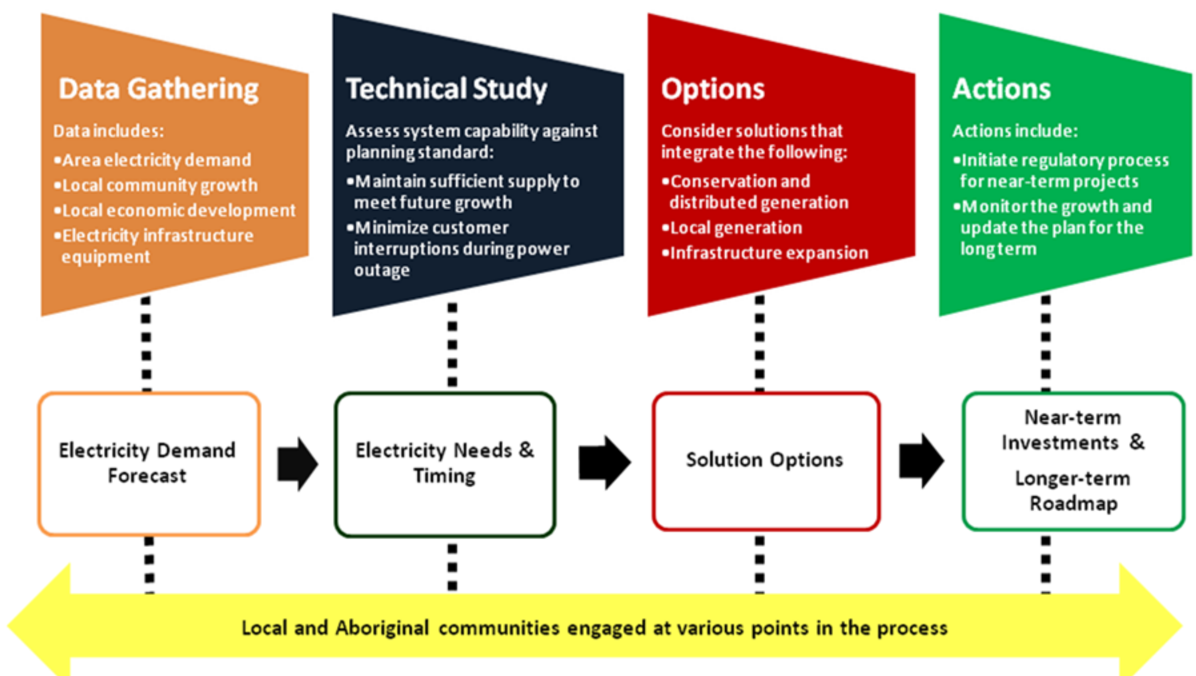
3.2 The IESO's Approach to Regional Planning

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 the 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 area. The steps of an IRRP are illustrated in Figure 3-2 below.

Figure 3-2: Steps in the IRRP Process



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.

3.3 York Region Working Group and IRRP Development

The York Region IRRP process was commenced by the former OPA in 2011 in response to a request by PowerStream. At the time, PowerStream forecast that significant demand growth in its Southern York Region service would exceed the area's supply infrastructure and proposed that a joint integrated planning study be commenced that would also update a 2005 study that had been completed in Northern York Region (see Section 4.2). The OPA agreed that a coordinated, integrated approach was appropriate, and led the establishment of a technical Working Group ("the Working Group") consisting of representatives from the OPA, the IESO, PowerStream, Newmarket-Tay Power, Hydro One Distribution, and Hydro One Transmission. The OPA also developed Terms of Reference for the study.[5] The Working Group gathered data, identified near-, medium- and long-term needs in the Region, and recommended the near-term solutions included in this IRRP. Implementation began in 2012/2013 with the OPA issuing letters supporting the near-term projects so that they could be commenced immediately in order to be in-service in time to address imminent needs.[6]

This York Region IRRP is therefore a transitional IRRP in that it began prior to the development of the OEB's regional planning process and much of the work was completed before the new process and its requirements were known. When the regional planning process was formalized by the OEB in 2013, the Working Group revised the Terms of Reference to reflect the new process and updated the study information, including demand forecasts, and conservation and distributed generation data.[7] With this updated information, the Working Group reconfirmed

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[5] Original Terms of Reference:
http://www.ieso.ca/Documents/Regional-Planning/GTA_North/York-Terms-of-Reference.pdf
[6] OPA letter to Hydro One:
http://www.ieso.ca/Documents/Regional-Planning/GTA_North/OPA-Letter-Hydro-One-York-Subregion.pdf
OPA letter to PowerStream:
http://www.ieso.ca/Documents/Regional-Planning/GTA_North/Vaughan4%20MTS%20Letter%20-2012-12-14.pdf
[7] Revised August 2014 Terms of Reference:
http://www.ieso.ca/Documents/Regional-Planning/GTA_North/York-TOR-Addendum.pdf

the near-term needs revised the near-term plan and developed recommendations for the medium- and long-term plan. This IRRP reflects this revised and updated information.

4. Background and Study Scope

This report presents an integrated regional electricity plan for York Region for the 20-year period from 2014 to 2033. The planning process leading to this IRRP began in 2011, in recognition of the need for continued planning updates following the implementation of a 2005 integrated regional electricity plan for Northern York Region, and additional developments in the Region. These developments include the economic downturn of 2008/2009 and subsequent demand recovery, the adoption of widespread provincial DG programs such as FIT and microFIT, and demand growth in Southern York Region that was expected to exceed the existing infrastructure capability.

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, and the recommendations and implementation of the 2005 Northern York Region plan are summarized in Section 4.2.

4.1 Study Scope

The scope of this plan roughly corresponds to the Regional Municipality of York,[8] which is located in the northern GTA. The electricity infrastructure supplying this area is shown in Figure 4-1. Customers in York Region are supplied from transformer stations connected to a 230 kV transmission network that is supplied primarily from three major 500/230 kV transformer stations: Claireville, Parkway, and Cherrywood. In addition, York Energy Centre, a peaking resource consisting of two 180 MW simple cycle gas generation units, provides a local supply source in Northern York Region.

For the purposes of electricity planning, York Region can be considered two sub-systems: Northern York Region and Southern York Region (see Figure 4-1).

Northern York Region includes the municipalities of Aurora, Newmarket, King, East Gwillimbury, Whitchurch-Stouffville and Georgina, and the Chippewas of Georgina Island First Nation. Retail electricity customers in this area are served by PowerStream, Newmarket-

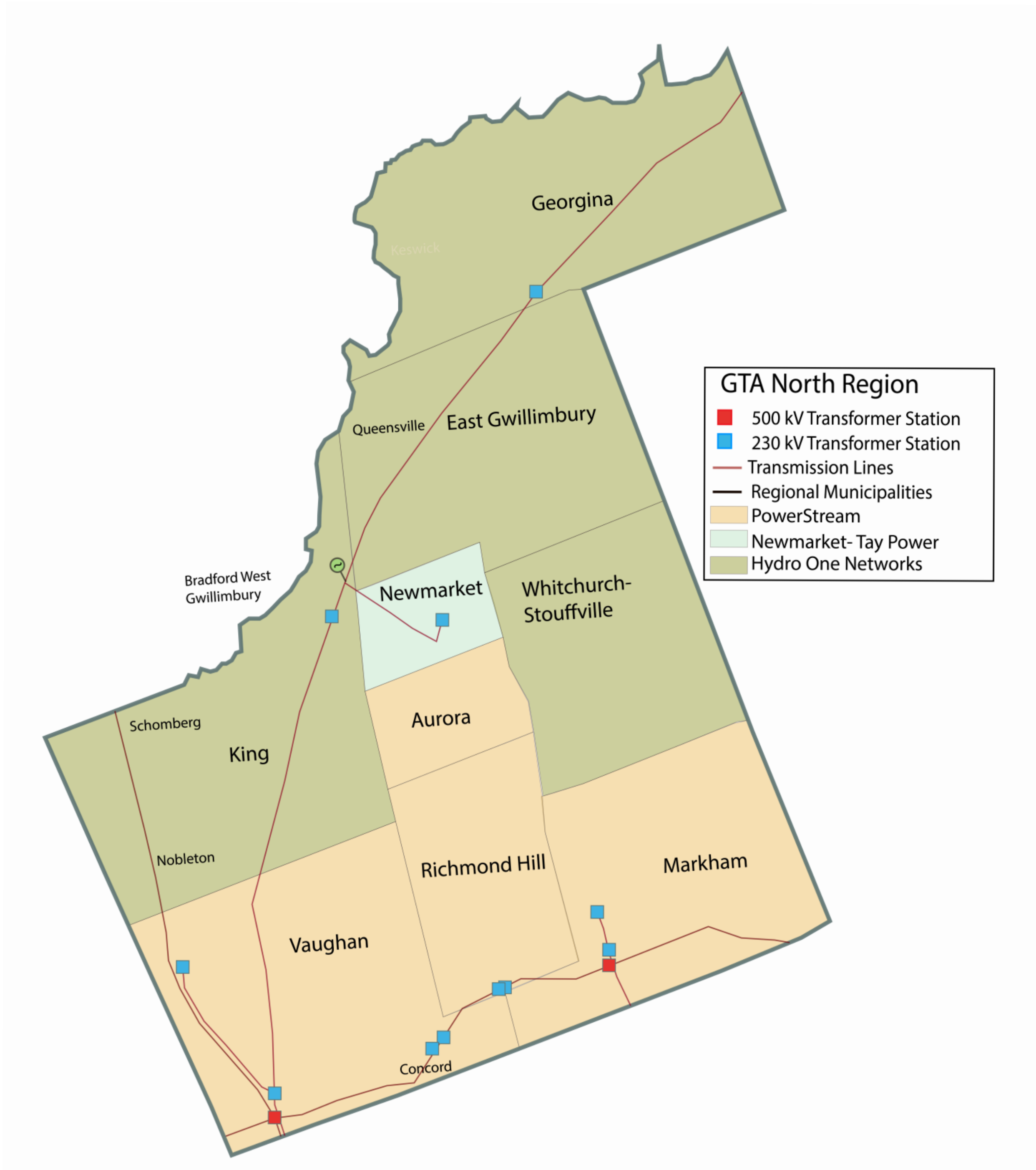
[8] For the purposes of this report, the term "York Region" refers to the electricity supply area that is the subject of this plan. This area roughly corresponds to the Regional Municipality of York boundaries, however as the electricity system was not developed along municipal boundaries there are some exceptions. As a result, customers in some areas near the boundaries of York Region are supplied from infrastructure outside the scope of this study (e.g., parts of Georgina are supplied from infrastructure further north), and some customers in Durham and Simcoe Regions are supplied from the York Region infrastructure. In addition, the Claireville-to-Kleinburg line is being studied as part of the GTA West Region and is thus not included in this IRRP.

Tay Power and Hydro One Distribution (see Figure 4-2). Transmission supply is from three transformer stations—Armitage, Holland and Brown Hill—that are connected to two 230 kV circuits, B82/83V, which originate at the Claireville station and extend northward towards Minden. These stations also supply some load that is outside the municipal boundary of York Region (e.g., the Holland station serves loads in the southeastern part of Simcoe County).

Figure 4-1: York Region Electricity Infrastructure

Southern York Region, which includes the municipalities of Vaughan, Richmond Hill, and Markham, is served at the distribution level by PowerStream through feeders supplied primarily from several transformer stations connected to 230 kV transmission lines that follow the Highway 407 corridor, known as the "Parkway Belt". In addition, some load is supplied from transformer stations along the Richview-Cherrywood 230 kV corridor further south. These stations are shared with other LDCs serving other parts of the GTA and are not part of the scope of this study.

Figure 4-2: Local Distribution Companies Supplying Customers in York Region

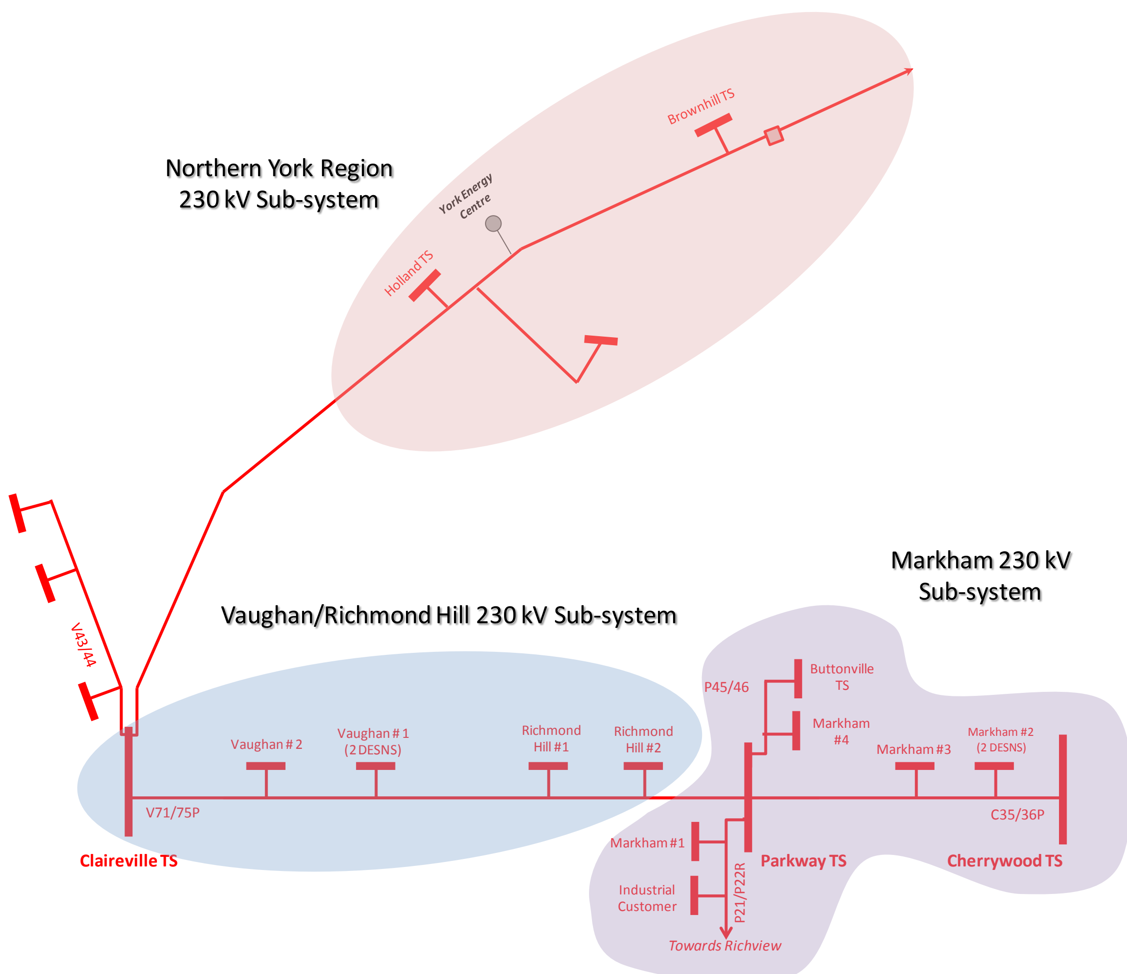


Although it is located within York Region, the Claireville-to-Kleinburg line is not included in the York Region IRRP study scope. This radial transmission line is being studied as part of the GTA West Region, as a substantial portion of the customer loads supplied from this line are located in that region. The Vaughan #3, Woodbridge and Kleinburg stations, which are connected to this line, are similarly not in scope for this IRRP.

To facilitate identification of transmission system needs based on system configuration, Southern York Region was further sub-divided in this study into two areas of focus: Vaughan/Richmond Hill and Markham. The specific electricity infrastructure supplying the resulting three sub-areas—Northern York Region, Vaughan/Richmond Hill, and Markham—are indicated in Figure 4-3.

To assess station capacity, slightly different sub-areas were defined that reflect the capability of the distribution system to transfer between stations (see Appendix B.1).

Figure 4-3: York Region Sub-Areas



* The figure is not drawn to scale

4.2 2005 Northern York Region Electricity Planning Study

In 2005, in response to a letter of direction from the OEB, the OPA led the development of an integrated planning study for Northern York Region.[9] At the time, the electricity supply infrastructure to this area had reached its limits and there was an urgent need to address customer reliability resulting from strong demand growth in Northern York Region. The planning study considered transmission, distribution, generation, and conservation solutions, and was developed with input from local stakeholders.

The resulting 2005 Northern York Region plan recommended six actions. The recommendations and their implementation status are summarized in Table 4-1.

Table 4-1: 2005 Northern York Region Integrated Plan Recommendations

Recommended Action	Implementation Status
1. Add capacitors at the Armitage TS	Completed
2. Install temporary emergency load transfer capability	Completed
3. Contract conservation resources	20 MW demand response procured (5-year term); provincial conservation efforts (ongoing)
4. Construct new Holland TS	In-service June 2009
5. Procure gas-fired generation	York Energy Centre in-service spring 2012; 230 kV switching not yet implemented
6. Plan a fourth TS to supply continued demand growth	Not yet implemented; has not been needed to date

These actions, with the exceptions noted in Table 4-1, have provided an adequate and reliable supply of electricity to Northern York Region for the last decade. The addition of a fourth TS, originally forecast to be needed in 2012, has not yet been required due to slower demand growth in Northern York Region.

A final step in the integration of YEC is the addition of 230 kV switching facilities. This action was not completed at the time YEC was developed as it was necessary to delay the facilities' design and location until the final connection details for YEC were known. When the current

[9] http://www.powerauthority.on.ca/integrated-power-system-plan/york-Region-final-recommendation-september-2005

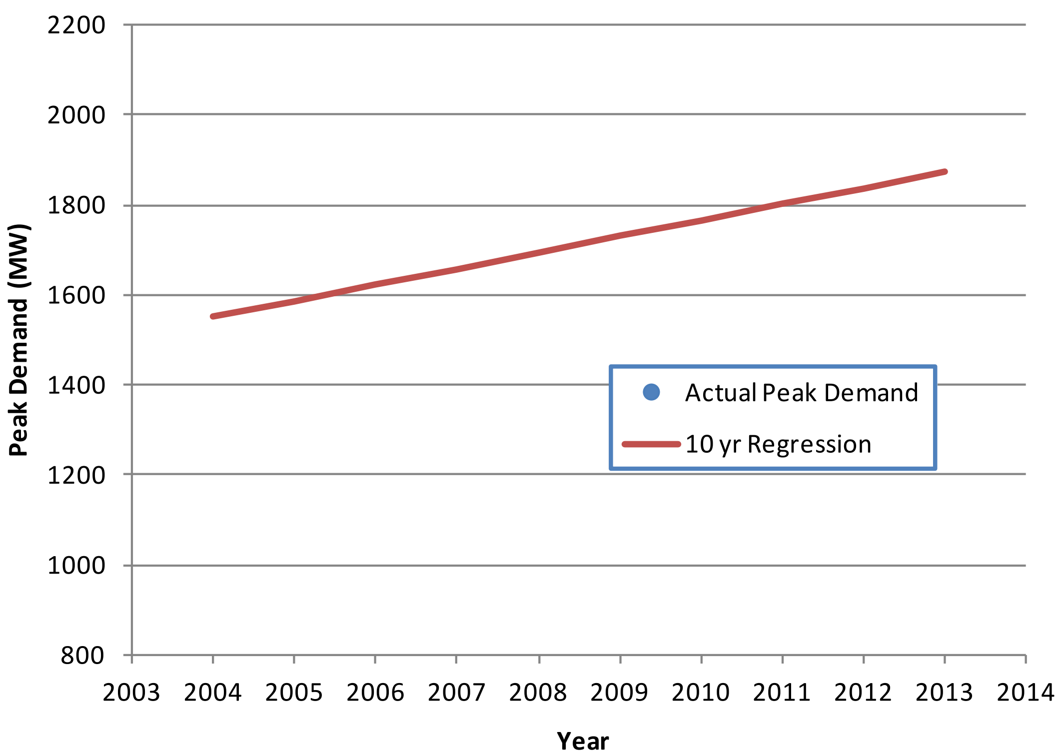
IRRP was initiated in 2011, the Working Group agreed to consider this requirement within the context and scope of the broader regional needs identified through the IRRP process.

5. Demand Forecast

5.1 Historical Demand

Over the past 10 years, York Region has experienced strong growth in electricity demand. Figure 5-1 shows the historical summer peak demand observed in the Region from 2004 to 2013. A noticeable peak in 2006 is coincident with the all-time peak in Ontario power demand, while a decline in demand in 2008 and 2009 shows the area's response to the global recession and cooler than average summer temperatures. By 2011, demand in the area exceeded pre-recession levels as a result of continued growth in the Region, and hotter than average temperatures. Over this period, electricity demand in York Region grew on average by 2.1% per year, adding over 320 MW of new electricity demand growth in 10 years.

Figure 5-1: Historical Electricity Demand in York Region



As discussed in Section 4.1, York Region can be viewed as three distinct sub-areas to facilitate understanding of load growth and system constraints that drive needs in the Region: Vaughan/ Richmond Hill, Markham, and Northern York Region. Over the past eight years, each region has experienced similar load trends, characterized by steady growth to 2006, a noticeable dip in 2008 and 2009, and a return to pre-recession load levels by 2010. In terms of overall demand, Vaughan/Richmond Hill experienced the largest increase, adding approximately 170 MW since 2004, producing an average annual growth rate of 2.4% per year. This is equivalent to the amount of load supplied by a typical transformer station. Over the same time period, Markham and Northern York Region added approximately 80 MW and 75 MW of peak demand, reflecting average annual growth rates of 1.8% and 2.0%, respectively.

The areas with the highest growth in demand were the four regional Centres: Vaughan Metropolitan Centre, Richmond Hill/Langstaff Gateway Centre, Markham Centre, and Newmarket Centre.[10] At the same time, land re-zoning and associated new development have pushed the urban boundaries of Vaughan, Richmond Hill, and Markham increasingly northward.

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. Therefore, 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 and provincial energy adequacy is planned through a separate process.

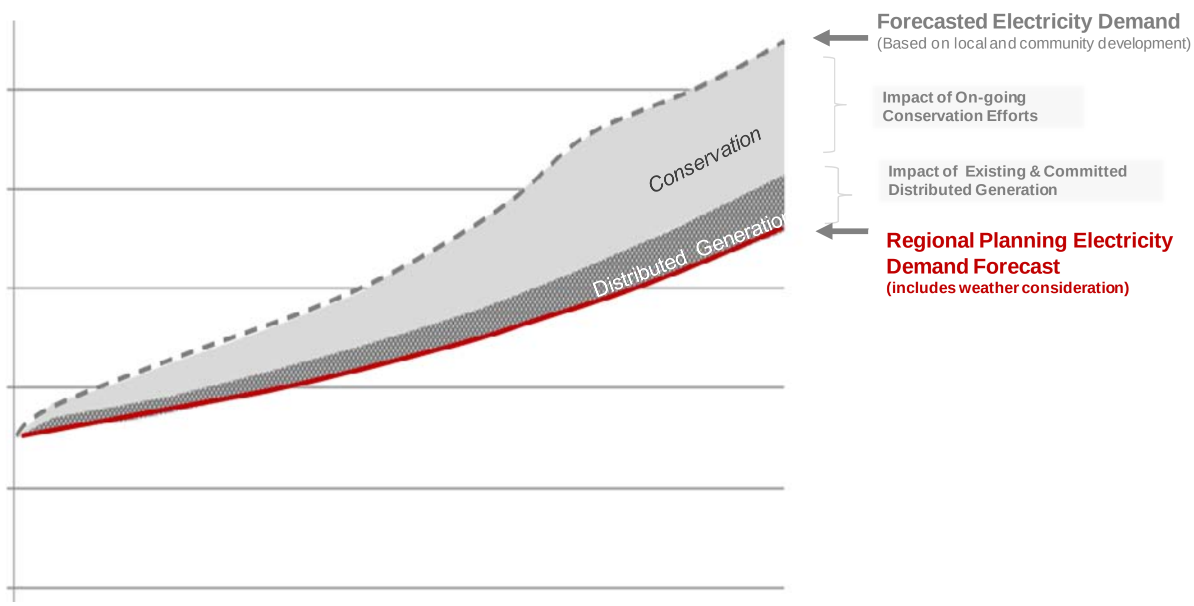
For the near and medium term, from 2014 to 2023, a regional peak demand forecast was developed as shown in Figure 5-2. Gross demand forecasts, assuming normal-year weather conditions, were provided by the LDCs. The LDCs' forecasts are based on growth projections included in regional and municipal plans, which in turn reflect the province's Places to Grow policy. These forecasts were then modified to produce a planning forecast — i.e., they were adjusted to reflect the peak demand impacts of provincial conservation targets and DG contracted through provincial programs such as FIT and microFIT and to reflect extreme

[10] York Region, Vision 2051 http://www.york.ca/wps/wcm/connect/yorkpublic/a6d9d1ce-0813-4376-a593-daccf2b7fd6e/vision+2051.pdf?MOD=AJPERES

weather conditions. The planning forecast was then used to assess any growth-related electricity needs in the Region.

Using a planning forecast that is net of provincial conservation targets is consistent with the province's Conservation First policy. However, this assumes that the targets will be met and that the targets, which are energy-based, will produce the expected local peak demand impacts. An important aspect of plan implementation will be monitoring the actual peak demand impacts of conservation programs delivered by the local LDCs and, as necessary, adapting the plan.

Figure 5-2: Development of Demand Forecasts



For the long-term outlook, from 2024 to 2033, two demand forecast scenarios were developed to reflect the greater uncertainty associated with forecasting this far into the future.

A higher-growth scenario was developed to reflect continued development in York Region consistent with the projections associated with the province's Places to Grow policy. This forecast scenario is also consistent with the growth assumptions associated with the long-term municipal plan projections. As with the near-term forecast, the provincial conservation targets up to 2033 are deducted from the gross demand projections to produce a planning forecast net of conservation.

A lower-growth scenario was developed consistent with the growth assumptions embodied in the government's LTEP. The low-growth scenario represents a future with lower electricity demand growth, due to higher electricity prices, increased electricity conservation, and lower energy intensity of the economy.

Additional details related to the development of the demand forecasts are provided in Appendix A.

5.3 Gross Demand Forecast

For the purposes of this study, each of the three LDCs serving the York Region study area prepared a summer peak demand forecast over the 20-year planning horizon. Information on known developments expected to contribute to demand growth in each service territory was included in the near-term portion of the forecast, while general trends expected for future growth were used for the later years. These gross demand forecasts were developed under coincident, median-weather assumptions, and then adjusted to extreme weather conditions by the IESO.

Overall, strong growth is expected to continue throughout York Region. Based on the LDCs' gross demand forecasts, the entire study area is expected to grow by over 1,000 MW of peak demand over the next 20 years, with an average annual growth rate of 2.5%, not including the impacts of conservation or DG. On a sub-area basis, Vaughan/Richmond Hill and Markham are expected to see the most growth with 397 MW and 422 MW of gross demand growth forecast between 2014 and 2033, reflecting average annual growth rates of 2.1% and 3.1%, respectively. Northern York Region is expected to add 264 MW, growing at approximately 2.3% per year.

The continued high growth shown in these forecasts are consistent with the *Places to Grow Growth Plan for the Greater Golden Horseshoe* (2013 consolidation),[11] which projects an additional 557,000 people living in York Region in 2031 compared to 2011. This represents an average annual population increase of 2.2%, per year, though population growth cannot be directly correlated to growth in electricity demand. Other factors, such as the presence of new or intensified commercial areas, and saturation of high-energy-consuming end uses such as air conditioning, substantially contribute to demand for electricity during peak summer hours.

[11] https://www.placestogrow.ca/index.php?option=com_content&task=view&id=359&Itemid=12

York Region's Vision document projects that the growing population will largely drive development in the Region's urban areas, including the four regional centres of Vaughan, Richmond Hill/Langstaff Gateway, Markham and Newmarket, as well as the regional corridors of Yonge Street, Highway 7, and portions of Davis Drive and Green Lane.

While LDC information is considered the most reliable for producing location-specific near-term forecasts, longer-term forecasts carry greater uncertainty. In order to test a range of potential outcomes for the long term, the IESO produced a regional forecast scenario based on provincial growth factors and related planning initiatives, including the conservation targets described in the 2013 LTEP, (see Conservation Section 5.4, below as an alternate scenario). This forecast scenario projects growth rates on a regional, rather than station basis. These growth rates were applied across the study area beginning in 2023 to produce an alternate long-term forecast.

The gross demand forecasts for each station are provided in Appendix A.1.4.

5.4 Conservation Assumed in the Forecast

Conservation plays a key role in maximizing the useful life of existing infrastructure and maintaining reliable supply. Conservation is achieved through a mix of program-related activities including behavioral changes by customers and mandated efficiencies from building codes and equipment standards. These approaches complement each other to maximize conservation results. The conservation savings forecast for York Region have been applied to the gross peak demand forecast, along with DG resources, to determine the net peak demand for the Region.

In December 2013 the Ministry of Energy released a revised LTEP, which outlined a provincial conservation target of 30 TWh of energy savings by 2032. In order to represent the effect of these targets within regional planning, the IESO developed an annual forecast for peak demand savings based on the provincial energy savings target, which it 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 York Region. The resulting conservation assumed in the high-growth scenario is shown in Table 5-1. The above conservation forecast methodology was not applied in developing the low-growth forecast scenario. This is because the low-growth scenario already accounts for the anticipated impact of the 2032 conservation targets in its overall growth rate assumptions. Additional conservation forecast details are provided in Appendix A.2.

Table 5-1: Peak Demand Savings from 2013 LTEP Conservation Targets in York Region

Year	2015	2017	2019	2021	2023	2025	2027	2029	2031	2033
Savings (MW)	26	43	87	133	171	217	264	312	363	396

It is assumed that existing demand response ("DR") resources already accounted for in the base year will continue. Savings from potential future DR resources are not included in the forecast and are instead considered as possible solutions to identified needs.

5.5 Distributed Generation Assumed in the Forecast

In addition to conservation resources, DG in York Region is also anticipated to offset peak demand requirements. The introduction of the *Green Energy and Green Economy Act, 2009*, and the associated development of Ontario's FIT program, has increased the significance of distributed renewable generation in Ontario. This generation, while intermittent in nature, contributes to meeting the electricity demands of the province.

In developing the planning forecast, the effects of DG contracted but not yet in service in the Region as of February 2014, the latest information available when the forecast was developed, were included. The effects of projects that were already in-service by 2013 were not included as they are already embedded in the actual demand which is the starting point for the forecast. Future DG uptake was not included and is instead considered as an option for meeting identified needs.

Province-wide, as of February 2014, the date when the forecast assumptions were developed, the FIT program had contracted over 4,500 MW of new renewable generation. Within the York Region study area, a total of 70 MW of FIT applications had active contracts as of February 2014, all from solar photovoltaic ("PV") technologies. The installed capacity of these generation resources were adjusted to the expected solar output at the time of summer peak, which amounts to 34% of the total installed capacity. This is based on the solar capacity contribution values obtained from the IESO's 2014 Methodology to Perform Long Term Assessments.[12]

Each project's capacity contribution was subtracted from the peak demand at the TS to which it was connected, beginning in the project's anticipated in-service year. Additionally, only contracted projects which were not yet in service during the base year were accounted for in forecasts. This was done since LDCs relied on observed peak to build their forecasts, and actual demand would have already been affected by any in service DG projects.

In addition to renewable energy projects contracted through the FIT program, over 5 MW of Combined Heat and Power ("CHP") projects were accounted for in the forecast, as acquired through the OPA CHPSOP program. These projects were assumed to have a 100% capacity factor. Keele Valley Generating Station ("GS"), a landfill gas generation facility in York Region, was not included in the forecast as its fuel supply is diminishing. Moreover, as it is an existing distributed generation facility, its contribution to peak demand is embedded in actual demand data.

Additional details of the regional demand reductions from province-wide DG programs are provided in Appendix A.3.

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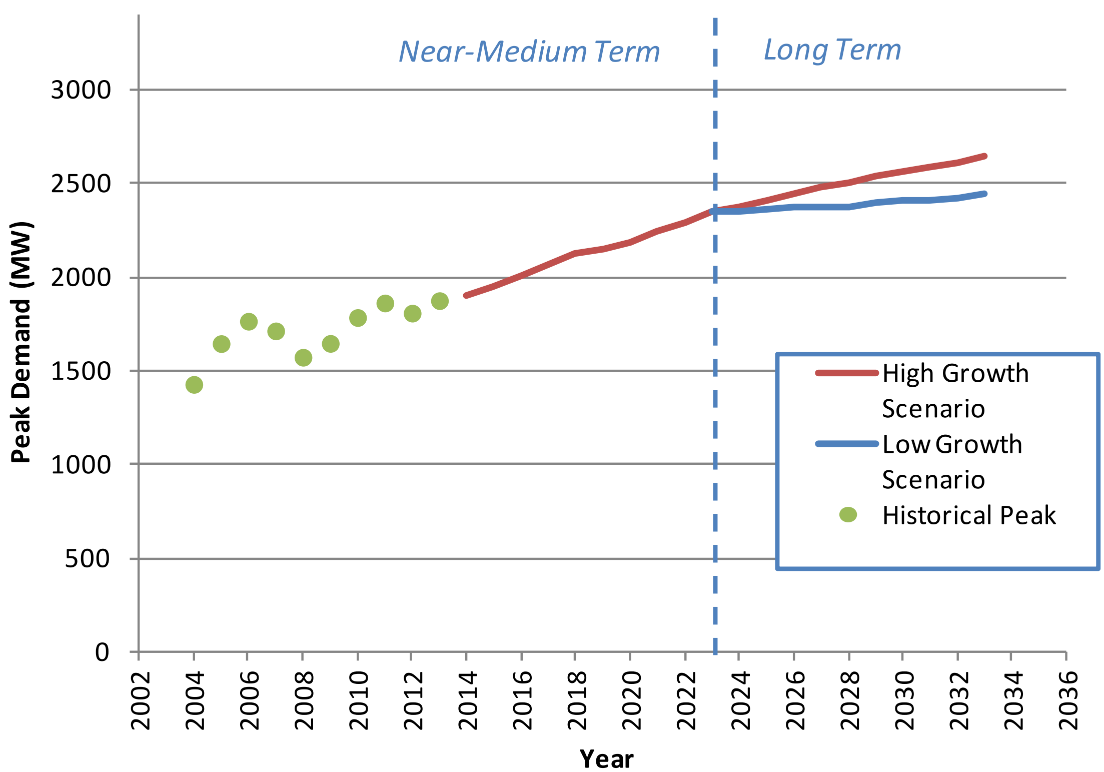
[12] See http://www.ieso.ca/Documents/marketReports/Methodology_RTAA_2014feb.pdf , page 16.

5.6 Planning Forecasts

After taking into consideration the combined impacts of conservation and DG, a 20-year planning forecast was produced based on the LDCs' demand forecasts which includes both a high-growth forecast which takes into consideration the Places to Grow growth plan, and a second low-growth net demand forecast considers the provincial LTEP. The final forecasts were also adjusted to account for typical station loading and operational practice, as defined by PowerStream.

Figure 5-3 shows the high-growth and low-growth forecast scenarios, along with historic demand in the area.

Figure 5-3: York Region Planning Forecast



The high-growth forecast assumes a total of 396 MW of new savings from conservation targets across York Region over the next 20 years. Combined with the effects of DG and existing conservation programs, the high-growth forecast assumes 40% of anticipated load growth is met through these measures, reducing the average annual growth rate from 2.5% to 1.8%.

Under the low-growth scenario, which includes conservation impacts in its underlying growth assumptions, the longer-term net growth rate averages 0.4% per year from 2024 to 2033.

Further details of the planning forecast scenarios are provided in Appendix A.4.

6. Needs

Based on the demand forecasts, system capability, and application of provincial planning criteria, the York Region Working Group identified electricity needs in the near, medium and long term. This section describes the identified needs for these three time horizons in York Region.

6.1 Need Assessment Methodology

Provincial planning criteria were applied to assess the capability of the existing electricity system to supply forecast electricity demand growth in York Region over the next 20 years. These criteria are discussed in Section 6.1.1 below. The practical application of these criteria to identify three broad categories of needs was conducted as follows:

- Step-down station capacity needs were identified by comparing forecast demand growth in three sub-areas (Northern York Region, Vaughan/Richmond Hill, and Markham) to the 10-day Limited Time Rating ("LTR"), or thermal capacity, of the existing stations in the area, to determine the net incremental requirement for transformation capacity in each sub-area. This was done at the sub-area rather than the TS level in recognition of the capability of the distribution system to transfer loads among nearby stations. The three sub-areas were defined to reflect this capability (see Appendix B.1).
- Supply capacity requirements were assessed using PSS/E, a power flow simulation tool, to analyze the capability of the existing system, including transmission and local generation infrastructure, to supply load growth. Technical system assumptions used in the power flow studies are detailed in Appendix B.2.
- Provincial criteria were applied to identify areas with a need to address the impacts of potential major supply interruptions. The amount of customer load supplied from specific circuits before and after potential major outages, and the capability to restore interrupted loads following a major outage, either through transmission system switching or transfers on the distribution system, were assessed in accordance with these criteria.

6.1.1 Ontario Resource and Transmission Assessment Criteria

The IESO's ORTAC,[13] the provincial standard for assessing the reliability of the transmission system, was applied to assess supply capacity and reliability needs.

ORTAC includes criteria related to assessment of the bulk transmission system, as well as the assessment of local or regional reliability requirements. The latter criteria are of relevance to this study and guided the technical studies performed in assessing the electricity system needs in York Region. They can be broadly categorized as addressing two distinct aspects of reliability: (1) providing supply capacity, and (2) limiting the impact of supply interruptions.

With respect to supply capability, ORTAC specifies that the transmission system must be able to provide continuous supply to a local area under specific transmission and generation outage scenarios. The performance of the system in meeting these conditions is used to determine the load meeting capability (LMC) of an area for the purpose of regional planning. The LMC is the maximum load that can be supplied in the local area with no interruptions in supply or, under certain permissible conditions, with limited controlled interruptions as specified by ORTAC. Further details of the application of these criteria to the York Region electricity system are provided in Appendix B.3.1.

With respect to supply interruptions, ORTAC requires that the transmission system be designed to minimize the impact to customers of major outages, such as a contingency on a double-circuit tower line resulting in the loss of both circuits, in two ways: by limiting the amount of customer load affected; and by restoring power to affected load within a reasonable timeframe. Specifically, ORTAC requires that no more than 600 MW of load be interrupted in the event of a major outage involving two elements. Further, load lost during a major outage is to be restored within the following timeframes:

- All load lost in excess of 250 MW must be restored within 30 minutes;
- All load lost in excess of 150 MW must be restored within four hours; and
- All load lost must be restored within eight hours.

For the load loss and restoration criteria, ORTAC includes provisions whereby a request for exemption may be made to the IESO.

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

6.2 Near-Term Needs

Several needs have been identified that either exist today, or are forecast to arise within the next five years in York Region. The near-term needs are concentrated in two distinct geographical areas. In Northern York Region and Vaughan, separate capacity and reliability needs have been considered together by the Working Group as it was recognized that they can be addressed through common solutions involving improvements to the 230 kV system running north from Claireville toward Minden. Other needs related to the system configuration of the Parkway Belt, which supplies customer loads in Richmond Hill and Vaughan, are addressed separately. The discussion of near-term needs that follows thus deals with these two areas distinctly.

6.2.1 Claireville-to-Minden System Near-Term Needs

The near-term needs arising in Vaughan and Northern York Region related to the Claireville-to-Minden system are summarized in Table 6-1. These needs are considered together due to common electricity system infrastructure.

Table 6-1: Claireville-to-Minden System Near-Term Electricity Needs

<table>
<tr><th colspan="2">Need</th><th>Description</th><th>Timing</th></tr>
<tr><td colspan="2">Transformer Station Capacity</td><td>Net demand growth in Vaughan is forecast to exceed the limits of the combined transformer stations in the area, with most new demand growth occurring near the northern boundaries of the City of Vaughan</td><td>2017</td></tr>
<tr><td colspan="2">System Supply Capability</td><td>Net peak demand is forecast to exceed the 650 MW supply capability of the transmission system + local generation</td><td>2021</td></tr>
<tr><td rowspan="2">Impact of Supply Interruptions</td><td>Load Security</td><td>Net peak demand is forecast to exceed the ORTAC load security limit of 600 MW</td><td>2018</td></tr>
<tr><td>Restoration</td><td>System not capable of meeting ORTAC restoration criteria in Northern York Region</td><td>Today</td></tr>
</table>

The first three needs—transformer station capacity, supply capability and load security—are each a consequence of forecast demand growth exceeding current system limits.

There is substantial demand growth forecast for the City of Vaughan in the next few years, as land re-zoning toward the northern boundary of the city has created opportunities for development. Based on forecast demand in this area, net of provincial conservation targets and DG, the capability of the existing stations in the Vaughan area will be exceeded in 2017. PowerStream has begun development of a new station in this area, Vaughan #4 MTS, to address this need.

The location of the new station was discussed among the Working Group, and it was agreed that it should connect to the Claireville-to-Minden line, due to the location of demand growth and lack of viable alternatives. Support for this connection location was documented in a letter from the OPA to PowerStream dated December 14, 2012.[14]

With the additional demand growth in Vaughan likely connecting to the Claireville-to-Minden line, a need for supply capacity was identified. To assess this need, the combined demand growth on this system, including the Armitage, Holland and Brown Hill transformer stations as well as the new station in Vaughan, was compared against the supply capability of the existing system. This system consists not only of the Claireville-to-Minden transmission line (B82/83V), but also the York Energy Centre, a local supply source. Based on application of ORTAC criteria to assess thermal and voltage limits, the combined supply capability of this system today is 650 MW, based on thermal limitations (see Appendix B.3.2).

In addition, it is necessary to consider the ORTAC load loss criteria, which specify that no more than 600 MW of load can be interrupted following a major outage involving two transmission elements. As this criterion is more limiting than the supply capability limit described above, the LMC of this system is defined as 600 MW.

Forecast net peak demand on the Claireville-to-Minden line is expected to reach 600 MW in 2018. Moreover, with a new TS planned to connect to this system, it will be necessary to ensure that the system has adequate capability to supply the station. There is therefore a need to increase the LMC on B82/83V to accommodate load growth in the near term, in order to coordinate with the development of additional TS capacity.

In addition to the growth-related needs described above, there is also a need to improve the capability of the system to restore customer loads following a major outage in Northern York

[14] OPA letter to PowerStream dated December 14, 2012 re: Siting Vaughan #4 MTS: http://www.ieso.ca/Documents/Regional-Planning/GTA_North/Vaughan4%20MTS%20Letter%20-2012-12-14.pdf

Region. Based on current demand levels, in the event of a major outage on the Claireville-to-Minden line, up to 500 MW of peak load in Northern York Region would be interrupted. York Energy Centre can assist with load restoration by providing a local supply source, however, as there are currently no fast-acting isolating devices (e.g., motorized disconnect switches or breakers) on the system that could quickly isolate a fault, the amount of time required to restore loads does not meet ORTAC criteria. Based on current manual fault isolation capability, at least 250 MW of load in Northern York Region does not meet the ORTAC 30-minute restoration criteria today. As demand grows in the area, the severity of this need will increase.

As with any radial line, in the event of a major outage on the Armitage Tap (the approximately 7 km section of B82/83V supplying Armitage TS), options for restoring loads are limited. Using existing distribution ties, about 65 MW of load at Armitage can be restored through transfers to the Holland TS within a 4-hour timeframe. However, about 280 MW of load at the Armitage station would not meet the ORTAC 30-minute or 4-hour restoration criteria. All load can be restored within eight hours by installing a temporary by-pass around the faulted section.

6.2.2 Parkway Belt Near-Term Needs

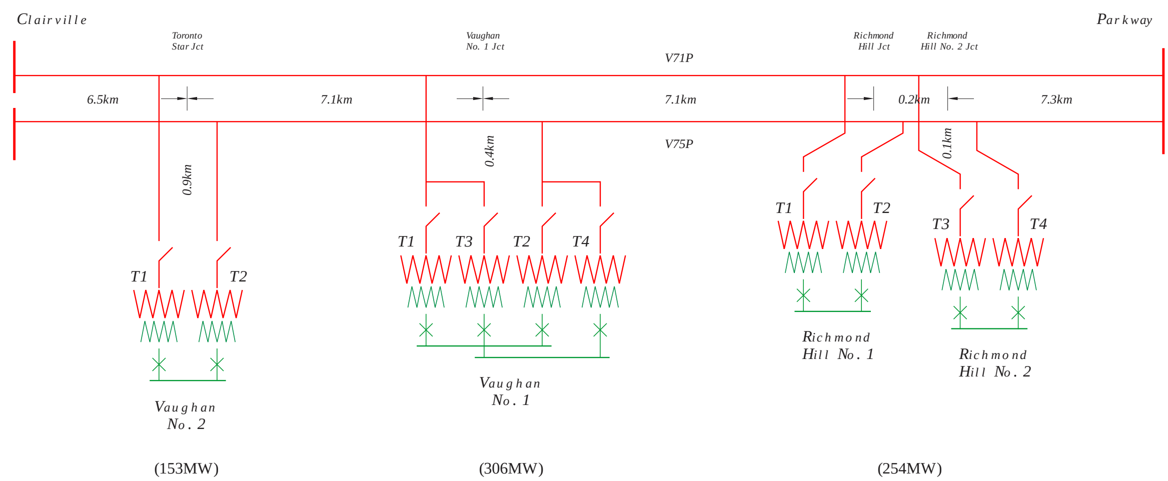
The near-term needs arising in Vaughan and Northern York Region related to the Parkway Belt are summarized in Table 6-2. These needs are considered together due to common electricity system infrastructure.

Table 6-2: Parkway Belt Near-Term Electricity Needs

Need		Description	Timing
Impact of Supply Interruptions	Load Security	Net peak demand exceeds the ORTAC load security limit of 600 MW	Today
	Restoration	System not capable of meeting ORTAC 30-minute criterion	Today

A large portion of the customer loads in Vaughan and Richmond Hill are supplied by stations connected to a double-circuit 230 kV transmission line extending between the Parkway and Claireville stations (the “Parkway-to-Claireville line”). This line is situated on the Parkway Belt corridor, which also includes two 500 kV transmission lines comprising a critical pathway for bulk power transfers across the northern GTA. The two 230 kV circuits on this corridor, V71/75P, were classified as "dual-function" in Hydro One's most recent rate application,[15] as they not only supply local customer loads, but also provide a parallel path to the 500 kV network supporting the bulk power system.

Figure 6-1: Existing Configuration of the Parkway-to-Claireville Line



Five step-down transformer stations are supplied by the Parkway-to-Claireville line, providing power to residential, commercial and industrial customers served by PowerStream (see Figure 6-1). These stations are fully utilized and under peak demand conditions supply up to 715 MW of customer demand. Currently, as there are no fast-acting sectionalizing devices on these circuits, in the event of a major outage involving the loss of both circuits, ORTAC load security and restoration criteria cannot be met. Specifically:

- ORTAC permits no more than 600 MW of load to be interrupted upon the loss of two transmission elements. Under peak demand conditions, with five stations currently supplied from the Parkway-to-Claireville line, 715 MW of load would be lost during a major outage involving both circuits on this line.
- ORTAC requires that, in the event of a major outage, all load lost in excess of 250 MW be restored within 30 minutes. There is, at present, sufficient load transfer capability on the distribution system to restore about 115 MW of the Parkway-to-Claireville load within

[15] http://www.hydroone.com/RegulatoryAffairs/Documents/EB-2012-0031/Exhibit%20G/G2-01-01.pdf

30 minutes. The remaining amount of peak load that cannot be restored to meet the 30-minute criterion is 330 MW, calculated as follows:

Total load interrupted	715 MW
minus 250 MW allowed by criteria	-250 MW
minus distribution transfer capability	-135 MW
amount of load not meeting 30-min criteria	**330 MW**

Hydro One has confirmed that a line crew would be able to manually isolate the faulted section of this line within a maximum of four hours to allow sufficient load to be restored to satisfy the ORTAC 4-hour restoration criterion. Hydro One has also confirmed that if emergency repairs were required to allow all of the load supplied from this line to be restored, that these could be completed within eight hours to satisfy the ORTAC 8-hour restoration criterion.

6.3 Medium-Term Needs

In the medium term (2019-2023), with continued demand growth in York Region as forecast, additional needs are expected to arise as early as 2021 as growth begins to exceed the capability of the Region's infrastructure (including the enhancements included in the near-term plan).

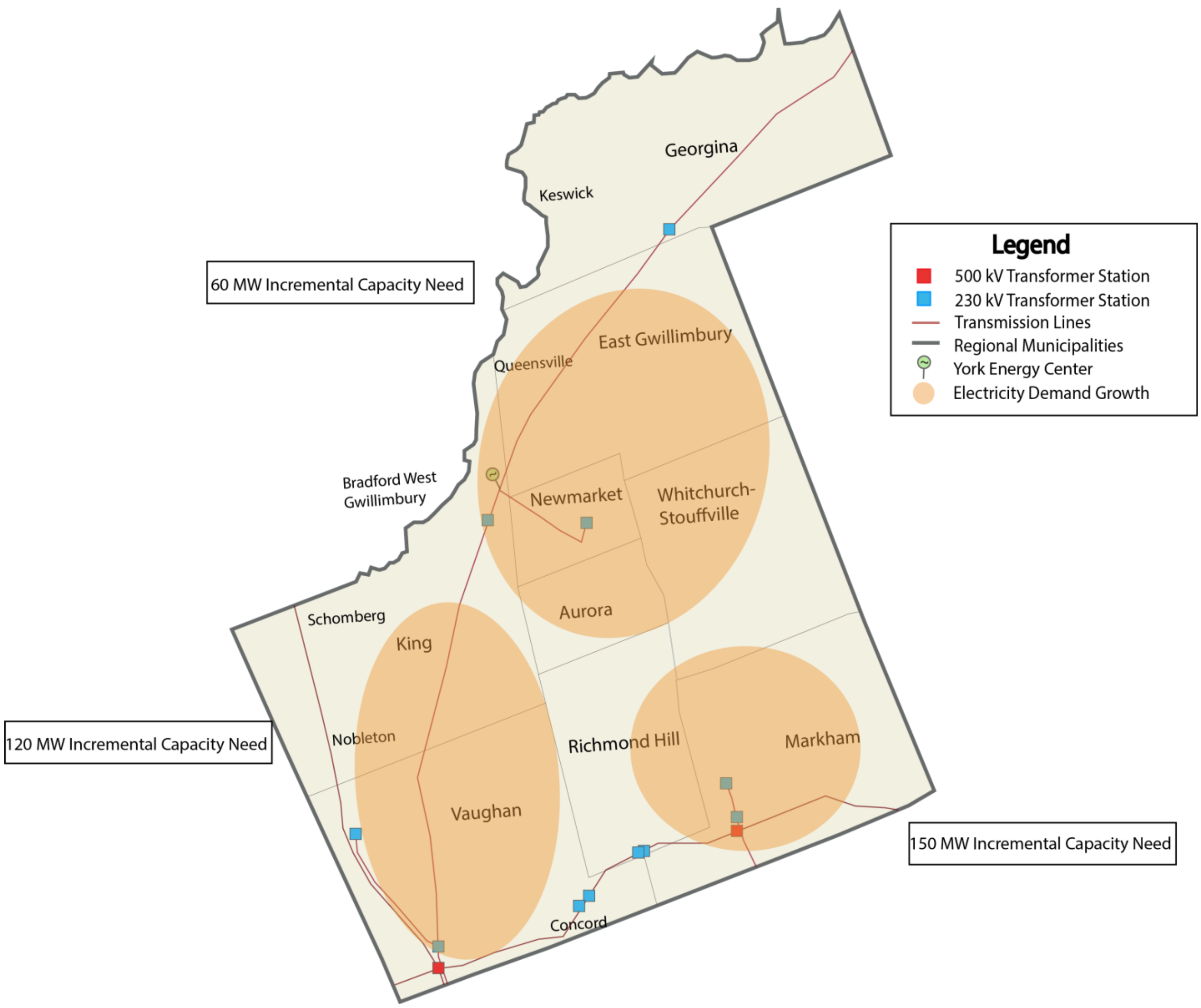
The amount of forecast demand growth beyond that which can be reliably supplied with existing transformer stations, including the new station in Vaughan that is part of the near-term plan detailed in Section 7.2, is shown by sub-area in Figure 6-2. In each sub-area, between 60 and 150 MW of demand growth, net of provincial conservation targets and DG, is expected to require additional supply.

The expected timing of these needs, based on the current forecasts, is 2021-2022 in Markham and 2023-2024 in both Vaughan and Northern York Region.

Based on current forecasts, new stations could initially be added to the existing transmission system without reinforcement, however in the long term the capability of the system to supply these stations would be exceeded (see Section 6.4).

An additional consideration is that not only is growth forecast to exceed the supply capacity in this timeframe, but with continued urbanization the majority of new growth is expected to be located far from existing electricity supply points. For example, in Southern York Region, the majority of forecast development is located 10 km or more to the north of the Parkway Belt, the major transmission supply to this area. If new stations were located near existing transmission infrastructure, rather than near the load, lengthy distribution lines would need to be constructed in order to bring supply to customers. In either case, it will be necessary to develop a plan to address the longer-term system needs in coordination with planning to address the station limits.

Figure 6-2: Incremental Transformation Capacity Needs (2019-2023)



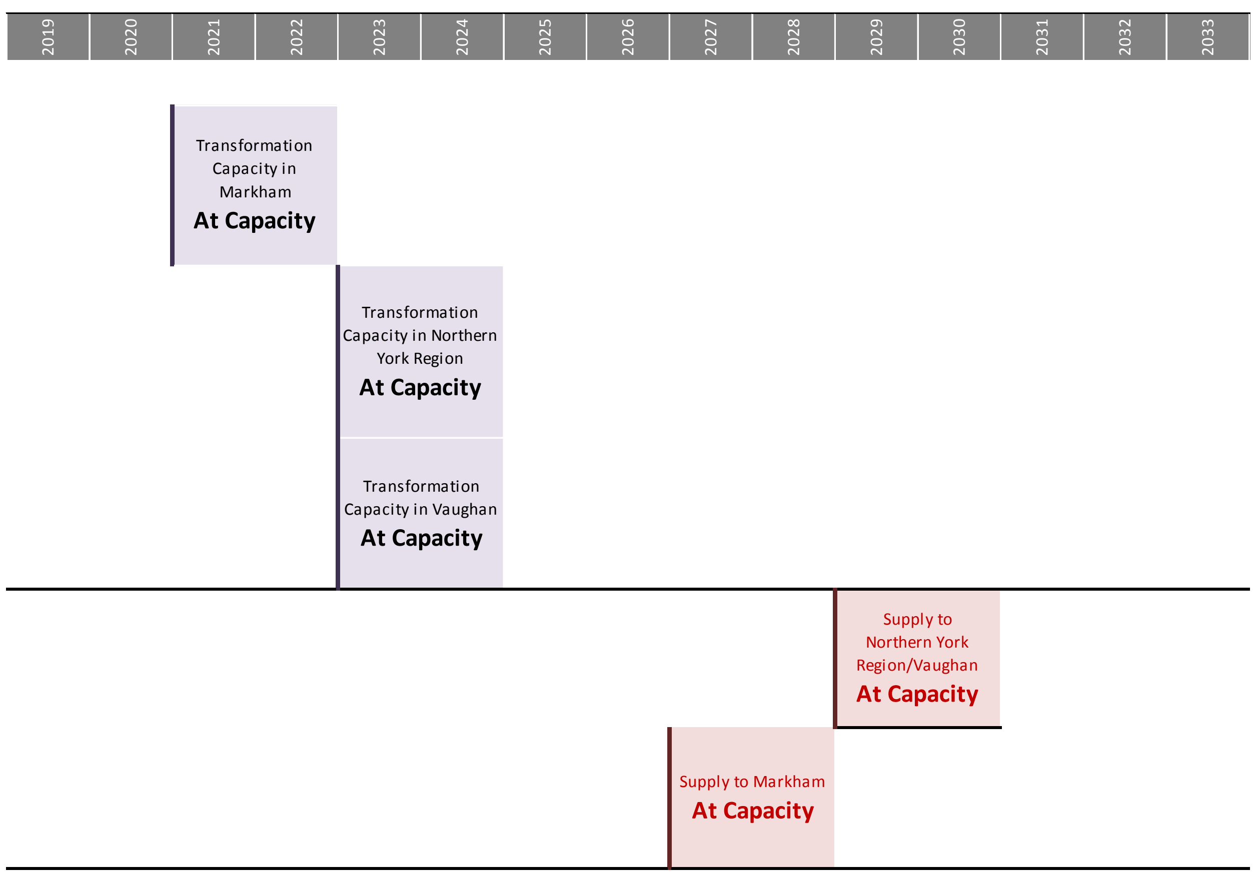
6.4 Long-Term Needs

In the long term (2024-2033), continued growth in the Region is expected to exceed the capability of the transmission system supplying the area. To assess needs in the long term, two demand forecast scenarios were considered: a low-growth and a high-growth forecast (see Section 5.6). The high-growth scenario points to significant demand growth requiring a major expansion of supply capability in the mid-to-late 2020s. In the low-growth scenario, fewer needs arise. The long-term needs are discussed for each forecast scenario below.

6.4.1 High-Growth Scenario

Under the high-growth scenario, continued strong demand growth in York Region would begin to exceed the capability of the existing electricity supply infrastructure around 2027. As shown in Figure 6-3, in addition to the transformer capacity needs identified as arising in the medium term (see Section 6.3), the transmission system is also expected reach its limits around 2027-2028 in Markham, when the Parkway-to-Buttonville line will become overloaded, and around 2029-2030 on the Claireville-to-Minden line when that system will reach its LMC.

Figure 6-3: High-Growth Scenario: Timing of Medium- and Long-Term Needs



These need dates are based on the assumption that any new stations would be sited near existing transmission supply points. Specifically, it is assumed that a new station in Markham would be sited at the existing Buttonville station site, and that new stations in Vaughan and

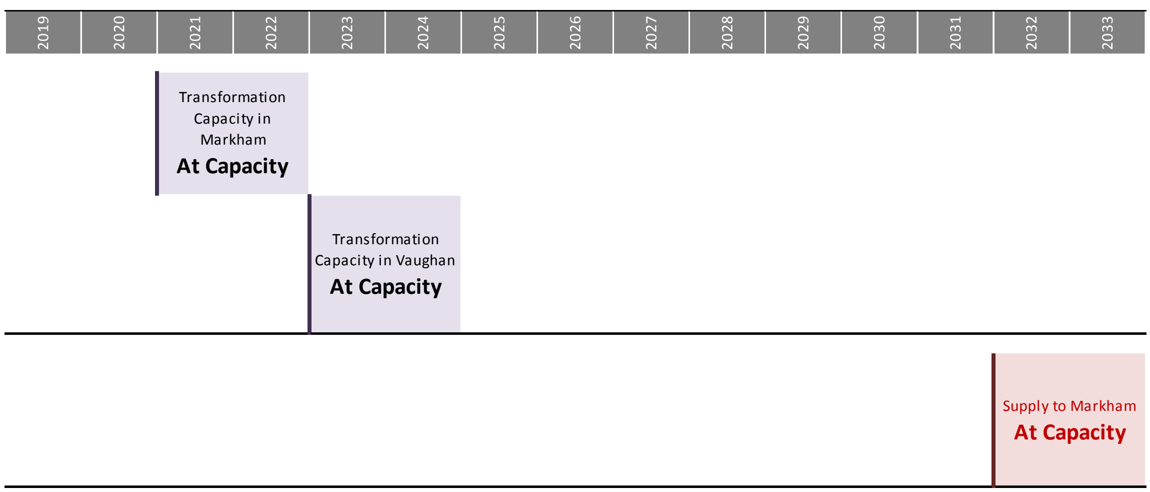
Northern York Region would be sited along the Claireville-to-Minden corridor. Should new stations be sited away from the existing infrastructure, additional transmission connection lines would be required, and the timing to bring them into service would be concurrent with the stations.

As noted in Section 6.3, a plan will need to be developed to address the transmission system limits in coordination with planning to address the medium-term station limits.

6.4.2 Low-Growth Scenario

Under the low-growth scenario, there are fewer needs arising in the long term. In this scenario, while station capability would continue to be exceeded in Markham and in Vaughan, in Northern York Region demand would stabilize within the capacity of existing station limits.[16]

Figure 6-4: Low-Growth Scenario: Timing of Medium- and Long-Term Needs



With the slower pace of growth in this scenario, transmission system capacity would continue to be adequate until around 2032 in Markham, and until sometime after the end of the study period in the Claireville-to-Minden system (see Figure 6-4). Nonetheless, the addition of new stations in Markham and Vaughan would still require planning the system to fully utilize them.

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[16] Although the demand in Northern York Region would slightly exceed the area's station capacity in the medium term (around 2023-2024), under the low-growth scenario conservation would subsequently contain demand so that an additional station would not be necessary in this sub-area. See Appendix B for details.

The location of new stations could also impact the timing and extent of the long-term system needs under this scenario.

7. Near-Term Plan

The plan to address the near-term electricity needs of York Region consists of specific actions and projects that are currently underway. As described in Section 6.1, the near-term needs are expected to arise in 2017 (see Section 6.2). The near-term plan has been in development since 2012, with projects formally handed off to PowerStream and Hydro One in 2012 and 2013 respectively so that they can be in service in time to meet the needs.[17] Each of these projects is undergoing the established project development procedures (e.g., EA process).

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

7.1 Alternatives for Meeting Near-Term Needs

In developing the near-term plan, the Working Group considered a range of integrated options. Factors that were considered in comparing alternatives included feasibility, cost, and consistency with long-term needs and options in York Region. In addition, solutions that maximize the use of existing infrastructure were given priority.

The following sections detail the alternatives that were considered, and comments on their performance in the context of the criteria described above.

7.1.1 Conservation

Conservation was implicitly considered as the first alternative to meet the needs through the development of a planning forecast that includes the peak-demand effects of the provincial conservation targets, along with contracted DG (see Sections 5.4 and 5.5).

Additional conservation beyond the targeted amounts included in the demand forecast could theoretically assist in meeting growth-related needs, such as the need for transformation capacity in Vaughan, and the need to provide additional LMC in the Claireville-to-Minden system. The conservation and DG resources included in the forecast for the stations in this area amount to 136 MW, or 38% of the forecast demand growth, during the first 10 years of the

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[17] OPA Letter to PowerStream re: Siting Vaughan #4 MTS:
http://www.ieso.ca/Documents/Regional-Planning/GTA_North/Vaughan4%20MTS%20Letter%20-2012-12-14.pdf
OPA Letter to Hydro One - York Region:
http://www.ieso.ca/Documents/Regional-Planning/GTA_North/OPA-Letter-Hydro-One-York-Subregion.pdf

study. In order to meet the capacity needs with conservation, an additional almost 50 MW of peak-demand reductions, incremental to the current LTEP conservation target, would be required by 2017. Moreover, to continue to meet these needs with conservation over time, additional peak demand savings equivalent to all further demand growth thereafter would also be necessary. By the end of 10 years, this would mean that a total of approximately 150 MW of peak demand savings from conservation would be necessary by 2023, incremental to the LTEP conservation target. Given the timing of the transformation and supply capacity needs (a solution needs to be in place by 2017), the magnitude of the transformation and supply capacity needs relative to the LTEP conservation target, and the challenges experienced by LDCs thus far in meeting the peak-capacity targets set for the 2011-2014 period,[18] the Working Group agreed that additional conservation was not a viable option to meet these needs.

Furthermore, for needs related to meeting ORTAC load restoration and load security criteria, conservation is not a feasible alternative, as these needs are driven by the configuration of the transmission and distribution systems, and are not related to demand growth. Therefore, the Working Group did not consider additional conservation as an alternative to address load restoration times in Northern York Region, nor the load restoration or load security needs on the Parkway Belt.

In summary, while additional conservation beyond the established targets was not considered as an alternative to meet the Region's near-term needs, the success of the near-term plan is dependent on the achievement of the peak-demand savings associated with meeting the LTEP conservation target. Efforts in the near-term should be focused on ensuring that these savings materialize. Therefore, monitoring conservation efforts to ensure that this goal is met are included as a recommendation in the near-term plan.

7.1.2 Local Generation

While in general local generation has the potential to meet both supply capacity and load restoration needs, this alternative was ruled out by the Working Group for meeting the near-term needs. For the Claireville-to-Minden system needs, a large local generation facility, York Energy Centre, is already in place, however without associated switching facilities its full capability cannot currently be utilized to meet local needs. Therefore, the Working Group

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[18] See "Conservation and Demand Management Report – 2013 Results: EB-2010-0215" (http://www.ontarioenergyboard.ca/oeb/_Documents/EB-2010-0215/CDM%20Summary%20Report%20-%202013%20Results_20141217.pdf)

focused on alternatives that would maximize the use of this existing local resource, enabling it to assist in meeting regional needs, rather than providing additional generation.

In the Parkway Belt system, local generation could assist with restoration if properly sited and integrated, however given the density of this urban area this option was ruled out by the Working Group based on feasibility concerns.

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.

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. These alternatives are described for the Claireville-to-Minden and Parkway Belt need areas below.

7.1.3.1 Claireville-to-Minden Alternatives

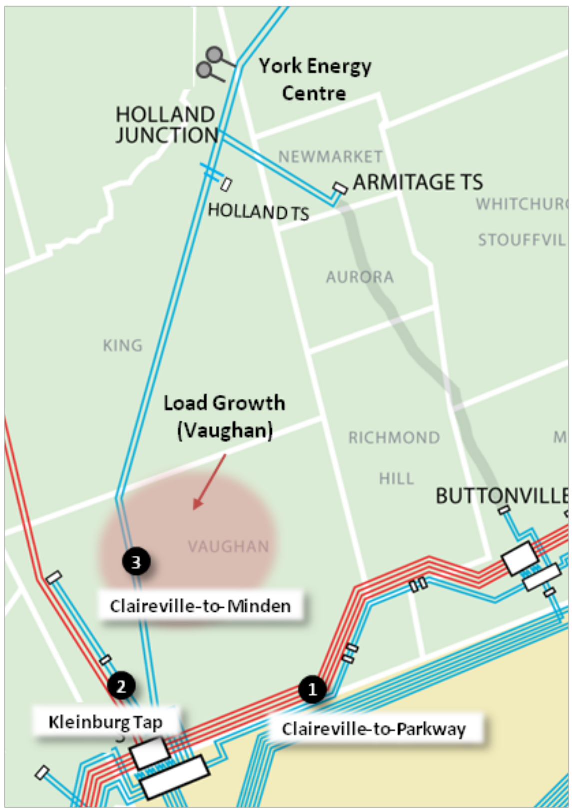
In addition to constructing a new station in Vaughan to supply demand growth, three "wires" alternatives to meet the needs in this area were considered: (1) finding an alternate location to site the Vaughan #4 MTS; (2) constructing a new transmission line; and (3) adding switching facilities in Northern York Region.

Alternate Siting of Vaughan #4 Station

As the connection of a new station in Vaughan to the Claireville-to-Minden line would trigger the need to increase the LMC of this system, the Working Group considered whether this could be avoided by finding an alternate supply point for this station. Two other potential transmission supply points in addition to the Claireville-to-Minden line were considered as shown in Figure 7-1: the Parkway-to-Claireville line; and the Claireville-to-Kleinburg line. These options, however, were rejected based on distribution and transmission considerations. From a distribution perspective, the Claireville-to-Minden supply point is preferred because the centre of forecast load growth to be supplied by the new station is near the northern boundary of the City of Vaughan. The Claireville-to-Minden line passes directly through this area, allowing the station to be optimally located to minimize distribution system expansion. The

Parkway-to-Claireville line and the Claireville-to-Kleinburg line are respectively located approximately 10 km to the south and 6 km to the west of this area of growth. Siting Vaughan #4 MTS near these supply points would require extensive distribution expansion in areas with limited available road allowances.

Figure 7-1: Potential Supply Points for Vaughan #4 MTS



From a transmission perspective, all three of the potential supply points have limitations that would prevent them from supplying a new station without transmission system reinforcement.

- **Claireville-to-Minden:** As described in Section 6.2.1, siting the station on the Claireville-to-Minden line would trigger a need to increase the LMC of this system.
- **Parkway-to-Claireville:** Siting the station on the Parkway-to-Claireville line would exacerbate the load loss and restoration needs described in Section 6.2.2. Connecting Vaughan #4 MTS to this line would add approximately 150 MW of customer demand to this system, bringing the total load that could be interrupted in a major outage to 850 MW.
- **Claireville-to-Kleinburg line:** With three transformer stations already connected to this 230 kV double circuit radial supply, the Claireville-to-Kleinburg line does not have sufficient supply capacity to supply another TS based on thermal limitations.

> Furthermore, this line does not currently meet ORTAC restoration criteria. Adding Vaughan #4 MTS to this line would require transmission reinforcement to address the thermal limitations and would exacerbate the existing load restoration need.

As a result, the Working Group concluded that the existing transmission infrastructure does not provide a suitable alternative for supplying the Vaughan #4 station.

New / Upgraded Transmission Line(s)

Another alternative is providing a new transmission supply to the area. This could be accomplished by upgrading lines along existing transmission corridors, or by establishing a new corridor. This alternative was rejected for the purpose of meeting the near- to medium-term needs on the basis of cost, environmental impact, the substantial lead time required to develop this alternative, and the availability of alternatives that maximize the use of existing infrastructure.

New Switching Facilities in Northern York Region

The final alternative considered to address the near-term needs in the Claireville-to-Minden system is to add new switching facilities in Northern York Region, including in-line breakers and motorized disconnect switches. This alternative was recommended by the Working Group as it meets all of the needs identified in this area, maximizes the use of the existing transmission and local generation infrastructure in the area, can be brought into service by 2017, and is less costly than other alternatives.

The addition of switching facilities was noted in the 2005 Northern York Region electricity plan, and in the IESO's System Impact Assessment for the York Energy Centre, as a necessary step in integrating the local generation. However, it was not pursued immediately as the location and scope of the equipment could not be determined until the final connection point for YEC was determined. This alternative is thus also a required step in completing the implementation of the 2005 Northern York Region plan. The recommended scope of this project is described in more detail in Section 7.2.3 below.

7.1.3.2 Parkway Belt Alternatives

Four "wires" alternatives were considered as potential means of addressing the load loss and restoration needs on the Parkway Belt: (1) a new transmission line; (2) in-line circuit breakers; (3) creating a permanent open point on the Parkway Belt; and (4) in-line circuit switchers.

New Transmission Line

An option involving the construction of a new radial transmission line westward from the Parkway station and the reconnection of the Richmond Hill 1 & 2 stations to this line would limit the maximum amount of load that would be interrupted to 460 MW. While this option would satisfy the load security criterion, it would not be able to meet the load restoration criteria. It was also the most costly option considered. The Working Group therefore decided that it should be eliminated from further consideration.

In-line Circuit Breakers

Installing two new in-line circuit breakers would satisfy the load security and load restoration criteria, however, it would require development of a new switching station in a densely developed urban area. This alternative was eliminated from consideration by the Working Group based on its cost and concerns about the feasibility of development given the density of the area.

Creating a Permanent Open Point

Creating a permanent open point on the Parkway-to-Claireville line, separating it into two radial lines emanating from the Parkway and Claireville stations, was discussed by the Working Group. Similar to the transmission line option, this would address the load security need but would still leave some load unable to meet the 30-minute load restoration criteria. However, as this alternative would also have a serious negative impact on the reliability of the bulk transmission system, it was rejected by the Working Group.

In-line Circuit Switchers

The installation of in-line circuit switchers on the Parkway Belt circuits would meet the load restoration requirements of ORTAC but would not address the load security criterion. While the circuit switchers would not be capable of clearing a fault, meaning that the entire load supplied from the Parkway-to-Claireville line would be interrupted in response to a fault, the circuit switchers would enable the circuits to be rapidly sectionalized following a fault, permitting as much load as possible to be restored rapidly (expected to be under 15-minutes) from the healthy sections of the Claireville-to-Parkway circuits. This option was recommended by the Working Group.

The Working Group considered whether to install two circuit switchers (one on each circuit) or four (two on each circuit). The option involving two circuit switchers is capable of meeting the ORTAC 30-minute criterion. While the addition of the incremental two circuit switchers would increase the ability to further sectionalize the line and allow additional load to be restored within 30 minutes, concerns were raised about the viability of the arrangement due to the added complexity of the protective relaying scheme. Due to these concerns, together with the limited benefit that the installation of the two additional circuit switchers would provide at a significant increase in the cost, the Working Group decided that this option should not be pursued.

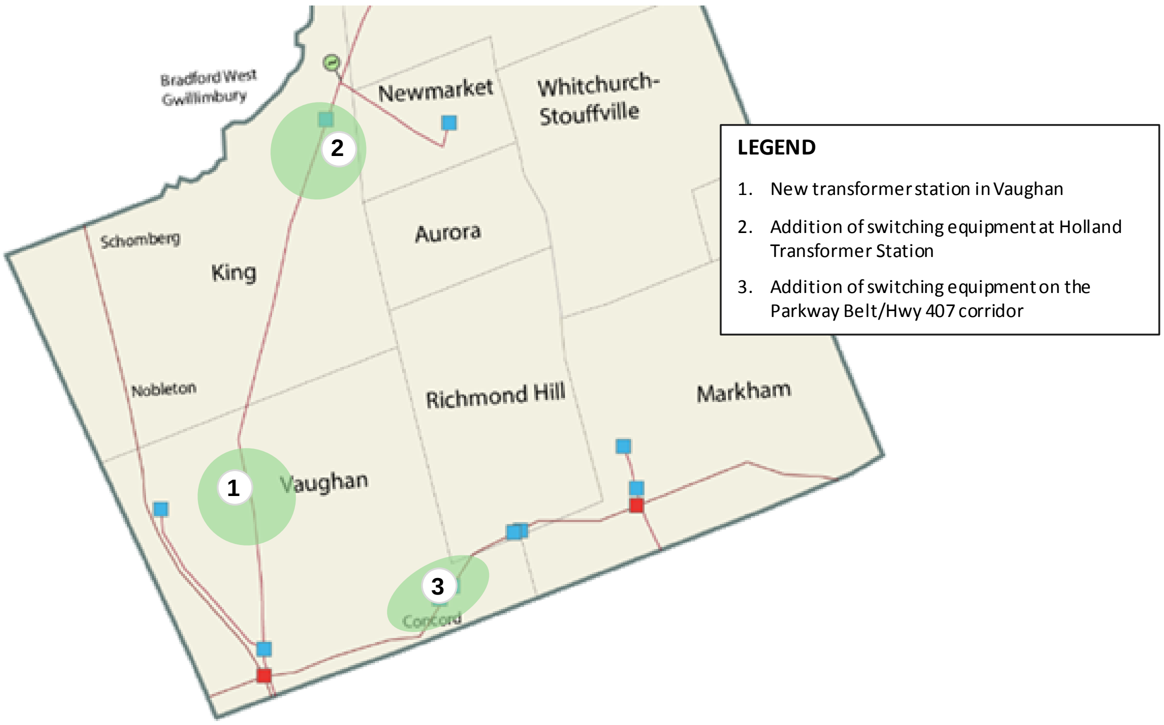
7.2 Recommended Near-Term Plan

Based on the evaluation of alternatives discussed above, the Working Group recommends the actions described below to meet the near-term electricity needs of York Region. Successful implementation of this plan will address the Region's electricity needs until the early-to-mid 2020s.

The first element of the near-term plan is implementation of targeted conservation and DG. To address reliability needs and to supply residual load growth in Vaughan, three transmission projects are also recommended. The development of these "wires" projects is currently underway, in accordance with letters from the former OPA in 2012 and 2013,[19] and they will also become part of a Regional Infrastructure Planning (RIP) process to be initiated by Hydro One as an outcome of this IRRP.

[19] OPA Letter to PowerStream re: Siting Vaughan #4 MTS:
http://www.ieso.ca/Documents/Regional-Planning/GTA_North/Vaughan4%20MTS%20Letter%20-2012-12-14.pdf
OPA Letter to Hydro One - York Region:
http://www.ieso.ca/Documents/Regional-Planning/GTA_North/OPA-Letter-Hydro-One-York-Subregion.pdf

Figure 7-2: Transmission Projects included in York Region Near-Term Plan



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 be focused as much as possible on measures that will provide peak-demand reductions. Monitoring of conservation success, including measurement of peak demand savings, will be an important element of the near-term plan, and will also lay the foundation for the long-term plan by reviewing the performance of specific conservation measures in the Region and assessing potential for further conservation efforts. A discussion of the LDCs' conservation plans is provided in Appendix C.1.

7.2.2 Vaughan #4 MTS

To address the need for additional TS capacity in Vaughan, the Working Group recommends development of a new transformer station. Named "Vaughan #4 MTS", this new station is currently being developed by PowerStream, with a targeted in-service date of 2017. An EA has been completed and a site at 5400 Kirby Road in northern Vaughan has been selected for the location of the station. The Working Group provided its support for the connection of this station on the Claireville-to-Minden line in 2012.[20]

7.2.3 Switching Facilities at the Holland Station

To improve the LMC of the Claireville-to-Minden system, and to enable ORTAC load restoration criteria to be met in Northern York Region, the following measures are recommended by the Working Group: the installation of two in-line breakers and associated motorized disconnect switches at the Holland property and; the design and implementation of a Load Rejection ("L/R") scheme for the Claireville-to-Minden system. Hydro One is currently developing this project.

Implementation of these measures will address most of the near and medium-term needs of the area. The Claireville-to-Minden system will be able to supply 850 MW of customer demand,[21] which is sufficient to supply forecast demand growth until the mid-to-late 2020's, and the impact of supply interruptions will be mitigated in Northern York Region, although some of the loads at the Armitage station may require additional measures to meet ORTAC restoration criteria if the Armitage Tap were lost.

The switching facilities to be installed as part of this project consist of two in-line breakers and six motorized disconnect switches. The location and configuration of this equipment has been discussed in detail with the York Region Working Group and the proposed design is shown in Figure 7-3.

This configuration was developed based on preliminary site and cost information, as well as system studies to assess project benefits. The proposed configuration was selected to allow the new infrastructure to be sited on Hydro One's existing Holland property, thus avoiding the need to establish new right-of-ways or obtain additional land.

The breakers will sectionalize B82/83V, maximizing the supply capability afforded by York Energy Centre and addressing the ORTAC load security requirement. Together, the breakers and the switches will also improve the time required to restore loads after a major outage on the

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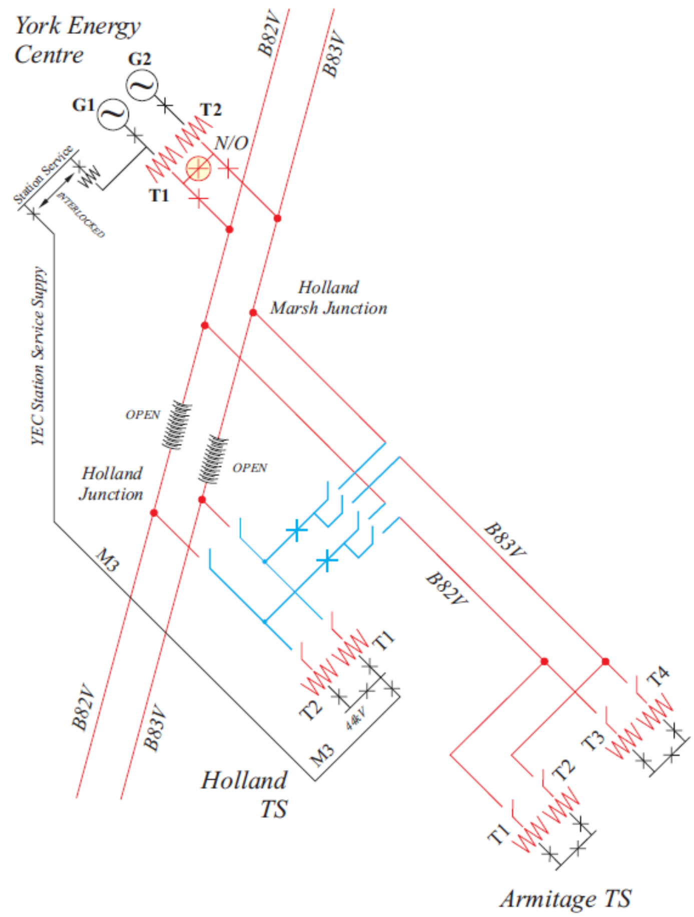
[20] OPA Letter to PowerStream re: Siting Vaughan #4 MTS:
http://www.ieso.ca/Documents/Regional-Planning/GTA_North/Vaughan4%20MTS%20Letter%20-2012-12-14.pdf
[21] Supporting details are provided in Appendix B.3.3.

Claireville-to-Minden line to within 30 minutes, allowing the area to meet ORTAC restoration criteria following a major outage.[22]

Figure 7-3: Proposed Switching Facilities



The assessment of the supply capability of the Claireveille-to-Minden system is based on application of ORTAC criteria governing permissible transmission and generation outage scenarios. To facilitate implementation of the supply capability afforded by application of the criteria, a L/R scheme, a type of special protection system ("SPS"), is required and would be armed under those contingency/outage conditions when L/R is permitted by ORTAC. As there are currently no L/R facilities in place to address contingencies on the Claireville-to-Minden

[22] The proposed configuration will improve restoration times following a major outage on the main section of B82/83V, allowing ORTAC criteria to be met. Following a major outage on the Armitage Tap, loads at Armitage TS may still not meet ORTAC criteria. However, because the switches make restoration of loads at Holland TS possible, additional distribution transfer capability to the Holland station could address Armitage load restoration needs in the event of a major outage on the Armitage Tap.

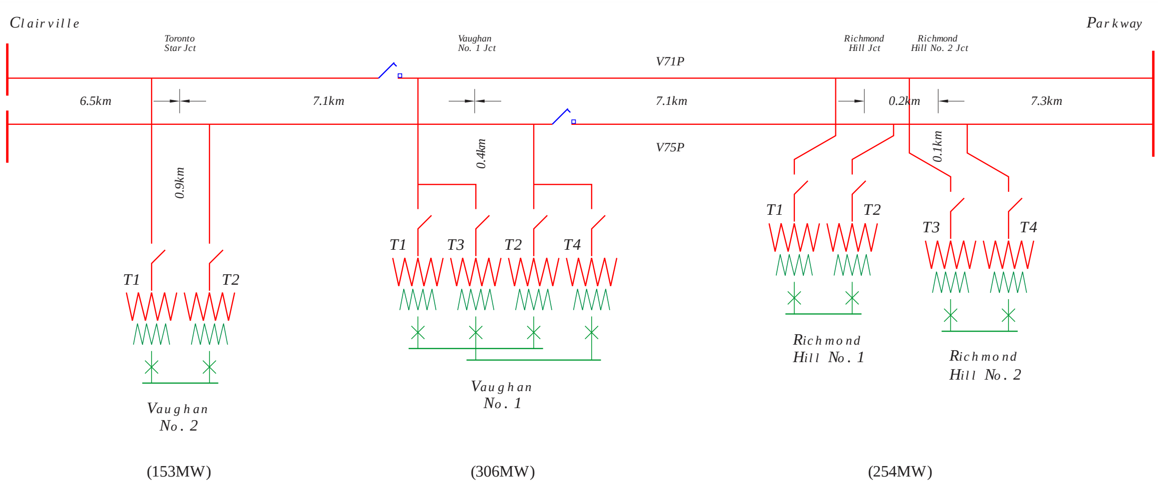
system, a L/R scheme must be developed by Hydro One with input from the IESO and the affected LDCs, in conjunction with the development of the Holland switching facilities.

7.2.4 Parkway Circuit Switchers

To address the Parkway Belt reliability needs, the Working Group recommends proceeding with installation of two in-line circuit switchers on the Parkway-to-Claireville line. While this alternative will not address the ORTAC load loss criterion, it will enable the load restoration criteria to be met. In effect, this means that, in the event of a major outage involving both of the 230 kV Parkway circuits, all load would be interrupted initially, but a significant portion of the load could be restored within 15 to 30 minutes. In the Working Group's opinion, this option strikes a reasonable balance between cost, reliability improvement, feasibility and other considerations.

The Working Group has discussed the scope of this project and has determined that, to enable the restoration needs to be met, the circuit switchers must be installed in the configuration depicted in Figure 7-4.

Figure 7-4: Two Circuit Switchers in Staggered Configuration on the Parkway-to-Claireville Line



Hydro One is proceeding with development of this project, with a targeted in-service date of spring 2018.

7.3 Implementation of Near-Term Plan

To ensure that the near-term electricity needs of York Region are addressed, it is important that the near-term plan recommendations be implemented in a timely manner. The specific actions and deliverables associated with the near-term plan are outlined in Table 7-1, along with their recommended timing, and the parties with lead responsibility for implementation. The development of the new station in Vaughan and the switching facilities at the Holland station are already underway.

The York Region Working Group will continue to meet at regular intervals during the implementation phase of this IRRP to monitor developments in the Region and to track progress toward these deliverables.

Table 7-1: Implementation of Near-Term Plan for York Region

Recommendation	Action(s)/Deliverable(s)	Lead Responsibility	Timeframe
1. Implement conservation and DG	Develop CDM plans	LDCs	May 2015
	Implement LDC CDM programs	LDCs	2015-2020
	Conduct EM&V of programs, including peak-demand impacts, and provide results to Working Group	IESO	annually
	Continue to support provincial DG programs	LDCs/IESO	ongoing
2. Develop new station in Vaughan	Design, develop and construct new station in northern Vaughan	PowerStream	In-service spring 2017
3. Add switching facilities at Holland	Design, develop and construct new switching facilities and load rejection scheme at the Holland station site	Hydro One	In-service spring 2017
4. Install in-line circuit switchers on Parkway 230 kV transmission line	Design, develop and construct circuit switchers on the Parkway Belt	Hydro One	In-service spring 2018

8. Medium and Long-Term Plan

In the medium and long term, the outlook for York Region's electricity system depends on the forecast assumptions made. Under the high-growth scenario, the Region could reach its capacity to supply growth beginning in the early-to-mid 2020s, with TS capacity and subsequently transmission system capability exceeded across the Region, and with specific needs arising in Markham, Richmond Hill and Vaughan (see Sections 6.3 and 6.4.1). At that time, assuming actual demand growth progresses according to this forecast scenario, there will be a need for major new electricity supply in the Region. Under the low-growth scenario, however, the needs are more modest and are focused in Southern York Region, but could still require significant infrastructure investment (see Section 6.4.2). Because decisions on solutions to meet the medium-term needs will have an impact on the long-term needs in the area, planning for the medium- and long-term needs must be coordinated, and are discussed together in this section.

The approach to developing medium- and long-term electricity plans is somewhat different than for near-term plans. For needs arising in the near term, specific projects must be committed in order to ensure that they are available in time to ensure that customer reliability is maintained. For needs arising in the medium and long term, there is an opportunity to develop and explore a broader set of options, as specific projects do not need to be committed immediately. Instead, the focus is on identifying possible approaches to meeting medium- and long-term needs, including alternatives that are not currently in widespread use but which show promise for the future, and identifying preliminary actions to develop alternatives, monitor growth, and engage with communities and stakeholders. This approach is designed to: maintain flexibility; avoid committing ratepayers to investments before they are needed; provide adequate time to assess the success of current and future potential of conservation measures in the Region; test emerging technologies; engage with all communities and stakeholders; coordinate with any municipal or community energy planning ("MEP/CEP") activities; and, lay the foundation for informed decisions in the future.

An important consideration in developing a medium/long-term plan is recognizing the timeframe within which decisions will need to be committed. This involves integrating the projected timing of needs with the expected lead time to bring alternatives into service. To enable fair consideration of all possible alternatives, this latter consideration is driven by the longest lead time among all the possible alternatives. This is usually associated with new major transmission infrastructure, which typically requires 5-7 years to bring into service, including conducting development work, seeking regulatory and other approvals, and constructing the facilities.

Based on the expected timing of the medium- and long-term needs in York Region, and the 5-7 year lead time for infrastructure alternatives, the Working Group expects that, if demand growth follows the high-growth scenario, a decision on the long-term plan will likely be required around 2018. Therefore, it is recommended that demand growth be monitored closely as part of the implementation of this IRRP and, if necessary, that the IRRP be revisited ahead of the 5-year schedule mandated by the OEB's regional planning process.

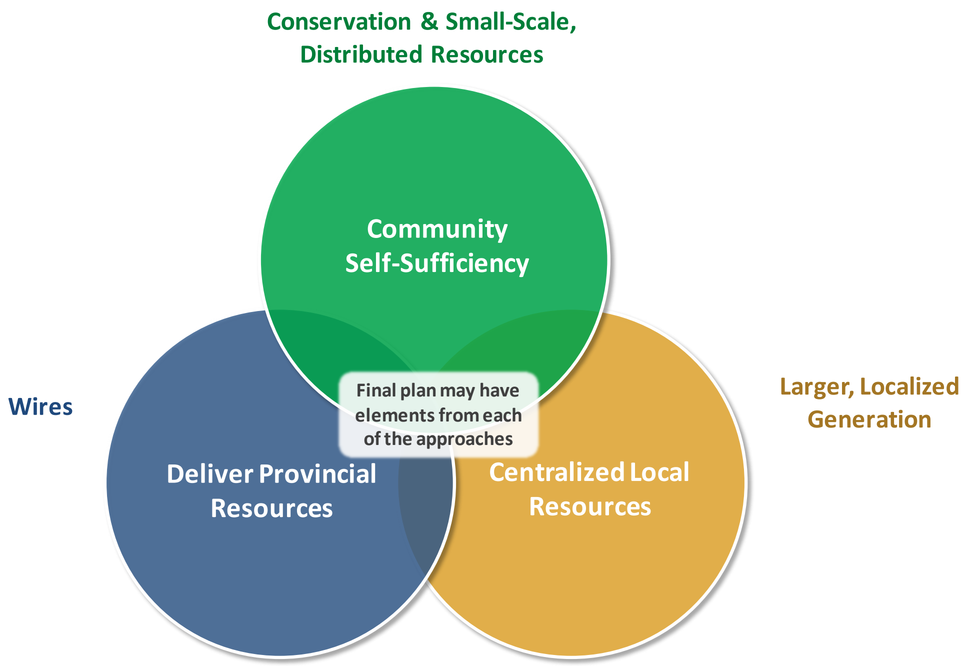
The following sections describe various approaches for meeting the medium- and long-term electricity needs of York Region, and lay out recommended actions to develop the medium/long-term plan and their implementation.

8.1 Approaches to Meeting Medium- and Long-Term Needs

In recent years, a number of trends, including technology advances, policy changes supporting DG, greater emphasis on conservation as part of electricity system planning, and increased 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 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 Medium- and Long-Term Needs



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 ("EV"). 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 these options

before commitment of specific projects is required. The success of this approach depends on early action to explore potential and develop options; it also requires the local community to take a lead role. This could be through a MEP/CEP process, or an LDC or other local entity taking initiative to pursue and develop options.

The intent of this framework is to identify which approach should 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. As well, 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.

Details of how these three approaches could be developed to meet the specific medium- and long-term needs of York Region are provided in the following sections.

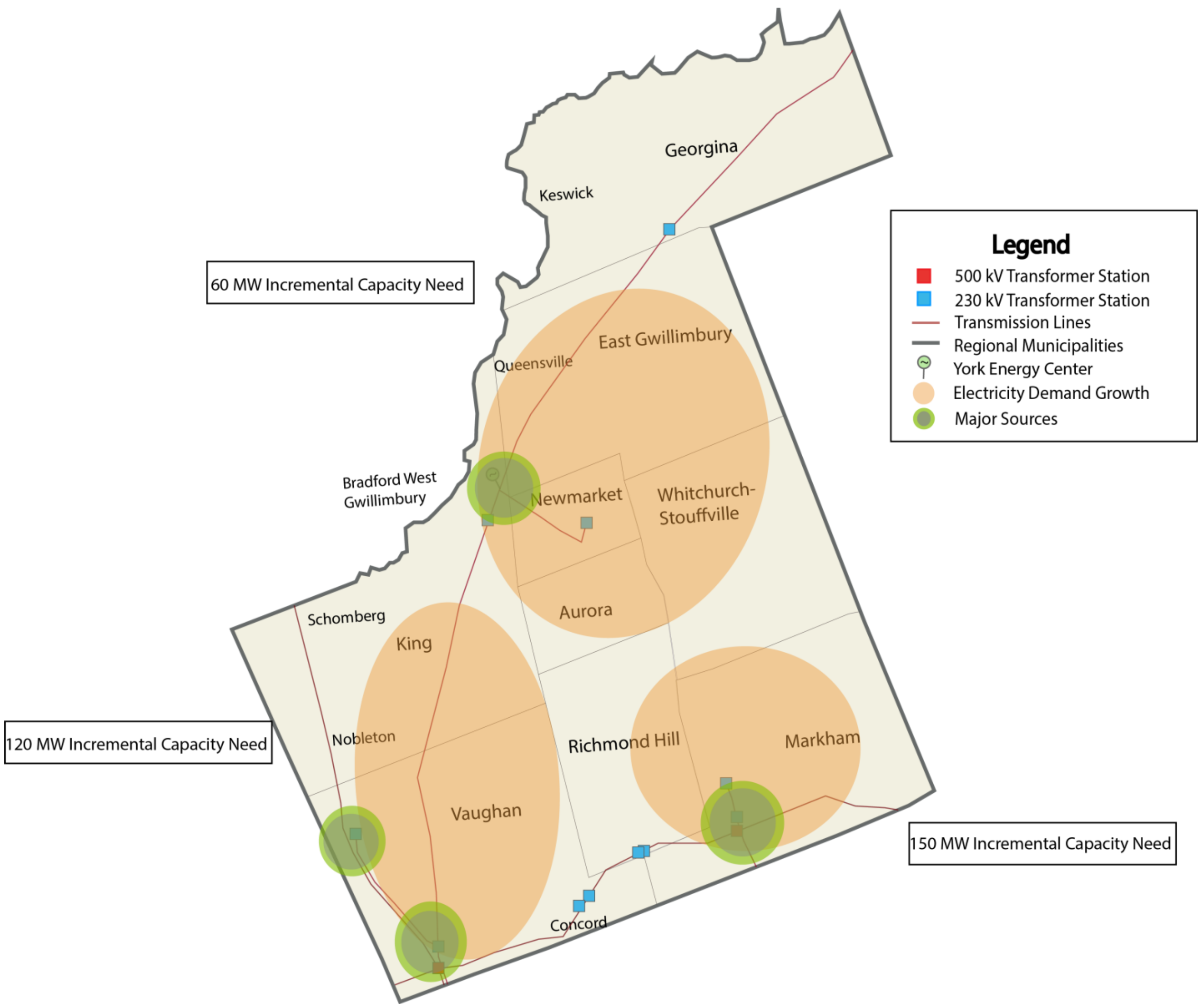
8.1.1 Delivering Provincial Resources

Under a "wires" based approach, which is the traditional approach taken to address regional electricity needs, the medium- and long-term needs of York Region would be met primarily through transmission and distribution system enhancements. If the substantial needs forecast under the high-growth scenario arise, this could necessitate major new transmission development to deliver power from the major sources supplying the area—the transformation facilities at the Claireville, Parkway and Cherrywood stations on the Parkway Belt, and the York Energy Centre in Northern York Region—to where the power is needed. These supply sources are indicated, along with the areas of need, in Figure 8-2.

A number of possible "wires"-based solutions could meet the medium- and long-term needs of the Region, including different route alternatives, as well as different possible balances between transmission and distribution infrastructure. Standard planning practices give preference to solutions that make use of existing utility corridors, or that involve development of new joint-use corridors for linear infrastructure. For example, Hydro One is currently conducting an EA for a new joint use corridor that would follow the MTO's development of the GTA West 400-series highway expansion. A section of this corridor is located in Vaughan, and could provide the basis for one possible "wires"-based approach to meeting long-term needs in York Region.

The costs of various "wires" solutions would depend not only on the specific infrastructure involved, but the cost of providing energy at the provincial system level to meet regional needs must also be accounted for.

Figure 8-2: Potential Transmission Supply Sources to Meet Medium- and Long-Term Needs: High-Growth Scenario



8.1.2 Large, Localized Generation

Addressing York Region's medium- and 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 medium- and long-term needs call for additional capacity during times of peak demand, large generation solutions 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 simple-cycle gas turbine ("SCGT") technology, would likely 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.

As the medium- and long-term growth requirements are forecast to arise in different areas of York Region, it is likely that more than one large local generation source would be required to meet the Region's needs. In some areas, generation may not be a technically feasible solution due to the nature of the needs, or the availability of sites for large generation sources. A centralized generation approach for York Region would likely involve multiple plants distributed in areas where they can feasibly meet localized needs, complemented by "wires" solutions in areas where generation is not technically feasible.

The cost of centralized generation options would depend on the size and technology of the units chosen, as well as the degree to which they can also contribute to a provincial capacity or energy need. "Wires" infrastructure required to address needs that cannot be met with generation, or to integrate centralized generation sources, would also be included in the economic assessment.

8.1.3 Community Self-Sufficiency

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

In York Region, there is strong community interest in this approach, as evidenced by municipalities and LDCs taking the lead in identifying and developing opportunities. These initiatives are described below, and additional details are provided in Appendix D.

Municipal and Community Energy Plans

A Municipal or Community Energy Plan ("MEP" or "CEP") is a comprehensive long-term plan to improve energy efficiency, reduce energy consumption and greenhouse gas ("GHG") emissions. A number of municipalities across the province are undertaking MEPs 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.

In York Region, the Town of East Gwillimbury completed a CEP in 2009,[23] and the Chippewas of Georgina Island First Nation is currently developing a CEP for their community. In addition, three municipalities in York Region are currently initiating Municipal Energy Planning processes: Newmarket, Markham, and Vaughan. The IESO and the LDCs serving these municipalities are participants in the working groups developing these plans, which are currently in the early stages of engagement. These initiatives are expected to be completed in 2016. Recommendations from these processes will help inform the next regional planning cycle by identifying community preferences, and specific local opportunities.

Newmarket-Tay and PowerStream

Newmarket-Tay Power and PowerStream are working together on an initiative to develop community self-sufficiency options in their service areas. The goal is to address future growth challenges through the use of new forms of customer engagement, new technologies and imaginative new solutions – in effect "to create a next-generation Ontario Supply Model".

This initiative targets the Long-Term Supply Planning Horizon or, as it has been referred to, "2020 & Beyond" because of the time required to pioneer, test and implement new technological solutions.

Under the overarching authority of the IESO, Newmarket-Tay and PowerStream will lead the engagement efforts in other communities and will play a key role in identifying members of the public to participate in a LAC (see Section 9). They will also play a critical integration and liaison role with closely related planning processes such as MEPs.

Newmarket-Tay and PowerStream's objectives are to successfully meet future customer demand and growth across York Region by developing and critically assessing the feasibility of new technologies and solutions, while at the same time:

- addressing regional electricity infrastructure and business (employment) needs
- satisfying system optimization and cost management objectives consistent with the asset management strategies of the utilities

[23] http://www.eastgwillimbury.ca/Asset3785.aspx?method=1

- pioneering new technologies and solutions showcasing the strategic vision and direction of the utilities.

Their plan involves the following elements:

- Develop a stakeholder engagement strategy and target groups
- Develop a liaison strategy (e.g., leadership, information and networking strategies)
- Identify promising technologies & solutions
- Recruit technology partners
- Recruit stakeholders
- Commission demonstration projects to prove technologies and identify integration and operational challenges
- Develop an "Innovation Cluster"[24]
- Incorporate proven solutions into utility asset plans.

The technology solutions are not limited to but will consider the following:

- Advanced fuel cell technologies (residential and commercial/industrial scale applications using alternative fuels to produce domestic hot water, heating and electricity)
- 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[25]
- Integration of EV technologies including charging and storage capabilities, especially for high EV penetration area applications
- Enhanced renewable generation opportunities enabled by next-generation storage technologies, such as lower cost batteries offering novel chemistries and greater storage efficiencies
- Micro-grid and micro-generation technologies coupled with next-generation storage technologies, such as micro-grids incorporating battery storage, photovoltaics (solar panels) and wind energy sources, integrated with energy management systems ("EMS")

[24] An "Innovation Cluster" is a grouping of independent enterprises, such as innovative start-ups (small, medium or large) and research organizations, specializing in a particular field, sector or Region. They are designed to stimulate innovative activity by promoting intensive interactions, sharing of facilities, and knowledge and expertise exchange, thus contributing to effective networking, technology transfer and dissemination of information amongst the group members.

[25] Home area networks are home energy management systems with remote monitoring and control capabilities providing enhanced energy management and oversight (e.g., demand response, outage notification, power quality and voltage monitoring).

- Combined Heat and Power (CHP) opportunities
- Renewed consideration of the Load Serving Entity/aggregator market model. Any decision to pursue this policy alternative would require prior assessment and approval of government and regulatory authorities and agencies.

The LDCs recognize 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.

PowerStream's recently implemented micro-grid field trial offers a glimpse of the potential for distribution systems to operate autonomously whether connected to or disconnected from the normal electrical supply. The micro-grid has the potential to deliver improved reliability and power quality as well as improved efficiency and load factor. Further, it has the ability to perform system control functions specifically targeting customer requirements as well as enabling system optimization through peak shaving (load shifting), price arbitrage and new technology integration (e.g. electric vehicles). PowerStream's micro-grid demonstrates operational risk mitigation and provides feedback on the feasibility, scalability and cost effectiveness for this emerging technology.

Hydro One Distribution

Hydro One is exploring a variety of program offerings that provide customer and electricity system benefits through energy efficiency, behavioural changes, load displacement, load shifting, demand response, and energy storage. Hydro One is willing to collaborate with local electricity utilities and gas utilities to develop programs and implement projects that will be cost-effective and benefit the greater electricity system.

8.2 Recommended Actions and Implementation

A number of alternatives are possible to meet the Region's long-term needs. While specific solutions do not need to be committed today, it is appropriate to begin work now to gather information, monitor developments, engage the community, and develop alternatives, to support decision-making in the next iteration of the IRRP. The long-term plan sets out the near-term actions required to ensure that options remain available to address future needs if and when they arise.

The recommended actions and deliverables for the long-term plan are outlined in Table 8-1, along with their recommended timing, and the parties with lead responsibility for implementation are assigned.

The York Region Working Group will continue to meet at regular intervals during the implementation phase of this IRRP to monitor developments in the Region and to track progress toward these deliverables.

Table 8-1: Implementation of Near-Term Actions in Support of Medium- and Long-Term Plan for York Region

Recommendation	Action(s)/Deliverable(s)	Lead Responsibility	Timeframe
1. Undertake engagement	Establish Local Advisory Committee (LAC)	IESO/LDCs	fall 2015
	Develop engagement plans with LAC input	LDCs	Q3-Q4 2015
	Undertake public/community engagement	LDCs	2015-2017
	Engage with First Nation communities	IESO	2015-2017
2. Develop community-based solutions	Commence near-term actions required to support the overarching plan for the evaluation and implementation of new technologies and solutions	PowerStream/ Newmarket-Tay Power	2015-2017
	Identify CDM potential[26]	IESO	2016
3. Continue ongoing work to establish future transmission corridor through Peel, Halton Hills, and northern Vaughan	Conduct EA for future-use corridor	Hydro One	2015-2018
	Work with relevant municipal, regional and provincial entities	IESO/Hydro One	2015-2018
4. Monitor load growth, CDM achievement, and DG uptake	Prepare annual update to the Working Group on demand, conservation and DG trends in the area, based on information provided by Working Group	IESO	annually
5. Initiate the next regional planning cycle early, if needed	Based on results of monitoring (see recommendation 4), commence the next Regional planning cycle in advance of the OEB-mandated schedule, if needed, to enable sufficient time to develop options	IESO	as required

[26] See Appendix C.2.

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. It also addresses activities undertaken to date for the York Region 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 York Region IRRP based on the core principles of creating transparency, engaging early and often, and bringing communities to the table (see Figure 9-1). These principles were articulated 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.

Creating Transparency

To start the dialogue on the York Region IRRP and build transparency in the planning process, a number of information resources were created for the plan. A dedicated web page 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. Information was also was posted on the websites of the Working Group members. A dedicated email subscription service was also established for the York 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 York Region IRRP was providing information to the municipalities and First Nation communities in the planning area. Presentations were made to the York Region municipal planners and Chief Administrative Officers ("CAOs") and during these meetings, key topics of discussion included confirmation of the growth projections, discussion of the near- and long-term needs identified in the Region, a review of the identified near-term projects including those that have already begun due to timing requirements, and a discussion of the possible approaches to address long-term needs. The identified next steps included monitoring and providing input into the Region's corridor development activities as well as the regional Official Plan review. The presentations and information were well received and form the foundation for building broader engagement and transparency in the development of the York IRRP.

Figure 9-1: York Region IRRP Community Engagement Process

Creating Transparency:
Creation of York IRRP Information Resources

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

Engaging Early and Often:
Municipal , First Nation & Métis Outreach

- Presentation and discussion with York Region Municipal Planners
- Presentation and discussion with York Region CAOs
- Information provided to First Nation communities who may have an interest in the planning area
- 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 communities & Métis Nation of Ontario as requested
- Webinar to discuss electricity needs, near-term solutions and formation of a LAC
- Formation of LAC to discuss long-term needs and local community engagement plan
- 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
- Concurrent engagement by PowerStream and Hydro One on near-term projects
- Status: beginning in May 2015; no time limit

The link between the York Region IRRP and the development of several MEPs in York Region was also identified as an opportunity. As a result, a staff member from the IESO and representatives from the LDCs are part of the Vaughan, Markham and Newmarket MEP Stakeholder Advisory Committees and will act as a bridge in the continued development of the IRRP and the MEPs to further add value by coordinating local and provincial priorities.

Similarly, the IESO will work with the Chippewas of Georgina Island First Nation to ensure the results of their CEP, once complete, are included in the on-going IRRP discussion.

Moving forward, engagement will continue on both the IRRP and the related near-term projects. For the projects identified as part of the near-term plan, PowerStream and Hydro One will undertake engagements on individual projects as needed. Information on these project-level engagements will be provided on the organization's website and will also be listed on the York IRRP main webpage.

Bringing Communities to the Table

Engagement on the IRRP will continue with a broader community discussion about the medium- and long-term needs identified in the regional plan. This engagement will begin with a webinar hosted by the working group to discuss the plan and initiate discussion of possible medium- and long-term options, including opportunities related to achieving community self-sufficiency. Presentations on the York Region IRRP will also be made to Municipal Councils and First Nation communities on request.

To further continue the dialogue, a York Region LAC will be established as an advisory body to the York Region IRRP Working Group. The purpose of the committee is to establish a forum for members to be informed of the regional planning process. 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. The LAC meetings will be open to the public and meeting information will be posted on the IESO website. Information on the formation of the York Region LAC is available on the York Region 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" available on the IESO website.[27]

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

[27] 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 York Region, a sub-region of the GTA North OEB planning region.[28] The IRRP identifies electricity needs in the Region over the 20-year period from 2014 to 2033, recommends a plan to address near-term needs, and identifies actions to develop alternatives for the medium and long term.

Implementation of the near-term plan is already underway. LDCs are developing CDM plans consistent with the Conservation First policy and infrastructure projects are being developed by PowerStream and Hydro One. These infrastructure projects will become part of a Regional Infrastructure Plan (RIP) to be conducted by Hydro One as an outcome of this IRRP.

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

The planning process does not end with the publishing of this IRRP. Communities will be engaged in the development of the options for the medium and long term. In addition, the York Region 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 medium and long term. If demand grows as forecast, it may be necessary to revisit the plan as early as 2017 in order to respect the lead time for the development of alternatives. If demand growth slows or conservation achievement is higher than forecast, the plan may be revisited according to the OEB-mandated 5-year schedule. This outcome would allow more time to develop alternatives and to take advantage of advances in technology in the next planning cycle.

[28] A second sub-Region addressing the Claireville-to-Kleinburg transmission line is being addressed as part of the West GTA Region.

YORK REGION
INTEGRATED REGIONAL RESOURCE PLAN - APPENDICES

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

Independent Electricity System Operator

York Region IRRP

Appendix A: Demand Forecasts

Appendix A: Demand Forecasts

This Appendix provides details of the methodology and data used to develop the demand forecasts for the York Region IRRP, including the gross demand forecasts provided by LDCs, conservation and distributed generation assumptions, and detailed planning forecasts.

A.1 Gross Demand Forecasts

Appendices A.1.1 through A.1.3 were prepared by the LDCs and describe their methodologies to prepare the gross demand forecast used in this IRRP. Gross demand forecasts by station are provided in Appendix A.1.4.

A.1.1 PowerStream's Gross Demand Forecast Methodology

PowerStream is jointly owned by the municipalities of Barrie, Markham and Vaughan, and is the second largest municipally-owned electricity distribution company in Ontario. PowerStream provides power and related services to more than 370,000 customers residing or owning businesses in communities located immediately north of Toronto and in Central Ontario. PowerStream serves communities including Alliston, Aurora, Barrie, Beeton, Bradford West, Gwillimbury, Markham, Penetanguishene, Richmond Hill, Thornton, Tottenham and Vaughan, as well as Collingwood, Stayner, Creemore and Thornbury through a partnership with the Town of Collingwood in the ownership of Collus PowerStream.

This study focuses only on the York Region area. PowerStream's service territory in York Region is composed of three distinct municipal districts (Vaughan, Markham and Richmond Hill) that have 28 kV distribution lines, as well as an Aurora district that has a 44 kV sub-transmission system. Aurora is supplied by five 44 kV feeders originating from Armitage TS in Newmarket.

The electric load forecast is one of the key drivers of PowerStream's planning activities. The primary purpose of the electricity load forecast is to address the key questions of: when, where, why and how much electricity will be required on the PowerStream system to allow PowerStream to evaluate planning alternatives and to ensure that there is sufficient capacity on the system to supply customers in a reliable and cost effective manner.

The reference level forecast was performed using two different methods of forecasting to determine if there was some convergence to a forecast load at the end of the study period, specifically:

- past system peak performance and trend (statistical) analysis; and
- end-use analysis using the latest information available from municipal reports.

The reference level forecast takes into account impacts from growth, weather, DG and conservation as follows:

Growth

Four municipalities (Markham, Richmond Hill, Vaughan and Aurora) projected the residential and non-residential development in their development charge background studies. These developments are the main drivers of electrical load growth in the PowerStream service territory. PowerStream's annual residential and non-residential load growths were forecast by multiplying unit usage for residential and watts per square foot for non-residential development. The annual projected load is expressed as a percentage of the existing load. The total growth over the forecast horizon is averaged out to an annual growth rate. The growth rate is also adjusted according to current market conditions.

Weather

PowerStream's summer system peaks invariably coincide with hot weather conditions (high temperatures). While other factors may be playing a part, peak demands are being driven largely by the use of air conditioning. Prolonged periods of hot weather present the biggest challenge to the reliability of PowerStream's distribution system when a significant number of customers are using their home and workplace air conditioners simultaneously, and diversity of operation between customers is lost.

Since long-term weather cannot be forecast, weather scenarios (normal and extreme summer) are created based on historical weather data.

Historical electrical peaks are weather normalized to account for weather impact.

An electricity distribution system should be able to maintain the supply to customers not only under normal weather, but also under extreme weather conditions. Electrical load forecasts under normal summer weather are created and provided to the IESO. Electrical load forecasts under extreme weather are produced by IESO utilizing algorithms.

Conservation and Demand Management (CDM)

PowerStream's load forecast is performed using the current year's actual peak (weather normalized) as a starting point. The impact of CDM programs in the previous years has been reflected in the actual peak.

PowerStream's CDM Strategy 2011 to 2014 Report has been filed and approved by the OEB. To meet its CDM target, PowerStream (including areas the utility serves outside of York Region) will achieve a 90 MW reduction in peak demand from 2011 to 2014.

PowerStream has a new target for post 2014. The new target is to achieve 535.4 GWh of energy savings persisting to 2020 by 2020.

The forecast provided by PowerStream does not include the impacts of conservation from 2014 onward. Conservation assumptions were developed by the IESO and applied to PowerStream's load forecast.

Distributed Generation (DG)

PowerStream will build new capacity when and where load is projected to occur. If DG is located near the load growth, it can reduce the need for new capacity. Thus, PowerStream can defer investments in wire-delivery facilities by relying on DG, at least for a short period of time, if not indefinitely.

PowerStream's load forecast is performed using the current year's actual peak (weather normalized) as a starting point. The impact of existing DG has been reflected in the actual peak.

The IESO will apply the effective impact of future DG on PowerStream's load forecast.

A.1.2 Newmarket-Tay Distribution Ltd. Gross Forecast Methodology

Introduction

Newmarket-Tay Power Distribution Ltd. ("NT Power") owns and operates the electricity distribution system within its OEB licensed service area, which is the Town of Newmarket including small areas bordering the municipalities of King and East Gwillimbury, in the Regional Municipality of York (Newmarket Service Area), as well as the Simcoe County communities of Port McNicoll, Victoria Harbour and Waubaushene, which are part of the Township of Tay (Tay Service Area). For the purpose of this study, the focus is only on the Newmarket Service Area. NT Power serves approximately 26,000 Residential and General Service customers within the Newmarket Service Area.

Community in Transition

The Town of Newmarket has been designated as an Urban Growth Centre under the Province of Ontario's Places to Grow strategy and as an area where future growth and intensification is to be directed. The Yonge St. and Davis Dr. corridors have been identified as one of four Regional Centres in the York Region Official Plan.

The Town of Newmarket is currently planning for the revitalization of Newmarket's Urban Centers which will shape the future of the community. The town has recently adopted a new Secondary Plan that sets ambitious targets for population and employment growth within its centres and corridors - primarily along Yonge St. and Davis Dr. The Secondary Plan will result in increased density (e.g., population and jobs) to meet the minimum density provisions of the Growth Plan (200 persons and jobs per hectare) and the Region of York Official Plan growth policies. For the purpose of this study, NT Power used the projections that meet provincial and regional planning requirements as developed by the Town of Newmarket through the Secondary Plan process.

Forecast Municipal Growth Rate Basis of Load Forecast

In developing the forecast, NT Power relied upon a combination of past historical growth, as well as ongoing discussions with planning staff of both the Town of Newmarket and the Region of York. The Region of York's approved official plan with forecast projected growth is the basis of this load forecast with further analysis associated with Newmarket's Secondary Plan. For the current load forecast the coincident peak data from 2013 has been used as the base for the load forecast. In developing the load forecast several factors must be considered and evaluated to determine potential growth within the service area. The electric load forecast is one of the key drivers of NT Power's planning activities at both the distribution planning level and overall supply requirements from the bulk wholesale transmission system.

Base Forecast: Trend and End Use Analysis

Trend Analysis uses historical consumption of electricity demand to predict future requirements. A combination of timeframes (5, 10, 15 years) is used to determine potential demand increases as compared to forecast growth. Regular updating and review is completed on an annual basis.

A second analysis is completed based on customer end use. As stated above, the Town of Newmarket is a community in transition with the primary focus for future growth centered on the Yonge St. and Davis Dr. corridors. The Town of Newmarket expects to achieve population and employment growth targets through increased density and vertical development. This anticipated significant increase in land-use intensification, as well as the complete renewal of the commercial sector, will provide the biggest impact on load growth over the forecast period.

The end-use analysis methodology considers that the demand for electricity is dependent on what it is used for. An analysis is completed on end-use usage and demand is subsequently allocated between residential and industrial/commercial/institutional ("ICI") type demand. Using standard historical usage data per end-use customer provides a basis to forecast expected demand with load growth across both residential and industrial ICI demand.

A.1.3 Hydro One Distribution Gross Forecast Methodology

Hydro One Distribution services the areas of York Region that are not serviced by other LDCs via four step-down transformer stations from 230 kV to 44 kV. This area includes the Chippewas of Georgina Island First Nation. The stations are Armitage TS, Holland TS, Brown Hill TS, and Kleinburg TS.

The reference level forecast is developed using macro-economic analysis, which takes into account the growth of demographic and economic factors. The forecast corresponds to the expected weather impact on peak load under average weather conditions, known as weather-normality. Furthermore, the forecast is unbiased such that there is an equal chance of the actual peak load being above or below the forecast. In addition, local knowledge, information regarding the loading in the area within the next two to three years, is utilized to make minor adjustments to the forecast.

A.1.4 Gross Forecasts, by Sub-Area and Station

Table A-1: Gross Demand Forecasts (MW)

NORTHERN YORK REGION	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Gross Load (normal weather)																				
Holland TS	128	131	134	137	141	143	147	150	154	157	161	164	168	171	175	178	181	183	185	187
Armitage TS	277	284	290	298	305	312	319	327	335	344	350	358	365	372	380	387	395	401	408	414
Brown Hill TS	78	80	83	86	89	92	95	98	102	105	109	112	116	120	124	128	133	137	141	146

VAUGHAN/RICHMOND HILL	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Gross Load (normal weather)																				
Richmond Hill MTS	238	238	238	238	238	238	238	238	238	238	238	238	238	238	238	238	238	238	238	238
Vaughan 1 MTS	290	310	327	356	373	396	421	447	473	500	520	540	562	582	603	619	636	653	669	687
Vaughan 2 MTS	143	143	143	143	143	143	143	143	143	143	143	143	143	143	143	143	143	143	143	143
Vaughan 3 MTS	143	143	143	143	143	143	143	143	143	143	143	143	143	143	143	143	143	143	143	143

*All new PowerStream growth in Vaughan area was assigned to Vaughan 1/1E, the newest station

MARKHAM	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Gross Load (normal weather)																				
Buttonville TS	112	131	131	143	143	143	143	143	143	143	143	143	143	143	143	143	143	143	143	143
Markham 1 MTS	84	76	76	76	76	76	76	76	76	76	76	76	76	76	76	76	76	76	76	76
Markham 2 MTS	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95
Markham 3 MTS	178	189	189	189	189	189	189	189	189	189	189	189	189	189	189	200	189	189	189	189
Markham 4 MTS	74	76	100	115	143	168	193	218	244	272	292	312	331	353	375	382	409	426	444	461

*All new PowerStream growth in Markham area was assigned to Markham 4 MTS, the newest station

A.2 Conservation

The forecast conservation savings included in the demand forecasts for the York Region IRRP were derived from the provincial conservation forecast, which aligns with the conservation targets described in the 2013 LTEP: "Achieving Balance: Ontario's Long-Term Energy Plan". The LTEP set an electrical energy conservation target of 30 TWh in 2032, with about 10 TWh of the energy savings coming from codes and standards ("C&S"), and the remaining 20 TWh from energy efficiency ("EE") programs. The 30 TWh energy savings target will also lead to associated peak demand savings. Time-of-Use ("TOU") rate impacts and Demand Response resources are focused on peak demand reduction rather than energy savings and, as such, are not reflected in the 30 TWh energy target and are considered separately in forecasting.

To assess the peak demand savings from the provincial conservation targets, two demand forecasts are developed. A gross demand forecast is produced that represents the anticipated electricity needs of the province based on growth projections, for each hour of the year. This forecast is based on a model that calculates future gross annual energy consumption by sector and end use. Hourly load shape profiles are applied to develop province-wide gross hourly demand forecasts. Natural conservation impacts are included in the provincial gross demand forecast, however the effects of the planned conservation are not included. A net hourly demand forecast is also produced, reflecting the electricity demand reduction impacts of C&S, EE programs, and TOU. The gross and net forecasts were then compared in each year to derive the peak demand savings. In other words, the difference between the gross and net peak demand forecasts is equal to the demand impacts of conservation at the provincial level.

The above methodology was used to derive the combined peak demand savings, which was further broken down to three categories as shown in Table-1. Peak demand savings associated with load shifting in response to TOU rates were estimated using an econometric model based on customers' elasticity of substitution and the TOU price ratio. The remaining peak savings were allocated between C&S and EE programs based on their energy saving projections, with about 1/3 attributed to C&S and 2/3 to EE programs.

The resulting peak demand savings in each year are represented as a percentage of total provincial peak demand in Table A-2, using 2013 as a base year.

Table A-2: Peak Demand Savings from Provincial Conservation Targets (% of load)

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
C&S	0.0%	0.2%	0.5%	0.6%	1.1%	1.6%	1.9%	2.3%	2.5%	2.6%	2.8%	2.9%	3.1%	3.6%	4.1%	4.4%	4.8%	5.1%	5.4%	5.4%
TOU	0.2%	0.3%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%
EE programs	0.5%	0.8%	1.0%	1.1%	1.3%	2.1%	3.1%	3.2%	3.6%	4.2%	5.0%	5.3%	5.8%	6.0%	6.5%	6.6%	6.9%	7.4%	7.8%	7.8%
Total	0.8%	1.3%	1.9%	2.2%	2.7%	4.1%	5.4%	5.9%	6.5%	7.1%	8.1%	8.6%	9.3%	10.0%	11.0%	11.4%	12.1%	12.8%	13.5%	13.5%

These percentages were applied to the gross demand forecasts provided by the York Region LDCs at the transformer station level to determine the peak demand savings assumed in the planning forecast. This allocation methodology relies on the assumption that the peak demand savings from provincial conservation will be realized uniformly across the province. Actions recommended in the York Region IRRP to monitor actual demand savings, and to assess conservation potential in the Region, will assist in developing region-specific conservation assumptions going forward.

Existing DR resources are included in the base year and gross demand forecasts. Additional DR resources can be considered as potential options to meet regional needs.

A.2.1 Conservation Assumptions by Sub-Area and Station

The following tables show the expected peak demand impact of provincial energy targets at each transformer station, developed according to the methodology described in Appendix A.2 above, for the purposes of the high-growth forecast.

Table A-3: Conservation Assumptions (MW)

NORTHERN YORK REGION	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Conservation (normal weather)																				
Holland TS	1	2	3	3	4	6	8	9	10	11	13	14	16	17	19	20	22	23	25	25
Armitage TS	2	4	6	6	8	13	17	19	22	24	28	31	34	37	42	44	48	51	55	56
Brown Hill TS	1	1	2	2	2	4	5	6	7	7	9	10	11	12	14	15	16	18	19	20

VAUGHAN/RICHMOND HILL	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Conservation (normal weather)																				
Richmond Hill MTS	2	3	5	5	7	10	13	14	15	17	19	21	22	24	26	27	29	31	32	32
Vaughan 1 MTS	2	4	6	8	10	16	23	26	31	35	42	47	52	58	66	71	77	84	91	93
Vaughan 2 MTS	1	2	3	3	4	6	8	8	9	10	12	12	13	14	16	16	17	18	19	19
Vaughan 3 MTS	1	2	3	3	4	6	8	8	9	10	12	12	13	14	16	16	17	18	19	19

MARKHAM	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Conservation (normal weather)																				
Buttonville TS	1	2	2	3	4	6	8	8	9	10	12	12	13	14	16	16	17	18	19	19
Markham 1 MTS	1	1	1	2	2	3	4	4	5	5	6	7	7	8	8	9	9	10	10	10
Markham 2 MTS	1	1	2	2	3	4	5	6	6	7	8	8	9	10	10	11	11	12	13	13
Markham 3 MTS	1	3	4	4	5	8	10	11	12	13	15	16	18	19	21	23	23	24	26	26
Markham 4 MTS	1	1	2	2	4	7	10	13	16	19	24	27	31	35	41	44	49	55	60	63

A.3 Distributed Generation

As of February 2014, the IESO (former OPA) had awarded 82 MW of DG contracts within the York Region study area. Of these, 22 MW had already reached commercial operation. Since LDCs were producing their demand forecasts to align with actual peak demand, any DG already in service during the most recent year's peak hour would already be accounted for in gross forecasts. As a result, only contracts for projects which had not yet reached commercial operation at the time the forecasts were produced needed to be incorporated.

Contract information provided the rated (installed) capacity, generation fuel type (solar and natural gas), connecting station, and maximum commercial operation date ("MCOD") for each project. For the purposes of this study, it was assumed that all active contracts would be connected on their MCOD. This was a conservative assumption, as some attrition would normally be expected from a field of over 130 contracts. While natural gas projects can be assumed to contribute their full installed capacity during summer peak, local weather conditions can greatly impact the contribution of solar projects to meeting demand. For the York Region IRRP, the IESO relied upon the summer Solar Capacity Contribution ("SCC") values, as described in section 3.2.2 of the 2014 Methodology to Perform Long Term Assessments[1] (copied below):

> Monthly Solar Capacity Contribution (SCC) values are used to forecast the contribution expected from solar generators. SCC values in percentage of installed capacity are determined by calculating the simulated 10-year solar historic median contribution at the top 5 contiguous demand hours of the day for each winter and summer season, or shoulder period month. As actual solar production data becomes available in future, the process of picking the lower value between actual historic solar data, and the simulated 10-year historic solar data will be incorporated into the SCC methodology until 10-years of actual solar data is accumulated, at which point the simulated solar data will be phased out of the SCC calculation.

Based on the current methodology, summer peak SCCs of 34% were assumed. After consideration of anticipated peak contribution of each contract, the total effective capacity for all active, unconnected DG contracts was estimated on a station by station basis. Consideration

[1] http://www.ieso.ca/Documents/marketReports/Methodology_RTAA_2014feb.pdf

was also given to anticipated in-service year, to ensure the effect of the project is not observed until the MCOD date. The final DG forecast is shown in Appendix A.3.1.

A.3.1 Distributed Generation Assumptions by Sub-Area and Station

The following tables show the expected peak demand impact of DG contracts which were active as of February 2014, but which had not yet reached commercial operation. These contributions were subtracted from the gross demand forecasts on a station by station basis.

Table A-4: Distributed Generation Assumptions (MW)

NORTHERN YORK REGION	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Distributed Generation																				
Holland TS	0.32	0.78	0.78	0.78	0.78	0.78	0.78	0.78	0.78	0.78	0.78	0.78	0.78	0.78	0.78	0.78	0.78	0.78	0.78	0.78
Armitage TS	2.38	2.66	2.66	2.66	2.66	2.66	2.66	2.66	2.66	2.66	2.66	2.66	2.66	2.66	2.66	2.66	2.66	2.66	2.66	2.66
Brown Hill TS	10.2	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5

VAUGHAN/RICHMOND HILL	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Distributed Generation																				
Richmond Hill MTS	0.00	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60
Vaughan 1 MTS	0.10	1.86	1.86	1.86	1.86	1.86	1.86	1.86	1.86	1.86	1.86	1.86	1.86	1.86	1.86	1.86	1.86	1.86	1.86	1.86
Vaughan 2 MTS	0.58	1.09	1.09	1.09	1.09	1.09	1.09	1.09	1.09	1.09	1.09	1.09	1.09	1.09	1.09	1.09	1.09	1.09	1.09	1.09
Vaughan 3 MTS	0.00	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45

MARKHAM	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Distributed Generation																				
Buttonville TS	0.24	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30
Markham 1 MTS	0.25	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86
Markham 2 MTS	3.47	3.51	3.51	3.51	3.51	3.51	3.51	3.51	3.51	3.51	3.51	3.51	3.51	3.51	3.51	3.51	3.51	3.51	3.51	3.51
Markham 3 MTS	2.65	3.08	3.08	3.08	3.08	3.08	3.08	3.08	3.08	3.08	3.08	3.08	3.08	3.08	3.08	3.08	3.08	3.08	3.08	3.08
Markham 4 MTS	0.00	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07

A.4 Planning Forecasts

Two planning level forecasts were developed for the York IRRP: a high-growth forecast; and a low-growth forecast.

The high-growth forecast is the primary forecast used for carrying out system studies, and was based on gross demand forecast by LDCs within their service territories. The underlying growth projections upon which this forecast is based are consistent with municipal growth plans, which in turn are in alignment with *Places to Grow, the Provincial Growth Plan for the Greater Golden Horseshoe*. The LDC forecasts were adjusted by the IESO to account for the anticipated peak demand impacts of provincial energy targets, the effect of contracted distributed generation, and effect of extreme weather conditions.

The low-growth forecast was prepared by the IESO by applying the percentage annual growth rates predicted by the demand forecast model underlying the LTEP for the broader Central Ontario and GTA zones, and applying these growth rates uniformly across the load centres. Because York Region overlaps with both of these zones, the growth rate for the Toronto zone was used for Southern York Region (roughly corresponding with the municipalities of Vaughan, Richmond Hill, Markham, and Buttonville), and the growth rate for Central Ontario was used for Northern York Region (roughly corresponding with the municipalities of Whitchurch-Stouffville, Georgina, East Gwillimbury, Newmarket, and King).[2] Zonal growth rates were prepared based on direction provided in the 2013 LTEP, and they account for anticipated peak demand impacts of new Conservation programs. Because this forecast does not allow for variations in growth levels within a planning area, and instead applies the same growth rate across a large zone, this forecast does not provide the same precision or benefits of local knowledge as the high-growth forecast. As a result, this forecast was used as a long term (2024-2033) sensitivity scenario, to account for the lower level of certainty associated with development plans prepared over a decade in advance. Since this forecast made use of a percentage growth factor, it was required to assume a starting value for station demand in 2023. In order to align this long term forecast with the common near/mid-term forecast, the high-growth forecast was used as the starting point.

[2] The northern and southern sub-regional boundaries in this study are based on electrical boundaries and do not correspond directly with the municipal boundaries.

In both forecasts, the final demand allocated to PowerStream stations was adjusted to account for load transfers and typical station loading practices. This ensures that a station already at full capacity would continue at full utilization, even if incremental peak demand reducing measures (conservation and DG) would have produced a net decrease in load. The IESO worked with PowerStream to understand and implement transfers consistent with their expected operation.

The final high-growth and low-growth forecasts are provided in Appendices A.4.1 and A.4.2, respectively.

A.4.1 High-Growth Planning Forecast by Sub-Area and Station

Table A-5: High-Growth Planning Forecast (MW)

NORTHERN YORK REGION	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Net Load (Extreme)																				
Holland TS	134	136	138	142	144	145	146	149	152	154	156	158	160	162	164	166	168	168	169	170
Armitage TS	289	294	299	306	312	314	317	324	330	336	338	344	349	352	356	361	365	368	371	377
Brown Hill TS	72	74	76	79	81	83	85	88	90	93	95	98	101	104	107	110	113	116	119	123

VAUGHAN/RICHMOND HILL	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Net Load (Extreme)																				
Richmond Hill MTS	254	254	254	254	254	254	254	254	254	254	254	254	254	254	254	254	254	254	254	254
Vaughan 1 MTS	287	306	306	306	306	306	306	306	306	306	306	306	306	306	306	306	306	306	306	306
Vaughan 2 MTS	153	153	153	153	153	153	153	153	153	153	153	153	153	153	153	153	153	153	153	153
Vaughan 3 MTS	153	153	153	153	153	153	153	153	153	153	153	153	153	153	153	153	153	153	153	153
Vaughan 4 MTS	0	0	24	47	69	83	97	119	140	160	170	185	200	212	222	233	241	248	256	272

MARKHAM	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Net Load (Extreme)																				
Buttonville TS	153	153	153	153	153	153	153	153	153	153	153	153	153	153	153	153	153	153	153	153
Markham 1 MTS	81	81	81	81	81	81	81	81	81	81	81	81	81	81	81	81	81	81	81	81
Markham 2 MTS	101	101	101	101	101	101	101	101	101	101	101	101	101	101	101	101	101	101	101	101
Markham 3 MTS	202	202	202	202	202	202	202	202	202	202	202	202	202	202	202	202	202	202	202	202
Markham 4 MTS	24	42	62	89	112	125	137	158	178	198	207	220	232	244	255	265	273	279	287	303

A.4.2 Low-Growth Forecast by Sub-Area and Station

Table A-6: Low-Growth Planning Forecast (MW)

NORTHERN YORK REGION	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Net Load (Extreme)	(Places to Grow)										
Holland TS	154	153	153	153	153	152	152	152	152	152	152
Armitage TS	336	334	334	334	333	332	332	332	331	330	333
Brown Hill TS	93	93	93	93	92	92	92	92	92	92	92

VAUGHAN/RICHMOND HILL	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Net Load (Extreme)	(Places to Grow)										
Richmond Hill MTS	254	254	254	254	254	254	254	254	254	254	254
Vaughan 1 MTS	306	306	306	306	306	306	306	306	306	306	306
Vaughan 2 MTS	153	153	153	153	153	153	153	153	153	153	153
Vaughan 3 MTS	153	153	153	153	153	153	153	153	153	153	153
Vaughan 4 MTS	160	162	168	173	177	179	186	190	194	198	210

MARKHAM	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Net Load (Extreme)	(Places to Grow)										
Buttonville TS	153	153	153	153	153	153	153	153	153	153	153
Markham 1 MTS	81	81	81	81	81	81	81	81	81	81	81
Markham 2 MTS	101	101	101	101	101	101	101	101	101	101	101
Markham 3 MTS	202	202	202	202	202	202	202	202	202	202	202
Markham 4 MTS	198	200	207	213	218	220	228	234	238	242	256

York Region IRRP

Appendix B: Needs Assessment

Appendix B: Needs Assessment

This Appendix provides information on the methodology and data used to assess needs in the York Region IRRP.

B.1 Station Capacity Assessment

In order to assess the need for additional transformer station capacity, planning forecasts were compared to the 10-day limited time rating ("LTR") of the stations in the Region. In order to account for transfer capability between adjacent stations, three groupings of stations were considered:

- **Northern York Region:** Holland TS, and Armitage TS.[3]
- **Vaughan:** Vaughan #1, #2, and #3 stations for the near term; in the medium and long term, the new Vaughan #4 station was also assumed to be available.
- **Markham/Richmond Hill:** Markham #1, #2, #3, and #4 stations, Richmond Hill MTS, and Buttonville TS.

For each of these station groupings, the combined capacities of the stations were compared against the combined planning forecasts at the included stations to determine when new station capacity is likely to be needed.

B.1.1 Near-Term Station Capacity Assessment (2014-2018)

In the near term, station capacity is forecast to be exceeded beginning around 2016 in Vaughan. There is adequate station capacity in Markham/Richmond Hill and Northern York Region in the near term.

Subareas	Combined Station LTR (MW)	Near-Term Planning Forecast 2014-2018 (MW)				
		2014	2015	2016	2017	2018
Markham/Richmond Hill	944	815	833	853	880	903
Northern York Region	485	423	430	437	448	456
Vaughan	612	593	612	636	659	681

[3] Brown Hill TS is not included in the Northern York Region group due to its distance from the Holland and Armitage stations. Brown Hill TS has adequate station capacity to accommodate forecast growth throughout the 20-year planning period.

B.1.2 Medium and Long-Term Station Capacity Assessment (2019-2033): High-Growth Scenario

Under the high-growth scenario, station capacity is forecast to be exceeded in Markham/Richmond Hill beginning around 2021, and in Northern York Region and Vaughan around 2023.

Sub-areas	Combined Station LTR (MW)	High-Growth Scenario 2019-2033 (MW)														
		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Markham/Richmond Hill	**944**	916	928	949	969	989	998	1011	1023	1035	1046	1056	1064	1070	1078	1094
Northern York Region	**485**	459	463	473	481	490	494	502	509	515	520	527	533	536	540	547
Vaughan	**765**	695	709	731	752	772	782	797	812	824	834	845	853	860	868	884

B.1.3 Medium and Long-Term Station Capacity Assessment (2019-2033): Low-Growth Scenario

Under the low-growth scenario, station capacity is forecast to be exceeded in Markham/Richmond Hill beginning around 2021, and in Vaughan around 2023. Station capacity is expected to be adequate throughout the study period in Northern York Region under this scenario.

Sub-areas	Combined Station LTR (MW)	Low-Growth Scenario 2019-2033 (MW)														
		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Markham/Richmond Hill	**944**	916	928	949	969	989	991	998	1004	1009	1011	1019	1025	1029	1033	1047
Northern York Region	**485**	459	463	473	481	490	487	488	487	486	484	485	484	483	482	485
Vaughan	**765**	695	709	731	752	772	774	780	785	789	791	798	802	806	810	822

B.2 System Load Flow Base Case Setup and Assumptions

The system studies for this IRRP were conducted using PSS/E Power System Simulation software. The reference PSS/E case was adapted from the 2015 base case that was produced by the IESO for the 2010 Northeast Power Coordinating Council ("NPCC") Review. This load flow includes all eight Bruce nuclear units and the new 500 kV double-circuit line between the Bruce Complex and Milton SS. All the units at Darlington are assumed to be in-service, and all of the units at the Pickering generating station are assumed to be unavailable due to their scheduled retirement as early as 2015. Summer ambient conditions of 35 □C and 4 km/hr wind for overhead transmission circuits were assumed in this study. For transformers, 10-day LTRs are respected under post-contingency conditions.

In additional to the bulk system assumptions, the base case includes the following recent changes and specific characteristics of the York Region system:

- Both units at York Energy Centre (YEC)—G1 and G2—were included in the study. Under YEC's current connection configuration, the bus tie between G1 and G2 is normally open and does not have the capability to provide backup under N-1 contingency conditions.
- Due to declining gas feedstock from the landfill site that is its fuel source, the output of the Keele Valley Generating Station is uncertain, particularly in the later years of the study. Therefore, this facility was assumed to be out of service.
- Des Joachim GS and southbound flows on the North-South Tie Interface contribute to the area supply at the northern end of the Claireville-to-Minden system. For this study, the North-to-South flow was assumed to be about 1,530 MW, and the output of Des Joachim GS was assumed to be 280 MW (~78% of installed capacity).
- All capacitor banks at Armitage TS, Holland TS, Beaverton TS and Lindsay TS were assumed to be in service.

B.3 Load Meeting Capability of the Claireville-to-Minden System

B.3.1 Application of Planning Criteria

In the Claireville-to-Minden system, supply capacity is provided by both the transmission system, as well as the two generating units at York Energy Centre.

In accordance with ORTAC, the system must be designed to provide continuous supply to a local area under specific transmission and generation outage scenarios. The ORTAC criteria governing supply capacity for local areas are presented in Table B-1. For areas with local generation, such as the Claireville-to-Minden system, ORTAC gives credit to the supply capacity provided by local generation by allowing controlled load rejection as an operational measure under specified outage conditions.

The performance of the system in meeting these conditions is used to determine the supply capability of an area for the purpose of regional planning. Supply capability is expressed in terms of the maximum load that can be supplied in the local area with no interruptions in supply or, under certain permissible conditions, with limited controlled interruptions as specified by ORTAC.

Table B-1: ORTAC Supply Capacity Criteria for Systems with Local Generation

<table>
<tr><th colspan="2">Pre-contingency</th><th>Contingency[1]</th><th>Thermal Rating</th><th>Maximum Permissible Load Rejection</th></tr>
<tr><td rowspan="6">All transmission elements in-service</td><td rowspan="3">Local generation in-service</td><td>N-0</td><td>Continuous</td><td>None</td></tr>
<tr><td>N-1</td><td>LTE[2]</td><td>None</td></tr>
<tr><td>N-2</td><td>LTE[2]</td><td>150 MW</td></tr>
<tr><td rowspan="3">Local generation out-of-service</td><td>N- 0</td><td>Continuous</td><td>None</td></tr>
<tr><td>N-1</td><td>LTE[2]</td><td>150 MW[3]</td></tr>
<tr><td>N-2</td><td>LTE[2]</td><td>>150 MW[3]
(600 MW total)</td></tr>
</table>

1. N-0 refers to all elements in-service; N-1 refers to one element (a circuit or transformer) out of service; N-2 refers to two elements out of service (for example, loss of two adjacent circuits on same tower, breaker failure or overlapping transformer outage),N-G refers to local generation not available (for example, out of service due to planned maintenance).
2. LTE: Long-term emergency rating. 50-hr rating for circuits, 10-day rating for transformers.
3. Only to account for the capacity of the local generating unit out of service

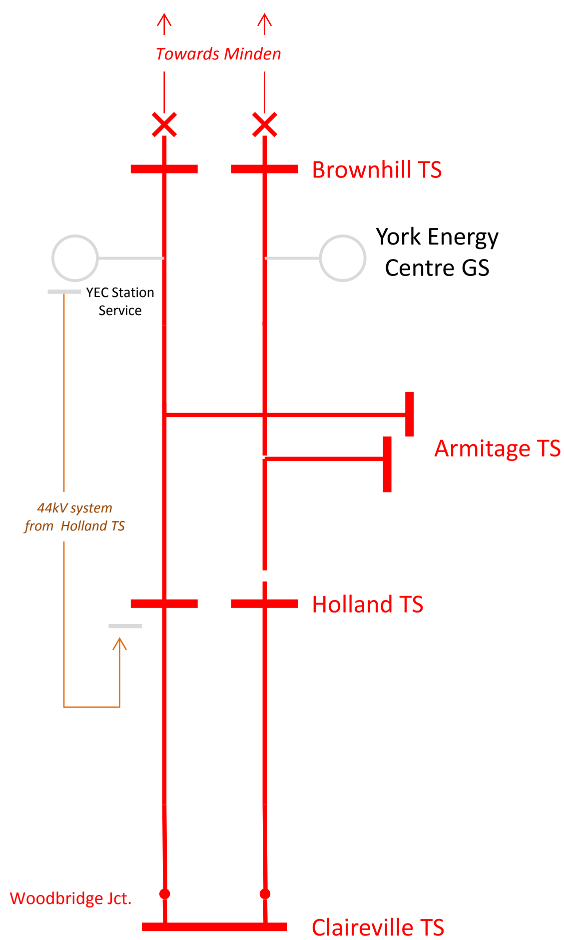
B.3.2 Existing System

The Claireville-to-Minden system, shown in Figure B-1, was assessed under applicable transmission and generation outage scenarios, and load security criteria, as defined by ORTAC. The Load Meeting Capability (LMC) of the system is defined by the most limiting contingency or criterion identified through this assessment.

The LMC of the existing Claireville-to-Minden system, which consists of the 230 kV double-circuit transmission line carrying the circuits B82V and B83V, as well as the local generation at York Energy Centre, is 600 MW. This is defined by the ORTAC load security criterion, which specifies that no more than 600 MW may be lost by configuration in a contingency involving two system elements. Currently, with no isolating devices on the system between Claireville and Brown Hill, this is the most limiting criterion on this system.

While not currently limiting, the supply capability of the system based on contingency analysis is only slightly higher than the load security limit. The next most limiting contingency is a thermal limitation on the section of B82V or B83V between Holland and Claireville following an outage involving the companion circuit. This contingency would limit the supply capability of the Clairieville-to-Minden system to 650 MW.

Figure B-1: Existing Claireville-to-Minden System Configuration

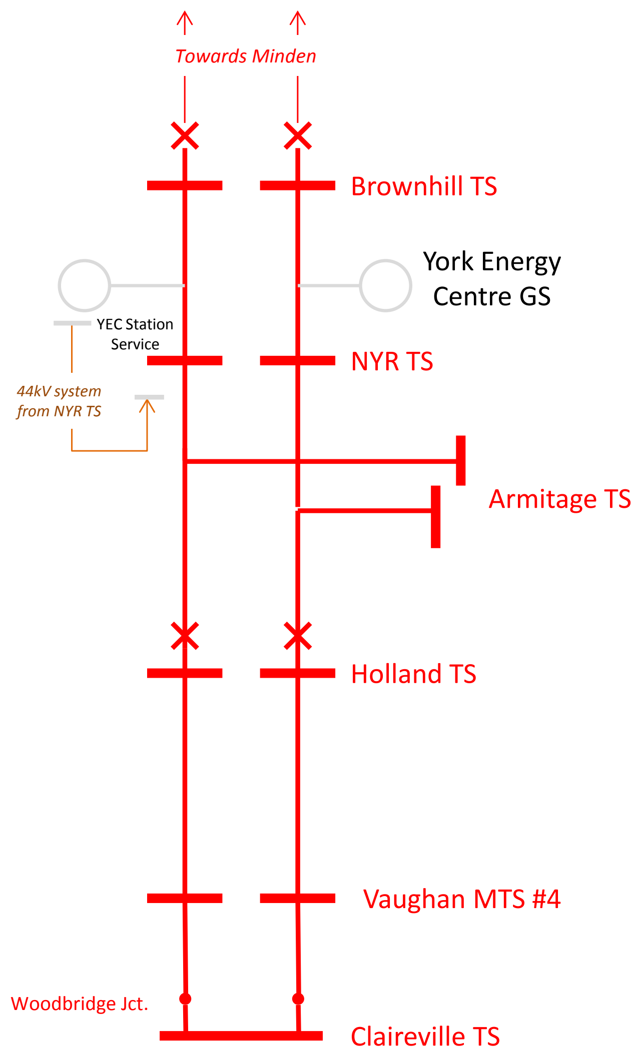


B.3.3 With Addition of In-Line Breakers at Holland TS

The installation of two in-line breakers at the Holland station site, along with motorized disconnect switches and a Load Reduction (L/R) scheme, is part of the recommended near-term plan for York Region (see Figure B-2). The in-line breakers will address the 600 MW load loss limit by sectionalizing the line. In combination with the L/R scheme, the breakers will also increase the supply capability of the system. The new LMC on the Claireville-to-Minden system with these enhancements will be 850 MW. The most limiting contingency defining this LMC is an outage on B82V between the Brown Hill and Holland stations while the YEC unit connected to B83V is unavailable. Under these conditions, the section of B83V north of the breakers would be thermally limited.

The station service supply arrangement for YEC has an impact on the capability of the Claireville-to-Minden system. Currently, its primary supply is through a 44 kV feeder originating at Holland TS. In determining the LMC described above, it was assumed that, as load growth in Northern York Region progresses to the point that a new station is required, the station would be connected north of the in-line breakers, and the station service supply for YEC would be reconnected to that station. If the YEC station service were to continue to be supplied from Holland TS the LMC of the Claireville-to-Minden system would be limited to approximately 700-750 MW.

Figure B-2: Claireville-to-Minden System Configuration after Addition of Holland Switching Facilities



York Region IRRP

Appendix C: Conservation

Appendix C: Conservation

This Appendix includes descriptions provided by the LDCs of their conservation plans, and describes efforts planned to assess conservation potential going forward. In addition to LDC programs, the Chippewas of Georgina Island First Nation have participated in the IESO's Aboriginal Conservation Program.

C.1 LDC Conservation Plans

The following summaries were provided by LDCs to introduce their CDM Plans for the years 2015-2020, required as part of the Conservation First Framework for 2015-2020. LDCs are required to submit their CDM Plans to the IESO by April 30, 2015. Additional details can be found on each LDC's respective website.

C.1.1 PowerStream

On December 18, 2014, PowerStream submitted its 2015-2020 CDM Plan to the IESO. The plan outlines how it will achieve the new conservation target of 535 GWh over 2015 to 2020.

The plan includes a comprehensive mix of conservation programs to be made available to various types of customers including residential, commercial and industrial customers. Many of the Province-Wide CDM programs designed and funded by the IESO under the 2011-2014 framework will continue to be available under the 2015-2020 framework. PowerStream anticipates that these existing provincial programs, along with some planned enhancements, will continue to contribute the majority of savings within the program portfolio. The plan also calls for new and innovative local programs to supplement the provincial programs.

The annual CDM savings forecast over 2015-2020 was developed at a program level based on inputs from several sources including: CDM achievable potential study conducted by the IESO, PowerStream's historical CDM results, market research, input from third party consultants and CDM management staff. The key steps in developing the CDM savings forecast were as follows:

Step 1 – Provincial Programs. Savings were forecast by estimating the annual participation levels (e.g. number of projects or participants) for each continuing Provincial Program and multiplying the participation forecast by the average savings per project achieved in the program historically.

Step 2 – Anticipated Enhancements to Provincial Programs. Energy savings for anticipated enhancements to the Provincial Programs during the 2015-2020 timeframe were developed based on a review of similar program design elements in other jurisdictions. Based on steps 1 and 2, PowerStream estimates that Provincial Programs (including planned enhancements) will contribute energy savings amounting to about 64% of its 6-year CDM target.

Step 3 – New Programs. In its CDM Plan submission to the IESO, PowerStream identified five concepts for new CDM programs. The detailed program design and business cases for these programs are yet to be developed and approved by the IESO. For the purposes of its CDM Plan, PowerStream made a high level estimate of potential energy savings based on a review of similar programs in other jurisdictions. The delivery costs for the programs were then estimated by multiplying the forecast energy savings by the 'budget rates' (i.e., $310/MWh for residential programs; $240/MWh for non-residential programs) used by the IESO in allocating PowerStream its overall CDM delivery budget of $140.7 million.

Step 4 – Shortfall. Based on all planned CDM programs (current provincial programs, planned enhancements to provincial programs, and new programs), PowerStream estimates achieving about 75% of its 2020 CDM target. In its CDM Plan, PowerStream has identified 131 GWh (25% of target) as a current shortfall. PowerStream plans to achieve 100% of its IESO-allocated target and will continue to explore and develop new program ideas for addressing this shortfall.

PowerStream's 2015-2020 conservation targets are being built into the development of the IRRP and RIP for GTA North, as well as PowerStream's Distribution System Plan. PowerStream is also actively supporting the City of Vaughan and the City of Markham with their Community Energy Plans, by providing data and by participating on advisory committees.

C.1.2 Newmarket-Tay Power

Conservation and demand management will play a significant role in meeting future load growth within York Region. Conservation and demand management targets established in the 2013 LTEP are a key component of the near-term plan for York Region. Based on the success and lessons learned from the initial 2011-2014 CDM framework, Newmarket-Tay Power Distribution is currently preparing a detailed CDM plan for the second CDM framework 2015-2020. Efforts will be focused as much as possible on measures that provide peak demand reduction.

Newmarket-Tay Power Distribution Ltd. will be an active participant in all provincial programs for residential, commercial and industrial sectors. Additional targeted efforts will be directed towards those programs that offer a higher degree of impact on demand reduction. Programs such as the Feed-in-Tariff, (FIT) Demand Response (DR) and Combined Heat and Power (CHP) are expected to have the largest impact towards achieving success. The potential evolution of existing microFIT program to a net metering program outlined in the Conservation First document may prove to be a mechanism to increase customer participation in this area of demand reduction. Newmarket-Tay Power Distribution is reviewing an opportunity to proceed with various pilots to increase customer participation in this area.

The provincial Conservation First policy provides a clear mandate to significantly increase the focus on conservation. Ontario's vision is to invest in conservation first, before new generation, where cost-effective.

As outlined in the Conservation First policy, CDM savings can be achieved in a range of ways:

- Energy efficiency: Using more energy efficient technology that consumes less electricity, such as LED lighting. Building codes and product efficiency standards help improve the energy efficiency of new buildings and appliances.
- Behavioural changes: Increasing awareness and encouraging different behaviour to reduce energy use, for example through social benchmarking.
- Demand management: Reducing or shifting consumption away from peak times, using time-of-use pricing with smart meters and programs like Peaksaver PLUS® and Demand Response 3.
- Load displacement: Reducing load on the grid by enabling customers to improve the efficiency of their energy systems by recovering waste heat or generating electricity required to meet their own needs.

To help meet its conservation goals under the new Conservation First framework in Ontario for 2015-2020, Newmarket-Tay has teamed up with other LDCs of similar size to create a company called CustomerFirst to assist with the design and delivery of conservation programs.

By working together, CustomerFirst member utilities will find efficiencies in the delivery of conservation programs and this will lead to cost savings for electricity customers. Through collaboration and sharing of resources and expertise, CustomerFirst will look for innovative conservation programs including programs designed specifically for the Newmarket-Tay region. With increased customer participation in cost-effective programs that are available to all customer types and sectors, Newmarket-Tay along with the other members of CustomerFirst will continue to put conservation first and realize conservation savings that will contribute to the supply plan for the York Region.

C.1.3 Hydro One Distribution

The Government of Ontario has identified CDM as the most cost-effective electricity supply option. Hydro One has been actively delivering CDM programs since 2005 and will look to build on its efforts over the years to provide its most comprehensive CDM offerings to date during the 2015-2020 Conservation First framework. While Hydro One will be working diligently towards achieving an ambitious 2020 energy savings target as part of the new Conservation First framework, it also recognizes the need and significance of delivering peak demand savings.

Hydro One will make CDM programs available to each of its customer segments, including low-income and First Nations customers. Hydro One is participating in a number of utility working groups developing enhancements to existing CDM programs. Once implemented, these program enhancements will help to drive both higher levels of participation and deeper savings opportunities for program participants. In addition to Province-Wide CDM programs, Hydro One also plans on developing local and regional CDM programs that will aim to help customers save on their bills and defer investments in its asset infrastructure.

As per the CDM Requirement Guidelines for Electricity Distributers released by the OEB on December 19, 2014,[4] Hydro One's distribution planning will incorporate its CDM plans at the outset of the planning process. Thus, distribution investments to increase the system capacity will only be implemented as the regional solution where CDM is not a viable option.

C.2 Conservation Potential

The IESO is currently undertaking an Achievable Potential Study to develop of an updated forecast for conservation potential in Ontario. The Study will be used to inform:

- the 2015-2020 Conservation First Framework mid-term review, including developing aggregate and LDC-specific achievable potential estimate in 2020;
- the short-term and long-term planning and program design; and

[4] CDM Requirement Guidelines for Electricity Distributors EB-2014-0278: http://www.ontarioenergyboard.ca/oeb/_Documents/Regulatory/CDM_Guidelines_Elec_Distributors_20141219.pdf

- the 2016 Long Term Energy Plan (LTEP), including developing 20-year provincial economic potential and achievable potential estimates.

The study is scheduled for to be completed by June 1, 2016. Local consumption and conservation potential information is expected to be collected, with finer granularity than has previously been available, through this study. For example, achievable potential will be estimated by sub-sector and end use for each LDC. With this information, the IESO and LDCs will be in a better position to address identified needs in York Region in the next iteration of the plan.

York Region IRRP

Appendix D: Development of Community Based Solutions

Appendix D: Development of Community Based Solutions

This Appendix includes sections provided by the LDCs describing their view on developing community-based solutions.

D.1 Newmarket-Tay and PowerStream

As outlined in foregoing sections of this report, York Region is one of the fastest growing areas in Ontario, and the GTA, with forecast electricity load growth of 2-3% annually over the next 20 years (600 MW). In the absence of offsetting load reduction initiatives the construction of substantial new generation, transmission and distribution supply infrastructure will be required.

Siting new electricity supply infrastructure has become a contentious and difficult exercise with various stakeholders citing concerns with regards to the transparency of the process and opportunities for input.

Moreover, identifying representative participants from different customer segments, developing their knowledge of integrated supply planning considerations, effectively incorporating their input, and completing the required work in time to meet growing electricity demand requirements is not without challenge.

In direct response to these concerns a new approach designated "Community Self-Sufficiency" has been developed. The goal of Community Self-Sufficiency is to address these challenges through the use of new forms of customer engagement, new technologies and imaginative new solutions – in effect "To create a next-generation Ontario Supply Model".

This initiative targets the Long-Term Supply Planning Horizon or, as it has been referred to, "2020 & Beyond" because of the time required to pioneer, test and implement new technological solutions.

Under the overarching approval authority of the IESO, Newmarket-Tay and PowerStream will lead the engagement efforts in our communities. We will play a key role in identifying members of the public to participate in Local Advisory Committees as well playing a critical integration & liaison role with closely related planning processes such as the Municipal Energy Plans.

Our objectives are to successfully meet customer demand and growth across York Region throughout the supply planning period:

- While addressing regional electricity infrastructure and business (employment) needs;
- While satisfying system optimization and cost management objectives consistent with the asset management strategies of the utilities: and
- While pioneering new technologies and solutions showcasing the strategic vision and direction of our utilities.

Our Plan at a Glance:

- Develop stakeholder engagement strategy
- Develop liaison strategy
- Identify promising technologies & solutions
- Recruit technology partners
- Recruit stakeholders
- Commission test bed facility
- Develop "Innovation Cluster"
- Incorporate proven solutions into utility asset plans.

The technology solutions are not limited to but will consider the following:

- Advanced fuel cell technologies
- Advanced storage technologies – particularly in combination with fuel cells
- Aggressive DR 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 (CHP) opportunities
- Renewed consideration of the Load Serving Entity/Aggregator market model.

There are 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 casual factor for asset replacement.

PowerStream's recently implemented micro-grid field trial offers a degree of risk mitigation as it does provide a means to evaluate and provide feedback on the feasibility, scalability and cost effectiveness for new and experimental technologies.

D.2 Hydro One Distribution

Hydro One is exploring a variety of program offerings that provide customer and electricity system benefits through energy efficiency, behavioural changes, load displacement, load shifting, demand response, and energy storage. Hydro One is willing to collaborate with local electricity utilities and gas utilities to develop programs and implement projects that will be cost-effective and benefit the greater electricity system.

YORK REGION
SCOPING ASSESSMENT OUTCOME REPORT

AUGUST 28, 2018

Connecting Today. Powering Tomorrow.

Table of Contents

Scoping Assessment Outcome Report Summary			
Region:	GTA North (York Region)		
Start Date	May 1, 2018	**End Date**	August 28, 2018

1. Introduction

GTA North Region is one of the 21 electricity planning regions in Ontario as identified through the Ontario Energy Board's (OEB) formalized Regional Planning Process. Since the geographical boundaries of GTA North Region roughly encompass the Region of York, this planning region is often referred to as York Region.

This Scoping Assessment Outcome Report is part of the Ontario Energy Board's ("OEB" or "Board") Regional Planning process. The scoping assessment process was led by the Independent Electricity System Operator ("IESO"), in collaboration with the Regional Participants[1] to determine the regional planning approach for the GTA North (York Region) for the needs that were identified for further assessment and/or to require regional coordination. These needs were identified by the Regional Participants in Needs Assessment Report[2] led by Hydro One Networks Inc. ("Hydro One") and published in March 2018.

The IESO, in collaboration with the Regional Participants, further reviewed the needs identified along with information collected during the Needs Assessment, information on potential wires and non-wires alternatives, and the overall regional area impact to assess and determine the best planning approach for the whole or parts of the region. The available planning options considered in the Scoping Assessment include: an Integrated Regional Resource Plan (IRRP), a Regional Infrastructure Plan (wires only plan), or a Local Plan. More details on the criteria used to determine the appropriate regional planning approach are provided in Appendix A.

This Scoping Assessment report:

- defines the region (or sub-regions) for needs requiring more comprehensive planning as identified in the Needs Assessment report;
- determines the appropriate regional planning approach and scope for the region where a need for regional coordination or more comprehensive planning is

[1] Regional Participants , which includes Independent Electricity System Operator (IESO), transmitter, local utilities serving a particular planning region, are required by the OEB to participate in the formalized regional planning process.

[2] The Regional Infrastructure Plan from the previous planning cycle and the Needs Assessment report for the GTA North Region (York Region) can be found at: https://www.hydroone.com/about/corporate-information/regional-plans/gta-north

identified;

- establishes a terms of reference when an IRRP is the recommended approach; and
- establishes a Working Group to carry out the IRRP.

2. Team

The Scoping Assessment was carried out with the following Regional Participants:

- Independent Electricity System Operator
- Alectra Utilities Corporation
- Newmarket-Tay Power Distribution Ltd.
- Toronto Hydro Electric System Ltd.
- Veridian Connections Inc.
- Hydro One Networks Inc. (Distribution)
- Hydro One Networks Inc. (Transmission)

3. Categories of Needs, Analysis and Results

3.1 Overview of the Region

GTA North Region (York Region)

The GTA North Region (York Region), as shown in Figure 1, roughly comprises of municipalities in York Region (Vaughan, Richmond Hill, Markham, Aurora, Newmarket, King, East Gwillimbury, Whitchurch-Stouffville and Georgina) and Chippewas of Georgina Island. Its electrical infrastructure also serves parts of the City of Toronto, Brampton, and Mississauga.

Figure 1: Geographical Boundaries of GTA North (York Region)

GTA North Region (York Region) is one of the fastest growing regions in Ontario. Provincial policies, including the Places to Grow Act and the Greenbelt Act, have played a key role in facilitating and driving development in this region. While a large portion of the land in this region is part of the designated Greenbelt area and is protected from urban development, the 2005 Places to Grow Act has promoted rapid intensification and development in specific designated urban areas surrounding and south of the Greenbelt. Extensive urbanization in these areas over the past decade has resulted in continued increase in electricity demand. In 2017, GTA North (York Region) had an electricity demand peak of over 2000 MW. Under the updated province's Places to Grow Act 2017, significant population growth and intensification are expected to continue in GTA North (York Region) in the coming decades.

At the same time, many communities in GTA North (York Region), including the City of

Markham, the City of Vaughan, Town of Newmarket, Region of York and Chippewas of Georgina Island First Nations, are actively engaged in local energy planning activities and are exploring opportunities to better manage their energy uses using community-based energy solutions, such as energy storage, combined heat and power and renewable energy resources.

230kV Network Supplying GTA North (York Region)

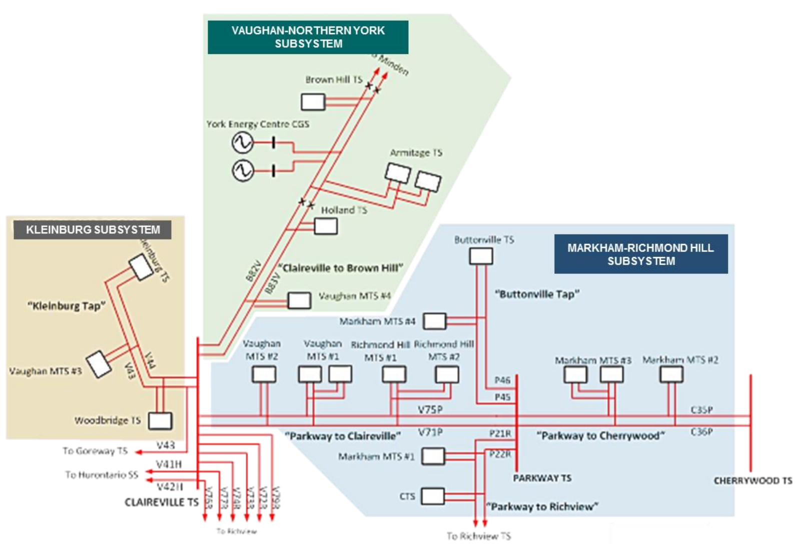
Today, as shown in Figure 2, power is delivered from the rest of the province into this region through a 230kV bulk network. In addition to delivering power into this area, this 230kV bulk network also serve as major pathways for power to flow between Northern Ontario and Southern Ontario as well as across the GTA.

From 230 kV subsystems shown in Figure 2, power is then delivered through transformer stations to various communities and customers through low-voltage distribution networks. There are 20 customer and utility-owned transformer stations that service the various communities and customers in this region.

The low-voltage distribution system is managed and operated by five LDCs: Alectra Utilities Corporation ("Alectra"), Newmarket-Tay Power Distribution Ltd., Toronto Hydro Electric System Ltd., Veridian Connections Inc., and Hydro One Distribution. All LDCs are directly connected to the transmission system, with the exception of Veridian which has low voltage connections to Hydro One distribution feeders.

In addition to transmission and distribution systems, York Energy Centre, a 393 MW gas-fired generation, also provide a local source of supply to the community.

Figure 2: Single Line Diagram of GTA North Region (York Region)



For the purpose of Regional Planning, this 230kV bulk network is broken down into three 230kV subsystems, as shown in Figure 2:

- **Kleinburg 230kV Subsystem (V44/43)** - This subsystem consists of 3 step-down transformer stations that primarily supply rural and urban communities in Vaughan and Caledon, with smaller amounts of supply provided to Brampton, Mississauga, and Toronto. Power is delivered into this subsystem from Claireville TS.

- **Vaughan-Northern York 230kV Subsystem (B82/83H, H82/83V)** - This subsystem consists of five step-down transformer stations that supply northern Vaughan and communities in Northern York region (Aurora, Newmarket, King, East Gwillimbury, Whitchurch-Stouffville and Georgina and Chippewas of Georgina Island). York Energy Centre GS is connected to these 230kV circuits. This subsystem also serves as a major pathway for power to flow between Northern Ontario and Southern Ontario.

- **Markham-Richmond Hill 230kV Subsystem (V75/71P, P45/46, P21/22R, C35/36P)** - This subsystem consists of 12 step-down transformer stations that are located in urban communities in the Markham, Richmond Hill and Vaughan areas. This subsystem is further broken down into four subcomponents: (1) Buttonville Tap - P45/46 (2) Parkway to Cherrywood - P21/22R (3) Parkway to Claireville - V71/75P and (4) Parkway to Richview - C35/36P, as shown in Figure 2. This subsystem also serves as a major pathway for power to flow across the GTA.

3.2 GTA North (York Region) Regional Planning Activities

Previous Planning Cycle

Regional planning in GTA North (York Region) has been underway for a number of years. A regional planning Working Group for GTA North Region (York Region), consisting of the Independent Electricity System Operator (IESO), Newmarket-Tay Power Distribution Ltd., Alectra Utilities and Hydro One Transmission and Distribution, has been active since 2011. In 2013, the planning process was restructured to conform to the timelines and requirements of the Ontario Energy Board's (OEB) formalized Regional Planning Process. The first cycle of the regional planning process for GTA North Region (York Region) was completed in 2016, with the focus on ensuring there is adequate supply to support near-term strong growth in the Vaughan area and minimizing the impact of supply interruptions under major outage conditions. Through this formalized regional planning process, a number of projects were recommended to support the near-term growth and to maximizing the use of the existing system, including the installation of a new transformer station in Vaughan and new switching equipment at Holland transformer station and on the parkway belt/Hwy 407 corridor. All of these projects have since come into service. Even with the implementation of these near-term projects and on-going conservation efforts identified in the 2015 York

Region IRRP, electricity demand growth is forecasted to exceed the system capability in the Markham-Richmond Hill area in early 2020s and Northern York-Vaughan in the mid and late 2020s.

In-Between Planning Cycles

Since the completion of the first cycle of the regional planning process in GTA North (York Region), the Working Group has taken steps to better understand the extent to which non-wires solutions can be used to help manage the electricity demand growth in GTA North (York Region) in the medium to longer term. Specifically, in 2016, Alectra Utilities and the IESO conducted a study to examine the feasibility of implementing residential solar-storage technology in Markham, Richmond Hill and Vaughan. Given the timing and magnitude of electricity demand growth in the Markham-Richmond Hill area, the study confirmed that it is not feasible to solely rely on residential solar-storage technology to defer the near-term supply need in this area. The IESO, on behalf of the Working Group, confirmed the need for a new transformer station and associated lines in the Markham-Richmond Hill area by 2023, and provided a letter to Hydro One and Alectra to initiate the development work for this project.

Over the last couple of years, the IESO, along with the local utilities, has continued to engage with municipalities and Indigenous communities in GTA North (York Region) to confirm the projected growth, inform them of the near-term need for a new transformer station and associated distribution and/or transmission line in the Markham-Richmond Hill area and to discuss at a high-level the medium- and longer-term planning activities in York Region.

Next Regional Planning Cycle For GTA North (York Region)

In accordance with the OEB's regional planning process, a regional planning cycle should be triggered every five years, or less if there are emerging needs. Based on the OEB Regional Planning Process Timeline the next regional planning process for GTA North (York Region) should be completed by 2020. In accordance to these timelines, the lead transmitter – Hydro One Transmission – kicked off the next cycle of the regional planning process with the completion of the Need Assessments for GTA North (York Region) in March 2018. The Need Assessment report identified that some of the needs required further assessment and coordinated regional planning, resulting in the initiation of the Scoping Assessment process.

3.3 Needs Identified

This section provides a summary of the needs identified through the Hydro One's Needs Assessment for North GTA over the 10 year period (2018-2027). For the purpose of the Scoping Assessment, the IESO has grouped these identified needs into the following key categories of needs: (1) Need to provide an adequate, reliable supply (2) Need to minimize the impact of supply interruptions, and (3) Need to coordinate and align end of life asset replacements with evolving needs in this region (4) Bulk System needs and considerations

Part 1: Need to provide an adequate, reliable supply to support longer-term growth

A. Transformer Station Capacity

Transformer station capacity is the electricity system's ability to deliver power to the local distribution network through the regional transformer stations. This is limited by the load meeting capability ("LMC") of the step-down transformer stations in the local area, which is the maximum demand that can be supplied from the transformer stations based on equipment rating and outage conditions.

Table 1 summarizes the transformer station capacity needs identified as part of the GTA North (York Region) Needs Assessment.

Table 1: Transformer Station Capacity Needs

Transformer Stations [3]	Status
Markham MTS 4	Electricity demand growth forecast to exceed transformer capability (Markham MTS 4) in the 2025-2026 timeframe
Vaughan MTS 4	Electricity demand growth forecast to exceed transformer station capability (Vaughan MTS 4) after 2027
Northern York Region TS's (Holland TS/Armitage TS)	Electricity demand growth forecast to exceed transformer stations capability (Holland TS/Armitage TS) after 2027

Similar to the findings from the previous planning cycle, the 2018 GTA North (York Region) Needs Assessment confirmed that electricity demand growth is expected to exceed the capability of the system in Markham-Richmond Hill and Vaughan-Northern York Region over the longer term. However, the timing of these needs have been deferred due to slower than expected electricity demand growth.

Although the demand at Kleinburg TS is not expected to exceed its capability within the next 10 years, continued growth in the southern Caledon and Bolton areas could drive the need for a new transformer and additional supply capacity on the Kleinburg 230kV subsystem over the longer-term (beyond 2027). A more detailed assessment of this longer-term need is required and should be assessed in coordination with other needs identified in the GTA North Region (York Region).

[3] Due to transfer capabilities between transformers stations in GTA-North, needs arise within a sub system of stations once their collective capacity has been exceeded. For instance, a need in Markham indicates that all existing Markham transformer stations have reached their limit.

B. Supply Capacity

Supply capacity is the electricity system's ability to provide continuous supply to a local area under applicable transmission and generation outage scenarios as specified in the Ontario Resource and Transmission Assessment Criteria (ORTAC) and various bulk system conditions.

Table 2 summarizes the supply capacity needs identified as part of the Hydro One's GTA North (York Region) Needs Assessment.

Table 2: Supply Capacity Needs

Subsystem	Status
Northern York Region - Vaughan 230kV Subsystem (Claireville to Brown Hill)	Electricity demand growth forecast to exceed system capability beyond 2027 An interruption to the York Energy Centre Generation Station (YEC GS) service supply could lead to the loss of all generation output. This could limit the supply capability on B82/83V under certain outage conditions today

Given that York Region 230kV networks (e.g., Northern York Region-Vaughan 230kV System, Markham-Richmond Hill 230kV) also serve as major pathways for power to flow between Northern Ontario and Southern Ontario and across the GTA, the ability to supply demand growth in these subsystems could be impacted by varying bulk system conditions. A more detailed assessment of the supply capacity on the York Region 230kV networks under varying bulk system conditions is required and should be assessed in coordination with other needs identified in the GTA North Region (York Region).

Part 2: Need to Minimize the Impact of Supply Interruptions

A. Load Restoration

Load restoration describes the electricity system's ability to restore power to those affected by a major transmission outage within reasonable timeframes. The specific load restoration requirements prescribed by ORTAC.

Table 3 summarizes the load restoration needs identified in the GTA North (York Region) Needs Assessment report.

Table 3: Load Restoration Needs

System	Status
Parkway to Buttonville circuits (P45/46)	Following the simultaneous loss of two transmission elements, load supplied by the Parkway to Buttonville circuits is at risk of not meeting the 30 minute restoration guidelines established by ORTAC as early as 2021.
Claireville to Kleinburg circuits (V43/44)	Following the simultaneous loss of two transmission elements, load supplied by the Claireville to Kleinburg circuits is at risk of not meeting the 30 minute restoration guidelines established by ORTAC today. This restoration need was identified during the previous planning cycle as part of Northwest GTA IRRP. At that time, the study team recommended that this need be addressed in coordination with the IESO's GTA West bulk system planning initiative. Since the subsequent GTA West bulk system study did not address the restoration need, the study team recommends that the need be revisited in this planning cycle.

B. **Load security**

Load security describes the total amount of electricity supply that would be interrupted in the event of a major transmission outage. The specific load security requirements prescribed by ORTAC.

Table 4 summarizes the load security needs identified as part of the GTA North (York Region) Needs Assessment.

Table 4: Load Security Needs

System	Status
Parkway to Claireville circuits (V71/75P)	Following the simultaneous loss of two transmission elements, over 600 MW of load served by the Parkway to Claireville circuits could be at risk of interruption. This exceeds the security guidelines established by ORTAC today. In the previous planning cycle, the study team recommended the installation of inline switches at the Vaughan MTS #1 junction in order to improve the capability of the system to restore load in the event that both 230 kV circuits V71P/V75P are lost. While the installation of these switches will improve the load restoration capabilities and overall reliability on the Parkway to Claireville corridor, it does not address the load security need on V71P/V75P.

	Given the changes that have happened since the last cycle of the regional planning process, the study team agreed to review and to revisit these needs in this planning cycle.

C. **Customer Service Reliability and Performance**

Customer Service Reliability and Performance measures the frequency and duration of supply interruption experienced by customers over a defined period of time. Supply interruptions may be caused by equipment outages on the distribution or transmission networks supplying this area. Various factors that affect reliability include, but are not limited to, a facility's exposure to various elements, age and maintenance of equipment, length and configuration of the network, and the repair crew's accessibility to facilities.

Today, LDCs are required by the OEB to report their customer service reliability and performance for the overall service territory as part of their annual scorecard. From the overall service area perspective, no customer service reliability and performances needs are identified for LDCs serving GTA North Region (York Region). However, a more detailed assessment may be required to examine the customer service reliability and various performances at the regional level and to identify any potential localized customer reliability considerations. This assessment will be done in coordination with other needs identified in the GTA North Region (York Region).

<u>Part 3: Need to coordinate and align end of life asset replacements with evolving needs in this region</u>

Equipment reaching the end of its life and planned sustainment activities may impact the needs assessment and options development. The need to replace aging transmission assets may present opportunities to better align investments with evolving power system priorities. This may involve up-sizing equipment in areas with capacity needs, or downsizing or even removing equipment that is no longer considered useful.

A. **Facilities Reaching End of Life in the Next 10 Years**

Table 5 summarizes the end of life replacement in the next 10 years, as identified in the GTA North (York Region) Needs Assessment.

Table 5: Equipment Reaching End-of-life in the Next 10 Years

Equipment	Anticipated End-of-life Replacement Timeline
Woodbridge TS: T5 transformer	2022/2023

B. **Facilities forecasted to be reaching its expected service life over the next 20 years**

For the purpose of long-term planning, expected service life of facilities could be a good high-level indication of the end of life replacements longer-term needs. Currently work is underway to develop a process to systematically gather information on the expected service life of facilities over a 20 year period for a specific area, such as York Region. Based on expected service life information, there could be more end of life replacement considerations identified over the 20 year period and should be assessed in coordination with other needs identified in the GTA North Region (York Region).

Part 4: Bulk System Needs and Considerations

Bulk system needs typically focus on the adequacy and reliability of the 500kV and 230kV bulk networks that are driven by broader provincial electricity needs and broader policy direction, such as assessing the impact of refurbishment of nuclear facilities or renewable energy policies on the electricity system.

Bulk system needs were not part of the scope of the Needs Assessment for the GTA North Region (York Region). Given that York Region 230kV networks also serve as major pathways for power to flow between Northern Ontario and Southern Ontario and across the GTA, a more detailed assessment of the York Region 230kV networks under varying bulk system conditions is required and should be assessed in coordination with other needs identified in the GTA North Region (York Region).

3.4 Analysis of Needs and Planning Approach

Needs to be Addressed in Local Planning

A local planning process is recommended to address the end-of-life need at Woodbridge TS (T5), as it is single component replacement and there is limited opportunity to reconfigure and resize the facility to align with other regional needs.

Needs to be Addressed in Integrated Regional Resources Plan (IRRP)

With the exception of Woodbridge TS (T5) end of life replacements, the remaining needs discussed in Section 3.3:

- Have the potential to be addressed by non-wires solutions
- Could be impacted by varying bulk systems flows
- Could potentially be addressed in a coordinated manner (e.g., one solution may be able to address multiple needs)
- Impacts multiple LDCs in GTA North (York Region)
- Would require on-going engagement and coordination with community-level energy planning activities

As such, these needs should be addressed in a coordinated manner and an IRRP is recommended for the GTA North Region (York Region).

Needs to be addressed in Bulk System Planning

Bulk system needs were not part of the scope of the Needs Assessment for the GTA North Region (York Region). Although the regional planning process will consider various bulk system conditions as part of the analysis, the detailed assessment of the bulk system is typically addressed through the system planning process and is beyond the scope of this IRRP.

4. Conclusion

The Scoping Assessment concludes that:

- A coordinated approached is required to address the needs identified in the GTA North (York Region) Needs Assessment and an IRRP is recommended. The draft Terms of Reference for the GTA North (York Region) IRRP, outlining the scope, objectives and timeline of the IRRP can be found in Appendix B.

- A Local Planning process is recommended for end-of-life needs at Woodbridge TS. The Working Group will actively monitor the replacement plan for this facilities to ensure that any changes to replacement plan (e.g., changes to the replacement timeline, additional components at the station need to be replaced) will be considered in a coordinated manner as part of regional planning activities in this region, as needed.

List of Acronyms

CDM	Conservation and Demand Management
DG	Distributed Generation
IESO	Independent Electricity System Operator
IPSP	Integrated Power System Plan
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
LDC	Local Distribution Company
MW	Megawatt
NA	Needs Assessment
NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council
OEB	Ontario Energy Board
OPA	Ontario Power Authority
ORTAC	Ontario Resource and Transmission Assessment Criteria
RAS	Remedial Action Scheme
RIP	Regional Infrastructure Plan
RPP	Regional Planning Process
SA	Scoping Assessment
TS	Transformer Station

Appendix A: Selecting a Regional Planning Approach

Needs identified through the Needs Assessment (NA) will be reviewed during the Scoping Assessment to determine whether a Local Plan (LP), Regional Infrastructure Plan (RIP), or Integrated Regional Resource Plan (IRRP) regional planning approach is more appropriate. Where multiple sub-regions are identified, each will be considered individually. It is possible that a combination of LP, RIP and IRRP planning approaches could be selected in different sub-regions, although if the need for wires-type solution is urgent, it will typically trigger a hand-off letter instead.

The three potential planning outcomes are designed to carry out different functions, and selection should be made based on the unique needs and circumstances in each area. The criteria used to select the regional planning approach within each sub-region are consistent with the principles laid out in the PPWG Report to the Board[4], and are discussed in this document to ensure consistency and efficiency throughout the Scoping Assessment.

IRRPs are comprehensive undertakings that consider a wide range of potential solutions to determine the optimal mix of resources to meet the needs of an area for the next 20 years, including consideration of conservation, generation, new technologies, and wires infrastructure. RIPs focus instead on identifying and assessing the specific wires alternatives and recommend the preferred wires solution for an area and are thus, narrower in scope. LPs have the narrowest scope; only considering simple wires solutions that do not require further coordinated planning. A LP process is recommended when needs are:

a) Local in nature (only affecting one LDC or customer)
b) Limited investments of wires (transmission or distribution) solutions
c) Does not require upstream transmission investments
d) Does not require plan level community and/or stakeholder engagement and,
e) Does not require other approvals such as Leave to Construct (S92) application or Environmental Approval.

If it is determined that coordinated planning is required to address identified needs, either a RIP or IRRP may be initiated. A series of criteria have been developed to assist in determining

[4] http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2011-0043/PPWG_Regional_Planning_Report_to_the_Board_App.pdf

which planning approach is the most appropriate based on the identified needs. These are discussed below. In general, an IRRP is initiated:

- Wherever a non-wires measure has the potential to meet or significantly defer the needs identified by the transmitter during the Needs Assessment
- Community or stakeholder engagement is required, or
- The planning process or outcome has the potential to impact bulk system facilities

If it is determined that the only feasible measures involve new/upgraded transmission and/or distribution infrastructure, with no requirement for engagement or anticipated impact on bulk systems, a RIP will be selected instead.

Wires type transmission/distribution infrastructure solutions refer, but are not limited, to:

- Transmission lines
- Transformer/ switching stations
- Sectionalizing devices including breakers and switches
- Reactors or compensators
- Distribution system assets

Additional solutions, including conservation and demand management, generation, and other electricity initiatives can also play a significant role in addressing needs. Because these solutions are non-wires alternatives, they must be studied through an IRRP process.

Determining the feasibility of non-wires alternatives to meet identified needs should also consider issues such as timelines for implementing solutions. For instance, if a need has been identified as immediate or near term, non-wires solutions that rely on lengthy development and roll-out periods may not be feasible.

Appendix B: Terms of Reference

GTA North Region (York Region) IRRP

Terms of Reference

GTA North Region is one of the 21 electricity planning regions in Ontario as identified through the Ontario Energy Board's (OEB) formalized Regional Planning Process. Since the geographical boundaries of GTA North Region roughly encompass the Region of York, this planning region is often referred to as York Region.

These Terms of Reference establish the objectives, scope, key assumptions, roles and responsibilities, activities, deliverables and timelines for GTA North Region (York Region) Integrated Regional Resource Plan ("IRRP").

1. Background

1.1. <u>GTA North Region (York Region)</u>

The GTA North Region (York Region), as shown in Figure B-1, roughly comprises of municipalities in York Region (Vaughan, Richmond Hill, Markham, Aurora, Newmarket, King, East Gwillimbury, Whitchurch-Stouffville and Georgina) and Chippewas of Georgina Island. Its electrical infrastructure also serves parts of the City of Toronto, Brampton, and Mississauga.

Figure B-2: Geographical Boundaries of GTA North (York Region)

GTA North (York Region) is one of the fastest growing regions in Ontario. Provincial policies, including the Places to Grow Act and the Greenbelt Act, have played a key role in facilitating and driving development in this region. While a large portion of the land in this region is part of the designated Greenbelt area and is protected from urban development, the 2005 Places to Grow Act has promoted rapid intensification and development in specific designated urban areas surrounding and south of the Greenbelt. Extensive urbanization in these areas over the past decade has resulted in continued increase in electricity demand. In 2017, GTA North (York Region) had an electricity demand peak of over 2000 MW. Under the updated province's Places to Grow Act 2017, significant population growth and intensification are expected to continue in GTA North (York Region) in the coming decades.

At the same time, many communities in York Region, including the City of Markham, the City of Vaughan, Town of Newmarket, Region of York and Chippewas of Georgina Island First Nations, are actively engaged in local energy planning activities and are exploring opportunities to better manage their energy uses using community-based energy solutions, such as energy storage, combined heat and power and renewable energy resources.

1.2. Regional Electricity Planning Activities in GTA North (York Region)

Previous Planning Cycle

Regional planning in GTA North (York Region) has been underway for a number of years. A regional planning Working Group for York Region, consisting of the Independent Electricity System Operator (IESO), Newmarket-Tay Power Distribution Ltd., Alectra Utilities and Hydro One Transmission and Distribution, has been active since 2011. In 2013, the planning process was restructured to conform to the timelines and requirements of the Ontario Energy Board's (OEB) formalized Regional Planning Process. The first cycle of the regional planning process for GTA North (York Region) was completed in 2016, with the focus on ensuring there is adequate supply to support near-term strong growth in the Vaughan area and minimizing the impact of supply interruptions under major outage conditions. Through this formalized regional planning process, a number of projects were recommended to support the near-term growth and to maximizing the use of the existing system , including the installation of a new transformer station in Vaughan and new switching equipment at Holland transformer station and on the parkway belt/Hwy 407 corridor. All of these projects have since come into service. Even with the implementation of these near-term projects and on-going conservation efforts identified in the 2015 York Region IRRP, electricity demand growth is forecasted to exceed the system capability in the Markham-Richmond Hill area in early 2020s and Northern York-Vaughan in the mid and late 2020s.

In-Between Planning Cycles

Since the completion of the first cycle of the regional planning process in GTA North (York Region), the Working Group has taken steps to better understand the extent to which non-wires solutions can be used to help manage the electricity demand growth in GTA North (York Region) in the medium to longer term. Specifically, in 2016, Alectra Utilities and the IESO conducted a study to examine the feasibility of implementing residential solar-storage technology in Markham, Richmond Hill and Vaughan. Given the timing and magnitude of electricity demand growth in the Markham-Richmond Hill area, the study confirmed that it is not feasible to solely rely on residential solar-storage technology to defer the near-term supply need in this area. The IESO, on behalf of the Working Group, confirmed the need for a new transformer station and associated lines in the Markham-Richmond Hill area by 2023, and provided a letter to Hydro One and Alectra to initiate the development work for this project.

Over the last couple of years, the IESO, along with the local utilities, has continued to engage with municipalities and Indigenous communities in GTA North (York Region) to confirm the projected growth, inform them of the near-term need for a new transformer station and associated distribution and/or transmission line in the Markham-Richmond Hill area and to discuss at a high-level the medium- and longer-term planning activities in York Region.

Next Regional Planning Cycle for GTA North (York Region)

In accordance with the OEB's regional planning process, a regional planning cycle should be triggered every five years, or less if there are emerging needs. Based on the OEB Regional Planning Process Timeline the next regional planning process for GTA North (York Region) should be completed by 2020. In accordance to these timelines, the lead transmitter – Hydro One Transmission – kicked off the next cycle of the regional planning process with the completion of the Need Assessments for GTA North (York Region) in March 2018. The Need Assessment report identified that some of the needs required further assessment and coordinated regional planning, resulting in the initiation of the Scoping Assessment process.

Based on the needs identified in the Needs Assessment, the Scoping Assessment process concluded that a coordinated approach is required to address the needs identified in GTA North (York Region) and an Integrated Regional Resources Plan (IRRP) is recommended for the GTA North (York Region).

2. Objectives

The GTA North (York Region) IRRP will assess the adequacy and reliability of electricity supply to customers in York Region and will develop a set of recommended actions to maintain reliability of supply to the region over the next 20 year (2018-2037) in a transparent and coordinated manner.

Specifically, the IRRP will:

- Explore innovative/non-wires solutions and determine the extent to which these solutions can be leveraged to address electricity needs in York Region
- Determine whether there is a need to initiate development work or to fully commit infrastructure investments (wires or non-wires) in this planning cycle
- Assess potential risks over the longer term and identify near-term actions to manage/mitigate these risks, where applicable

3. Scope

The following components will be included as part of the scope of this IRRP:

3.1. Supply Reliability and Adequacy Assessment

The GTA North (York Region) IRRP will assess the adequacy and reliability of the 230kV network supplying York Region (see sub-section below "230kV York Region Networks" for more information) based on industry standards (e.g., Ontario Resources and Transmission Assessment Criteria (ORTAC)) and demand forecast discussed in Section 3.2. Specifically, the IRRP will review needs identified and discussed as part of the Scoping Assessment, with the focus on the following key areas of needs:

- Need to provide an adequate, reliable supply
- Need to minimize the impact of supply interruptions
- Need to coordinate and align end of life asset replacements with evolving needs in this region

Given that York Region 230kV networks also serve as major pathways for power to flow between Northern Ontario and Southern Ontario and across the GTA, the IRRP will also assess the York Region 230kV networks under varying bulk system conditions. However, the detailed assessment of the bulk system and distribution network is typically addressed through the bulk and distribution system planning process and is beyond the scope of this IRRP.

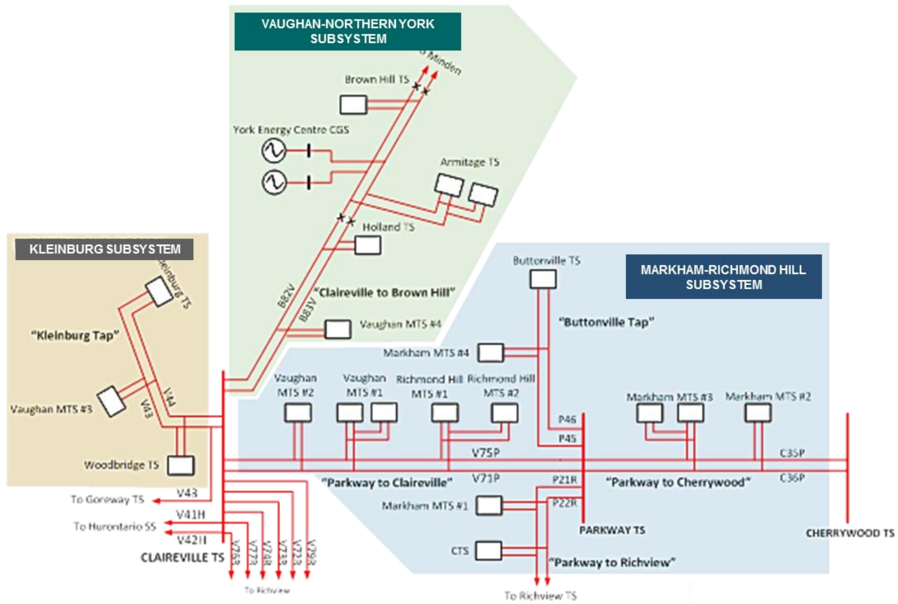
York Region 230kV networks

Today, as shown in Figure B-2, power is delivered from the rest of the province into this Region through 230kV bulk network. In addition to delivering power into this area, this 230kV bulk networks also serve as major pathways for power to flow between Northern Ontario and Southern Ontario and across the GTA.

From these 230 kV subsystems, power is then delivered through transformer stations to various communities and customers through low-voltage distribution networks. There are 20 customer and utility-owned transformer stations that service the various communities and customers in this region. The low-voltage distribution system is managed and operated by five LDCs: Alectra Utilities Corporation ("Alectra"), Newmarket-Tay Power Distribution Ltd., Toronto Hydro Electric System Ltd., Veridian Connections Inc., and Hydro One Distribution. All LDCs are directly connected to the transmission system, with the exception of Veridian which has low voltage connections to Hydro One distribution feeders.

In addition to transmission and distribution system, York Energy Centre, a 393 MW gas-fired generation, also provide a local source of supply to the community.

Figure B-2: Single Line Diagram of GTA North (York Region)



For the purpose of Regional Planning, this 230kV bulk network can be broken down into three 230kV subsystems, as shown in Figure B-2:

- **Kleinburg 230kV Subsystem (V44/43)** - This subsystem consists of 3 step-down transformer stations that primarily supply rural and urban communities in Vaughan and Caledon, with smaller amounts of supply provided to Brampton, Mississauga, and Toronto. Power is delivered into this subsystem from Claireville TS.

- **Vaughan-Northern York 230kV Subsystem (B82/83H, H82/83V)** - This subsystem consists of five step-down transformer stations that supply northern Vaughan and communities in Northern York region (Aurora, Newmarket, King, East Gwillimbury, Whitchurch-Stouffville and Georgina and Chippewas of Georgina Island). York Energy Centre GS is connected to these 230kV circuits. This subsystem also serves as a major pathway for power to flow between Northern Ontario and Southern Ontario.

- **Markham-Richmond Hill 230kV Subsystem (V75/71P, P45/46, P21/22R, C35/36P)** - This subsystem consists of 12 step-down transformer stations that are located in urban communities in the Markham, Richmond Hill and Vaughan areas. This subsystem is further broken down into 4 sub components: (1) Buttonville Tap - P45/46 (2) Parkway to Cherrywood - P21/22R (3) Parkway to Clarieville - V71/75P and (4) Parkway to Richview - C35/36, as shown in Figure B-2. This subsystem also serves as a major pathway for power to flow across the GTA.

<u>**3.2 Development of 20 Year Demand Forecast and Scenarios**</u>

A 20 year Reference "Business As Usual" Summer Peak Demand forecast (2018-2037) for GTA North (York Region) will be developed as part of the IRRP. Specifically, the Reference forecast will consider the following assumptions:

- LDCs' Gross Demand Forecast for their service area. This is developed based on local economic development and growth assumptions outlined in community growth plans.
- Estimated peak demand impact of Provincial Energy Conservation Programs, including existing and contracted distributed generation.
- Impact of extreme temperature

To assess potential longer risks and uncertainties, the IRRP will also take into the consideration the following in the development of demand forecast:

- Electrification (e.g., EV, Electrification of Transportation)
- Community Energy and Growth Plans (e.g., Updated 2017 Places to Grow)
- Impact of behind the meter activities (e.g., Industrial Conservation Initiative (ICI), solar/storage)
- Impact of climate change (e.g., hotter summers, storms)

3.3 Options Development and Evaluation

The IRRP will develop and evaluate a wide range of non-wires and wires solutions to address needs identified over a 20 year period (2018-2037).

Non-Wires Options

Specifically, the IRRP will examine the extent to which feasible, cost-effective non-wires solutions could help manage electricity demand growth in GTA North (York Region) over the longer term. Two non-wires-related initiatives are underway in GTA North (York Region) to support and to inform the development of potential non-wires options in GTA North (York Region):

- **York Region Non-Wires Alternative and Interoperability Pilot:** A pilot is being initiated to explore opportunities to address potential barriers to implementing non-wires solutions in York Region, including potential funding mechanisms (e.g., revenue stacking, market-based solutions) and interoperability considerations. Findings from the pilot could help determine the extent to which non-wires alternatives can be used to address the regional electricity needs in York Region over the longer term. Lessons learned from this pilot also will inform the development of longer-term non-wires alternative framework in Ontario. The pilot will be conducted in phases over several years and is expected to be completed in early 2020s.
- **York Local Achievable Potential Study:** A study is being initiated to gather information on the cost and feasibility of implementing non-wires alternatives and community energy based solutions in York Region. The study is expected to be completed in early 2019.

While the detailed implementation of the two initiatives discussed is beyond the scope of the IRRP, the results from these two initiatives will help inform the recommendations for this IRRP.

Wires Options

Should traditional wires options be required, the IRRP will explore potential wires options to address the needs identified. Where applicable, the IRRP, with the input from communities and local utilities, will identify opportunities to align with linear infrastructure corridor and potential end of life asset replacements, if applicable.

Options Evaluation

Both wires and non-wires options will be evaluated based on a wide range of considerations, including technical feasibility, project lead time, cost, flexibility, alignment with planning policies and priorities and consistency with long-term needs, and opportunity to maximize the use of existing infrastructure and local considerations.

3.4 Recommended Actions

This IRRP will identify a set of recommended actions to maintain reliability of supply in GTA North (York Region) over the next 5-10 years (2018-2027) and to mitigate any potential longer-term risks and uncertainties (beyond 2028).

Depending on the urgency and timing of the electricity needs and risks identified, the IRRP could recommend a combination of following actions:

- Active monitoring
- Project development work to shorten lead time for the project, without commitment
- Commitment of Project and Proceed with Project Implementation (e.g., resources acquisition, transmission procurement, regulatory approval)
- Interim measures to manage the near-term requirements, until longer-term solutions could come into service
- Additional pilots or studies to gather more information
- Coordination with other planning or related processes (e.g., community or bulk system planning)

Should the IRRP identify the need for infrastructure investment, the IRRP will provide a rationale and define high-level project requirements to support project development and implementation. The outcomes from the GTA North (York Region) IRRP would help inform the Hydro One and LDCs rate filing and any related transmission/resources acquisitions processes.

It is important to note that detailed discussion of acquisition mechanisms, cost allocation, cost recovery, siting, operations and implementation of recommended projects are beyond the scope of IRRP.

3.5 Community and Stakeholder Engagement

Communities and stakeholders will be engaged throughout the IRRP process. Below is the scope of community and stakeholder engagement for this IRRP:

- Local electricity needs and considerations
- Status and key assumptions from Community Energy Planning (e.g., energy intensity, Electric Vehicles and fuel switching scenarios)
- Status and key assumptions in Growth Plans and local economic developments (housing, population growth, commercial and industrial development)
- Impact of climate change in York Region
- Long-term Land Use and Infrastructure Corridor Plans
- Local interests in developing and implementing community-based energy solutions and factors that could facilitate or hinder the implementation of community-based energy solutions. For example:
  - Existing or planned pilot projects
  - Available local funding to support these pilots
  - Local policy/programs that enable/hinder the development of these projects
  - Support from local utilities, community groups and government
  - Land use impact and considerations

The IESO Regional and Community Engagement group will work with the Working Group to develop an engagement plan and approaches (e.g., webinars, community advisory committee) to gather this input, and the draft plan will be posted on the IESO's website for a public comment period.

4. Study Approach & Outcomes

The IRRP is broken down into several workstreams.

Workstreams		Activities	Outcomes
1	Data Gathering	▪ Work with local utilities, communities and stakeholders to better understand electricity demand growth and local energy planning activities in GTA North (York Region) ▪ Initiate Local Achievable Potential Study to better understand the cost, feasibility and characteristics of non-wires solutions (e.g., distributed energy resources, energy efficiency) in the GTA North (York Region) ▪ Gather local information, including customer segmentation ▪ Develop demand forecast and scenarios ▪ Estimate peak demand impact of provincial energy conservation targets and contracted distributed generation ▪ Set up system study base cases	▪ Demand forecast and scenarios ▪ Local Achievable Potential Study ▪ Customer segmentation information ▪ Coordinate with Local Energy Planning Activities (e.g., if applicable) ▪ System study base cases
2	Need Assessment	▪ Assess the reliability and adequacy of the system based on the demand forecast and system study base cases ▪ Define the high-level requirements	▪ Need definition and potential longer-term risks
3	Non-Wires Options Development	▪ Incorporate findings from the York Region Local Achievable Potential Study ▪ Leverage the Local Achievable Potential Study to help inform non-wires options development ▪ Incorporate findings and key learnings from the York Non-Wires Alternatives Pilot	▪ The extent to which cost-effective, feasible non-wires solutions could be acquired to address needs in the local area ▪ A high-level scope, feasibility and cost of non-wires options
4	Wires Options Development	▪ Develop potential wires options ▪ Identify opportunities to align with linear infrastructure corridor and end of life replacements considerations, where applicable	▪ High-level scope, feasibility and costs estimate of wires options

5	Options Evaluation	▪ Evaluate wires and non-wires options based on a wide range of considerations	▪ Benefits and shortfalls of each of the options and the extent to which the options can address the needs identified
6	Recommendations	▪ Develop a set of recommended actions	▪ A report summarizing the key findings and recommendations
7	Community Engagement	▪ Work with the Regional and Community Engagement Team to prepare engagement plan ▪ Prepare for and participate in community engagement ▪ Respond to and consider community and stakeholders' input in the analysis and development of the recommendations	▪ Community Engagement Plan ▪ A summary of community and stakeholders' input

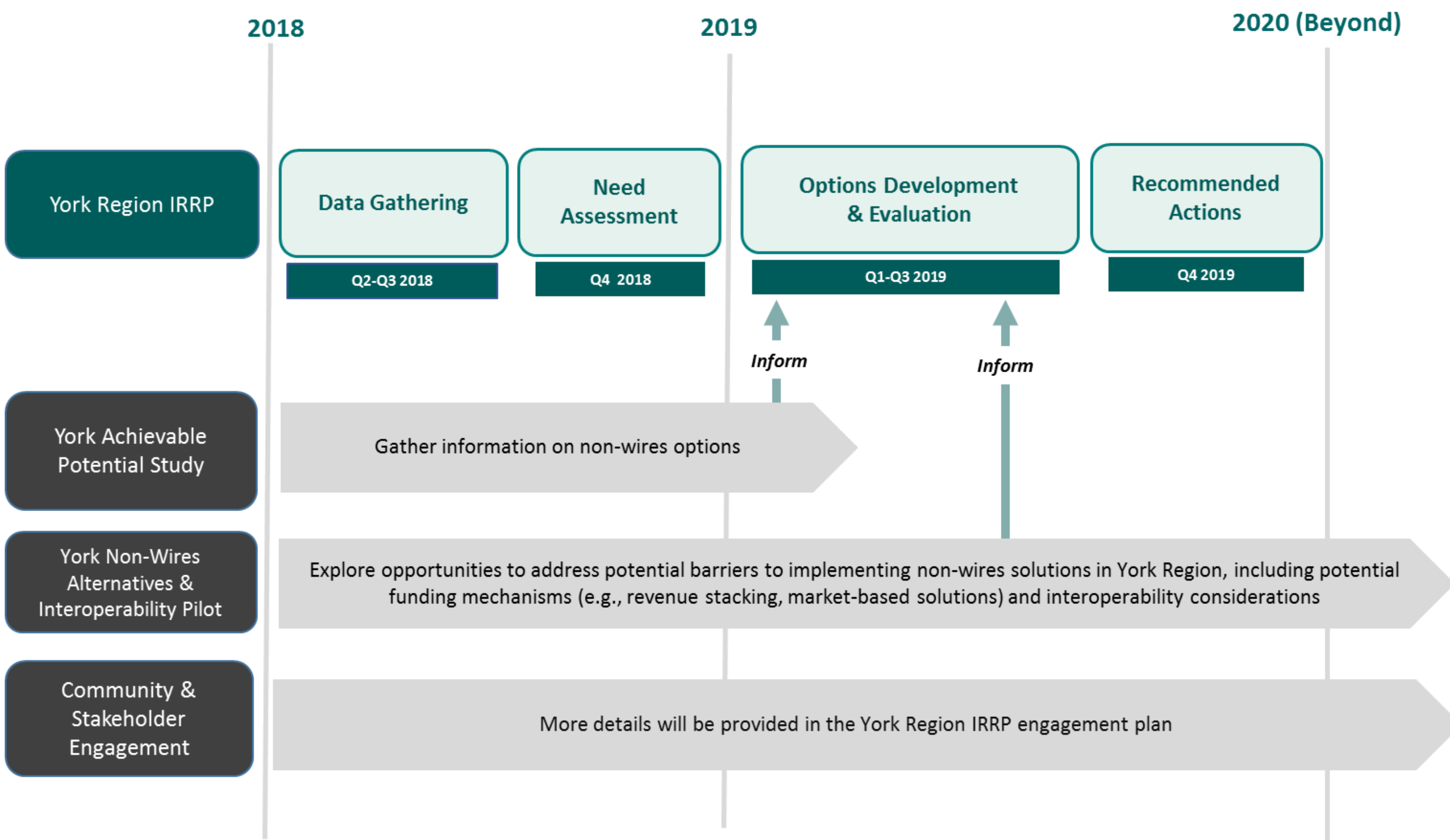
5. GTA North (York Region) IRRP Working Group

In accordance to the OEB's Regional Planning Process, the IESO is responsible for carrying out the Integrated Regional Resources Planning Process (IRRP), in collaboration with the local distribution companies and transmitter. As such, the GTA North (York Region) IRRP Working Group ("Working Group") has been established to help carry out the IRRP in York Region. This Working Group consists of system planning representatives from the following organizations:

- Independent Electricity System Operator *(Team Lead for IRRP)*
- Hydro One Transmission
- Hydro One Distribution
- Alectra Utilities
- Newmarket-Tay Power Distribution Ltd.

Although the planning representatives will be key members of GTA North (York Region) IRRP Working Group, where appropriate, others representatives (e.g., conservation, engagement, innovation, demand forecasting) may be invited to attend Working Group meetings and engagements. It is important to note that the York Region 230kV transmission system also supplies a few of the distribution feeders Toronto Hydro and Veridian Connections' customers. Given that the scope of the GTA North (York Region) IRRP, as discussed in Section 3, has minimal impact on Toronto Hydro and Veridian Connections', Toronto Hydro and Veridian Connections agreed that it is not necessary for them to be active members of the Working Group. The Working Group will keep Toronto Hydro and Veridian Connections informed of any developments in the GTA North (York Region) IRRP that may have an impact on their customers and will coordinate as required.

6. High-level Timeline



GTA West

REGIONAL INFRASTRUCTURE PLAN

January 25, 2016

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Prepared by:
Hydro One Networks Inc. (Lead Transmitter)

With support from:

Company
Burlington Hydro Electric Inc.
Enersource Hydro Mississauga Inc.
Halton Hills Hydro Inc.
Hydro One Brampton Networks Inc.
Hydro One Networks Inc. (Distribution)
Independent Electricity System Operator
Milton Hydro Distribution Inc.
Oakville Hydro Electricity Distribution Inc.

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DISCLAIMER

This Regional Infrastructure Plan ("RIP") report was prepared for the purpose of developing an electricity infrastructure plan to address electrical supply needs identified in previous planning phases and also any additional needs identified based on new and/or updated information provided by the RIP Working Group.

The preferred solution(s) that have been identified in this report may be reevaluated based on the findings of further analysis. The load forecast and results reported in this RIP report are based on the information provided and assumptions made by the participants of the RIP Working Group.

Working Group participants, their respective affiliated organizations, and Hydro One Networks Inc. (collectively, "the Authors") make no representations or warranties (express, implied, statutory or otherwise) as to the RIP report or its contents, including, without limitation, the accuracy or completeness of the information therein and shall not, under any circumstances whatsoever, be liable to each other, or to any third party for whom the RIP report was prepared ("the Intended Third Parties"), or to any other third party reading or receiving the RIP report ("the Other Third Parties"), for any direct, indirect or consequential loss or damages or for any punitive, incidental or special damages or any loss of profit, loss of contract, loss of opportunity or loss of goodwill resulting from or in any way related to the reliance on, acceptance or use of the RIP report or its contents by any person or entity, including, but not limited to, the aforementioned persons and entities.

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EXECUTIVE SUMMARY

THIS REGIONAL INFRASTRUCTURE PLAN ("RIP") WAS PREPARED BY HYDRO ONE WITH SUPPORT FROM THE WORKING GROUP IN ACCORDANCE WITH THE ONTARIO TRANSMISSION SYSTEM CODE REQUIREMENTS. IT IDENTIFIES INVESTMENTS IN TRANSMISSION FACILITIES, DISTRIBUTION FACILITIES, OR BOTH, THAT SHOULD BE DEVELOPED AND IMPLEMENTED TO MEET THE ELECTRICITY INFRASTRUCTURE NEEDS WITHIN THE GTA WEST REGION.

The participants of the RIP Working Group included members from the following organizations:

- Hydro One Networks Inc. (Transmission)
- Burlington Hydro Electric Inc.
- Enersource Hydro Mississauga Inc.
- Halton Hills Hydro Inc.
- Hydro One Brampton Networks Inc.
- Hydro One Networks Inc. (Distribution)
- Independent Electricity System Operator ("IESO")
- Milton Hydro Distribution Inc.
- Oakville Hydro Electricity Distribution Inc.

This RIP is the final phase of the regional planning process and it follows the completion of the Northwest GTA Integrated Regional Resource Plan ("IRRP") in April 2015; and the GTA West Southern Sub-Region's Needs Assessment ("NA") and Scoping Assessment ("SA") in May 2014 and September 2014, respectively.

This RIP provides a consolidated summary of needs and recommended plans for both the Northern Sub-Region and Southern Sub-Region that make up the GTA West Region.

The major infrastructure investments planned for the GTA West Region over the near and medium-term (2016-2025), identified in the various phases of the regional planning process, are given in the table below with anticipated in-service date and estimated cost. Several long-term needs beyond 2026 have been identified, and further assessments are currently underway as part of the IESO Bulk System Study.

No.	Project	I/S Date	Cost
1	Build new Halton Hills Hydro MTS	2018	$19M (1)
2	Build new Halton TS #2	2020	$29M (1)
3	Build new 44/27.6 kV DS to relieve Erindale TS T1/T2	2018-2019	$5M
4	Upgrade (reconductor) circuits H29/H30 (2)	2023-2026	$6.5M

Notes:

(1) Excludes cost for distribution infrastructure

(2) The plan will be reviewed and finalized in the next regional planning cycle

The following needs will be considered in the scope of the Bulk System Study led by the IESO:

- Richview x Trafalgar (R14T/R17T & R19TH/R21TH) circuit capacity need;
- Radial supply to Halton TS (T38/T39B) circuit capacity need;
- Supply security and restoration to several load pockets in GTA West Region.

The IESO's Northwest GTA IRRP has identified that Halton Hills, Caledon, Brampton, and Vaughan area is expected to grow by 849-1132 MW by 2031, as forecast by the Province "Places to Grow" program. A new electricity corridor will be required for additional transmission facilities required to meet this long-term need in the area. The RIP Working Group recommends further assessments to be carried out and complete technical details, layout of high voltage electricity infrastructure no later than Q4 2016. Following this, Environmental Approval and acquisition of land rights would be under taken to ensure that the transmission facilities on this corridor can be placed to meet the needs.

As per the OEB mandate, the Regional Plan should be reviewed and/or updated at least every five years. It is expected that the next planning cycle for this region will start in 2018. If there is a need that emerges due to a change in load forecast or any other reason, the next regional planning cycle can be started earlier to address the need.

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1. INTRODUCTION

THIS REPORT PRESENTS THE REGIONAL INFRASTRUCTURE PLAN ("RIP") TO ADDRESS THE ELECTRICITY NEEDS OF THE GTA WEST REGION.

The report was prepared by Hydro One Networks Inc. (Transmission) ("Hydro One") on behalf of the Working Group in accordance with the regional planning process established by the Ontario Energy Board ("OEB") in 2013. The Working Group included members from the following organizations:

- Hydro One Networks Inc. (Transmission)
- Burlington Hydro Electric Inc.
- Enersource Hydro Mississauga Inc.
- Halton Hills Hydro Inc.
- Hydro One Brampton Networks Inc.
- Hydro One Networks Inc. (Distribution)
- Independent Electricity System Operator ("IESO")
- Milton Hydro Distribution Inc.
- Oakville Hydro Electricity Distribution Inc.

The GTA West Region encompasses the municipalities of Brampton, southern Caledon, Halton Hills, Mississauga, Milton, and Oakville. The region includes the area roughly bordered geographically by Highway 27 to the north-east, Highway 427 to the south-east, Regional Road 25 to the west, King Street to the north and Lake Ontario to the south, as shown in Figure 1-1.

Bulk electricity in the region is supplied by Burlington TS from the west, Claireville TS from the north, Richview TS and Manby TS from the east, and 500/230 kV Trafalgar TS autotransformers, and distributed by a network of 230 kV transmission lines and 17 step-down transformer stations. The summer 2015 peak load of the region was approximately 2900 MW.

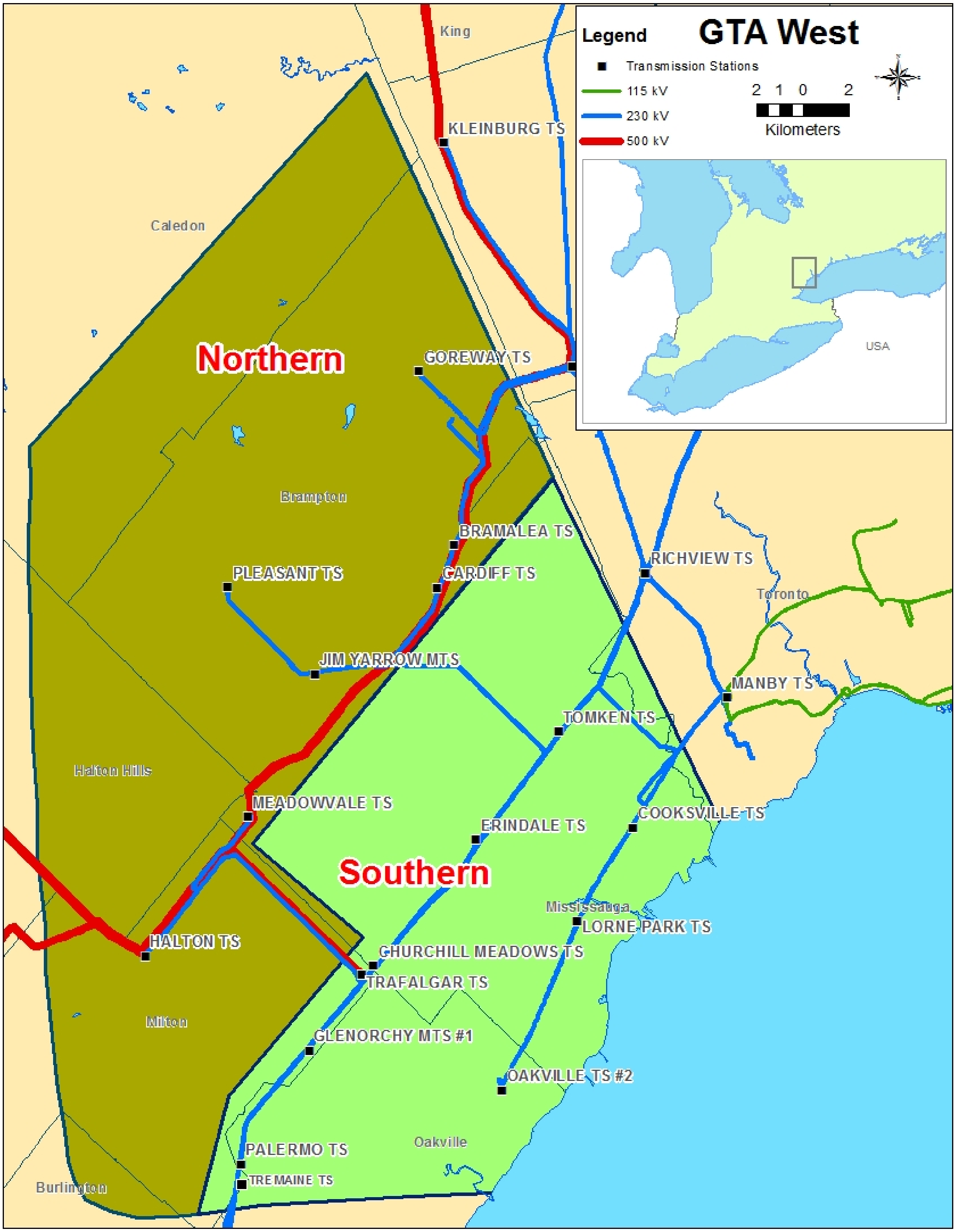

Figure 1-1 GTA West Region Map

1.1 Scope and Objectives

This RIP report examines the needs in the GTA West Region. Its objectives are to:

- Identify new supply needs that may have emerged since previous planning phases (e.g., Needs Assessment, Scoping Assessment, Local Plan, and/or Integrated Regional Resource Plan);
- Assess and develop wires plans to address these needs;
- Provide the status of wires planning currently underway or completed for specific needs;
- Identify investments in transmission and distribution facilities or both that should be developed and implemented on a coordinated basis to meet the electricity infrastructure needs within the region.

The RIP reviews factors such as the load forecast, transmission and distribution system capability along with any updates with respect to local plans, conservation and demand management ("CDM"), renewable and non-renewable generation development, and other electricity system and local drivers that may impact the need and alternatives under consideration.

The scope of this RIP is as follows:

- A consolidated report of the needs and relevant wires plans to address near and medium-term needs (2015-2025) identified in previous planning phases (Needs Assessment, Scoping Assessment, Local Plan, or Integrated Regional Resource Plan);
- Identification of any new needs over the 2015-2025 period and wires plans to address these needs based on new and/or updated information;
- Develop a plan to address any longer terms needs identified by the Working Group.

1.2 Structure

The rest of the report is organized as follows:

- Section 2 provides an overview of the regional planning process;
- Section 3 describes the region;
- Section 4 describes the transmission work completed over the last ten years;
- Section 5 describes the load forecast and study assumptions used in this assessment;
- Section 6 describes the results of the adequacy assessment of the transmission facilities and identifies the needs;
- Section 7 discusses the needs and provides the alternatives and preferred solutions;
- Section 8 provides the conclusion and next steps.

2. REGIONAL PLANNING PROCESS

2.1 Overview

Planning for the electricity system in Ontario is done at essentially three levels: bulk system planning, regional system planning, and distribution system planning. These levels differ in the facilities that are considered and the scope of impact on the electricity system. Planning at the bulk system level typically looks at issues that impact the system on a provincial level, while planning at the regional and distribution levels looks at issues on a more regional or localized level.

Regional planning looks at supply and reliability issues at a regional or local area level. Therefore, it largely considers the 115 kV and 230 kV portions of the power system that supply various parts of the province.

2.2 Regional Planning Process

A structured regional planning process was established by the Ontario Energy Board in 2013 through amendments to the Transmission System Code ("TSC") and Distribution System Code ("DSC"). The process consists of four phases: the Needs Assessment [1] ("NA"), the Scoping Assessment ("SA"), the Integrated Regional Resource Plan ("IRRP"), and the Regional Infrastructure Plan ("RIP").

The regional planning process begins with the NA phase which is led by the transmitter to determine if there are regional needs. The NA phase identifies the needs and the Working Group determines whether further regional coordination is necessary to address them. If no further regional coordination is required, further planning is undertaken by the transmitter and the impacted local distribution company ("LDC") or customer and develops a Local Plan ("LP") to address them. These needs are local in nature and can be best addressed by a straight forward wires solution.

In situations where identified needs require coordination at the regional or sub-regional levels, the IESO initiates the SA phase. During this phase, the IESO, in collaboration with the transmitter and impacted LDCs, reviews the information collected as part of the NA phase, along with additional information on potential non-wires alternatives, and makes a decision on the most appropriate regional planning approach. The approach is either a RIP, which is led by the transmitter, or an IRRP, which is led by the IESO. If more than one sub-region was identified in the NA phase, it is possible that a different approach could be taken for different sub-regions.

The IRRP phase will generally assess infrastructure (wires) versus resource (CDM and Distributed Generation) options at a higher or more macro level, but sufficient to permit a comparison of options. If the IRRP phase identifies that infrastructure options may be most appropriate to meet a need, the RIP phase will conduct detailed planning to identify and assess the specific wires alternatives and recommend

[1] also referred to as Needs Screening

a preferred wires solution. Similarly, resource options which the IRRP identifies as best suited to meet a need are then further planned in greater detail by the IESO. The IRRP phase also includes IESO led stakeholder engagement with municipalities and establishes a Local Advisory Committee (LAC) in the region or sub-region.

The RIP phase is the final stage of the regional planning process and involves: confirmation of previously identified needs; identification of any new needs that may have emerged since the start of the planning cycle; and development of a wires plan to address the needs where a wires solution would be the best overall approach. This phase is led and coordinated by the transmitter and the deliverable of this stage is a comprehensive report of a wires plan for the region. Once completed, this report can be referenced in rate filing submissions or as part of LDC rate applications with a planning status letter provided by the transmitter. Reflecting the timelines provisions of the RIP, plan level stakeholder engagement is not undertaken at this stage. However, stakeholder engagement at a project specific level will be conducted as part of the project approval requirement.

To efficiently manage the regional planning process, Hydro One has been undertaking wires planning activities in collaboration with the IESO and LDCs for the region as part of and/or in parallel with:

- Planning activities that were already underway in the region prior to the new regional planning process taking effect;
- The NA, SA, and LP phases of regional planning;
- Participating in and conducting wires planning as part of the IRRP for the region or sub-region.

Figure 2-1 illustrates the various phases of the regional planning process (NA, SA, IRRP, and RIP) and their respective phase trigger, lead, and outcome.

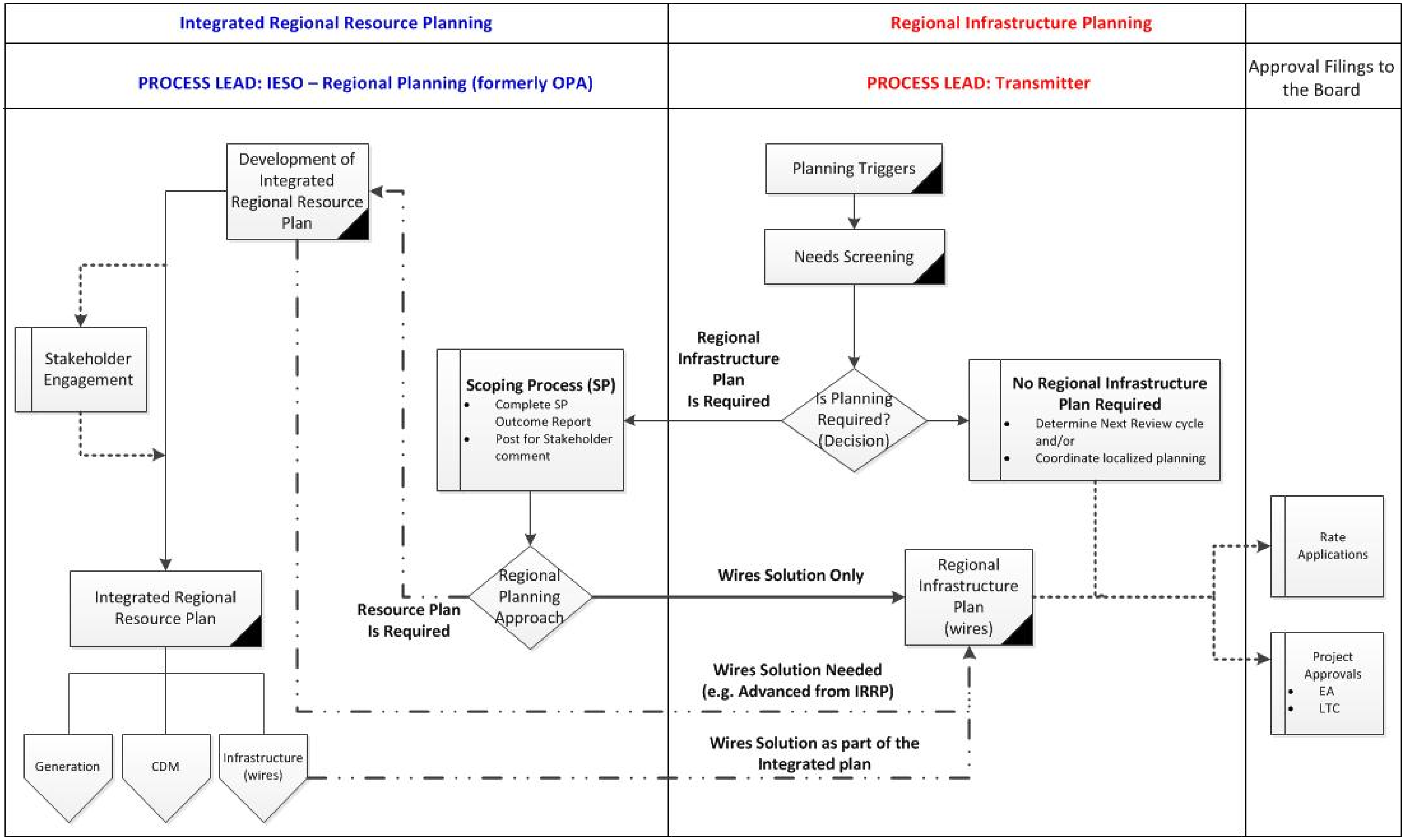

Figure 2-1 Regional Planning Process Flowchart

2.3 RIP Methodology

The RIP phase consists of four steps (see Figure 2-2) as follows:

1. Data Gathering: The first step of the RIP process is the review of planning assessment data collected in the previous stages of the regional planning process. Hydro One collects this information and reviews it with the Working Group to reconfirm or update the information as required. The data collected includes:
   - Net peak demand forecast at the transformer station level. This includes the effect of any distributed generation or conservation and demand management programs.
   - Existing area network and capabilities including any bulk system power flow assumptions.
   - Other data and assumptions as applicable such as asset conditions, load transfer capabilities, and previously committed transmission and distribution system plans.
2. Technical Assessment: The second step is a technical assessment to review the adequacy of the regional system including any previously identified needs. Additional near and mid-term needs may be identified at this stage.
3. Alternative Development: The third step is the development of wires options to address the needs and to come up with a preferred alternative based on an assessment of technical considerations, feasibility, environmental impact and costs.
4. Implementation Plan: The fourth and last step is the development of the implementation plan for the preferred alternative.

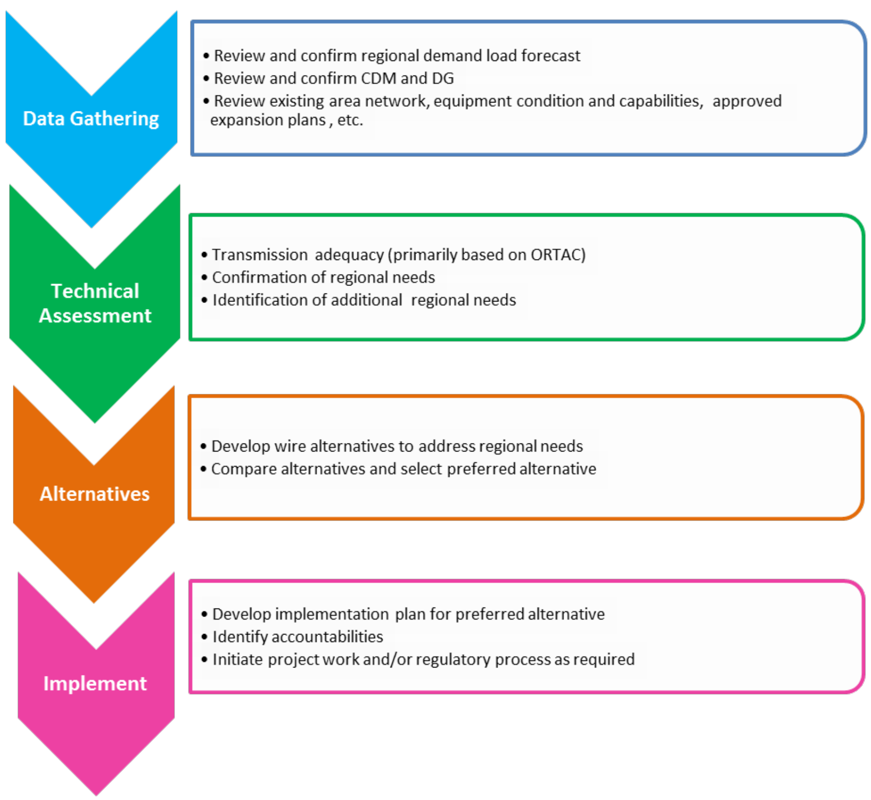

Figure 2-2 RIP Methodology

3. REGIONAL CHARACTERISTICS

THE GTA WEST REGION ENCOMPASSES THE MUNICIPALITIES OF BRAMPTON, SOUTHERN CALEDON, HALTON HILLS, MISSISSAUGA, MILTON, AND OAKVILLE. THE REGION INCLUDES THE AREA ROUGHLY BORDERED GEOGRAPHICALLY BY HIGHWAY 27 TO THE NORTH-EAST, HIGHWAY 427 TO THE SOUTH-EAST, REGIONAL ROAD 25 TO THE WEST, KING STREET TO THE NORTH AND LAKE ONTARIO TO THE SOUTH.

Bulk electricity in the region is supplied by Burlington TS from the west, Claireville TS from the north, Richview TS and Manby TS from the east, and 500/230 kV autotransformers at Trafalgar TS, and distributed by a network of 230 kV transmission lines and 17 step-down transformer stations. Local generation in the region includes the two gas fired plants: Sithe Goreway CGS (839 MW rated capacity) and TCE Halton Hills CGS (683 MW rated capacity). The summer 2015 regional coincidental peak load of the region is approximately 2900 MW.

LDCs supplied from electrical facilities in the GTA West Region are Burlington Hydro Electric Inc., Enersource Hydro Mississauga Inc., Halton Hills Hydro Inc., Hydro One Brampton Networks Inc., Hydro One Networks Inc. (Distribution), Milton Hydro Distribution Inc., and Oakville Hydro Electricity Distribution Inc. The LDCs receive power at the step down transformer stations and distribute it to the end users – industrial, commercial and residential customers.

The April 2015 Northwest GTA IRRP report, prepared by the IESO in conjunction with Hydro One and the LDC, focused on the Northern Sub-Region which included the 230 kV facilities in the northern part of Region. The May 2014 Southern GTA Needs Assessment report, prepared by Hydro One, considered the remainder of the GTA West Region.

For the purpose of regional planning, the GTA West Region is divided into Northern and Southern Sub-Regions. A single line diagram showing the electrical facilities of the GTA West Region, consisting of the two sub-regions, is shown in Figure 3-1. More details regarding transformer stations and transmission lines in the region are provided in Appendix A and B, respectively.

GTA West – Northern Sub-Region

The Northern Sub-Region covers the GTA West Region area north of Highway 407. It is supplied by 230 kV circuits out of Trafalgar TS, Claireville TS and Hurontario SS through seven 230/44 kV or 230/27.6kV step down transformer stations, local generation consist of the Sithe Goreway GS located in Brampton and the TransCanada Halton Hills GS located in Halton Hills, Generation is also connected to the LV buses of Bramalea TS in Brampton.

Enersource, Hydro One Brampton, Milton Hydro and Halton Hills Hydro are the three main Local Distribution Companies in the Sub-Region. They receive power at the step down transformer stations and distribute it to the end use customers.

The GTA West – Northern Sub-Region was identified as a "transitional" sub-region, as planning activities in this sub-region were already underway before the new regional planning process was introduced. The NA and SA phases were deemed to be complete, and the regional planning process was considered to be in the IRRP phase. The Northwest GTA IRRP was completed for the Northern Sub-Region in April 2015.

GTA West – Southern Sub-Region

The Southern Sub-Region covers the GTA West Region area south of Highway 407. It is supplied by 230 kV circuits out of Trafalgar TS, Richview TS and Manby TS. There are a total of nine steps down 230/44 kV or 230/27.6 kV step down transformer stations serving the area customers.

Enersource Hydro Mississauga and Oakville Hydro are the main LDCs serving the GTA West - Southern Sub-Region. There is one large industrial customer (Ford Motor Company) in Oakville.

The NA and SA for the Southern Sub-Region were completed in May and September 2014, respectively. A Local Plan has also been developed in this sub-region to address a near-term station capacity need at Erindale TS, further discussed in Section 7.2.

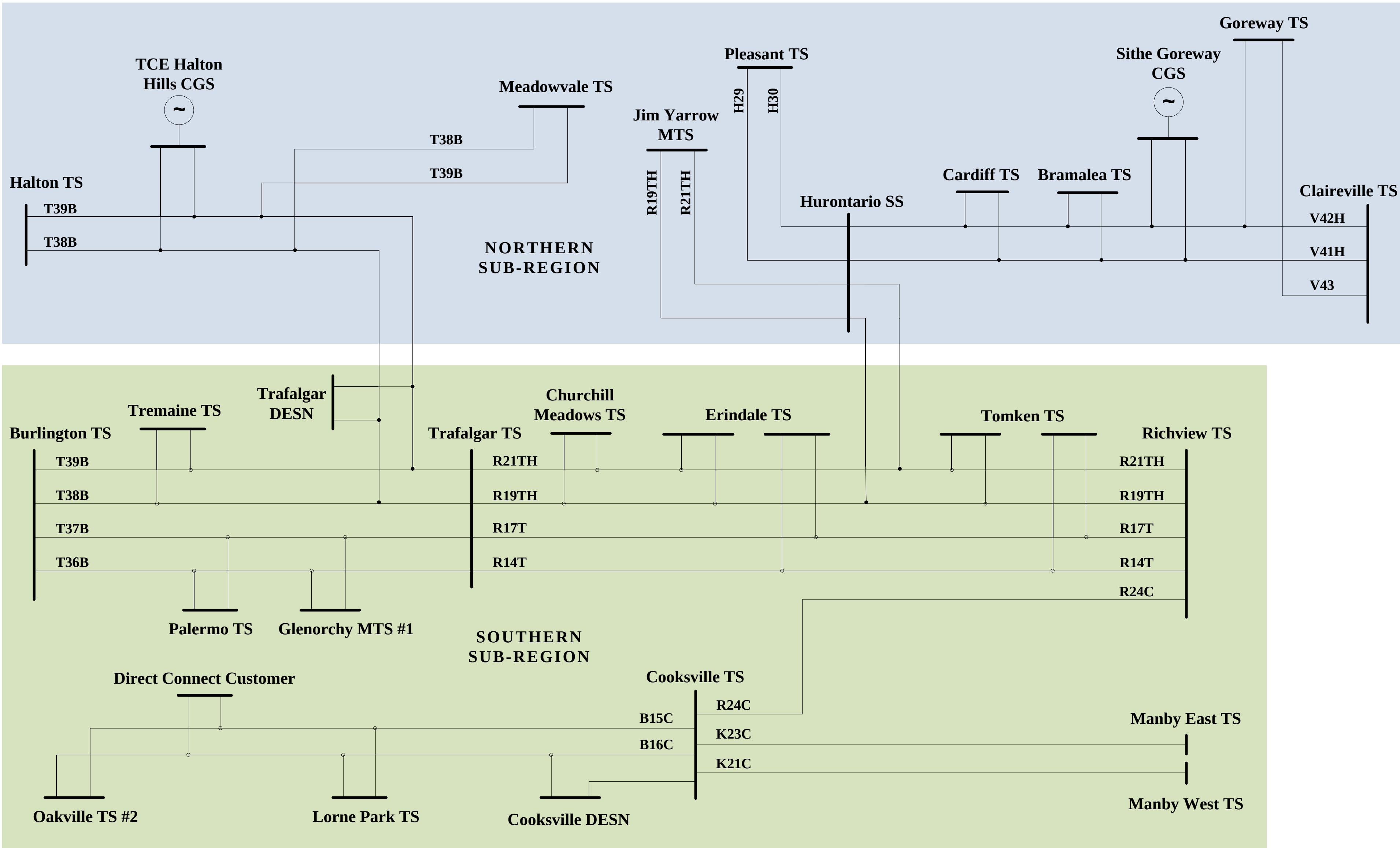

Figure 3-1 GTA West Region Single Line Diagram

4. TRANSMISSION FACILITIES COMPLETED AND/OR UNDERWAY IN THE LAST TEN YEARS

IN THE LAST TEN YEARS A NUMBER OF TRANSMISSION PROJECTS HAVE BEEN PLANNED AND COMPLETED BY HYDRO ONE, OR ARE UNDERWAY, AIMED AT IMPROVING THE SUPPLY CAPABILITY AND RELIABILITY IN THE GTA WEST REGION.

A brief listing of those projects is given below:

- Cardiff TS (2005) – built a new step down transformer station consisting of two 50/83 MVA transformers in Brampton supplied from 230 kV circuits V41H and V42H. This station provided additional load meeting capability to meet Enersource Hydro Mississauga Inc. requirements.
- Sithe Goreway CGS (2008) – connect a new 839 MW gas-fired combined cycle generation station in Brampton connected to 230 kV circuits V41H and V42H. This generation station provided necessary local power to supply the GTA West Region.
- Halton TS Shunt Capacitor - installed 43.2 MX of shunt capacitor banks at Halton TS 27.6 kV bus for voltage support (2009).
- Churchill Meadows TS (2010) – built a new step down transformer station consisting of two 75/125 MVA transformers in Mississauga supplied from 230 kV circuits R19TH and R21TH. This station provided additional load meeting capability to meet Enersource Hydro Mississauga Inc. requirements.
- Hurontario SS and underground cable work - built a new switching station Hurontario SS, 4.2 km of double circuit 230 kV Line from Hurontario SS to Cardiff TS and 3.3 km of underground cable from Hurontario SS to Jim Yarrow TS (2010). The new switching station and associated line work connects the R19T/R21T circuits and the V42/V43H circuits to provide relief and improved reliability to Pleasant TS and Jim Yarrow MTS.
- Halton Hills CGS (2010) – connected a new 683 MW gas-fired combined cycle generation station in Halton Hills connected to 230 kV circuits T38B and T39B. This generation station provided necessary local power to supply the GTA West Region.
- Glenorchy MTS (2011) – connected new Oakville Hydro-owned Glenorchy MTS to 230 kV circuits T36B and T37B. This station provided additional load meeting capability to meet Oakville Hydro requirements
- Tremaine TS (2012) – built a new step down transformer station consisting of two 75/125 MVA transformers in Burlington supplied from 230 kV circuits T38B and T39B. This station provided additional load meeting capability to meet Burlington Hydro and Milton Hydro requirements.

5. FORECAST AND STUDY ASSUMPTIONS

5.1 Load Forecast

The load in the GTA West Region is expected to grow at an average rate of approximately 0.8% annually from 2015 to 2025, and 0.5% from 2025 to 2035. The growth rate varies across the region ranging from 1.1% in the Northern Sub Region to 0.5% in the Southern Sub Region over the first 10 years. Longer term is a more uniform growth rate of 0.5% across both Northern and Southern Sub Regions. .

Figure 5-1 shows the GTA West Region load forecast from 2016 to 2035. The forecast shown is the regional coincidental forecast, representing the sum of the load in the area for the 17 step-down transformer stations at the time of the regional peak, and is used to determine any need for additional transmission reinforcements. The coincidental regional peak is forecast to increase from approximately 2900 MW in 2015 to 3300 MW in 2035. Non-coincident forecast for the individual stations in the region is available in Appendix A, and is used to determine any need for station capacity relief.

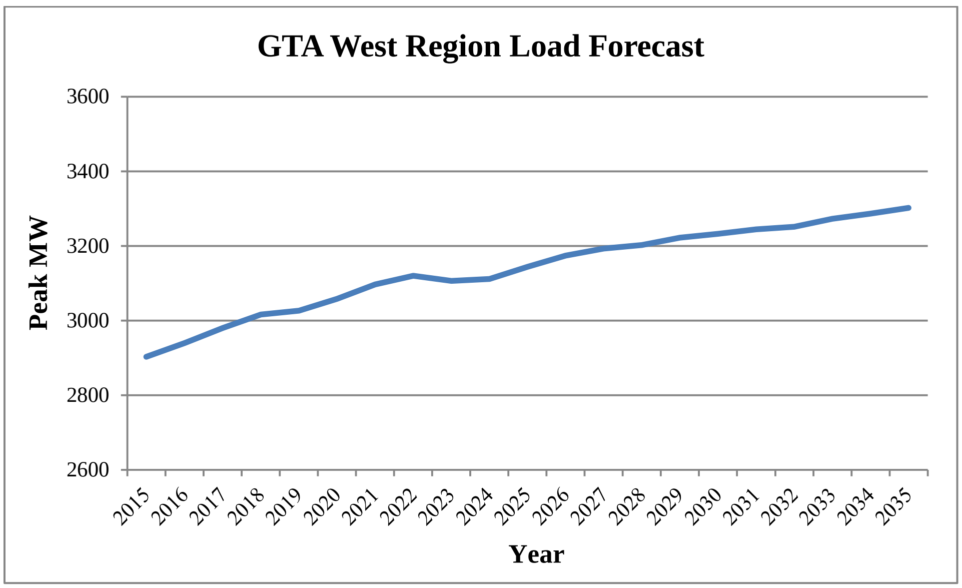

Figure 5-1 GTA West Region Extreme Weather Peak Load Forecast

The regional coincidental load forecast was developed by projecting the 2015 summer peak loads corrected for extreme weather, using the area station growth rates as per the 2015 IESO Northwest GTA IRRP and as per the 2014 Hydro One's Need Assessment Study for the GTA West Southern Sub-Region. The growth rate accounts for CDM measures and connected DG. Details on CDM and connected DG information used in this report are provided in the Northwest GTA IRRP and the Southern Sub-Region's NA, and not repeated in this report.

5.2 Other Study Assumptions

The following other assumptions are made in this report.

- The study period for the RIP assessments is 2015-2035.
- All planned facilities for which work has been initiated and are listed in Section 4 are assumed to be in-service.
- Summer is the critical period with respect to line and transformer loadings. The assessment is based therefore based on summer peak loads.
- Station capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity, assuming a 90% lagging power factor for stations having no low-voltage capacitor banks and 95% lagging power factor for stations having low-voltage capacitor banks, or on the basis of historical power factor data.
- Normal planning supply capacity for transformer stations in the region is determined by the summer 10-day Limited Time Rating (LTR).

6. ADEQUACY OF EXISTING FACILITIES AND REGIONAL NEEDS

THIS SECTION REVIEWS THE ADEQUACY OF THE EXISTING TRANSMISSION SYSTEM AND STATION FACILITIES SUPPLYING THE GTA WEST REGION AND LISTS THE FACILITIES REQUIRING REINFORCEMENT OVER THE 2016-2025 PERIOD.

Within the current regional planning cycle, three regional assessments have been conducted for the GTA West Region. The findings of these assessments are input to the RIP. These assessments are:

1) The Northwest GTA Integrated Regional Resource Plan (IRRP), April 2015 [1]
2) The GTA West Southern Sub-Region’s Needs Assessment (NA) Report, May 2014 [2]
3) The GTA West Southern Sub-Region’s Scoping Assessment (SA) Report, September 2014 [3]

The IRRP and NA planning assessments identified a number of regional needs to meet the area forecast load demand over the 2016-2025 period. These regional needs are summarized in Table 6-1. Table 6-1 also includes the longer-term needs (up to 2035) that have been identified in the Northern Sub-Region. A detailed description and status of work initiated or planned to meet these needs is given in Section 7.

A review of the loading on the transmission lines and stations in the GTA West Region was also carried out as part of the RIP report. Sections 6.1 to 6.3 present the results of this review.

Table 6-1 Needs Identified in Previous Phases of the GTA West Regional Planning Process

Type	Section	Needs	Timing
Station Capacity	7.1	Halton TS	2018-2020
	7.2	Erindale TS (T1/T2)	Today
Transmission Circuit Capacity	7.3	Richview x Trafalgar (R14T/R17T & R19TH/R21TH)	Within 5 years
	7.4	Radial Supply to Pleasant TS (H29/H30)	2023-2026
	7.5	Radial Supply to Halton TS (T38B/T39B)	2029+
Supply Security	7.6	Supply Security to Halton Radial Pocket (T38B/T39B)	2027
Supply Restoration	7.7	Supply Restoration in Northern Sub-Region [(1)]: - Halton Radial Pocket (T38B/T39B) - Pleasant Radial Pocket (H29/H30) - Cardiff/Bramalea Supply (V41H/V42H)	Today
	7.8	Supply Restoration in Southern Sub-Region: - West of Cooksville (B15C/B16C) - Richview x Trafalgar x Hurontario (R19TH/R21TH) - Richview x Trafalgar (R14T, R17T)	Today
Long-Term Growth	7.9	Pleasant TS (T1/T2) NWGTA Electricity Corridor	2026-2033+

(1) The Northwest GTA IRRP also identified an issue and need to assess “Kleinburg Radial Pocket” supply restoration. This need is being assessed as part of the IESO led Bulk System Study and is not part of this RIP.

6.1 230 kV Transmission Facilities

All 230 kV transmission facilities in the GTA West Region, with the exception of Hurontario SS to Pleasant TS 230 kV circuits H29 and H30 are classified as part of the Bulk Electricity System (BES). A number of these circuits also serve local area stations within the region and the power flow on them depends on the bulk system transfer as well as local area loads. These circuits are as follows (refer to Figure 3-1):

1. Claireville TS to Hurontario SS (230 kV Circuits V41H, V42H, V43) – Supply Bramalea TS, Cardiff TS, and Goreway TS
2. Hurontario SS to Pleasant TS (230 kV Circuits H29, H30) – Supply Pleasant TS
3. Trafalgar TS to Burlington TS, radial tap to Halton TS and Meadowvale TS (230 kV Circuits T38B, T39B) – Supply Halton TS, Meadowvale TS, and Trafalgar DESN
4. Trafalgar TS to Burlington TS (230 kV Circuits T36B, T37B, T38B, T39B) – Supply Glenorchy MTS #1, Palermo TS, and Tremaine TS
5. Richview TS to Trafalgar TS (230 kV Circuits R14T, R17T) – Supply Erindale TS and Tomken TS
6. Richview TS to Trafalgar TS, with tap to Hurontario SS (230 kV Circuits R19TH, R21TH) – Supply Churchill Meadows TS, Erindale TS, Jim Yarrow MTS, and Tomken TS
7. Richview TS and Manby TS to Cooksville TS (230 kV Circuits R24C, K21C, K23C, B15C, B16C) – Supply Cooksville DESN, Ford Oakville CTS, Lorne Park TS, and Oakville TS #2

Based on current forecast station loadings and bulk transfers, the H29/H30 circuits will require reinforcement by 2023-2026. The H29/H30 upgrade will be addressed by Hydro One based on the recommendation stemming from the Northwest GTA IRRP led by the IESO. The Trafalgar to Richview 230 kV circuits (R14T/R17T) will require reinforcement in the near term based on GTA West Southern Sub-Region's NA. This need will be further assessed in the IESO led Bulk System Study.

6.2 500/230 kV Transformation Facilities

All loads are supplied from the 230 kV transmissions system. The primary source of 230 kV supply is the 500/230 kV autotransformers at Trafalgar TS and Claireville TS, as well as 230 kV supply from Burlington TS. Additional support is provided from the 230 kV generation facilities at Halton Hills CGS and Sithe Goreway CGS. Based on the long term forecast in the Northwest GTA IRRP, Trafalgar TS and Claireville TS may require relief in the next 10 years. This need will be studied under the IESO led Bulk System Study.

6.3 Step-Down Transformation Facilities

There are a total of sixteen step-down transformer stations in the GTA West Region. Based on the local station load forecast, Halton TS and Erindale TS would require station capacity relief in the near term, as shown in Table 6-2.

Table 6-2 Step-Down Transformer Stations Requiring Relief

Station	Capacity (MW)	2015 Loading (MW)	Need Date
Halton TS	185.9	176.4	2018
Erindale TS (T1/T2)	181.3	208.3	Now
Pleasant TS (T1/T2)	148.1	124.8	2026-2033 (1)

(1) 2026 under the "Higher Growth" scenario, while 2033 under the "Expected Growth" scenario. Please refer to Northwest GTA IRRP [1]

7. REGIONAL PLANS

THIS SECTION DISCUSSES NEEDS, PRESENTS WIRES ALTERNATIVES AND THE CURRENT PREFERRED WIRES OPTIONS FOR ADDRESSING THE ELECTRICAL SUPPLY NEEDS FOR THE GTA WEST REGION. THESE NEEDS ARE LISTED IN TABLE 6-1 AND INCLUDE NEEDS PREVIOUSLY IDENTIFIED IN THE NORTHWEST GTA IRRP AND THE NA FOR THE GTA WEST SOUTHERN SUB-REGION AS WELL AS THE ADEQUACY ASSESSMENT CARRIED OUT AS PART OF THE CURRENT RIP REPORT.

7.1 Halton TS Station Capacity

7.1.1 Description

Halton TS supplies Halton Hills Hydro through 3 feeders and Milton Hydro through 9 feeders at the station. As the load in Halton Hills and Milton continues to grow, the peak load at Halton TS is expected to exceed the station peak load by 2018.

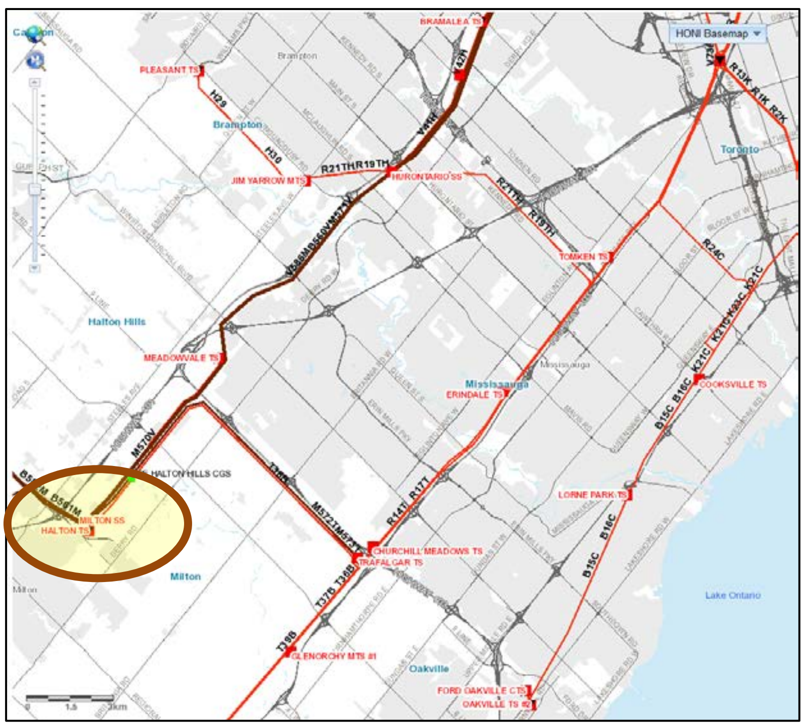

Figure 7-1 Halton TS and Surrounding Areas

7.1.2 Recommended Plan and Current Status

The recommendation of the IRRP is to build two new step-down stations: one to provide supply for Halton Hills Hydro loads and second to supply Milton Hydro load. The Halton Hills Hydro station is expected to be required in 2018, while the Milton Hydro station is expected to be required in 2020.

The IRRP recommends that Halton Hills Hydro 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. Halton Hills Hydro has started a Request for Proposal for the work to construct Halton Hills MTS. The station will consists of two 50/83 MVA transformers with capacity to connect eight distribution feeders. The existing Halton Hills CGS will be expanded to accommodate the HV connection of Halton Hills MTS. There are no transmitter costs for this station. The expected in-service date is spring of 2018. The cost for this station is estimated to be $19 million.

The IRRP recommends Hydro One to initiate engineering work for the development of Halton TS #2 in 2017 (3 year lead-time), at the site of the existing Halton TS, with a tentative in-service date of 2020. The Halton Hills TS #2 will consist of two 75/125 MVA transformers with capacity to connect eight distribution feeders. It will tap to circuits T38B and T39B. The cost for Hydro One to build Halton TS #2 is estimated to be $29 million.

7.2 Erindale TS (T1/T2) Station Capacity

7.2.1 Description

Erindale TS solely supplies Enersource Hydro Mississauga Inc. The existing Erindale TS (T1/T2) DESN load currently exceeds the normal supply capacity. However, there is extra capacity available in the area's 44 kV system that can be utilized by building a step down (44/27.6 kV) distribution station.

Options for providing the required relief were investigated in Local Planning for Erindale TS T1/T2 DESN Capacity Relief [4]. As per the Local Plan, Hydro One and Enersource agreed that this is primarily a distribution planning issue that will involve planning and building a new DS by Enersource to utilize the extra 44 kV station capacity in the area.

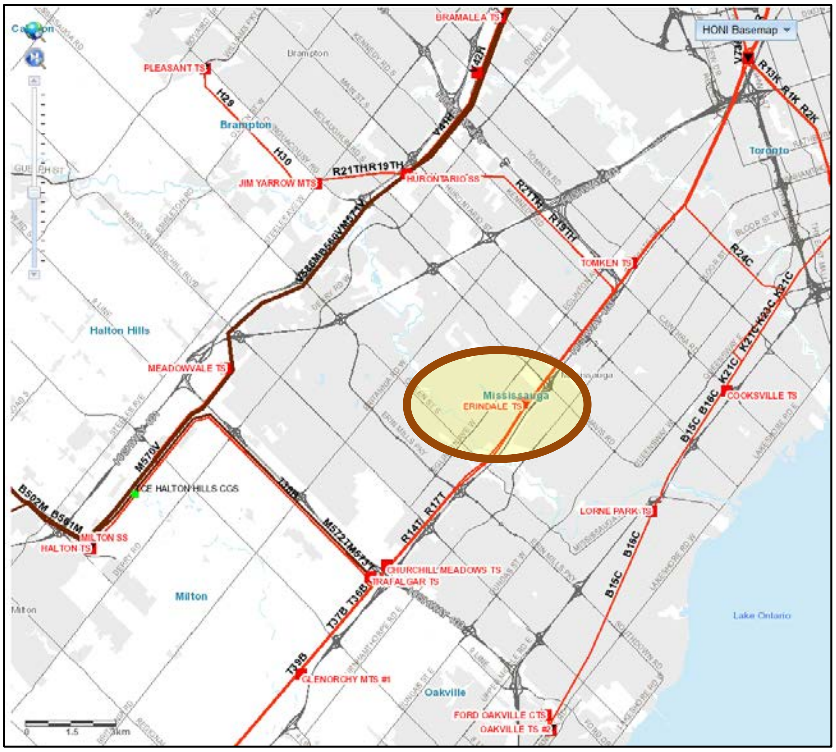

Figure 7-2 Erindale TS and Surrounding Areas

7.2.2 Recommended Plan and Current Status

The proposed DS ("Mini-Britannia MS") is planned to be supplied from Churchill Meadows TS (44 kV system) and provide additional capacity to feed the 27.6 kV load currently supplied by Erindale TS T1/T2. This configuration will reduce over-capacity loading at Erindale TS T1/T2 while balancing the loading capability on 44 kV system via Churchill Meadows TS.

At completion, the substation will house two power transformers (40 MVA capacity), two high voltage switchgears and two low voltage switchgears that will deliver power via four 27.6 kV feeders.

This option is expected to cost $5 million. Under this option, Enersource will build the new DS, own it and recover the costs through the distribution rates. The expected in-service date for the DS is 2018-2019.

7.3 Richview x Trafalgar Transmission Circuit Capacity

7.3.1 Description

As identified in the GTA West Southern Sub-Region's NA, with a single-circuit contingency and high Flow East Towards Toronto (FETT) interface flows, loading on the Richview TS to Trafalgar TS circuits (R14T, R17T, R19TH, R21TH) exceeded their summer long-term emergency ratings in the near-term.

7.3.2 Recommended Plan and Current Status

As these circuits are part of the Bulk Electric System, this need is being further assessed in the IESO-led bulk power system planning.

7.4 Radial Supply to Pleasant TS Transmission Circuit Capacity

7.4.1 Description

Pleasant TS consists of 3 DESNs supplied by 230 kV H29/H30 circuits. Due to growth in load forecasted at Pleasant TS, these circuits are expected to reach their thermal capacity by 2023 at the earliest.

The IRRP process, completed in April 2015, identified the need, discussed alternatives, and recommended a solution to resolve this need.

7.4.2 Recommended Plan and Current Status

The existing conductors used for 230kV circuits H29/H30 going to Pleasant TS are 795.0 kcmil ACSR 26/7 with summer long term emergency rating of 1090 A (at 127°C). They extend 8.5km north from Hurontario SS to Pleasant TS. Based on the study conducted in the Northwest GTA IRRP, this rating limits the maximum load-carrying capacity to approximately 417 MW of load at Pleasant TS.

Preliminary feasibility study shows that the existing towers can support larger conductors. The recommended new conductors would be 1192.5 kcmil ACSR 54/19 with summer long term emergency rating of approximately 1400 A (at 127°C). As per the load flow study conducted in the IRRP, this would supply over 500 MW of load at Pleasant TS. The estimated budgetary cost of this upgrade is about $6.5 million.

The Working Group recommends regularly monitoring the actual load growth and reassessing this issue during the next regional planning cycle.

7.5 Radial Supply to Halton TS Transmission Circuit Capacity

7.5.1 Description

The Northwest GTA IRRP study identified that the thermal capacity of supply circuit to Halton TS from Trafalgar TS to Burlington TS (T38B/T39B) may be exceeded with a single-circuit contingency and Halton Hills GS out of service in the mid-term. However, under this scenario, the ORTAC permits up to 150 MW of load shedding to prevent system overloads. With this control action in place, this need is observed in the long-term in 2029 at the earliest.

7.5.2 Recommended Plan and Current Status

As per the IRRP recommendation, this regional need is being further assessed in the IESO-led bulk power system planning.

7.6 Supply Security to Halton Radial Pocket (T38B/T39B)

7.6.1 Description

As the load connected to T38B/T39B continues to grow, it is expected by 2027 the Halton Radial Pocket will not be able to meet the ORTAC supply security criteria, which states that no more than 600 MW can be interrupted due to a loss of two major power system elements, as shown in Table 7-1.

Table 7-1 Halton Radial Pocket Load Forecast

Year	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Halton Radial Pocket Load (MW)	463	471	482	490	491	492	503	512	562	571	585	598	**609**

7.6.2 Recommended Plan and Current Status

The Working Group recommends that the bulk power system study led by IESO account for this supply security issue on T38B/T39B in their planning process.

7.7 Supply Restoration in Northern Sub-Region

The Northwest GTA IRRP study identified that the following circuits are currently at risk of not meeting the supply security and restoration criteria:

Table 7-2 Supply Restoration Need in Northern Sub-Region

Load Pocket	2015 Peak Load (MW)	Load (MW) That Can Be Restored Within 30-min (1)	30-min Restoration Shortfall (MW) (2)
Halton Radial Pocket • Tremaine • Trafalgar DESN • Meadowvale • Halton • Halton Hills Hydro MTS (1) • Halton #2 (1) Supply: T38B/T39B	463	146	**67**
Pleasant Radial Pocket • Pleasant DESNs Supply: H29/H30	359	52	**57**
Bramalea/Cardiff Supply • Bramalea DESNs • Cardiff Supply: V41H/V42H	456	140	**66**

(1) Available 30-min restoration through emergency distribution load transfer following the loss of transmission supply (based on IRRP)
(2) Calculated as follows: Actual Load minus 250 MW minus 30minRestorationCapability. 250 MW is the maximum amount of load not restored within 30-min following loss of two elements.
(3) Halton Hills Hydro MTS and Halton TS #2 are expected to be in-service in 2018 and 2020.

The Northwest GTA IRRP also identified "Kleinburg Radial Pocket" supply restoration need. However, this need will be discussed in more details in the IESO's Bulk System Studies.

As per the IRRP recommendation, all of the above restoration needs are being further assessed in the IESO-led bulk power system planning.

It is expected that with new increased forecasted load at Tremaine TS provided by Milton Hydro and Burlington Hydro, circuitsT38B/T39B Burlington TS to Trafalgar TS will experience higher power flow, and the need date may be moved closer. Therefore, the Working Group recommends that the bulk power system study led by IESO account for this increased flow on T38B/T39B in their planning process.

7.8 Supply Restoration in Southern Sub-Region

The GTA West Southern Sub-Region SA identified that the following circuits are at a risk of not meeting the supply security and restoration criteria in the medium term to long term time frame:

Table 7-3 Supply Restoration Need in Southern Sub-Region

Load Pocket	2015 Peak Load (MW)	Load (MW) That Can Be Restored Within 30-min (1)	30-min Restoration Shortfall (MW) (2)	Load (MW) That Can Be Restored Within 4-hour (1)	4-hour Restoration Shortfall (MW) (3)
West of Cooksville • Oakville #2 • Ford Oakville • Lorne Park Supply: B15C/B16C	304	46	**8**	110	**44**
Richview x Trafalgar x Hurontario • Churchill Meadows • Erindale T5/T6 • Tomken T3/T4 • Jim Yarrow Supply: R19TH/R21TH	555	165	**140**	465	None
Richview x Trafalgar • Erindale T1/T2 • Erindale T3/T4 • Tomken T1/T2 Supply: R14T/R17T	498	115	**133**	390	None

As per the Southern Sub-Region's SA recommendation, all of the above restoration needs are being further assessed in the IESO-led bulk power system planning.

7.9 Long-Term Growth & NWGTA Electricity Corridor Need

Growth projections in the Ontario Governments - Growth Plan for the Greater Golden Horseshoe [5] indicates that the population in Halton Hills, Caledon, Brampton, and Vaughan area is expected to grow significantly over the 20 years period, from 930,000 people in 2011 to 1.5 million people in 2031. Growth plan of this magnitude translates to an overall electrical demand of approximately 849 to 1132 MW by 2031 [1]. Supply electrical demand related to this growth will require new transmission and distribution infrastructure in the area because current electricity infrastructure in the area is limited and at its capacity. Planning and Environmental Approval for a proposed new 400 series Highway, extending from Highway 400 to the Highway 401/407 ETR interchange, has been paused by the Ministry of Transportation. However, opportunities for multi-use transportation/ electricity transmission line corridor must be investigated as new transportation and electricity plans for the area are developed, to maintain consistency with direction outlined in the Provincial Policy Statement.

Existing electricity supply to new developments in the area is technically limited by transmission line and transformer station supply capacity. In addition, there are customer service quality concerns, such as reliability performance and low voltage levels on the LDC's distribution feeders due to the long distance between the locations of new development and existing transformer stations.

Based on the latest load forecast, electrical load at Pleasant TS, which supplies Brampton, is anticipated to exceed its station capacity as early as 2026 [1]. As the result, new station will be required to meet growing electrical needs.

Since a typical 75/125 MVA 230 kV step-down transformer station is capable of supplying up to 170 MW of load, up to 6 new stations in strategic locations could be required to effectively meet load growth in the area over the next 10-20 years. In order to provide adequate supply to these new step-down stations, new 230 kV transmission lines will be required within the general vicinity of the area's load growth centers.

In addition to the need for supply capacity to meet growth, several locations are at risk for not meeting ORTAC criteria following the loss of two transmission elements: Halton radial pocket, Pleasant radial pocket, Bramalea/Cardiff supply, and Kleinburg radial pocket. These needs should also be studied and addressed in a coordinated manner to develop optimal solutions for both GTA North and GTA West Region. As a result, a high degree of integration will be required between regional planning in the two adjacent regions going forward.

Siting a new transmission corridor in the area would provide an alternate supply route to enable continued electrical service when other lines are out of service. Currently it is estimated that over 250 MW of load will not be restored within the timelines prescribed by the criteria. The situation and risk will continue to worsen with continued growth and load will be at higher risk of prolonged power outages following major system contingencies.

An important first phase for providing the required transmission capacity is to identify land / right of ways, which can accommodate economical overhead transmission lines. This includes completing an Environmental Approval followed with an application to the OEB for Leave to Construct (Section 92). The EA process and acquisition of land rights process may take up to five years. Allowing the area to develop without identifying the electricity corridor in municipal plans and not acquiring land rights for transmission corridor now would be significantly arduous after municipal and community development has already taken place without consideration of electricity needs. Identifying and preserving rights-of-way ahead of the forecasted need will help rate payers and municipalities avoid cost associated with underground cables in the future, which is significantly more costly ranging from 5 to 10 times higher than overhead lines.

Continued load growth throughout the GTA, and changing generation patterns across the province, are expected to stress the bulk transmission system's capacity. One option for addressing this need is the addition of a major new 500/230 kV supply point at the existing Milton SS. This new 500/230 kV supply point will provide an additional source to the local network and would need to be supplemented with the incorporation of new 230 kV lines and reconfiguration of the 230 kV system in the area. A new corridor providing new 230 kV transmission lines connecting Milton TS in GTA West and Kleinburg TS in GTA North will allow for better overall bulk system performance in the long-term.

Existing projections of electricity corridor needs can be as early as 2025. The RIP concludes that based on growth projections outlined in the Growth Plan for the Greater Golden Horseshoe [5] a new electricity corridor will be ultimately required to provide additional transmission capacity to meet load growth; provide alternate supply route to various locations to meet restoration criteria; and improve bulk electricity transfer capability.

The RIP Working Group recommends that:

a) The required transmission corridor be identified within the appropriate Regional and Municipal Official Planning documents.

b) Hydro One, the IESO and LDCs undertake immediate action to further assess the location and pace of growth, as well as the related high voltage electrical facilities required for inclusion in a future electricity infrastructure plan. The plan should include but not limited to details with respect to conceptual layout of transmission lines, line terminations, switching stations and the number and approximate location of step-down transformer stations.

c) Following this, Environmental Approval and acquisition of land rights should be under taken to ensure that the transmission facilities on this corridor can be placed to meet the needs.

d) Hydro One, the IESO and LDCs should complete the assessment, technical details, layout of high voltage electricity infrastructure no later than Q4 2016.

8. CONCLUSIONS

THIS REGIONAL INFRASTRUCTURE PLAN REPORT CONCLUDES THE REGIONAL PLANNING PROCESS FOR THE GTA WEST REGION. THIS REPORT MEETS THE INTENT OF THE PROCESS DESCRIBED IN SECTION 2 WHICH IS ENDORSED BY THE OEB AND MANDATED IN THE TSC AND DSC.

This RIP report addresses regional needs identified in the earlier phases of the Regional Planning process and any new needs identified during the RIP phase. These needs are summarized in the Table 8-1 below.

Table 8-1 Regional Plans – Needs Identified in the Regional Planning Process

No.	Need Description
I	Halton TS station capacity
II	Erindale TS T1/T2 station capacity
III	Radial supply to Pleasant TS (H29/H30) circuit capacity
IV	Richview x Trafalgar (R14T/R17T & R19TH/R21TH) circuit capacity
V	Radial supply to Halton TS (T38B/T39B) circuit capacity
VI	• Supply security to Halton Radial Pocket • Supply restoration to Halton Radial Pocket, Pleasant Radial Pocket, and Bramalea/Cardiff Supply load pockets • Supply restoration to West of Cooksville, Richview x Trafalgar, and Richview x Trafalgar x Hurontario load pockets
VII	Long term need for a new NWGTA electricity transmission corridor

Next steps, lead responsibility, and timeframes for implementing the wires solutions are summarized in the Table 8-2 below. Investments to address the long-term need where there is time to make a decision (Need III) will be reviewed and finalized in the next regional planning cycle.

Table 8-2 Regional Plans - Next Steps, Lead Responsibility and Plan In-Service Dates

Project	Next Steps	Lead Responsibility	I/S Date	Cost	Needs Mitigated
Build new Halton Hills Hydro MTS	LDC to carry out the work	Halton Hills Hydro	2018	\$19M (1)	I
Build new Halton TS #2	Transmitter to carry out the work	Hydro One	2020	\$29M (1)	I
Build new 44/27.6 kV DS to relieve Erindale TS T1/T2	LDC to carry out the work	Enersource	2018-2019	\$5M	II
Upgrade (reconductor) circuits H29/H30 (2)	Transmitter to carry out the work, and monitor growth	Hydro One	2023-2026	\$6.5M	III
• R14T/R17T & R19TH/R21TH circuit capacity need • T38/T39B circuit capacity need • Supply security and restoration need	IESO to carry out Bulk System Study	IESO	TBD	TBD	IV, V, VI
Need for a new transmission corridor in NWGTA	Working Group to complete assessments, technical details & layout by Q4 2016	Hydro One, IESO, LDCs	TBD	TBD	VII

Notes:

(1) Excludes cost for distribution infrastructures
(2) The plan will be reviewed and finalized in the next regional planning cycle

As per the OEB mandate, the Regional Plan should be reviewed and/or updated at least every five years. It is expected that the next planning cycle for this region will start in 2018. If there is a need that emerges due to a change in load forecast or any other reason, the next regional planning cycle can be started earlier to address the need.

9. REFERENCES

[1] Independent Electricity System Operator. “Northwest GTA Integrated Regional Resource Plan”. April 28, 2015.
http://www.ieso.ca/Documents/Regional-Planning/GTA_West/2015-Northwest-GTA-IRRP-Report.pdf

[2] GTA West Southern Sub-Region Study Team. “Needs Screening Report – GTA West Southern Sub-Region”. May 30, 2014.
http://www.hydroone.com/RegionalPlanning/GTAWest/Documents/Needs%20Assessment%20Report%20-%20GTA%20West%20-%20Southern%20Subregion.pdf

[3] GTA West Southern Sub-Region Study Team. “GTA West Southern Sub-Region Scoping Assessment Outcome Report”. September 19, 2014.
http://www.ieso.ca/Documents/Regional-Planning/GTA_West/Scoping-Assessment-Outcome-Report-September-2014.pdf

[4] Hydro One Networks Inc., Enersource Hydro Mississauga Inc. “Local Planning Report – Erindale TS T1/T2 DESN Capacity Relief – GTA West Southern Sub-Region”. July 9, 2015.
http://www.hydroone.com/RegionalPlanning/GTAWest/Documents/Local%20Planning%20Report%20-%20Erindale%20TS%20Capacity%20-%209_July_2015.pdf

[5] Ministry of Infrastructure. Places to Grow: “Growth Plan for the Greater Golden Horseshoe, 2006”. Office Consolidation June 2013.
https://placestogrow.ca/content/ggh/2013-06-10-Growth-Plan-for-the-GGH-EN.pdf

Appendix A. Stations in the GTA West Region

Station (DESN)	Voltage (kV)	Supply Circuit
Halton TS	230/27.6	T38B/T39B
Meadowvale TS	230/44	T38B/T39B
Jim Yarrow MTS	230/27.6	R19TH/R21TH
Pleasant TS (T1/T2)	230/44	H29/H30
Pleasant TS (T5/T6)	230/27.6	H29/H30
Pleasant TS (T7/T8)	230/27.6	H29/H30
Cardiff TS	230/27.6	V41H/V42H
Bramalea TS (T1/T2)	230/27.6	V41H/V42H
Bramalea TS (T3/T4)	230/44	V41H/V42H
Bramalea TS (T5/T6)	230/44	V41H/V42H
Goreway TS (T1/T2)	230/27.6	V42H/V43
Goreway TS (T5/T6)	230/27.6	V42H/V43
Goreway TS (T4)	230/44	V42H/V43
Tremaine TS	230/27.6	T38B/T39B
Trafalgar TS	230/27.6	T38B/T39B
Palermo TS	230/27.6	T36B/T37B
Glenorchy MTS #1	230/27.6	T36B/T37B
Churchill Meadows TS	230/44	R19TH/R21TH
Erindale TS (T1/T2)	230/27.6	R14T/R17T
Erindale TS (T3/T4)	230/44	R14T/R17T
Erindale TS (T5/T6)	230/44	R19TH/R21TH
Tomken TS (T1/T2)	230/44	R14T/R17T
Tomken TS (T3/T4)	230/44	R19TH/R21TH
Oakville TS #2	230/27.6	B15C/B16C
Lorne Park TS	230/27.6	B15C/B16C
Cooksville TS (T1/T2)	230/27.6	B16C
Cooksville TS (T3/T4)	230/27.6	B16C

Appendix B. Transmission Lines in the GTA West Region

Location	Circuit Designations	Voltage (kV)
Hurontario SS to Pleasant TS	H29, H30	230
Richview TS to Trafalgar TS	R14T, R17T	230
Richview TS to Trafalgar TS & Hurontario SS	R19TH, R21TH	230
Trafalgar TS to Burlington TS	T36B, T37B, T38B, T39B	230
Claireville TS to Hurontario SS	V41H, V42H	230
Claireville TS to Kleinburg TS (1)	V43	230
Cooksville TS to Oakville TS	B15C, B16C	230
Manby TS to Cooksville TS	K21C, K23C	230
Richview TS to Cooksville TS	R24C	230

(1) Only V43 sections that supplies Goreway TS is included

Appendix C. Distributors in the GTA West Region

Distributor Name	Station Name	Connection Type
Burlington Hydro Inc.	Palermo TS	Tx
	Tremaine TS	Tx
Enersource Hydro Mississauga Inc.	Bramalea TS	Dx
		Tx
	Cardiff TS	Tx
	Churchill Meadows TS	Tx
	Cooksville TS	Tx
	Erindale TS	Tx
	Lorne Park TS	Tx
	Meadowvale TS	Tx
	Oakville TS #2	Dx
	Tomken TS	Tx
Halton Hills Hydro Inc.	Halton TS	Dx
		Tx
	Pleasant TS	Dx
Hydro One Brampton Networks Inc.	Bramalea TS	Tx
	Goreway TS	Tx
	Jim Yarrow MTS	Tx
	Pleasant TS	Tx
Hydro One Networks Inc. (Distribution)	Bramalea TS	Tx
	Halton TS	Tx
	Oakville TS #2	Tx
	Palermo TS	Tx
	Pleasant TS	Tx
	Trafalgar TS	Tx
Milton Hydro Distribution Inc.	Halton TS	Tx
	Palermo TS	Dx
	Tremaine TS	Tx
Oakville Hydro Electricity Distribution Inc.	Glenorchy MTS #1	Tx
	Oakville TS #2	Tx
	Palermo TS	Tx
	Trafalgar TS	Dx

Appendix D. GTA West Stations Load Forecast

GTA West Non-Coincident Stations Load Forecast (MW)

DESN	Sub-Region	LTR (MW)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Bramalea TS T1/T2	N	188.4	124.6	124.7	124.3	124.2	122.0	122.7	122.7	122.5	121.7	119.9	119.2	121.4	121.0	119.7	119.6	118.3	118.2	118.1	119.0	119.3	119.5
Bramalea TS T3/T4	N	105.7	99.5	99.4	99.3	99.0	97.5	97.2	97.0	96.7	96.0	94.8	94.4	94.8	94.2	93.3	93.1	92.3	91.9	91.6	92.1	92.0	91.9
Bramalea TS T5/T6	N	159.1	122.9	123.0	122.7	122.6	120.3	120.9	120.7	120.4	119.4	117.4	116.7	118.2	117.6	116.2	116.0	114.6	114.4	114.3	115.2	115.4	115.6
Cardiff TS T1/T2	N	113.5	108.8	109.1	109.8	110.0	109.4	108.8	109.2	109.4	109.6	109.3	109.6	109.8	109.8	109.6	109.9	110.1	110.0	110.0	111.0	111.3	111.6
Goreway TS T1/T2	N	184.0	35.5	39.7	41.8	44.8	44.5	49.7	52.6	55.0	55.0	54.2	58.9	62.0	63.4	62.5	63.1	62.4	62.0	61.9	63.7	64.1	64.6
Goreway TS T4	N	84.0	29.8	29.8	29.8	29.8	29.8	29.8	29.8	29.8	29.8	29.8	29.8	29.8	29.8	29.8	29.8	29.8	29.8	29.8	29.8	29.8	29.8
Goreway TS T5/T6	N	177.2	177.2	177.2	177.2	177.2	177.2	177.2	177.2	177.2	177.2	177.2	177.2	177.2	177.2	177.2	177.2	177.2	177.2	177.2	177.2	177.2	177.2
Halton Hills Hydro MTS	N	97.1	0.0	0.0	0.0	3.5	8.1	11.7	15.8	19.7	23.5	26.9	32.2	37.2	42.1	46.7	51.7	51.9	51.9	52.0	52.9	53.2	53.6
Halton TS T3/T4	N	185.9	176.4	179.1	184.4	186.0	186.0	186.0	186.0	186.0	186.0	186.0	186.0	186.0	186.0	186.0	186.0	186.0	186.0	186.0	186.0	186.0	186.0
Halton TS #2	N	146.3	0.0	0.0	0.0	0.0	0.0	2.3	11.0	18.5	66.2	72.5	80.2	87.2	93.5	99.0	105.9	112.1	118.2	116.9	117.9	120.0	122.1
Jim Yarrow MTS T1/T2	N	156.6	132.3	134.9	136.3	138.3	138.3	142.6	144.6	146.1	146.1	145.2	148.1	149.6	149.8	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0
Meadowvale TS T1/T2	N	180.8	128.7	127.1	126.0	124.4	121.9	119.4	118.1	116.5	115.0	113.0	111.6	110.1	108.5	106.7	105.4	104.0	102.4	100.9	100.2	99.0	97.8
Pleasant TS T1/T2	N	148.1	124.8	127.5	131.2	134.3	134.3	135.0	136.3	137.6	138.5	138.0	139.9	141.1	141.8	142.0	142.7	143.8	144.7	145.8	148.4	150.0	151.6
Pleasant TS T5/T6	N	189.3	189.3	189.3	189.3	189.3	189.3	189.3	189.3	189.3	189.3	189.3	189.3	189.3	189.3	189.3	189.3	189.3	189.3	189.3	189.3	189.3	189.3
Pleasant TS T7/T8	N	187.7	45.1	54.5	56.8	57.9	57.9	63.5	66.7	69.3	70.0	68.0	74.7	77.8	79.4	77.0	77.0	76.7	76.1	75.8	79.0	79.8	80.6

DESN	Sub-Region	LTR (MW)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Churchill Meadows TS T1/T2	**S**	**172.5**	101.6	102.0	102.3	102.2	101.3	100.5	100.5	100.4	100.2	100.0	99.9	99.7	99.5	99.3	99.2	99.0	98.8	98.7	98.5	98.3	98.1
Cooksville TS T3/T4	**S**	**119.8**	52.9	52.4	53.3	54.2	54.5	54.8	55.6	56.5	57.5	58.1	58.7	59.3	60.0	60.6	61.2	61.9	62.5	63.2	63.8	64.5	65.2
Cooksville TS T1/T2	**S**	**119.7**	49.8	49.4	50.1	51.0	51.3	51.6	52.3	53.2	54.1	54.7	55.2	55.8	56.4	57.0	57.6	58.2	58.8	59.4	60.0	60.6	61.3
Erindale TS T1/T2	**S**	**181.3**	208.3	210.2	211.9	212.6	210.9	208.7	208.2	207.4	206.5	206.3	206.1	205.8	205.6	205.4	205.2	205.0	204.8	204.5	204.3	204.1	203.9
Erindale TS T3/T4	**S**	**193.0**	150.6	150.9	151.0	150.8	149.4	148.0	148.0	147.8	147.5	147.1	146.7	146.4	146.0	145.6	145.2	144.8	144.5	144.1	143.7	143.4	143.0
Erindale TS T5/T6	**S**	**195.1**	171.9	172.2	172.4	172.2	170.6	169.0	169.0	168.8	168.4	168.0	167.5	167.1	166.7	166.3	165.8	165.4	165.0	164.6	164.1	163.7	163.3
Glenorchy MTS #1 T1/T2	**S**	**153.0**	50.1	57.5	68.0	80.7	107.4	133.5	152.4	158.9	91.0	94.9	98.9	103.1	107.6	112.2	117.0	122.0	127.2	132.6	138.3	144.2	150.4
Lorne Park TS T1/T2	**S**	**144.6**	119.4	118.4	120.4	122.5	123.3	123.9	125.6	127.7	130.0	131.4	132.8	134.2	135.7	137.1	138.6	140.1	141.6	143.1	144.6	146.2	147.8
Oakville TS #2 T5/T6	**S**	**185.2**	157.8	157.0	157.7	158.2	157.2	156.1	156.5	156.8	157.2	157.1	157.1	157.0	156.9	156.8	156.8	156.7	156.6	156.5	156.5	156.4	156.3
Palermo TS T3/T4	**S**	**109.5**	82.6	84.0	87.1	90.4	89.2	88.1	87.8	87.3	86.8	87.3	87.9	88.5	89.0	89.6	90.2	90.7	91.3	91.9	92.5	93.1	93.7
Tomken TS T1/T2	**S**	**173.3**	138.8	140.6	142.0	142.4	141.1	139.7	139.4	138.9	138.3	138.2	138.2	138.1	138.1	138.0	138.0	137.9	137.8	137.8	137.7	137.7	137.6
Tomken TS T3/T4	**S**	**192.8**	149.7	151.7	153.2	153.6	152.3	150.7	150.5	149.9	149.3	149.3	149.2	149.2	149.1	149.1	149.0	149.0	148.9	148.9	148.8	148.8	148.8
Trafalgar TS T1/T2	**S**	**124.0**	85.1	84.7	84.5	83.9	82.8	81.6	81.2	80.7	80.2	79.6	79.0	78.4	77.9	77.3	76.7	76.1	75.6	75.0	74.5	73.9	73.4
Tremaine TS T1/T2	**S**	**189.5**	72.9	79.7	86.8	92.6	91.8	91.1	91.1	90.9	90.7	93.3	96.0	98.7	101.5	104.4	107.4	110.4	113.6	116.8	120.1	123.6	127.1

Notes:

- Northern (N) Sub-Region's stations load forecast is based on the IRRP [1] "Expected Growth" Scenario.
- Southern (S) Sub-Region's stations load forecast is based on the NA [2] non-coincident stations load forecast.
- Halton Hills Hydro MTS and Halton TS #2 are assumed to be in-service in 2018 and 2020, respectively. Some load from Glenorchy MTS will be transferred to the new Halton TS #2 in 2023, as shown by the corresponding increase and decrease at those stations.
- Load forecast were updated for Palermo TS, Tremaine TS, and Glenorchy MTS based on new information provided by Milton Hydro and Burlington Hydro.

Appendix E. List of Acronyms

Acronym	Description
A	Ampere
BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
CIA	Customer Impact Assessment
CGS	Customer Generating Station
CTS	Customer Transformer Station
DESN	Dual Element Spot Network
DG	Distributed Generation
DSC	Distribution System Code
GS	Generating Station
GTA	Greater Toronto Area
HV	High Voltage
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
LDC	Local Distribution Company
LP	Local Plan
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low Voltage
MTS	Municipal Transformer Station
MW	Megawatt
MVA	Mega Volt-Ampere
MVAR	Mega Volt-Ampere Reactive
NA	Needs Assessment
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.
NUG	Non-Utility Generator
OEB	Ontario Energy Board
OPA	Ontario Power Authority
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Plan
ROW	Right-of-Way
SA	Scoping Assessment
SIA	System Impact Assessment
SPS	Special Protection Scheme
SS	Switching Station
TS	Transformer Station
TSC	Transmission System Code
UFLS	Under Frequency Load Shedding
ULTC	Under Load Tap Changer
UVLS	Under Voltage Load Rejection Scheme

GTA West

Southern Sub-Region

Scoping Assessment Outcome Report

September 19, 2014

Prepared by GTA West Southern Sub-Region Team





ONTARIO POWER AUTHORITY

GTA West Southern Sub-Region Study Team

Company	Name
Ontario Power Authority	Alexandra Barrett
Hydro One Networks Inc. (Transmitter)	Dhvani Shah
Independent Electricity System Operator	Philip Woo
Burlington Hydro Inc.	Joe Saunders
Enersource Hydro Mississauga Inc.	Branko Boras
Hydro One Networks Inc. (Distribution)	Charlie Lee
Milton Hydro Distribution Inc.	Ron Brajovic
Oakville Hydro Electricity Distribution Inc.	Dan Steele

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120 Adelaide Street West, Ste. 1600, Toronto, Ontario M5H 1T1 Tel 416 967-7474
Fax 416 967-1947 1-800-797-9604 Toll Free info@powerauthority.on.ca www.powerauthority.on.ca

Scoping Assessment Outcome Report Summary

Region: **Sub-Region:**	**Greater Toronto Area ("GTA") West** **Southern Sub-Region** **("GTA West Southern Sub-Region" or "Southern Sub-Region")**		
Start Date	June 24, 2014	End Date	September 19, 2014

1. Introduction

This Scoping Assessment Outcome Report is part of the Ontario Energy Board's ("OEB" or "Board") Regional Planning process. The Board endorsed the Planning Process Working Group's Report to the Board in May 2013 and formalized the process timelines through changes to the Transmission System Code and Distribution System Code in August 2013.

The first stage in the regional planning process, the Needs Screening, was carried out by Hydro One Networks Inc. ("Hydro One") for the GTA West Southern Sub-Region, which roughly encompasses the City of Mississauga, and the eastern portion of the Town of Oakville. The final Needs Screening report was issued on May 30, 2014, and concluded that there are needs in the area that may require regional coordination. The conclusion resulted in the Ontario Power Authority initiating this Scoping Assessment.

The purpose of this Scoping Assessment is to:

- Determine whether coordinated regional planning is required;
- Determine the appropriate regional planning approach (Regional Infrastructure Plan ("RIP") or an Integrated Regional Resource Plan ("IRRP"); and,
- Establish a draft terms of reference, including a working group, in the case where either an IRRP or RIP is the recommended approach for the GTA West Southern Sub-Region.

2. Team

The Scoping Assessment was carried out with the same regional participants that were involved in the Needs Screening process as follows:

- The Ontario Power Authority ("OPA")
- Independent Electricity System Operator ("IESO")
- Hydro One Networks Inc. ("Hydro One Transmission")
- Burlington Hydro Inc. ("Burlington Hydro")
- Enersource Hydro Mississauga Inc. ("Enersource")
- Hydro One Networks Inc. ("Hydro One Distribution")
- Milton Hydro Distribution Inc. ("Milton Hydro")
- Oakville Hydro Electricity Distribution Inc. ("Oakville Hydro")

Although needs were identified in only some of the LDC service territories, participation was encouraged from all LDCs involved the Scoping Assessment.

3. Categories of Needs, Analysis and Results

Two major categories of needs have been identified for the GTA West Southern Sub-Region: Capacity, and Load Restoration. The referenced transmission facilities are shown on the following map of the area:

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120 Adelaide Street West, Ste. 1600, Toronto, Ontario M5H 1T1 Tel 416 967-7474
Fax 416 967-1947 1-800-797-9604 Toll Free info@powerauthority.on.ca www.powerauthority.on.ca

Figure 1: GTA West Southern Sub-Region

CAPACITY

The 230/27.6 kV transformers at Erindale TS (T1/T2) have been identified to be loaded above their 10-day Limited Time Rating ("LTR") during summer peak.

Analysis:

Historical data trends confirm this situation has been present for a number of years. The application of Conservation and Demand Management ("CDM") targets shows that overload has the potential to remain flat over the long term[1]. Uptake of distributed generation ("DG") in the Southern Sub-regional area has been insufficient to address needs. Capacity is available at adjacent transformation facilities, and utilizing this existing capacity should be investigated as soon as possible.

LOAD RESTORATION

Three areas within the GTA West Southern Sub-Region do not meet load restoration levels based on the application of the Ontario Resource and Transmission Assessment Criteria ("ORTAC"). Details on these areas, and their respective load levels are included in the following table:

[1] Near term: 0-5 years
Mid term: 5-10 years
Long term: 10-20 years

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Table 1: Restoration Summary

		30 minute Restoration		4 hour Restoration	
Area	**Peak 10 yr load**	**Required to meet criteria**	**Available**	**Required to meet criteria**	**Available**
1. West of Cooksville B15/16C Oakville, Ford Oakville, Lorne Park	267 MW	17 MW	46 MW	117 MW	110 MW
2. Richview x Trafalgar R19/21TH Churchill Meadows, Erindale T5/T6, Tomken T3/T4, Jim Yarrow MTS	576 MW	326 MW	165 MW	426 MW	465 MW
3. Richview x Trafalgar R14/17T Erindale T1/T2 T3/T4, Tomken T1/T2	515 MW	265 MW	115 MW	365 MW	390 MW

Analysis:
Evaluation of load restoration transfer capacity confirms needs. A bulk system planning study is being conducted by the OPA for West GTA which will consider measures directly impacting load restoration capability along the Richview x Trafalgar corridor, and Cooksville West area.

4. Conclusion

The Scoping Assessment concludes that the identified Erindale TS T1/T2 capacity needs do not require regional coordination, as Enersource and Hydro One agree that available transformation capacity exists adjacent to the limiting asset, and options for providing the required relief should be investigated as soon as possible. Any necessary infrastructure investments will be planned directly between Enersource and Hydro One Transmission.

For the load restoration needs along the Richview x Trafalgar corridor and West of Cooksville area, the scoping report recommends that these needs be considered within the ongoing bulk system planning study currently being carried out in the Western portion of the GTA. This bulk system study is considering electricity needs in the municipalities of Oakville, Mississauga, Toronto, Brampton, Milton, Halton Hills and Caledon, and is being coordinated with other electricity planning studies in these areas. The OPA will ensure that relevant regional specific information is incorporated in the analysis.

With the load restoration needs being addressed through other planning studies, the scoping assessment has found that regional coordination via a Regional Infrastructure Plan (RIP) or an Integrated Regional Resource Plan (IRRP) is not needed at this time.

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Fax 416 967-1947 1-800-797-9604 Toll Free info@powerauthority.on.ca www.powerauthority.on.ca

Introduction

This Scoping Assessment Outcome Report is part of the OEB's formalized regional planning process. The Scoping Assessment was led by the OPA in collaboration with the regional participants identified in Section 2.0 to determine the regional planning approach for the GTA West Southern Sub-Region to address the needs identified by Hydro One in its Needs Screening Report.

Hydro One's Need Screening was only carried out for the GTA West Southern Sub-Region, as coordinated regional planning for the Northern Sub-Region, known as the Northwest GTA ("NW GTA"), was already underway. Within the Southern Sub-Region, the Needs Screening Report recommended that scoping be undertaken to identify the appropriate planning approach to address the following:

- Erindale TS T1/T2 27.6 kV DESN – there is an immediate need for increased transformation capacity.
- Load restoration for the loss of two elements.

Other needs have been identified which are currently being addressed in other OPA-led planning activities. These consist of capacity constraints on the Richview to Trafalgar corridor, and Richview to Manby circuits (addressed through the West GTA bulk system planning study and the Central-Toronto IRRP, respectively). As a result, they are not subject to this Scoping Assessment.

Additionally, load restoration under peak load conditions as per the IESO's ORTAC may not be met in some pockets in the Southern Sub-region. It was also agreed that these load restoration needs would be further investigated as part of this Scoping Assessment. Based on information provided by Hydro One, it was also confirmed that there is no end-of-life replacement needs for major facilities in the Southern Sub-Region within the period investigated by the Scoping Assessment.

A copy of the GTA West Southern Sub-Region Needs Screening Report is available on the Hydro One GTA West Regional Planning website, http://www.hydroone.com/RegionalPlanning/GTAWest, or is linked here.

The OPA, in collaboration with regional participants (Enersource, Oakville Hydro, Burlington Hydro, Milton Hydro, Hydro One Distribution, Hydro One Transmission, and the IESO), reviewed the information collected as part of the Needs Screening, along with additional information on potential wires and non-wires alternatives.

The purpose of the Scoping Assessment is to:

- Determine whether coordinated regional planning is required;
- Determine the appropriate regional planning approach (RIP or an IRRP); and,
- Establish a draft terms of reference, including working group participants, in the case where an IRRP or RIP is the recommended approach for the Southern Sub-Region.

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Fax 416 967-1947 1-800-797-9604 Toll Free info@powerauthority.on.ca www.powerauthority.on.ca

Categories of Needs, Analysis, and Results

A Scoping Assessment kick-off meeting was held on June 24, 2014, among the regional participants (OPA, Hydro One Transmission, the IESO, Enersource, Oakville Hydro, Burlington Hydro, Milton Hydro, and Hydro One Distribution) to further discuss the needs identified in the Needs Screening Report for the GTA West Southern Sub-Region.

A summary of the relevant needs is provided below:

Capacity Needs

The T1/T2 27.6kV facilities at Erindale TS have been exceeding their summer 10-day Limited Time Rating ("LTR") during summer peak consistently for the past several years.

The combination of transformers and capacitor banks at this station provides a total capacity of 191 MVA, or approximately 181 MW when assuming a 0.95 power factor. During the recent 2013 summer peak, electrical demand hit 208 MW, or 115% of the 10-day LTR of the station, the limit for normal operating conditions. Supplementary information gathered from Enersource as part of the Scoping Assessment has shown that this overloading condition has existed each summer in the past 10 years[2], and operational measures were used to mitigate risks. Further planning is required to address this ongoing overload and develop an appropriate solution.

Going forward, the 10-year forecast shows demand is expected to continue to exceed LTR. However, the effect of provincially mandated conservation targets are expected to stabilize the growth rate, and keep the overload steady at approximately 25-30 MW. Historical (coincident) peak demand, along with the Gross and Net (planning level) forecasts are shown in Figure 2 below:

[2] Peak data not yet available for 2014

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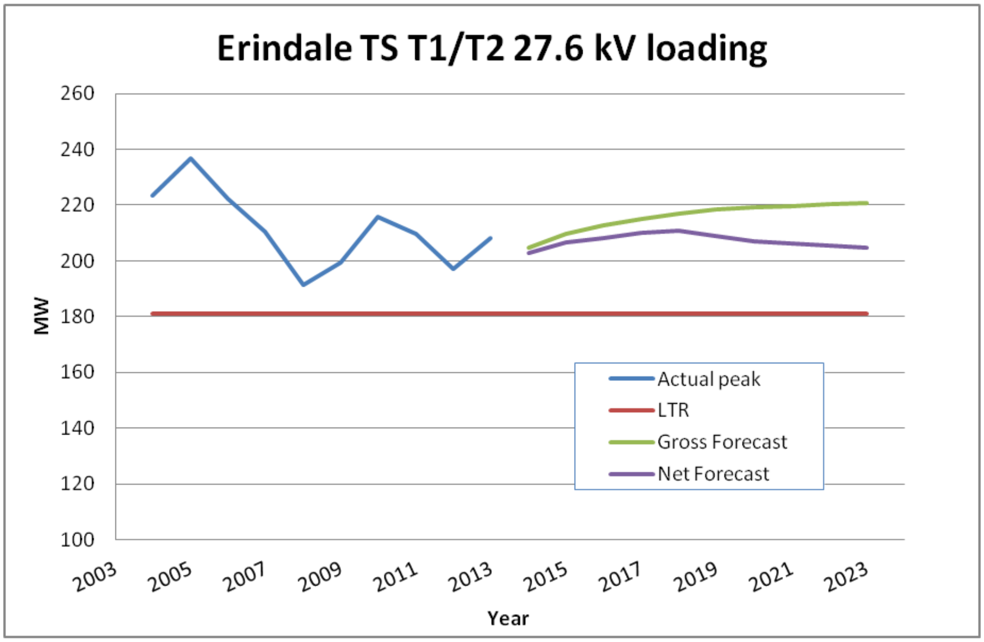
Figure 2: Erindale TS Loading



Conservation measures can play a valuable role by limiting the extent of the overload on the Erindale TS T1/T2 transformers. Local LDCs will be delivering conservation programs in the area to support meeting their CDM targets as part of the new Conservation First Framework. After accounting for LDC conservation targets, the increase in the amount of load relief required is mitigated and held at historical levels (as shown in the figure above). Given the immediacy of the capacity needs and the amount of incremental CDM required to meet the remaining capacity requirements, additional targeted conservation is deemed to be an unfeasible solution in the near term.

Additionally, DG contracts in the Erindale service territory currently total 7.1 MW of capacity, primarily made up of solar Feed in Tariff (“FIT”) projects, and a bioenergy project procured through the Renewable Energy Standard Offer Program (“RESOP”). Given the dense, largely residential load served by Erindale T1/T2, and the historic uptake in the area, it is not expected that up to 30-40 MW of new capacity could be procured to meet this need.

Capacity is available at other step down stations in the general vicinity of Erindale TS. This allows the possibility of supplying this shortfall through implementing transmission and distribution solutions. When capacity is available at adjacent stations, these types of solutions are typically the lowest cost option due to minimal new infrastructure requirements. Stations in the vicinity of Erindale TS that are projected to have surplus capacity over the next 10 years are listed in the table below:

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Table 2: Stations in Vicinity of Erindale TS

Station	Available Capacity	Notes
Erindale TS	T3/T4 (44kV): 37 MW T5/T6 (44kV): 17 MW	44/27.6 kV conversion required
Tomken TS	T1/T2 (44 kV): 25 MW T3/T4 (44 kV): 33 MW	44/27.6 kV conversion required
Lorne Park TS	(27.6 kV): 19 MW	Limited capacity available Non adjacent service territory: No intertie potential
Cooksville TS	T3/T4 (27.6 kV): 60 MW T5/T6 (27.6 kV): 24 MW	Non adjacent service territory: No intertie potential
Churchill Meadows TS	(44 kV): 74 MW	44/27.6 kV conversion required
Trafalgar TS	(27.6 kV): 34 MW	Requires feeder crossing of 403 highway

The available capacity is based on the minimum difference between the net (planning level) forecast and facility rating over the 10-year planning horizon. As a result, anticipated growth is already accounted for in this table.

Load Security and Restoration Assessment

Three areas within the GTA West Southern Sub-Region have been identified as being at risk for not meeting restoration levels as defined in ORTAC. ORTAC indicates 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 4 hours. The assessment should also consider restoration of all loads within 8 hours. Because West 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 8 hours. As a result, this analysis will only focus on 30 minute and 4 hour restoration capability.

The table below shows the anticipated 10-year peak for four areas that were investigated for Restoration needs (based on the net, planning level forecast), and the corresponding amount of load that should be restored within 30 minutes and 4 hours, respectively. Available distribution system restoration capability was supplied by LDCs based on the existing system configuration, and compared to ORTAC to determine where restoration needs may exist.

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Note that one of the four areas investigated, Burlington x Trafalgar T36/37B, was found to have adequate restoration capability:

Table 3: Restoration Summary

		30 minute Restoration		4 hour Restoration	
Area Circuit Affected stations	**Peak 10 yr load**	**Required to meet criteria**	**Available**	**Required to meet criteria**	**Available**
West of Cooksville B15/16C Oakville, Ford Oakville, Lorne Park	267 MW	17 MW	46 MW	117 MW	110 MW
Richview x Trafalgar R19/21TH Churchill Meadows, Erindale T5/T6, Tomken T3/T4, Jim Yarrow MTS	576 MW	326 MW	165 MW	426 MW	465 MW
Richview x Trafalgar R14/17T Erindale T1/T2 T3/T4, Tomken T1/T2	515 MW	265 MW	115 MW	365 MW	390 MW
Burlington x Trafalgar T36/37B Palermo TS, Glenorchy MTS #1	230 MW	--	65 MW	80 MW	140 MW

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…"[3]. Applications for exemption are to be jointly submitted to the IESO by the affected distributor and transmitter.

It should also be noted that the vulnerability to loss of supply for customers in the Cooksville West area was highlighted during the July 8, 2013 summer rain storm. This section of line was interrupted for several hours due to outages at Richview TS and Manby TS. Although this was a low probability extreme event, Enersource and Oakville Hydro have indicated that there are ongoing concerns about this reliability risk.

The OPA is currently carrying out a bulk system planning study for West GTA, which includes consideration for restoration needs identified for the Richview x Trafalgar corridor. Solutions to address bulk system needs have the potential to impact restoration capabilities throughout the area, including West of Cooksville. This study is expected to be complete by the end of 2014.

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

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Recommendation

Two categories of needs have been identified for the GTA West Southern Sub-Region: capacity needs at Erindale TS T1/T2 and load restoration needs along several double circuit corridors.

For Erindale TS T1/T2 27.6kV, given that the capacity need is immediate, but that available capacity exists on the Enersource system, it is recommended that wires based planning be pursued. Additionally, since all potentially affected stations serve Enersource load exclusively, it is recommended that this capacity need be addressed directly between Hydro One Networks Transmission and Enersource as part of regular customer planning, and not through a coordinated regional planning process.

For load restoration needs along the Richview x Trafalgar corridor and West of Cooksville area, it is recommended that these needs be considered as part of the ongoing bulk system planning study for West GTA. The OPA will regularly update Enersource, Oakville Hydro, and other affected or interested LDCs on the study progress, and ensure regional specific information is incorporated in the analysis. Should the bulk system planning study not resolve these load restoration needs, the planning approach is to revisit this issue as part of the OEB's ongoing regional planning process.

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Fax 416 967-1947 1-800-797-9604 Toll Free info@powerauthority.on.ca www.powerauthority.on.ca

Scoping Assessment Outcome Report Summary
Addenda: Results of Public Comment Period

Region: **Sub-Region:**	**Greater Toronto Area ("GTA") West** **Southern Sub-Region** **("GTA West Southern Sub-Region" or "Southern Sub-Region")**

Introduction

As part of the Ontario Energy Board's ("OEB") formalized Regional Planning process endorsed by the OEB in August 2013, the draft Scoping Assessment report is to be made available for public review with an opportunity for comments. Comments received are to be considered by the study team prior to a final decision on the Scoping Assessment outcome.

Comments

On August 19th, 2014, the Draft Scoping Assessment Outcome report was posted to the OPA website for a 2 week public comment period. A notifying email was sent out to all parties who had signed up to receive updates for the West GTA Planning Region. No comments were received.

Response

Comments were not received for the draft GTA West Southern Sub-Region Scoping Assessment. As a result, the draft document will be marked as final without material updates to the content or conclusions. The final Scoping Assessment will be posted to the OPA website by September 19th, 2014, completing this phase of the regional planning process.

Ontario Power Authority
120 Adelaide Street West, Ste. 1600, Toronto, Ontario M5H 1T1 Tel 416 967-7474
Fax 416 967-1947 1-800-797-9604 Toll Free info@powerauthority.on.ca www.powerauthority.on.ca

Hydro One Networks Inc.
483 Bay Street
Toronto, Ontario
M5G 2P5

NEEDS SCREENING REPORT

Region: Greater Toronto Area (GTA) West
Sub-Region: Southern Sub-Region

Revision: Final
Date: May 30, 2014

Prepared by: GTA West Southern Sub-Region Study Team

GTA West Southern Sub-Region Study Team

Company	Name
Hydro One Networks Inc. (Lead Transmitter)	Paul Cook Dhvani Shah
Ontario Power Authority	Alexandra Barrett
Independent Electricity System Operator	Phillip Woo
Burlington Hydro Inc.	Joe Saunders
Enersource Hydro Mississauga Inc.	Branko Boras
Hydro One Networks Inc. (Distribution)	Charlie Lee
Milton Hydro Distribution Inc.	Ron Brajovic
Oakville Hydro Electricity Distribution Inc.	Mike Brown

Disclaimer

This Needs Screening Report was prepared for the purpose of identifying potential needs in the GTA West Southern Sub-Region and to assess whether those needs require further coordinated regional planning. The potential needs that have been identified through this Needs Screening Report may be studied further through subsequent regional planning processes and may be reevaluated based on the findings of further analysis. The load forecast and results reported in this Needs Screening Report are based on the information and assumptions provided by study team participants.

Study team participants, their respective affiliated organizations, and Hydro One Networks Inc. (collectively, "the Authors") make no representations or warranties (express, implied, statutory or otherwise) as to the Needs Screening Report or its contents, including, without limitation, the accuracy or completeness of the information therein and shall not, under any circumstances whatsoever, be liable to each other, or to any third party for whom the Needs Screening Report was prepared ("the Intended Third Parties"), or to any other third party reading or receiving the Needs Screening Report ("the Other Third Parties"), for any direct, indirect or consequential loss or damages or for any punitive, incidental or special damages or any loss of profit, loss of contract, loss of opportunity or loss of goodwill resulting from or in any way related to the reliance on, acceptance or use of the Needs Screening Report or its contents by any person or entity, including, but not limited to, the aforementioned persons and entities.

NEEDS SCREEN EXECUTIVE SUMMARY

NAME	Paul Cook		
LEAD	Hydro One Networks Inc.		
REGION	GTA West – Southern Sub-Region		
START DATE	April 2, 2014	**END DATE**	June 1, 2014

1. INTRODUCTION

The purpose of this Needs Screening report is to undertake an assessment of the GTA West Southern Sub-Region, determine if there are regional needs that would lead to coordinated regional planning. Where regional coordination is not required and a "wires" only solution is necessary, such needs will be addressed between the relevant Local Distribution Companies (LDCs) and Hydro One, and other parties as required..

For needs that require further regional planning and coordination, the Ontario Power Authority (OPA) will initiate the Scoping process to determine whether an OPA-led Integrated Regional Resource Planning (IRRP) process, or the transmitter-led Regional Infrastructure Plan (RIP) process (wires solution), or both, are required.

2. REGIONAL ISSUE/ TRIGGER

The Needs Screening for the GTA West Southern Sub-Region was triggered in response to the Ontario Energy Board's (OEB) new Regional Planning process approved in August 2013. To prioritize and manage the regional planning process, Ontario's 21 regions were assigned to one of three groups, where Group 1 Regions are being reviewed first. The Needs Screening for this Sub-Region was triggered on April 2, 2014 and was completed on June 1, 2014.

3. SCOPE OF NEEDS SCREENING

The scope of this Needs Screening assessment was limited to the next 10 years because relevant data and information collected was up to the year 2023. Needs emerging over the next 10 years and requiring coordinated planning may be further assessed in the next planning cycle or as part of the OPA-led Scoping Assessment to develop a 20-year IRRP with strategic direction for the Region.

The assessment included a review of transmission system connection facilities capability which covers station loading, thermal and voltage analysis, system reliability, operational issues such as load restoration and assets approaching end of useful life.

4. INPUTS/DATA

Study team participants, including representatives from LDCs, the OPA, the Independent Electricity System Operator (IESO), and Hydro One transmission, provided information for the GTA West Southern Sub-Region. The information included load forecast, historical load, Conservation and Demand Management (CDM), Distributed Generation (DG), load restoration and performance information along with end-of-useful life of any major equipment. See Section 4 for further details.

5. ASSESSMENT METHODOLOGY

The assessment primary objective over the study period (2014 to 2023) is to identify the electrical infrastructure needs in the region. The study reviewed available information, load forecast and conducted single and double contingency analysis to confirm need, if and when required. See Section 5 for further details.

6. RESULTS

I REGIONAL SUPPLY CAPACITY

A. 230 kV transmission lines

- Thermal limits for several transmission circuits between Richview TS and Trafalgar TS (R14T, R17T, R19TH & R21TH) may be exceeded in the near term during certain contingency situations. This issue is being studied by the OPA as part of the bulk system planning studies.
- Thermal limits for transmission circuits between Richview TS and Manby TS are nearing capacity and require reinforcement in the near term. While these circuits are not part of the study area, they affect the loading on the transmission circuits between Cooksville TS and Oakville TS#2. This need is being addressed as part of the Central Toronto IRRP.

B. Area Connection Capacity

- Peak load on Erindale T1/T2 27.6 kV DESN has reached normal supply capacity and requires further assessment.
- Peak load on Erindale TS T5/T6 44 kV DESN, Tomken TS T1/T2 44 kV DESN, Lorne Park TS, and Oakville TS#2 may approach normal supply capacity by the end of the 10-year study period. The loading at these stations will be monitored and assessed in the next planning cycle for GTA West.

II SYSTEM RELIABILITY, OPERATION AND RESTORATION

Generally speaking, there are no significant system reliability and operating issues for one element out of service. However, for the loss of two elements, load restoration as per Ontario Resource and Transmission Assessment Criteria (ORTAC) criteria may not be met in some cases. Further study is required.

III AGING INFRASTRUCTURE / REPLACEMENT PLAN

During the study period, plans to replace major equipment do not affect the capacity needs identified. Transformer replacements at Cooksville TS are expected to increase the normal supply capacity at the station. See Section 6.3 for details.

7. RECOMMENDATIONS

Based on the assessment, the study team's recommendation is that coordinated regional planning is further required to assess some of the needs identified in Section 6 of this Needs Screening. Accordingly, the OPA should initiate Scoping Assessment for this Sub-Region. See Section 7 for further details.

It is expected that the plan for this subregion will be appended to the overall GTA West Regional Plan.

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1 INTRODUCTION

This Needs Screening report provides a summary of needs that are emerging in the GTA West Southern Sub-Region over the next ten years. The development of the Needs Screening report is in accordance with the regional planning process as set out in the Ontario Energy Board's (OEB) Transmission System Code (TSC) and Distribution System Code (DSC) requirements and the "Planning Process Working Group (PPWG) Report to the Board".

The purpose of this Needs Screening report is to undertake an assessment of the GTA West Southern Sub-Region, determine if there are regional needs that would lead to coordinated regional planning. Where regional coordination is not required and a wires-only only solution is necessary, such needs will be addressed between the relevant Local Distribution Companies (LDCs) and Hydro One, and other parties as required.

For needs that require further regional planning and coordination, the Ontario Power Authority (OPA) will initiate the Scoping process to determine whether an OPA-led Integrated Regional Resource Planning (IRRP) process, or the transmitter-led Regional Infrastructure Plan (RIP) process (wires solution), or both are required.

This report was prepared by the GTA West Southern Sub-Region Needs Screening study team (Table 1) and led by the transmitter, Hydro One Networks Inc. The report captures the results of the assessment based on information provided by the Local Distribution Companies (LDCs), Ontario Power Authority (OPA) and the Independent Electricity System Operator (IESO).

Table 1: Study Team Participants for GTA West Southern Sub-Region

No.	**Company**
1.	Hydro One Networks Inc. (Lead Transmitter)
2.	Ontario Power Authority
3.	Independent Electricity System Operator
4.	Burlington Hydro Inc.
5.	Enersource Hydro Mississauga Inc.
6.	Hydro One Networks Inc. (Distribution)
7.	Milton Hydro Distribution Inc.
8.	Oakville Hydro Electricity Distribution Inc.

2 REGIONAL ISSUE / TRIGGER

The Needs Screening for the GTA West Southern Sub-Region was triggered in response to the OEB's new Regional Infrastructure Planning process approved in August 2013. To prioritize and manage the regional planning process, Ontario's 21 regions were assigned to one of three groups, with Group 1 Regions being reviewed first. The GTA West Region belongs to Group 1.

This region is divided into two sub-regions: GTA West Northern Sub-Region and GTA West Southern Sub-Region. A Needs Screening has been triggered for the GTA West Southern Sub-Region. For the GTA West Southern Sub-Region, the Needs Screening was triggered on April 2, 2014 and was completed on June 1, 2014. The GTA West Northern Sub-Region currently has an IRRP under development and was initiated prior to the new Regional Infrastructure Planning process.

3 SCOPE OF NEEDS SCREENING

This Needs Screening covers the GTA West Southern Sub-Region over an assessment period of 2014 to 2023. The scope of the Needs Screening includes a review of system capability, which covers transformer station loading and transmission thermal and voltage analysis. System reliability, operation, load security and restoration, and asset sustainment issues were also briefly reviewed as part of this screening.

3.1 GTA West Southern Sub-Region Description and Connection Configuration

The scope of this Needs Screening covers the GTA West Southern Sub-Region. This Sub-Region is roughly bordered geographically by Highway 427 to the east, Tremaine Road to the west, Lake Ontario to the south and Highway 407 on the north. This Sub-Region comprises the municipalities of Mississauga and Oakville. The GTA West Southern Sub-Region is highlighted in yellow in Figure 1.

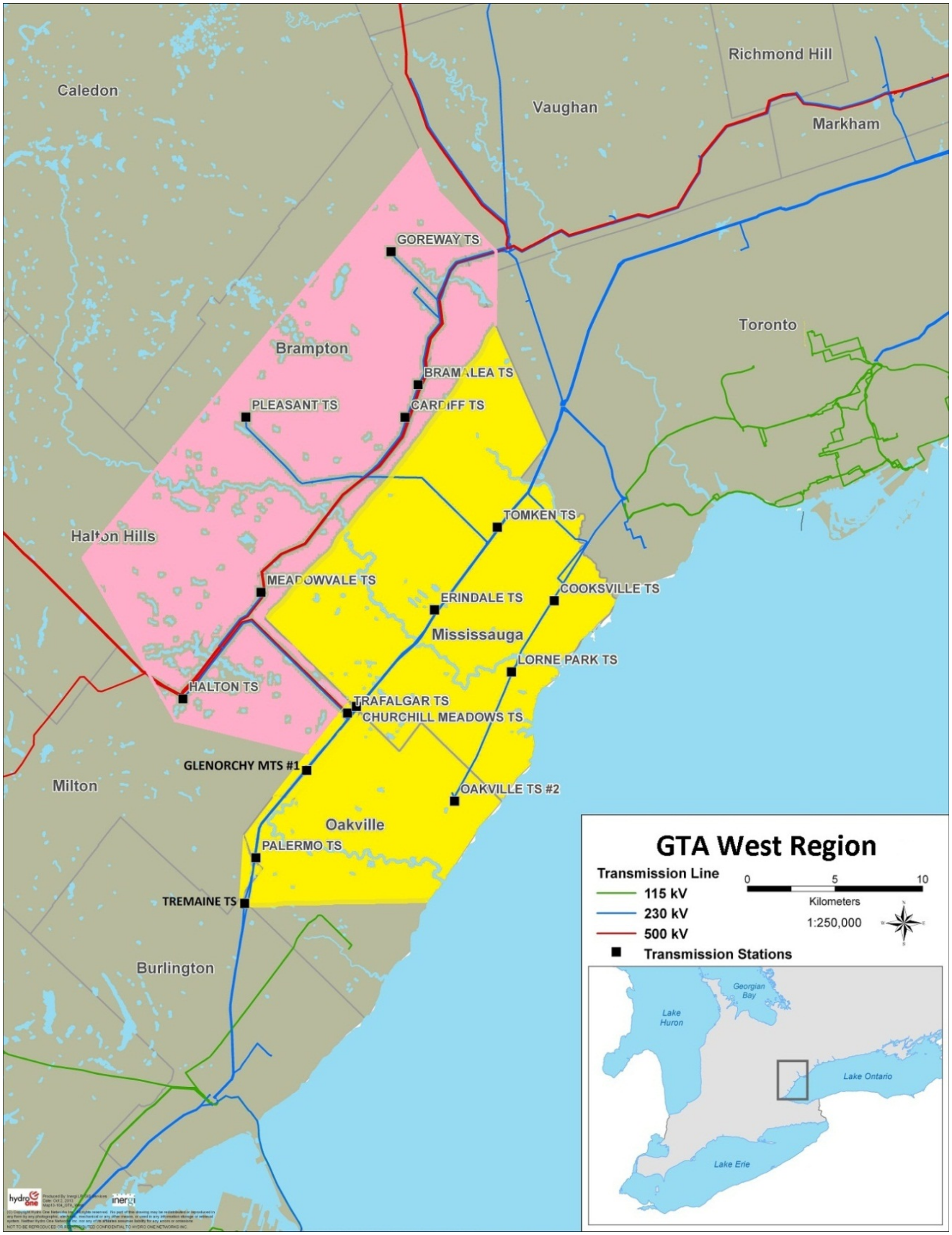

Figure 1: GTA West Southern Sub-Region Map

3.2 Electrical Areas

The GTA West Region was divided into the following electrical areas (sub-regions):

- GTA West, Northern Sub-Region
- GTA West, Southern Sub-Region

Electrical supply to the GTA West Southern Sub-Region is provided through 230 kV transmission lines and step-down transformation facilities as shown in Figure 2. This Sub-Region is roughly bounded electrically by the Richview TS to Manby TS 230 kV transmission lines on the east, the Richview TS to Trafalgar TS to Burlington TS 230 kV transmission lines on the north and the Manby TS to Cooksville TS to Oakville TS 230 kV transmission lines on the south. The distribution system in this Sub-Region is at two voltage levels, 44 kV and 27.6 kV.

The following circuits are not included in the GTA West Southern Sub-Region
- The 230 kV tap to Halton TS and Meadowvale TS, and all the circuits and stations on or north of the Parkway Belt Corridor, including the 230 kV tap to Kleinburg TS and the 230 kV tap to Jim Yarrow MTS and Pleasant TS. These circuits are included in the GTA West Northern Sub-Region.
- The circuits and stations supplied from the Richview TS to Manby TS transmission corridor. These circuits are included in the Metro Toronto Region.
- The 115 kV circuits B7 and B8, Bronte TS and Burlington TS. These circuits are included in the Burlington-Nanticoke Region.

A single line diagram of the 230 kV system in the GTA West Southern Sub-Region is shown in Figure 2 below.

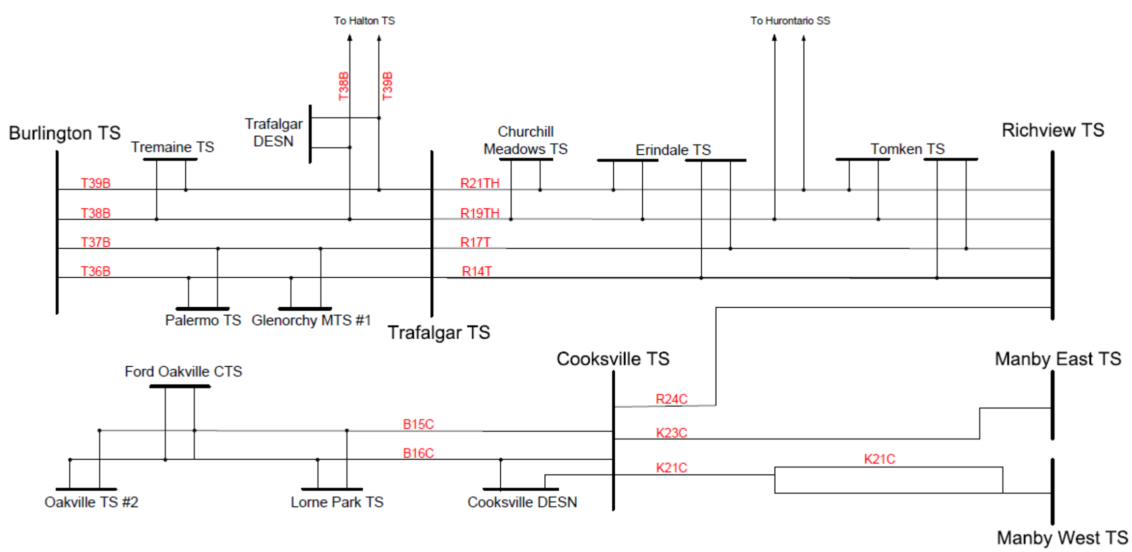

Figure 2: Single Line Diagram – GTA West Southern Sub-Region

4 INPUTS AND DATA

In order to conduct this Needs Screening, study team participants provided the following information and data to Hydro One:

- IESO provided:
  i. Historical regional coincident peak load and station non-coincident peak load;
  ii. A list of existing reliability and operational issues.
- LDCs provided historical net load (2011-2013) and gross load forecast (2014-2023).
- Hydro One provided transformer, station and line ratings.
- Conservation and Demand Management (CDM) and Distributed Generation (DG) data provided by the OPA.
- Any relevant planned transmission and distribution investments provided by the transmitter and LDCs, etc.

4.1 Load Forecast

As per the data provided by the study team, the load growth rates at the stations in the GTA West Southern Sub-Region over the 2014-2023 study period is summarized in Table 2 below.

Table 2: Average Annual Gross Load Growth Rates

Sub-Area	Near Term (2014-2018)	Mid-Term (2019-2023)
44 kV System	1.1%	0.4%
27.6 kV System	1.4%	1.8%
Total Sub-Region	1.3%	1.4%

Note that the average load growth in the 27.6 kV system west of Trafalgar TS has been approximated due to load transfers between stations from other Regions or Sub-Regions.

5 ASSESSMENT METHODOLOGY

The following methodology and assumptions were made in this Needs Screening assessment:

1. The Region is summer peaking so this assessment is based on summer peak loads.

2. Forecast loads are based on the anticipated forecast growth rates provided by the Region's LDCs using historical 2013 summer peak load as reference point.
3. The 2013 historical peak loads are adjusted for extreme weather conditions according to Hydro One methodology.
4. A station annual load growth rate based on LDCs forecast is assumed over the study period.
5. Gross load forecast is used to develop a worst-case scenario to identify needs. Net load forecast is only used to assess if needs can be deferred beyond the study period.
6. Review and assess the impact of any on-going or planned development project in GTA West Southern Sub-Region during the study period.
7. Review and assess the impact of any critical/major elements planned/identified to be replaced at the end of their useful life such as auto transformers, cables and stations.
8. To identify the emerging needs in each area, the study was performed observing all elements in service and one or two elements out of service.
9. Station capacity adequacy is assessed by comparing non-coincident peak load with the station's normal supply capacity assuming a 90% lagging power factor for stations having no low-voltage capacitor banks and 95% lagging power factor for stations having low-voltage capacitor banks. Normal supply capacity for transformer stations in this Sub-Region as determined by the summer 10-Day Limited Time Rating (LTR).
10. Transmission adequacy assessment is primarily based on :
    - Stations loads are coincident with relevant peak.
    - With all elements in service, the system is to be capable of supplying forecast demand with equipment loading within continuous ratings and voltages within normal range.
    - With one or two elements out of service, the system is to be capable of supplying forecast demand with circuit loading within their Long-Term Emergency (LTE) ratings and transformers within their 10-Day LTR.
    - All voltages must be within pre and post contingency ranges as per ORTAC criteria.

This needs screening assessment was conducted to identify emerging needs and to determine whether further coordinated regional planning should be undertaken or not for the Sub-Region. It is expected that studies in the subsequent regional planning process will undertake detailed analysis and also assess ORTAC performance requirements, including loss of two elements.

6 RESULTS

This section summarizes the results of the Needs Screening in the GTA West Southern Sub-Region.

6.1 Transmission Capacity Needs

6.1.1 230kV Region Supply

With one element out of service, loading on the Richview TS to Trafalgar TS circuits may exceed their LTE ratings in the near term, while under high FETT flows. This issue requires further assessment and is being dealt with by OPA-led bulk power system planning.

The loading on the 230 kV Richview TS to Manby TS circuits is expected to exceed the circuit LTE rating over the near-term. This issue is being assessed as part of the OPA-led IRRP for Central Toronto.

6.1.2 230kV Connection Facilities

There are several needs emerging in this subregion. Some of the needs identified during the study period include, but not limited to, the following:

- Existing peak load on the Erindale TS T1/T2 27.6 kV DESN is above that DESN's normal supply capacity. Peak load at this station is forecast to exceed capacity by about 40 MW by the end of the 10-year study period. Therefore, further assessment is required.
- Palermo TS is currently loaded up to its normal supply capacity. The load at the station is forecast to remain constant for the next 10 years as load growth in the area will be managed by transfers to Tremaine TS and to Glenorchy MTS #1.
- The forecast peak loads at Erindale TS T5/T6 44 kV DESN, Tomken TS T1/T2 DESN, Lorne Park TS and Oakville TS #2 may approach, but do not exceed, their respective normal supply capacity by the end of the 10-year study period.

6.2 System Reliability, Operation and Load Restoration

Generally speaking, there are no significant system reliability and operating issues for one element out of service.

The load interrupted due to the loss of a double-circuit line is well below the limit of 600 MW during the study period. The total load on 230kV transmission circuits R19TH and

R21TH may approach, but will not exceed, 600 MW for loss of a double-circuit line by the end of the 10-year study period.

Load restoration under peak load conditions as per ORTAC criteria may not be met for the loss of two elements and requires further study.

6.3 Aging Infrastructure and Replacement Plan of Major Equipment

During the study period:

- All four transformers at Cooksville TS are scheduled to be replaced by end of 2014. The 10-day LTR of the new transformers is expected to be higher than that of the existing transformers, thus increasing the normal supply capacity of both DESNs. No transmission issues are expected as a result.
- There are no significant lines sustainment plans scheduled in the near term for circuits in this subregion.

6.4 Other Considerations

The stations in southern Mississauga and east Oakville, namely Cooksville TS, Lorne Park TS and Oakville TS, are supplied radially from Richview TS via five 230kV circuits, which also terminate at Manby TS. On July 8, 2013, a severe rainstorm caused flooding and complete station outages at Richview and Manby transformer stations. As a result of this extreme event, customers normally supplied from Cooksville TS, Lorne Park TS, and Oakville TS experienced prolonged power outage. Subsequent steps in the planning process for this area will investigate the technical and economic feasibility of options for mitigating this risk.

7 RECOMMENDATIONS

Based on the Needs Screening assessment, the study team's recommendations are as follows:

a) Coordinated regional planning is further required by the OPA to undertake Scoping Assessment for the following needs identified in Section 6.
    - Erindale TS T1/T2 27.6kV DESN – there is an immediate need for increased transformation capacity. This issue may be managed in the interim by distribution load transfers.
    - Load restoration for the loss of two elements.

As part of its Scoping Assessment process, the OPA will determine if the OPA-led IRRP process and/or the transmitter-led RIP process (for wires solutions) should be further undertaken.

b) The following potential needs in Section 6 will be monitored and assessed in the next Regional Planning cycle for the GTA West area.
   - Normal supply capacity at Erindale TS T5/T6 44 kV DESN, Tomken TS T1/T2 DESN, Lorne Park TS and Oakville TS #2.
   - Monitor and assess load growth on 230kV transmission circuits R19TH and R21TH for loss of a double-circuit line (600MW limit)

The Northern subregion of GTA West region currently has an OPA-led IRRP study underway. It is expected that the plan for this subregion will be appended to the overall GTA West Regional Plan.

8 NEXT STEPS

Following the Needs Screening process, the next regional planning step, based on the results of this report, is for OPA to initiate a Scoping Assessment(s) to determine which of the needs in Section 7a) require an IRRP and/or RIP.

9 REFERENCES

- Planning Process Working Group (PPWG) Report to the Board The Process for Regional Infrastructure Planning in Ontario – May 17, 2013
- Tremaine TS SIA and CCRA
- Glenorchy MTS #1 SIA and CCRA
- IESO 18-Month Outlook

ACRONYMS

BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
CIA	Customer Impact Assessment
CGS	Customer Generating Station
CTS	Customer Transformer Station
DESN	Dual Element Spot Network
DG	Distributed Generation
DSC	Distribution System Code
FETT	Flow East Towards Toronto
GTA	Greater Toronto Area
GS	Generating Station
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Planning
kV	Kilovolt
LDC	Local Distribution Company
LTR	Limited Time Rating
LV	Low-voltage
MTS	Municipal Transformer Station
MW	Megawatt
MVA	Mega Volt-Ampere
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.
NS	Needs Screening
OEB	Ontario Energy Board
OPA	Ontario Power Authority
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Planning
SIA	System Impact Assessment
SS	Switching Station
TS	Transformer Station
TSC	Transmission System Code
ULTC	Under Load Tap Changer

Hydro One Networks Inc.
483 Bay Street
Toronto, Ontario
M5G 2P5

LOCAL PLANNING REPORT

ERINDALE TS T1/T2 DESN CAPACITY RELIEF

GTA WEST – SOUTHERN SUBREGION

Revision: 0
Date: July 9, 2015

Prepared by:

Hydro One Networks Inc.

Enersource Hydro Mississauga Inc.

GTA West Region Local Planning Study Team	
Organization	**Name**
Hydro One Networks Inc. (“HONI”)	Dhvani Shah Lukito Adiputra Ajay Garg
Enersource Hydro Mississauga Inc. (“Enersource”)	Branko Boras

Disclaimer

This Local Planning Report was prepared for the purpose of developing wires-only options and recommending preferred solution(s) to address local needs identified in the Needs Assessment and Scoping Assessment Reports for GTA West – Southern Subregion that do not require further coordinated regional planning. The preferred solution(s) that have been identified through this Local Planning Report may be reevaluated based on the findings of further analysis. The load forecast and results reported in this Local Planning Report are based on the information and assumptions provided by study team participants.

Study team participants, their respective affiliated organizations, and Hydro One Networks Inc. (collectively, "the Authors") make no representations or warranties (express, implied, statutory or otherwise) as to the Local Planning Report or its contents, including, without limitation, the accuracy or completeness of the information therein and shall not, under any circumstances whatsoever, be liable to each other, or to any third party for whom the Local Planning Report was prepared ("the Intended Third Parties"), or to any other third party reading or receiving the Local Planning Report ("the Other Third Parties"), for any direct, indirect or consequential loss or damages or for any punitive, incidental or special damages or any loss of profit, loss of contract, loss of opportunity or loss of goodwill resulting from or in any way related to the reliance on, acceptance or use of the Local Planning Report or its contents by any person or entity, including, but not limited to, the aforementioned persons and entities.

LOCAL PLANNING EXECUTIVE SUMMARY

REGION	GTA West Southern Subregion
LEAD	Hydro One Networks Inc. (HONI)

1. INTRODUCTION

The purpose of this Local Planning (LP) report is to develop wires-only solutions to address local needs identified in GTA West Southern Subregion. The development of the LP report is in accordance with the regional planning process as set out in the Planning Process Working Group (PPWG) Report to the Ontario Energy Board's (OEB) and mandated in the Transmission System Code (TSC) and Distribution System Code (DSC).

The Needs Assessment process for GTA West Southern Subregion, completed in May 2014, identified potential needs in the subregion over the next ten years (2014 to 2023). One of these needs is a need for additional station capacity at Erindale TS T1/T2 DESN. The peak load at Erindale TS T1/T2 DESN has reached the DESN's capacity, and is expected to exceed it by up to 40 MW by 2023.

The Scoping Assessment process, completed in September 2014, concluded that the Erindale TS T1/T2 DESN station capacity need can be addressed by a Local Planning process between HONI and the affected LDCs, in this case Enersource Hydro Mississauga Inc.

2. LOCAL NEEDS ADDRESSED IN THIS REPORT

This report addresses the local need for additional transformation capacity at Erindale TS T1/T2 DESN.

3. OPTIONS CONSIDERED

(1) **New DESN** – Transfer some existing 27.6 kV load from Erindale TS to a new DESN
(2) **Load transfer** – Transfer some existing 27.6 kV load from Erindale TS to Trafalgar TS or Cooksville TS
(3) **New Distribution Station (DS)** – Build a new 44/27.6kV DS. This DS will be supplied from a 44kV feeder out of one of the neighbouring DESNs in the area, like Erindale TS T3/T4 DESN, Churchill Meadows TS, or Tomken TS.

4. PREFERRED SOLUTION

Option (1) and (2) are not practical, due to relatively high project costs associated with (1) and the operational challenges of transferring the load in (2). Option (3) is the most feasible option and is currently being reviewed by Enersource. Under this option, Enersource will build a new 44/27.6kV DS.

5. NEXT STEPS

Enersource will assess and develop an implementation plan to build a new DS by the end of Q3 2015.

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1 INTRODUCTION

The Needs Assessment process for GTA West Southern Subregion, completed in May 2014, identified potential needs in the subregion over the next ten years (2014 to 2023). One of these needs is a need for additional station capacity at Erindale TS T1/T2 DESN. The peak load at Erindale TS T1/T2 DESN has reached the DESN's capacity, and is expected to exceed it by up to 40 MW by 2023.

The Scoping Assessment process, completed in September 2014, concluded that the Erindale TS T1/T2 DESN station capacity need can be addressed by a Local Planning process between HONI and the affected LDCs (i.e., Enersource).

This Local Planning report was jointly prepared by HONI and Enersource to assess a number of alternative solutions and provide a recommendation to meet this station capacity need.

Erindale TS Local Area

Erindale TS consists of 3 DESN's, namely:

- T1/T2 DESN, with 27.6 kV distribution voltage level, supplied by R14T and R17T
- T3/T4 DESN, with 44 kV distribution voltage level, supplied by R14T and R17T
- T5/T6 DESN with 44 kV distribution voltage level, supplied by R19TH and R21TH

R14T and R17T are 230 kV double-circuit lines connecting Trafalgar TS and Richview TS. R19TH and R21TH are 230 kV double-circuit lines connecting Trafalgar TS, Richview TS, and Hurontario SS. Single line diagram of the GTA West Southern Subregion is shown in Figure 1 below.

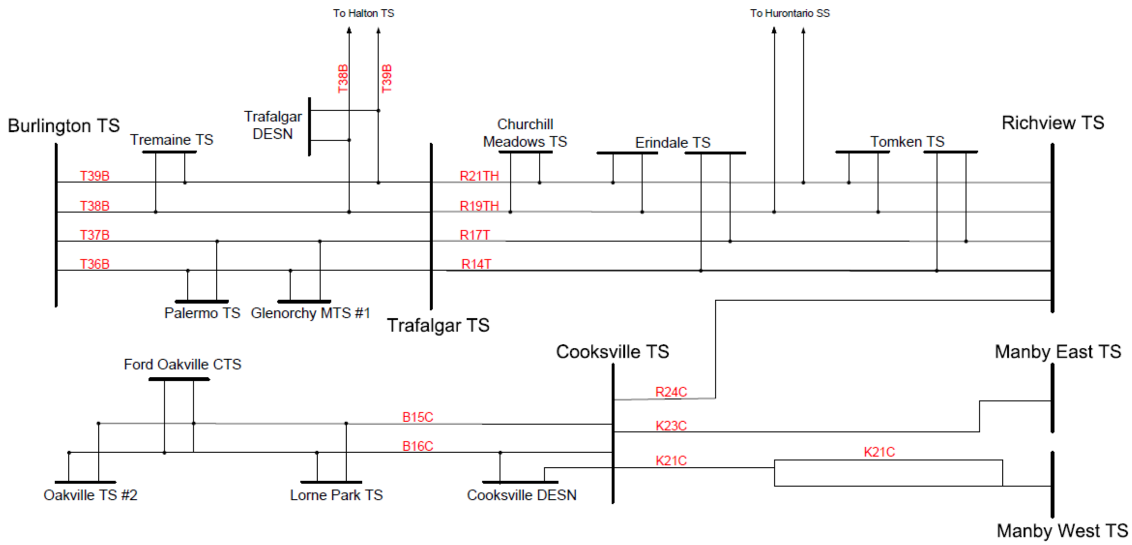

Figure 1. GTA West Southern Subregion Single Line Diagram

2 Options Considered

A number of options for providing the required relief, shown below, are being investigated. Any necessary infrastructure investment will be planned directly between Enersource and HONI.

Transmission Option:

(1) **New DESN –** Transfer some existing 27.6 kV load from Erindale TS to a new DESN

- Since the load is expected to be constant (no load growth) over the next 10 years, this option will be expensive and not economically viable.

Distribution Options:

(2) **Load transfer** – Transfer some existing 27.6 kV load from Erindale TS to Trafalgar TS or Cooksville TS

- Cooksville TS and Trafalgar TS are separated from Erindale T1/T2 by 44 kV service area. It would be operationally challenging and expensive to run a new 27.6 kV through 44 kV service territories.

(3) **New Distribution Station (DS) –** Build a new DS to utilize extra 44 kV station capacity at Erindale TS T3/T4 DESN, Churchill Meadows TS, or Tomken TS to offload Erindale TS T1/T2 DESN

- There is extra capacity available in the area 44 kV system that can be utilized by building a step down (44/27.6 kV) Distribution Station. This new DS will be supplied from a 44kV feeder. This is the most viable option that Enersource is currently reviewing. Under this option, Enersource will build the new DS, own it, and recoup the costs through the distribution rates.

3 PREFERRED SOLUTION

This is primarily a distribution planning issue that will involve planning and building a new DS by the LDC to utilize the extra 44 kV station capacity available at the neighbouring stations, such as Erindale TS (T3/T4) DESN, Churchill Meadows TS, or Tomken TS. Enersource Hydro Mississauga will assess and develop an implementation plan to build a new DS by the end of Q3 2015.

4 NEXT STEPS

A summary of the next steps, actions/solutions and timelines required to address the local needs are as follows:

Table 1. Solutions and Timeframe

Item #	Need	Action / Recommended Solution	Lead Responsibility	Timeframe
1	Erindale TS T1/T2 DESN capacity	• Assess and develop an implementation plan to build a new DS	Enersource	End of Q3, 2015

5 REFERENCES

i) GTA West Southern Subregion Need Assessment Report. Available online at: http://www.hydroone.com/RegionalPlanning/GTAWest/Documents/Needs%20Assessment%20Report%20-%20GTA%20West%20-%20Southern%20Subregion.pdf

ii) GTA West Southern Subregion Scoping Assessment Report. Available online at: http://www.ieso.ca/Documents/Regional-Planning/GTA_West/Scoping-Assessment-Outcome-Report-September-2014.pdf

6 ACRONYMS

BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
CIA	Customer Impact Assessment
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DSC	Distribution System Code
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ULTC	Under Load Tap Changer

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.

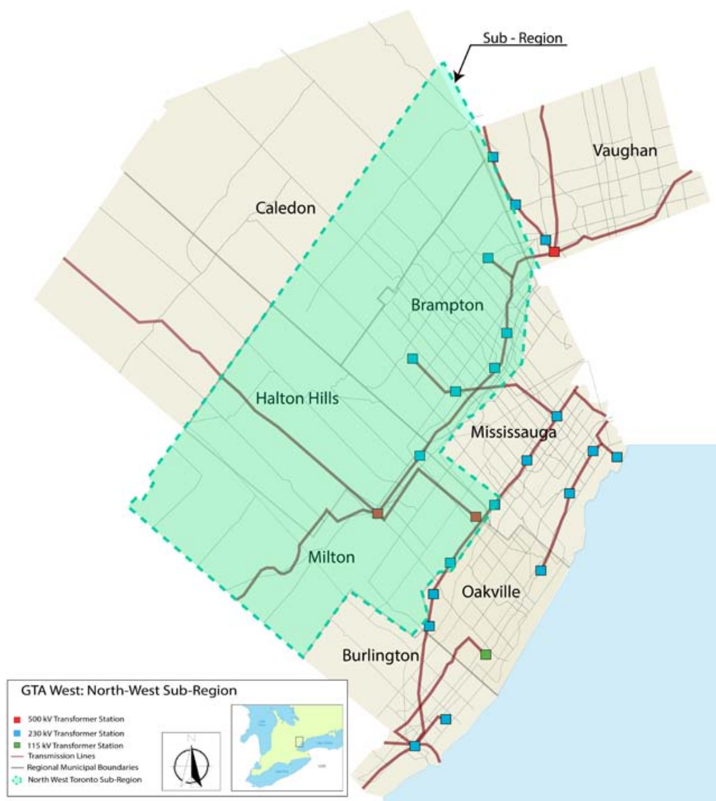
This report is organized as follows:

- 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)

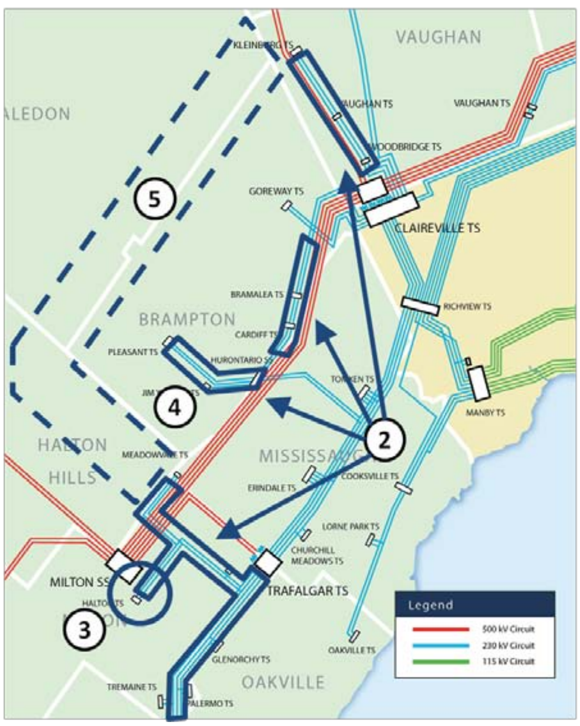


For the near and medium term, the IRRP identifies specific investments to be implemented. This is necessary to ensure that they are in service in time to address the region's more urgent needs, respecting the lead time for their development.

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

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**

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.

Recommended Actions:

1. Implement conservation and distributed generation

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

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

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

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

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

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

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

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

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

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

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

2.2 Long-Term Plan

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

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

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

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

Recommended Actions:

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

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

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

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

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

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

3. Development of the IRRP

3.1 The Regional Planning Process

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

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

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

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

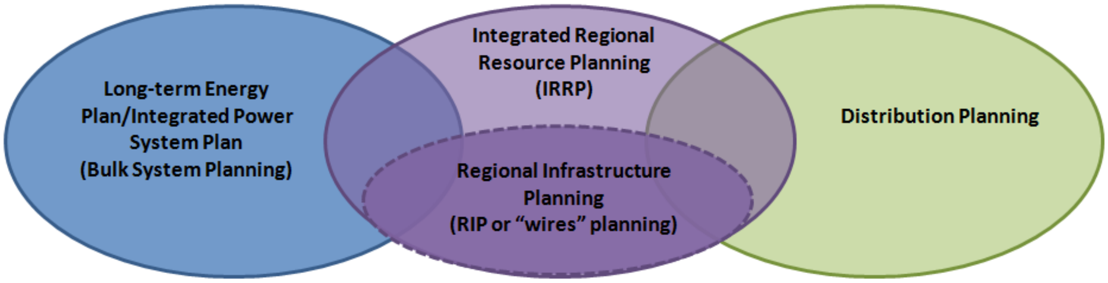
Infrastructure Plan ("RIP") is developed. The scoping assessment process also identifies any sub-regions that require assessment. There may also be regions where infrastructure investments do not require regional coordination and can be planned directly by the distributor and transmitter, outside of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

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

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

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

Figure 3-1: Levels of Electricity System Planning



Bulk System Planning

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

Regional Planning

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

Distribution Network Planning

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

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

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

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

3.2 The IESO's Approach to Regional Planning

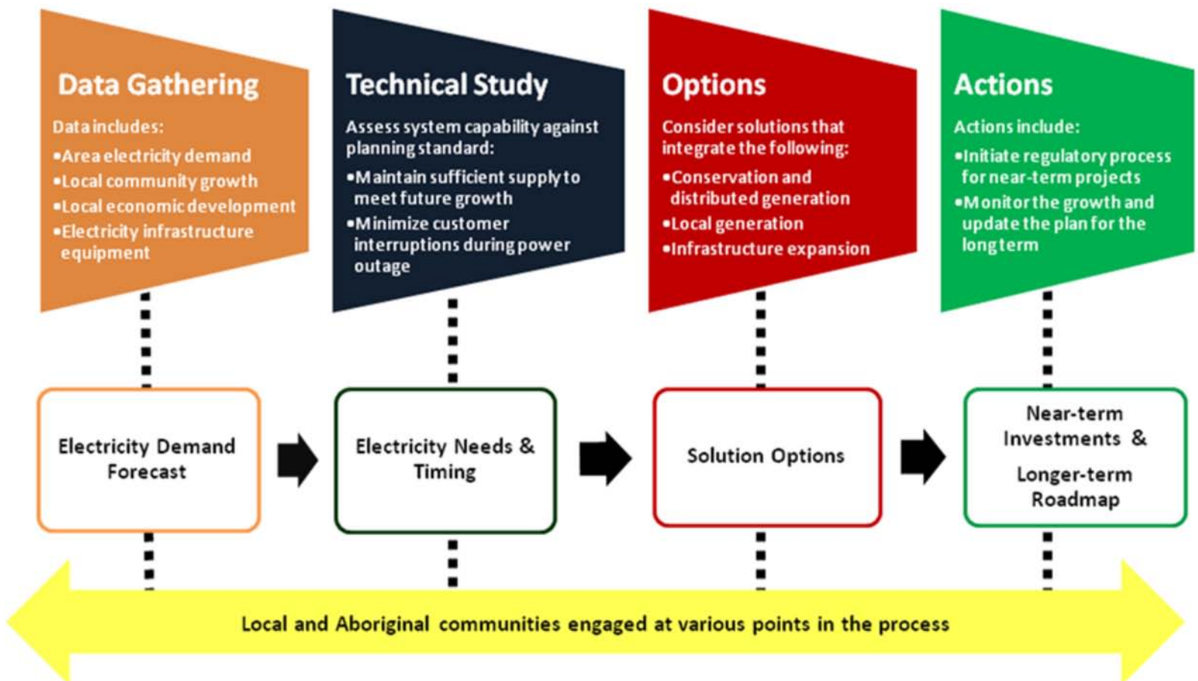
IRRPs assess electricity system needs for a region over a 20-year period. The 20-year outlook anticipates long-term trends so that near-term actions are developed within the context of a longer-term view. This enables coordination and consistency with the long-term plan, rather than simply reacting to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

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

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

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

Figure 3-2: Steps in the IRRP Process



3.3 Northwest GTA Working Group and IRRP Development

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

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

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

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

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

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

4. Background and Study Scope

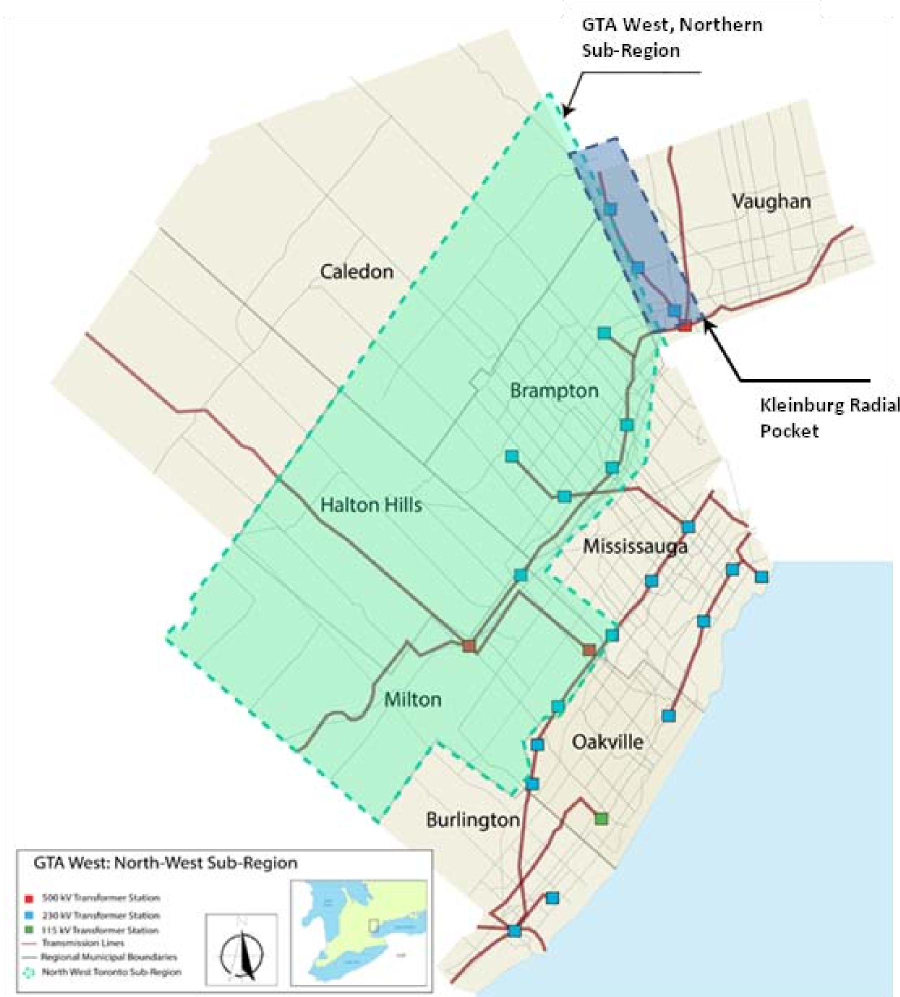
This report presents an integrated regional electricity plan for NW GTA for the 20-year period from 2014 to 2033. The planning process leading to this IRRP began in 2013, in recognition of the high electrical demand growth observed over the previous 10 years, expanding urban boundaries, limited existing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

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

4.1 Study Scope

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

Figure 4-1: Northwest GTA Planning Sub-region



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

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

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

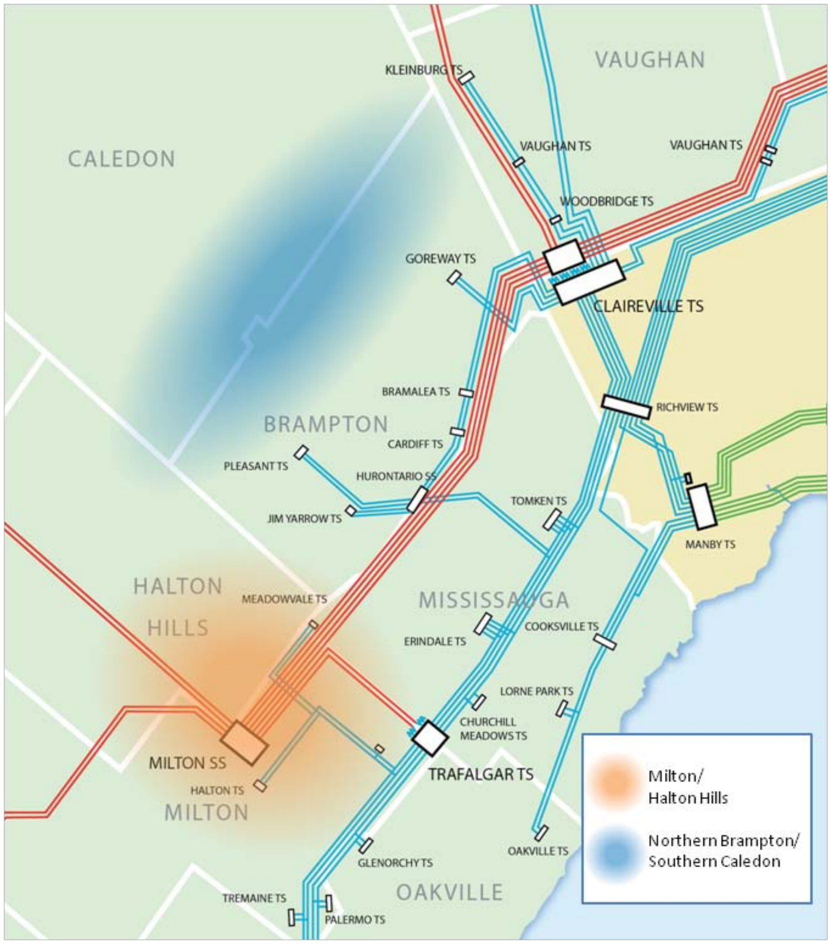
- The Northwest GTA sub-region is characterized by a large number of similarly configured radial pockets, meaning that restoration needs would be a common issue addressed across the entire planning area. The fact that there are so many radial pockets provides an opportunity for investigating common solutions.

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

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

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

Figure 4-2: Anticipated Growth Clusters, by Municipality



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

4.2 2006 West GTA Supply Study

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

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

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

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

4.3 Bulk Transmission System Study

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

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

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

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

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

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

These three facilities are highlighted on the map below:

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

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

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

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

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

5. Load Forecast

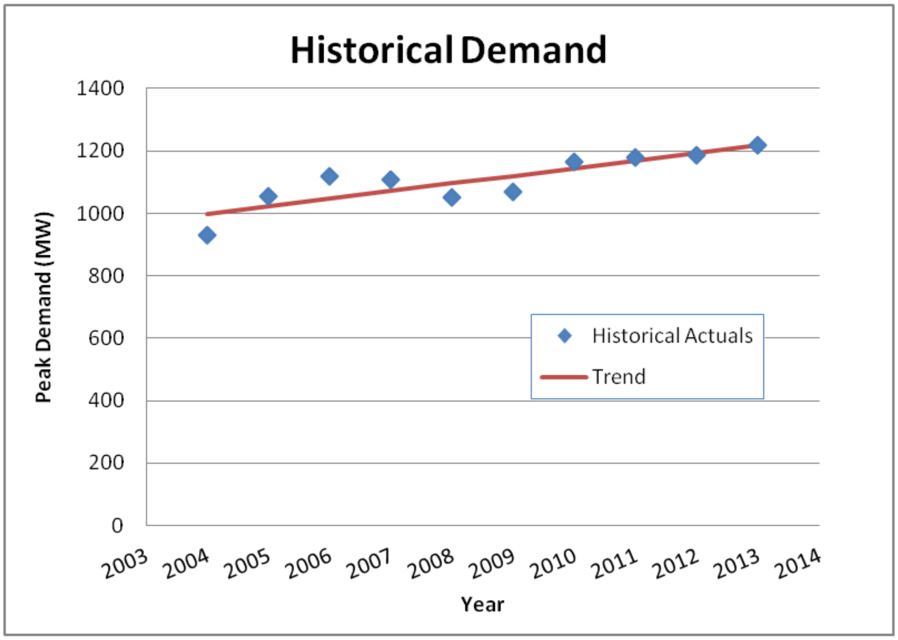
This section outlines the forecast of electricity demand within the Northwest GTA sub-region. It highlights the assumptions made for peak-demand load forecasts, the contribution of conservation to reducing peak demand and the role of distributed generation resources in supplying demand in this area.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

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

5.1 Historical Demand

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

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



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

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

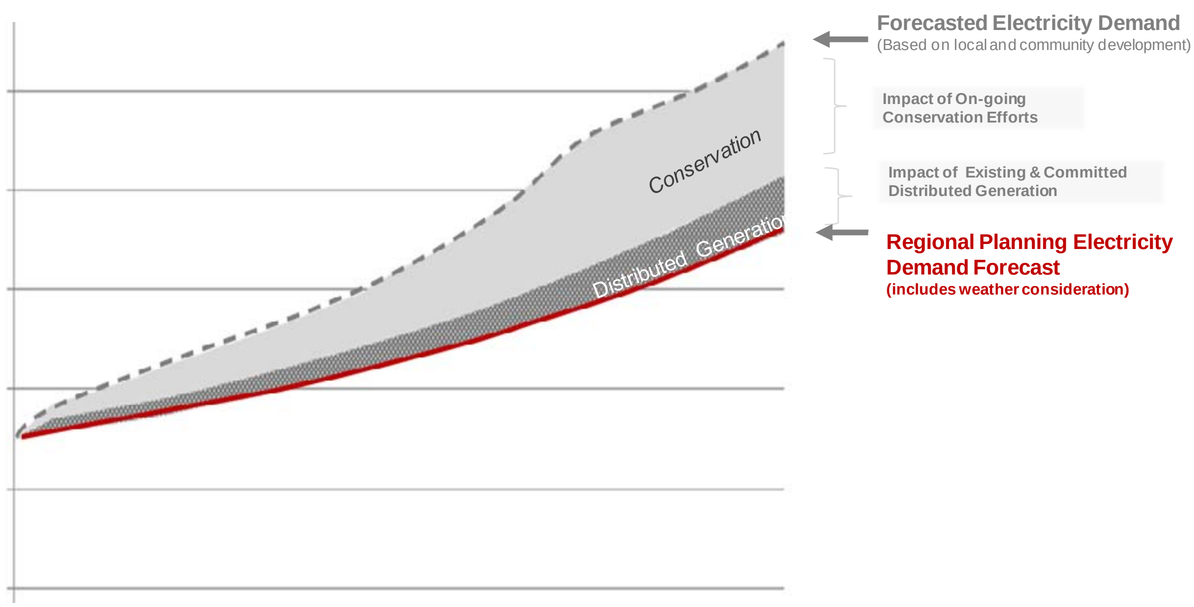
LDC	2009	2010	2011	2012	2013	Avg % Growth
Hydro One Brampton	739.35	800.67	807.70	810.65	825.55	2.32 %
Milton Hydro	130.82	143.42	156.18	156.93	168.28	6.05 %
Halton Hills Hydro	85.67	93.67	92.69	92.83	97.09	2.41 %
Hydro One Distribution (Caledon)	114.39	128.42	123.28	125.45	126.44	1.73 %
TOTAL	1070.24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

5.2 Demand Forecast Methodology

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

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

Figure 5-2: Development of Expected Growth Scenario



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

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

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

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

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

5.3 Gross Demand Forecast

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

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

5.4 Conservation Assumed in the Forecast

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

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

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

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

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

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

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

5.5 Distributed Generation Assumed in the Forecast

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

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

- Wind: 13.6%
- Solar: 34.0%

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

Table 5-3: DG Capacity Assumed by Station

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

5.6 Planning Forecasts

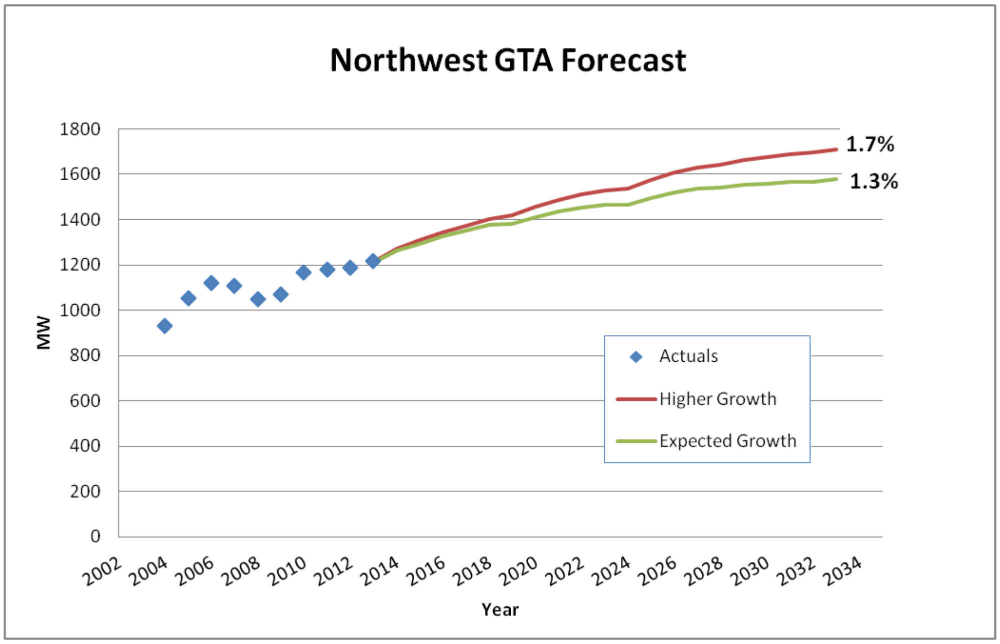
As described above, the IESO developed two planning forecasts:

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

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

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

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



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

6. Needs

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

6.1 Step-down Capacity Needs

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

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

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

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

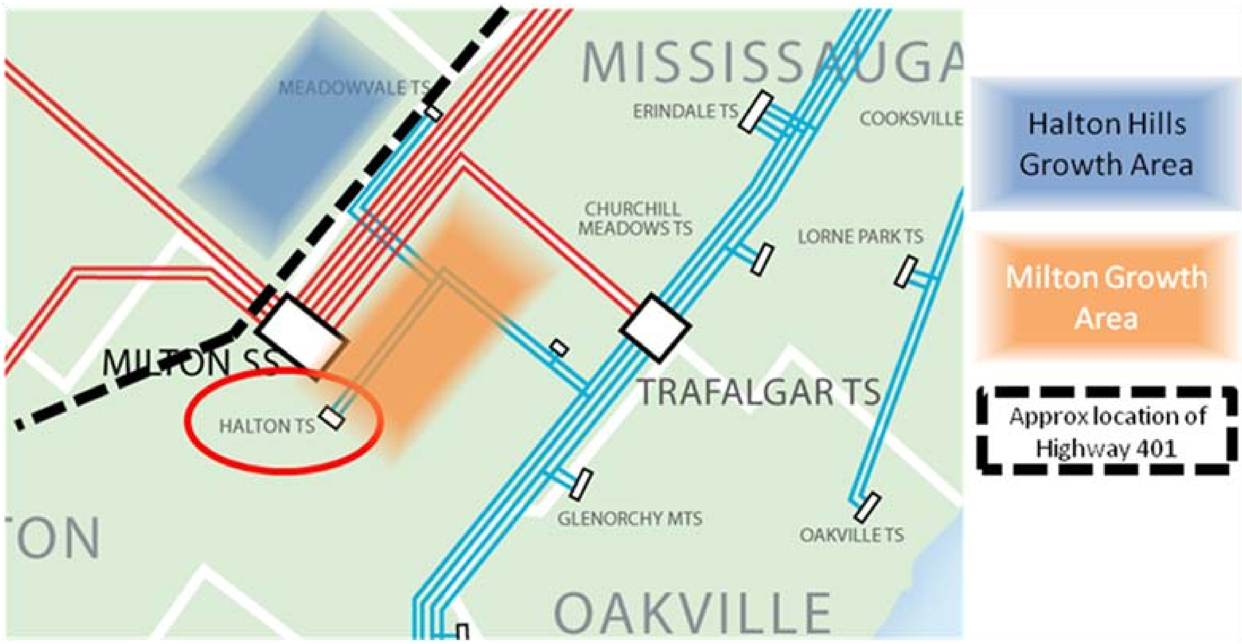
When a step-down station's capacity is reached, options for offloading the limiting station or asset include reducing net growth in the supply area (e.g., through enhanced conservation and/or DG measures), transferring loads through the distribution system to nearby stations with surplus capacity, or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

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

6.1.1 Halton 27.6 kV TS

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

Figure 6-1: Halton TS and Surrounding Service Territory



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

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

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

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

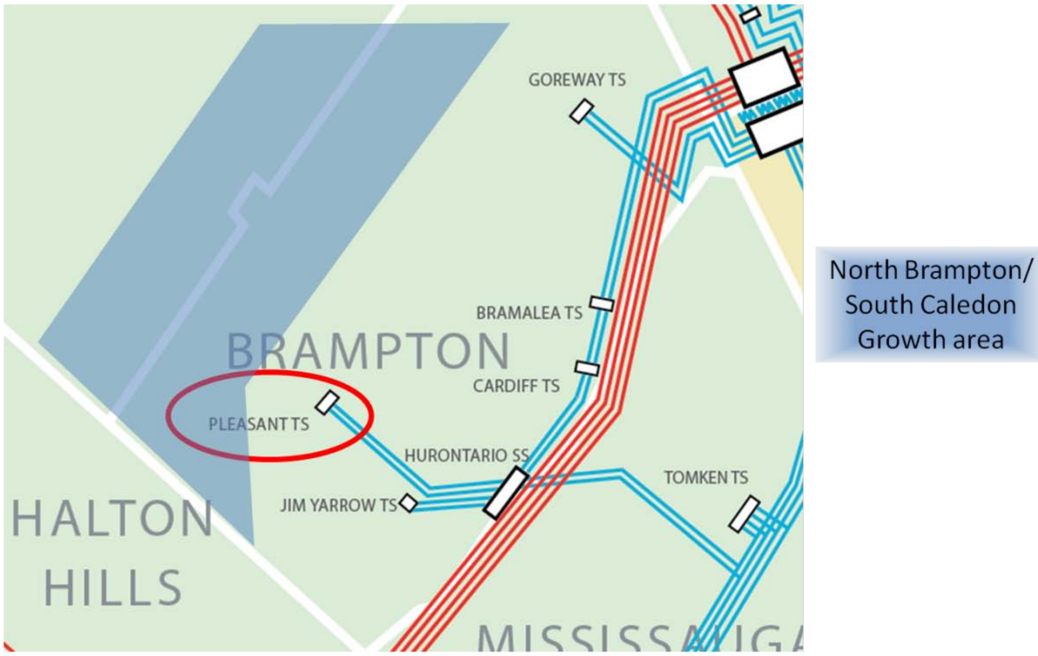
The following constraints must be accounted for when developing options for providing relief to Halton TS:

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

6.1.2 Pleasant TS (44 kV)

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

Figure 6-2: Pleasant TS and Surrounding Growth Areas



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

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

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

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

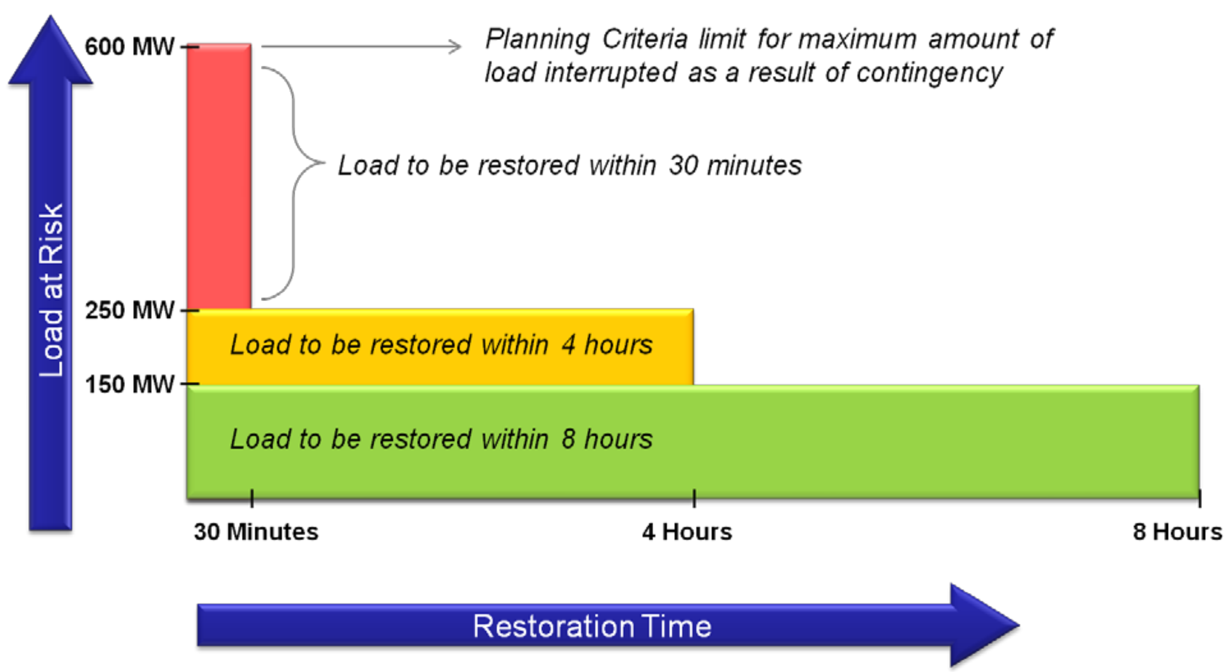
Actual loading on the 44 kV Pleasant TS will need to be reviewed during the next regional planning cycle given that the actual need date may vary from 2033. If new loads cannot be fully offset through conservation and DG initiatives, a new transmission line will be required to enable incremental capacity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

6.2 Supply Security and Restoration Needs

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

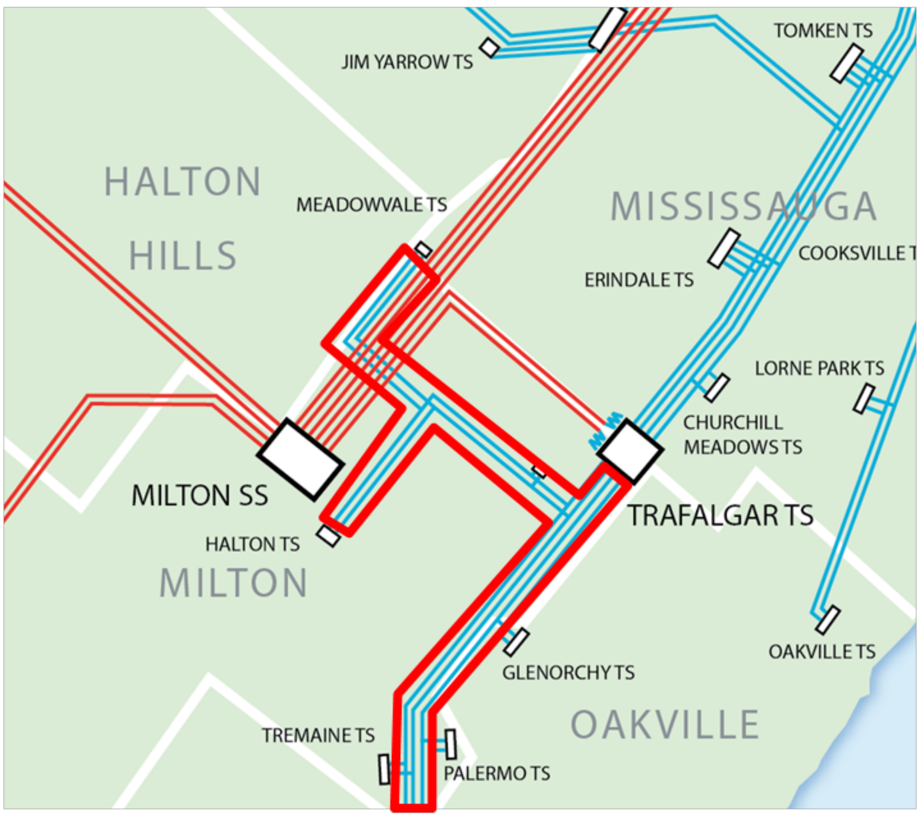
Because NW GTA is a densely populated area, it is assumed that sufficient maintenance and operations workforce are nearby to perform necessary repairs and restore loads within eight hours for expected failure modes. As a result, this analysis will only focus on 30-minute and four-hour restoration capability.

Figure 6-3: ORTAC Load Restoration Criteria



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

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



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

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

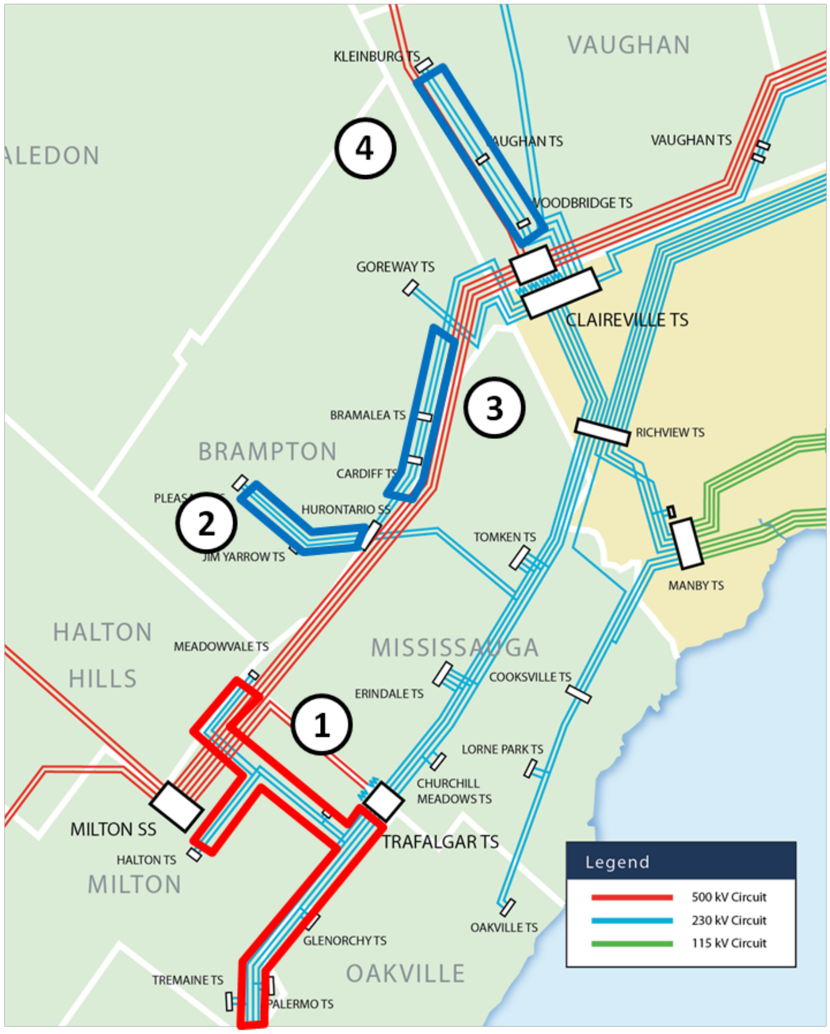
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Expected Growth	432	444	456	472	482	486	492	507	521	574	584	598	610
Higher Growth	435	449	462	478	487	495	510	527	543	599	613	629	645

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

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

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

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



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

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

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

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

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

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

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

6.3 Transmission Capacity Needs

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

6.3.1 Supply to Pleasant TS

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

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

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

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

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

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

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

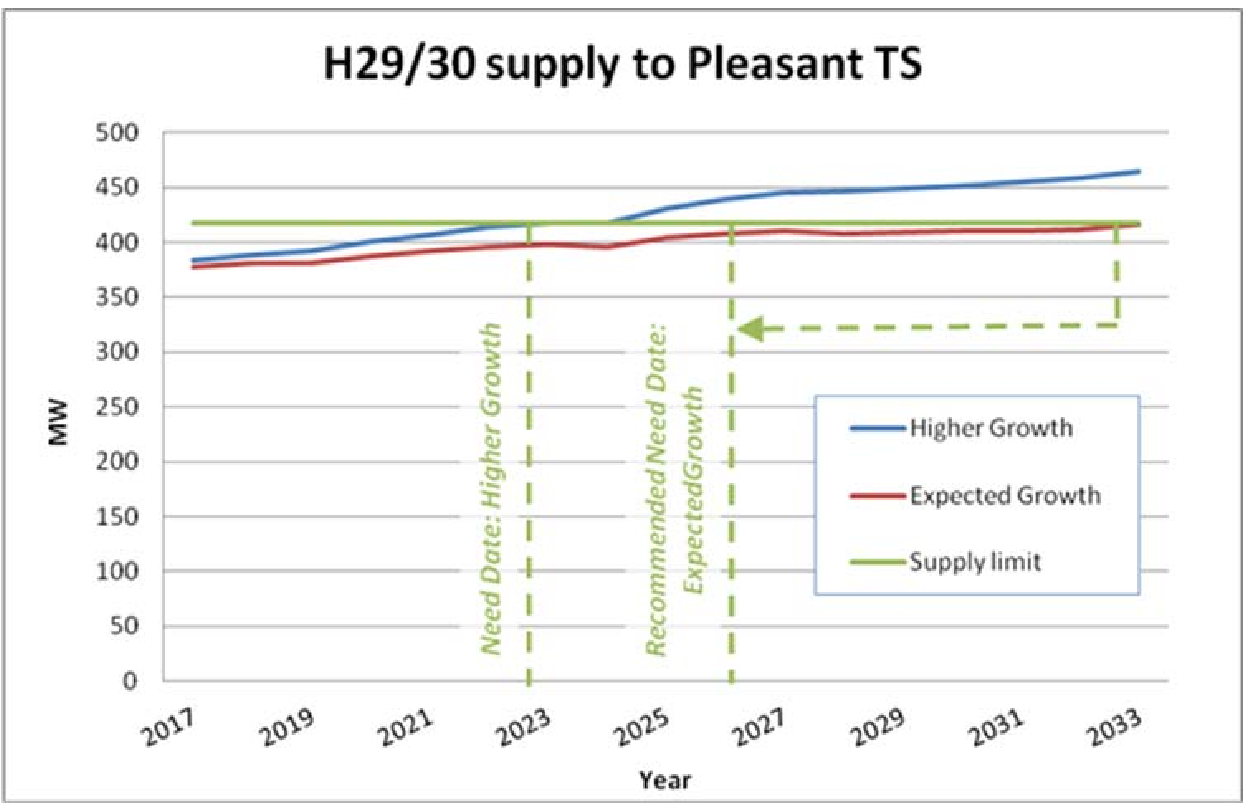


Figure 6-7 also shows that the need date under the Higher Growth forecast is less sensitive to small variations in demand, due to a stronger annual growth rate. As a result, it is not recommended that the need date be advanced under the Higher Growth forecast.

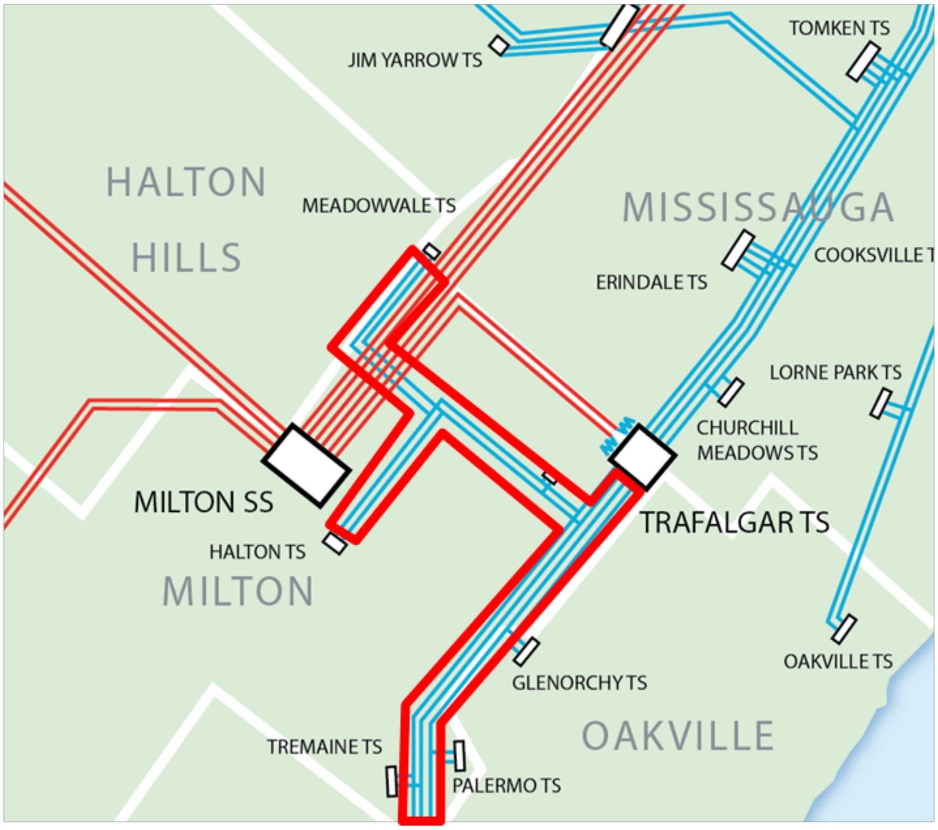
The H29/30 supply need was previously identified in 2007 through the System Impact Assessment ("SIA") for the third step-down station installed at Pleasant TS. The SIA conclusions noted that the supplying transmission lines (circuits H29/30) were expected to hit their thermal limit when the combined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

6.3.2 Halton Radial Pocket

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

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

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



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

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

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

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

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

6.4 Needs Summary

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

Table 6-8: Summary of Needs

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

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

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

7.1 Alternatives Considered

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

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

7.1.1 Conservation

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

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

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

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

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

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

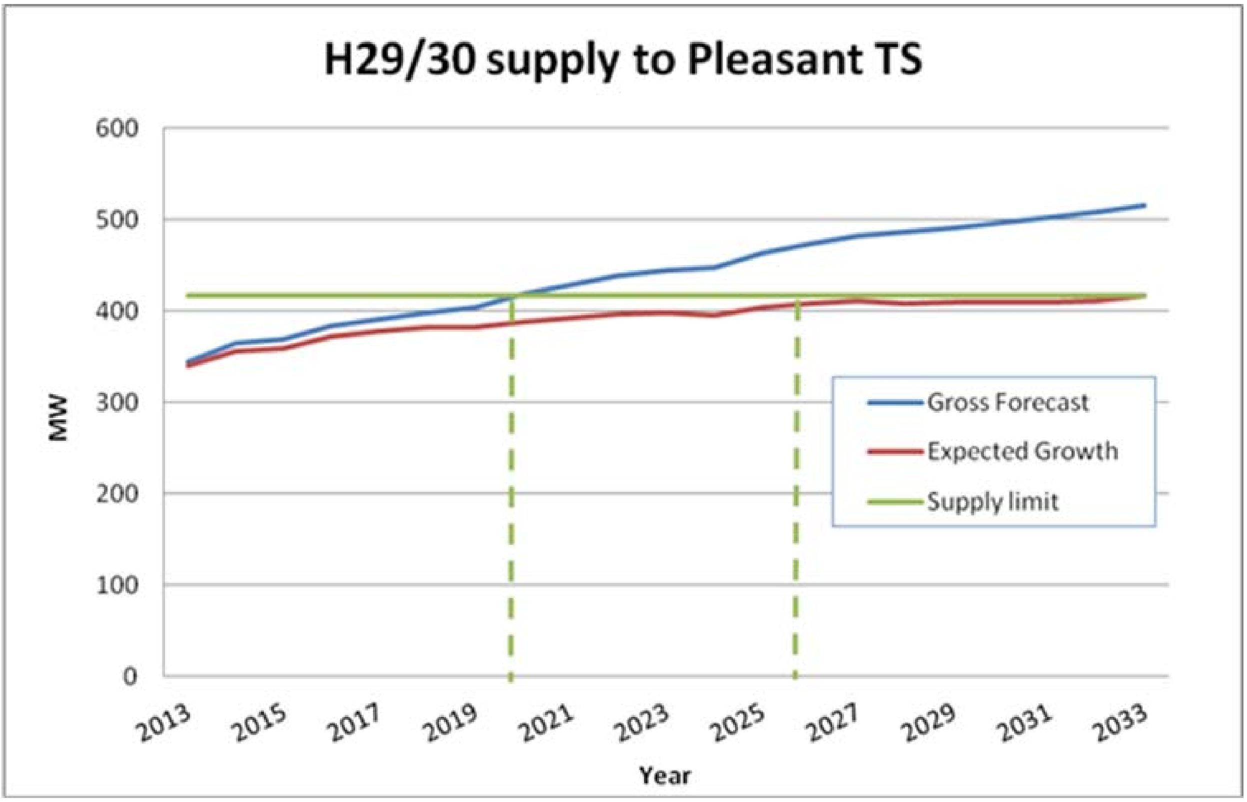
The examples below demonstrate the expected economic benefit from the achievement of the expected peak-demand savings from the LTEP energy reduction targets in two key areas in Northwest GTA: the Pleasant TS and Kleinburg TS service territories. While Pleasant TS and Kleinburg TS have been highlighted,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

Pleasant TS – Transmission line and step-down transformer needs

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

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

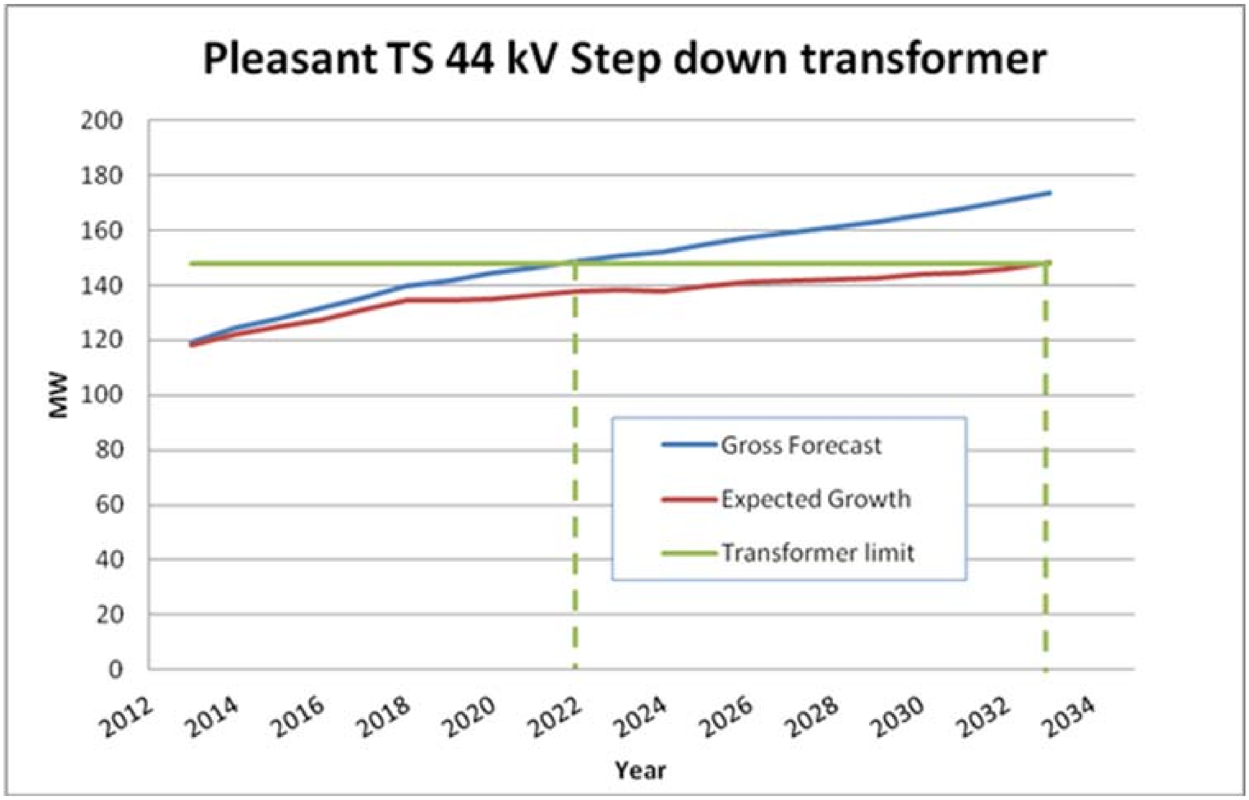
Figure 7-1: Effect of Conservation on H29/30 Needs



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

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

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

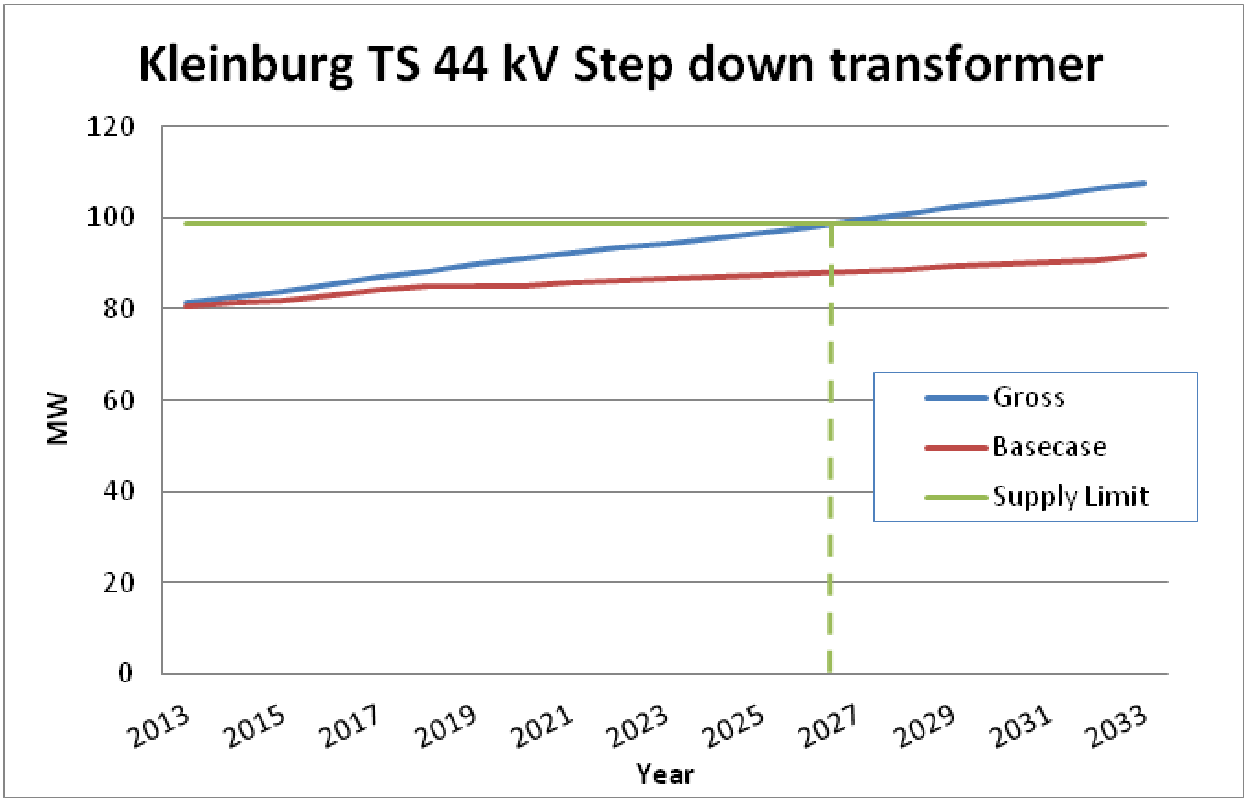


Kleinburg TS – Step-down transformer needs

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

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

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



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

7.1.2 Local Generation

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

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

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

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

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

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

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

7.1.3 Transmission and Distribution

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

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

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

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

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

Distribution load Transfers

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

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

from anticipated Milton and Halton Hills load centres to provide reliable service at the 27.6 kV level. For these reasons, load transfers to Pleasant TS were not considered.

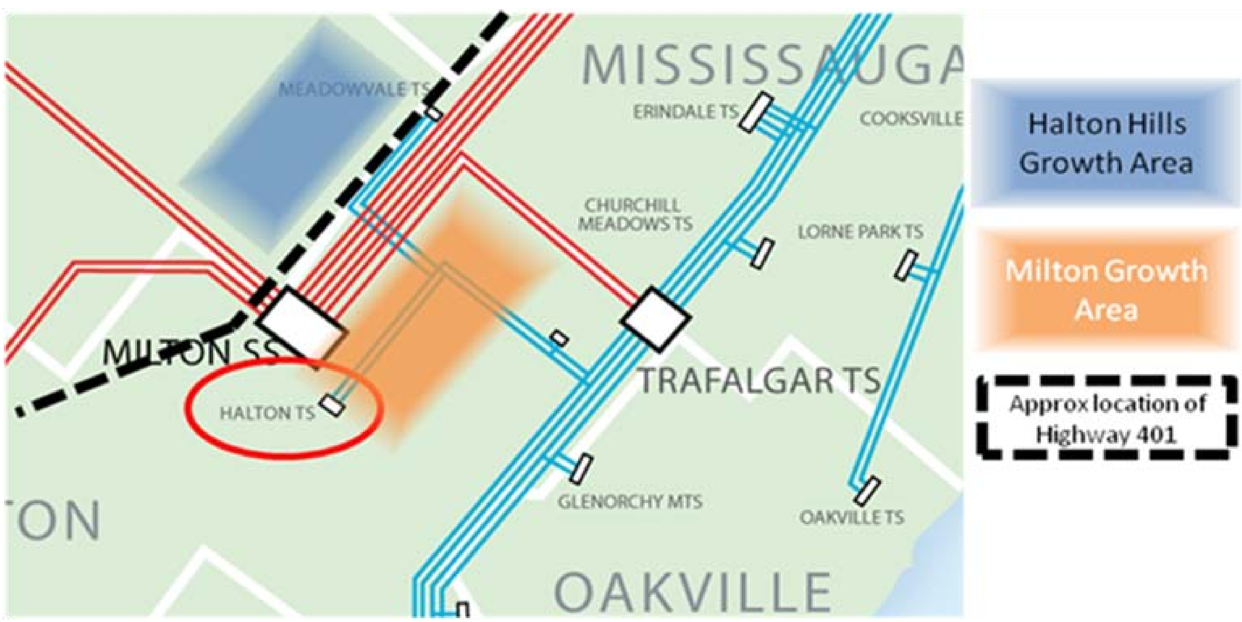
- **Meadowvale TS**: This station outputs at the 44 kV distribution level and so is not suitable for meeting growth currently supplied at the 27.6 kV level from Halton TS.

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

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

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

Figure 7-4: Halton TS and Nearby Elements



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

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

Two new step-down stations

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

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

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

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

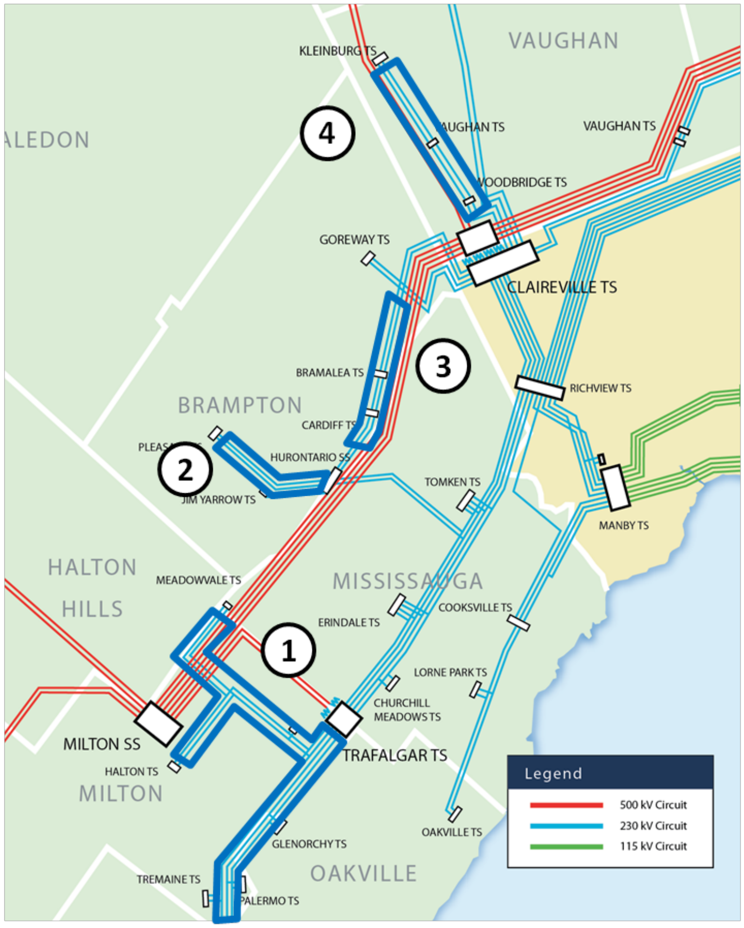
Under the Expected Growth forecast, the cost of a second step-down station is also slightly less when considering the cost of additional feeders, including tunneling, required to supply Halton Hills Hydro loads from a single station located south of Highway 401. As a result, the two station alternative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

7.1.3.2 Restoration needs

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

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

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



Possible infrastructure solutions were investigated and their conclusions discussed below.

Bulk transmission study underway

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

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

Pleasant TS Restoration

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

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

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

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

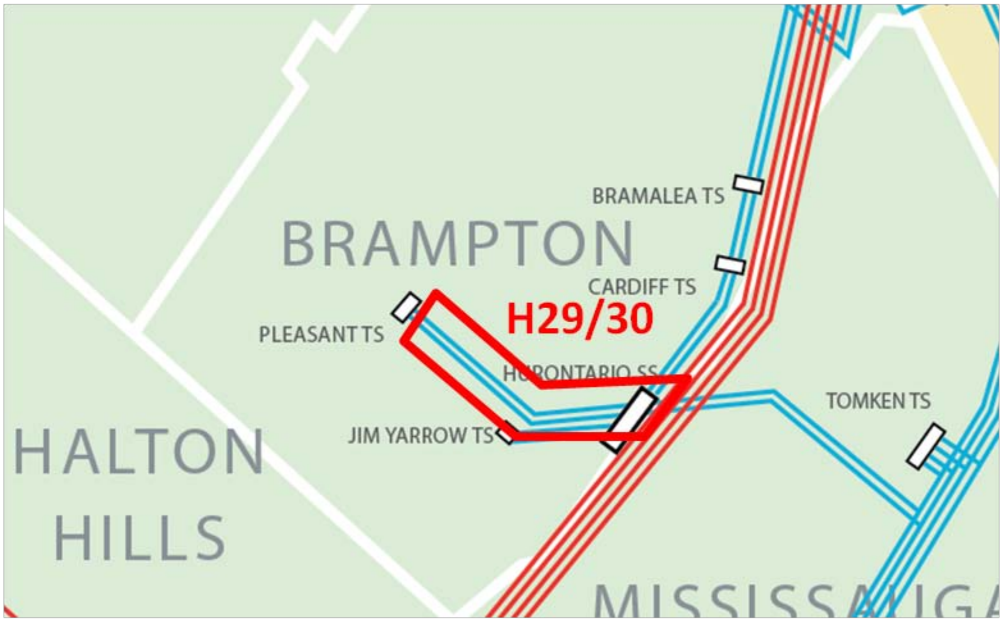
The assessment for the Pleasant TS supply situation found that mitigating solutions were estimated to be significantly more costly to customers in the area than the status quo. This is primarily due to the low probability of the event occurring. As a result, it is not economically prudent to pursue a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

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

7.1.3.3 Supply to Pleasant TS

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

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



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

Upgrading circuits H29/30

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

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

Advancement of long-term transmission solution

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

[13] Summer Long Term Emergency planning rating.

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

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

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

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

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

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

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

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

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

7.2 Recommended Near-Term Plan

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

7.2.1 Conservation

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

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

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

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

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

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

7.2.3 Reinforcement of H29/30

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

7.2.4 Restoration Needs

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

7.3 Implementation of Near-Term Plan

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

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

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

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

8. Options for Meeting Long-Term Needs

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

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

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

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

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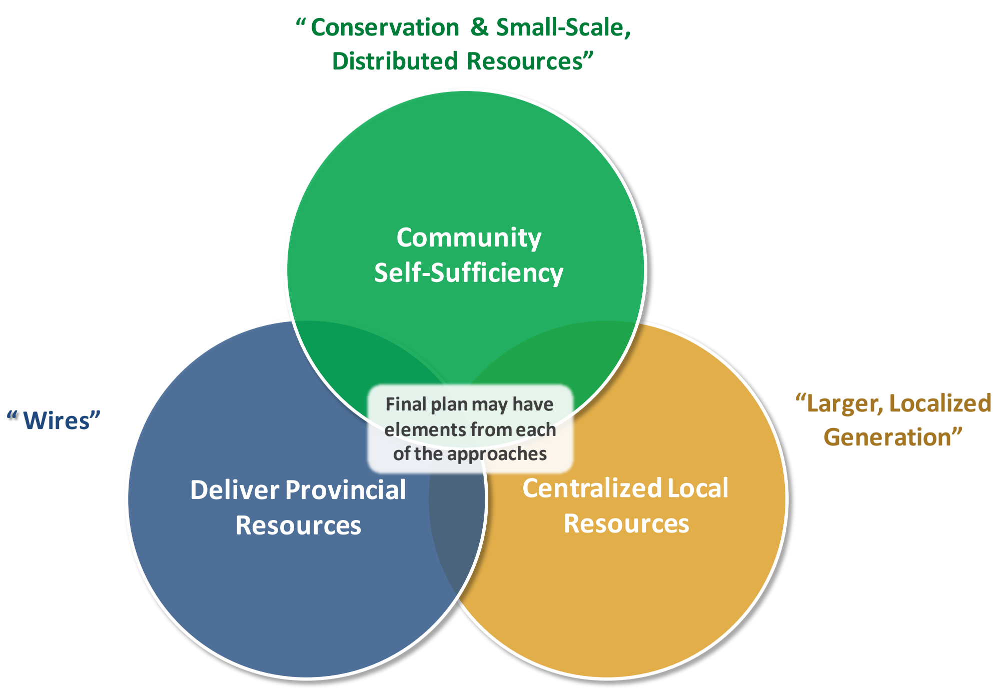
[14] http://www.mah.gov.on.ca/AssetFactory.aspx?did=10463

8.1 Approaches to Meeting Long-Term Needs

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

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

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



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

The three approaches are as follows:

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

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

8.1.1 Delivering Provincial Resources

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

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

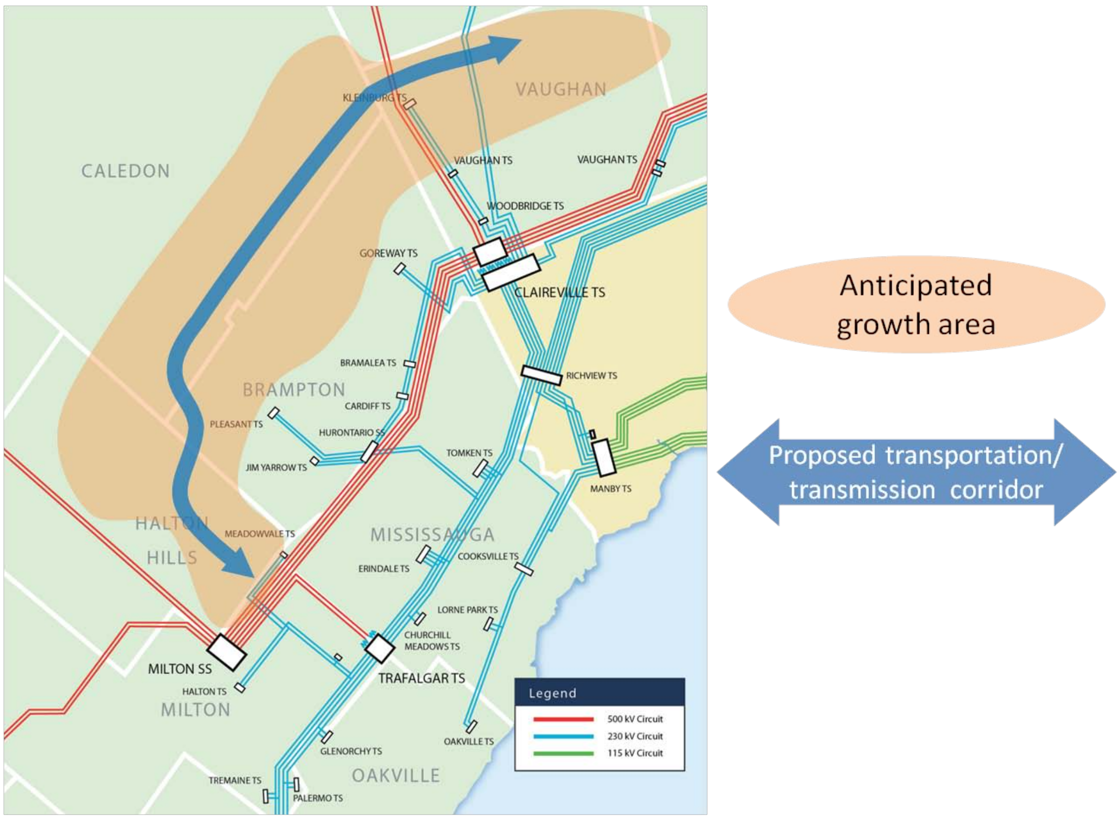
If peak reduction efforts, including conservation and distributed generation, are unable to defer these capacity needs (both circuit and transformer) and distribution solutions such as load transfers prove technically or economically infeasible, a new step-down transformer station will be required in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

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

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

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

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



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

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[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.

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

TORONTO REGION
SCOPING ASSESSMENT OUTCOME REPORT

FEBRUARY 9, 2018

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Connecting Today. Powering Tomorrow.

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Toronto Region Participants

Company
Independent Electricity System Operator
Hydro One Networks Inc. (Transmission)
Toronto Hydro-Electric System Limited
Alectra Utilities Corporation
Veridian Connections Inc.
Hydro One Networks Inc. (Distribution)

1 Toronto Region Scoping Assessment Outcome

Scoping Assessment Outcome Report Summary			
Region:	Toronto		
Start Date	November 10, 2017	**End Date**	February 9, 2018

1. Introduction

This Scoping Assessment Outcome report has been prepared in accordance with the Ontario Energy Board's ("OEB" or "Board") Regional Planning process. The Board endorsed the Planning Process Working Group's Report to the Board in May 2013 and formalized the process and timelines through changes to the Transmission System Code and Distribution System Code later in 2013.

The Toronto region has already undergone one regional planning cycle which was formally completed in 2016. In mid-2017, Hydro One identified that several end-of-life infrastructure needs would occur within the next 10 years in the City of Toronto. Based on this information, as well as the scale of the long-term needs identified in the previous regional planning cycle,[1] it was determined that the next regional planning cycle should be triggered. As a result, a new Needs Assessment report was developed for the Toronto region.[2]

The Needs Assessment report, published on October 24, 2017, concluded that several power system needs in the region require further regional coordination and more comprehensive planning to address. This triggered the IESO-led Scoping Assessment process, which is the second stage in the Regional Planning process, and the outcomes of which are reported in this document.

During the Scoping Assessment, the participants reviewed the nature and timing of all the known needs in Toronto to determine the most appropriate planning approach going forward. The planning approaches considered include an Integrated Regional Resource Plan ("IRRP") – where non-wires options have potential to address needs; a Regional Infrastructure Plan ("RIP") – which considers wires-only options; or a local plan undertaken by the transmitter and affected Local Distribution Company – where no further regional coordination is needed.

[1] See the Central Toronto Integrated Regional Resource Plan, Section 8. Link: http://www.ieso.ca/en/get-involved/regional-planning/gta-and-central-ontario/central-toronto-sub-region

[2] The Needs Assessment contains a summary of known power system needs in the region. It is the first stage of the regional planning process. The 2017 Needs Assessment report for Toronto can be found at: https://www.hydroone.com/abouthydroone/CorporateInformation/regionalplans/metrotoronto/Documents/Needs%20Assessment%20-%20Toronto%20Region%20-%20Final.pdf

This Scoping Assessment report:

- Lists the needs requiring more comprehensive planning, as identified in the Needs Assessment report;
- Recommends an IRRP as the appropriate regional planning approach for the Region, given the need for regional coordination and/or more comprehensive planning;
- Establishes a Terms of Reference for the IRRP; and
- Establishes the composition of the Working Group for the IRRP.

2. Team

The Scoping Assessment was carried out by a study team representing the following Regional Participants:

- Independent Electricity System Operator ("IESO");
- Hydro One Networks Inc. ("Hydro One Transmission");
- Toronto Hydro-Electric System Limited ("Toronto Hydro");
- Alectra Utilities Corporation;
- Veridian Connections Inc.; and
- Hydro One Networks Inc. ("Hydro One Distribution").

3. Categories of Needs, Analysis and Results

I. Overview of the Region

The Toronto electricity planning region includes the area within the municipal boundary of the City of Toronto. The region is supplied by thirty-five 230 kV and 115 kV transmission stations, as shown in Figure 1-1. Eighteen 230/27.6 kV step-down transformer stations supply the eastern, northern and western parts of the region. The central area of Toronto is supplied by two 230/115 kV autotransformer stations (Leaside TS and Manby TS), two 115/27.6 kV step-down stations, and fifteen 115/13.8 kV step-down stations. The Central Toronto area is shown in Figure 1-2.[3] A small number of distribution feeders from Toronto also supply customers in the City of Mississauga and City of Pickering.

[3] Refer to the 2015 Central Toronto IRRP for more detail about the electricity system service the City of Toronto, and Central Toronto. Note that the 2015 IRRP also included three 230/27.6 kV transmission stations within the study area. For the purpose of this regional plan, Central Toronto is defined as the area supplied by the legacy City of Toronto (pre-amalgamation) 115 kV transmission network.

Figure 1-1 Electricity Infrastructure in the Toronto Region

Figure 1-2 Electrical Supply in Central Toronto (Inset)

The peak summertime electricity demand in Toronto is approximately 5,000 MW (including 2,000 MW of demand in Central Toronto).[4] Since the provincial launch of Conservation and Demand Management ("CDM") programs in 2006, about 300 MW of electricity demand reductions have been successfully implemented in Toronto.

The 550 MW Portlands Energy Centre, located near downtown Toronto, is a natural gas-fired combined cycle power plant. This is the single largest source of generation within Toronto (connected to the Hearn SS shown in Figure 1-2).

Numerous distributed energy resource ("DER") facilities are located throughout the City. For example, through previous procurements such as the Feed-in Tariff program, Renewable Energy Standard Offer Program, and Combined Heat and Power ("CHP") Standard Offer Program, approximately 1,700 individual renewable and CHP facilities have either been contracted for, or placed in service in the City of Toronto. The total combined electrical supply capacity of these projects is 115 megawatts ("MW").[5]

II. Background

The first cycle of the regional planning process for the Toronto Region was formally completed in January 2016 with the publication of Hydro One's RIP for the Central Toronto area. An IRRP was completed for Central Toronto in April 2015, and in February 2017, an update was made to the plan resulting from plans to convert commuter heavy rail (Metrolinx - GO) from diesel to electric power.

In mid-2017, Hydro One identified a number of transmission system end-of-life needs in Toronto over the next 10 years. The scale and timing of these end-of-life needs highlighted a need for the initiation of another regional planning cycle. As a result, Hydro One initiated a Needs Assessment, which officially started the next regional planning cycle for the region. The Needs Assessment was completed in October 2017. The report identified a number of needs which require further regional coordination. As a result, this Scoping Assessment was completed.

III. Needs Identified

The Toronto Region Needs Assessment identified new needs, and reaffirmed the needs identified in the previous RIP/IRRP cycle. These needs will be assessed in detail in subsequent planning stages, considering other local factors, including initiatives affecting electrical demand, which are priorities of the City of Toronto (e.g., Greenhouse gas emission reduction

[4] The peak electricity demand in summer 2006 was 5,305 MW; in summer 2017, demand was 4,746 MW.
[5] This translates to about 44 MW of "effective" capacity that system planners can count on during the peak demand period (assuming 34% capacity factor for solar PV, 13.6% for wind, and 100% for all other fuel types, including CHP).

targets, presently articulated through the TranformTO strategy).

Table 1-1 lists these needs, their expected timing, and their level of prioritization for assessment and development of solution(s) based on factors such as the expected timing and magnitude of the need, including the lead time required to develop and implement solution(s). The needs are divided into three groups, where Group 1 needs should be assessed first. The assessment of these needs will consider their inter-dependencies in order to achieve the most economic and efficient solutions (refer to Appendix A). The 2017 Needs Assessment report for the Toronto Region contains additional details about these system needs.[6] Other needs identified in the Needs Assessment not listed in Table 1 will proceed with Local Planning or Regional Infrastructure Planning, as appropriate.

Table 1-1: Summary of Needs

Facilities	Need	Expected Timing
Group 1 Priority		
Main transformer station ("TS")	End-of-life of transformers T3 and T4, 115 kV line disconnect switches, installation of 115 kV Current Voltage Transformers	2021-2022
John TS	End-of-life of transformers T1, T2, T3, T4, T6, and 115 kV breakers	2024-2025
C5E/C7E 115kV underground transmission cables	End-of-life of underground cables from Esplanade TS to Terauley TS in downtown Toronto	2024-2025
H1L/H3L/H6LC/H8LC 115 kV overhead transmission lines	End-of-life of the overhead line sections between Bloor Street and Leaside Junction	2020-2021
L9C/L12C 115kV overhead transmission lines	End-of-life of the overhead line sections between Leaside TS and Balfour Junction	2021-2022
H2JK 115kV underground transmission cable H9EJ/H10EJ 115 kV overhead line section	Capacity on the underground cable H2JK between Don Fleet Junction and Esplanade TS Request to relocate the underground cable H2JK and overhead line H9EJ/H10EJ between Cherry Street and Don Fleet Junction due to Metrolinx Don Yard Expansion	2026 for line capacity need (timing to be updated based on demand outlook) Timing of possible relocation is to be determined
Group 2 Priority		
Manby TS	End-of-life of major station equipment including: autotransformers T7, T9, and T12, step-down transformer T13, and the 230 kV yard	2024-2025

[6] The 2017 Needs Assessment report for Toronto can be found at: https://www.hydroone.com/abouthydroone/CorporateInformation/regionalplans/metrotoronto/Documents/Needs%20Assessment%20-%20Toronto%20Region%20-%20Final.pdf

Bermondsey TS	End-of-life of transformers T3 and T4	2022-2023
East Harbor / Port Lands Area and Basin TS	Area transformation capacity to accommodate city growth	2025+ (timing to be updated based on demand outlook)
Leaside TS 230/115kV autotransformers (six in total)	Transformation Capacity, and risk of voltage collapse affecting Leaside 115 kV subsystem	Beyond 2027 (timing to be updated based on demand outlook)
Group 3 Priority		
Transmission lines/circuits: C14L+C17L (Warden TS and Bermondsey TS); C5E+C7E (Terauley TS); and K3W+K1W (Fairbank TS and Wiltshire TS)	Ability to restore load following double circuit outages	To be determined based on demand outlook
Leaside TS to Wiltshire TS 115 kV transmission corridor	Line capacity to accommodate city growth	2034 (timing to be updated based on demand outlook)
Manby TS 230/115kV autotransformers (six in total)	Transformation capacity to accommodate city growth	Beyond 2035 (timing to be updated based on demand outlook)
Manby West to Riverside Junction 115kV transmission corridor	Line capacity to accommodate city growth	Beyond 2035 (timing to be updated based on demand outlook)

Figure 2-1 shows the location of each of the needs listed in the above Table.

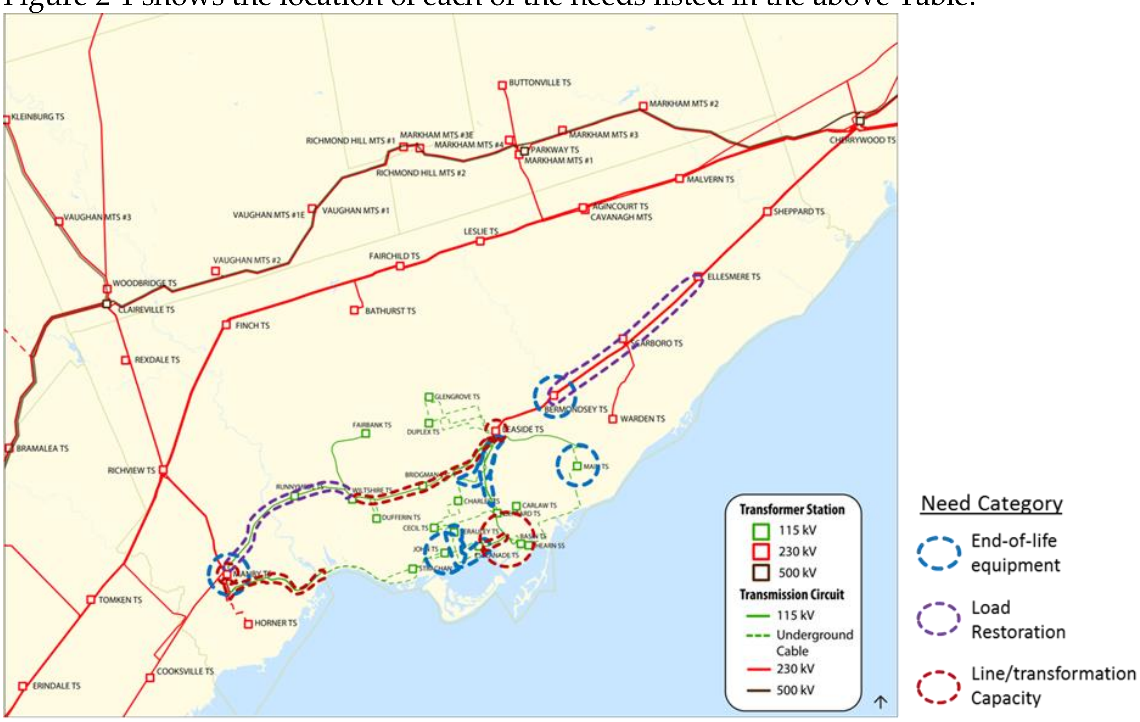

Figure 2-3 Location of Needs in the Toronto Region

IV. Results

The participants met to review the needs and timing for solutions, and to discuss the planning approaches available to address them. The review included discussion of the location of the needs within the region, and whether the region should be further divided into sub-regions to simplify subsequent regional planning stages. The scope of the discussion also included which participants from within the region would comprise the Working Group tasked with developing the Regional Plan.

The participants agreed that for each of the needs identified, a range of alternatives including wires and non-wires solutions should be assessed. Furthermore, a Local Advisory Committee that was established in 2016 to provide advice on regional planning activities in the City of Toronto has expressed that alternatives to conventional wires require deeper consideration in future plans. For these reasons, it was agreed that an IRRP should be undertaken to further assess these needs. The scope of an IRRP includes an assessment of Conservation and Demand Management, distributed energy resources, and other community-based solutions. A Terms of Reference for the IRRP is attached as Appendix A.

The participants also agreed, for the purpose of the next Regional Plan, that the City of Toronto should not be divided into sub-regions. While most of the needs identified impact electricity infrastructure in the downtown area, some needs have been identified in other parts of Toronto, outside of the central part of Toronto.

Lastly, because none of the needs identified directly impact facilities that supply customers of Alectra Utilities Corporation, Veridian Connections Inc., or Hydro One Distribution, it was agreed that the core Working Group for the IRRP will include the IESO, Toronto Hydro, and Hydro One Transmission. The other utilities will be informed and invited to participate if any needs, or proposed solutions, may affect their facilities or customers.

4. Conclusions

The Scoping Assessment concludes that:

- Based on the available information, an IRRP is to be undertaken for the Toronto Region.
- No sub-regions within Toronto will be created for the IRRP; the region should be treated whole for the purpose of developing a comprehensive plan.
- The implementation of recommendations from the previous IRRP should continue.
- The composition of the IRRP Working Group will include the IESO, Toronto Hydro, and Hydro One Transmission. Other Local Distribution Companies in the region will be informed of any needs or solutions that may affect their facilities or customers.

The Terms of Reference for the Toronto IRRP is attached in Appendix A.

List of Acronyms

CDM	Conservation and Demand Management
CHP	Combined Heat and Power
DER	Distributed Energy Resources
FIT	Feed-in-Tariff
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
LAC	Local Advisory Committee
LDC	Local Distribution Company
MW	Megawatt (equal to 1,000 kilowatts, or one million watts)
NA	Needs Assessment
NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council
OEB	Ontario Energy Board
ORTAC	Ontario Resource and Transmission Assessment Criteria
RIP	Regional Infrastructure Plan
RPP	Regional Planning Process
SA	Scoping Assessment
SOP	Standard Offer Program
TS	Transformer Station or Transmission Station

Appendix A: Terms of Reference

The Toronto Region IRRP

1. Introduction

These Terms of Reference establish the objectives, scope, roles and responsibilities, deliverables and timelines for an Integrated Regional Resource Plan ("IRRP") for the Toronto region.

Based on the power system needs identified throughout the region (including a number of end-of-life transmission stations and lines in the near term and medium term), strong urban growth and intensification projections in the City of Toronto, expansion of electrified transit, and potential opportunities for demand and supply solutions, an IRRP is the appropriate planning approach for this region.

The Toronto Region

The Toronto electricity planning region includes the area within the municipal boundary of the City of Toronto. The region is supplied by thirty-five 230 kilovolt ("kV") and 115 kV transmission stations as shown in Figure A-1. Eighteen 230/27.6 kV step-down transformer stations supply the eastern, northern and western parts of the region. The central area, including the downtown core, is supplied by two 230/115 kV autotransformer stations (Leaside TS and Manby TS),[7] that, in turn, supply seventeen 115 kV step-down stations (fifteen at 13.8 kV and two at 27.6 kV at the distribution side).

For the purpose of this IRRP, no divisions are proposed that would create any sub-regions to assess within the City of Toronto.

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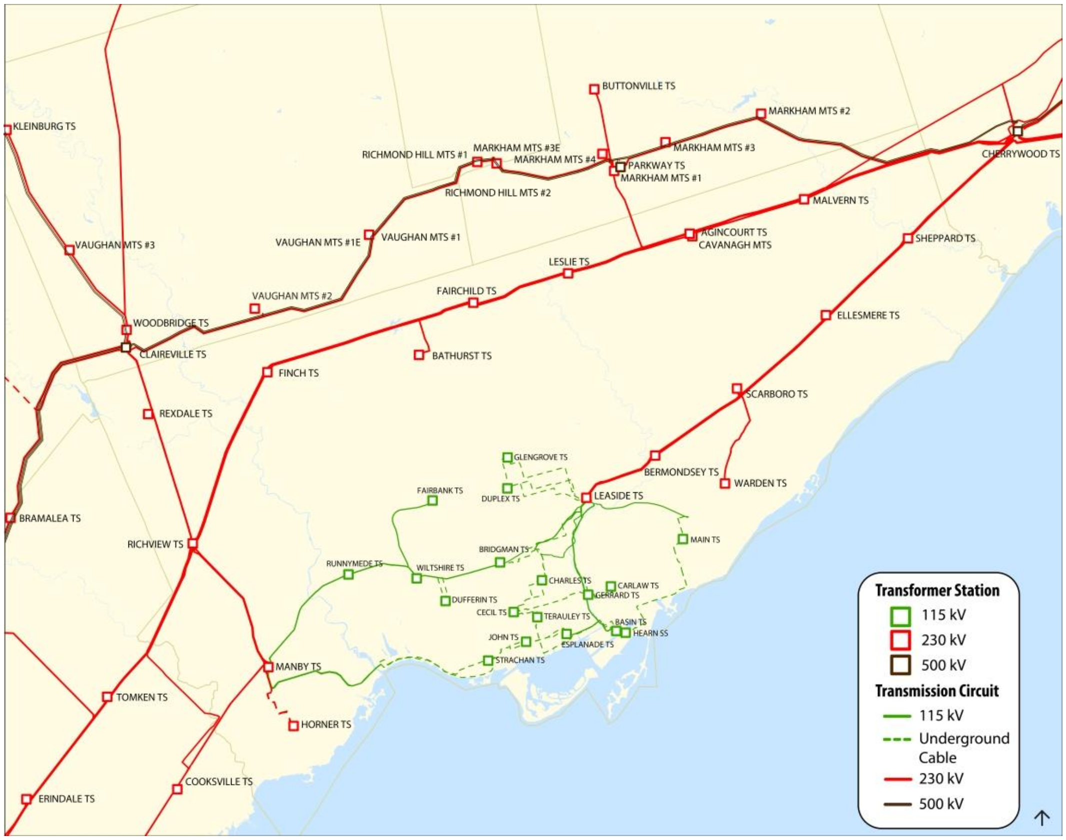
[7] The 2015 Central Toronto IRRP also included three 230/27.6 kV transformer stations within the study area. For the purpose of the IRRP going forward, the Central Toronto area is defined as the area supplied by the legacy City of Toronto 115 kV transmission network (pre-amalgamation), which includes the areas supplied by Leaside TS and Manby TS.

Figure A-1 Electricity Infrastructure in the Toronto Region



Source: IESO

2. Objectives

1. Assess the adequacy and reliability of the portion of the IESO-controlled grid[8] that provides electricity supply to the Toronto region over the next 25 years.[9]
2. Account for major asset renewal/end-of-life needs, capacity needs, enhancing reliability and resilience, uncertainty in the outlook for electricity demand, and local priorities in developing a comprehensive plan.
3. Evaluate opportunities for cost effective non-wires alternatives, including conservation and demand management ("CDM") and distributed energy resources ("DER"), as well as wires approaches for addressing the needs identified.
4. Develop an implementation plan that maintains flexibility in order to accommodate changes in key assumptions over time. The implementation plan should identify actions

[8] The scope of the assessment includes transmission stations.
[9] The typical planning horizon in a regional study is 20 years; however, Toronto Hydro produces a long-range forecast spanning 25 years and this forecast will be used as the basis for assessing long-term system needs in the IRRP.

for near-term needs, preparation work for medium-term needs, and planning direction for the long-term.

3. Scope

3.1 Needs to be Addressed

The IRRP will develop and recommend an integrated plan to meet the needs of the Toronto region. The plan is a joint initiative involving Toronto Hydro, Hydro One Transmission, and the IESO,[10] and will account for input from the community through engagement activities. The plan will integrate the electricity demand outlook scenarios, CDM, DER uptake, transmission and distribution system capabilities, and align with relevant community plans and other bulk system developments, as applicable.

The scope of the Toronto IRRP includes the following needs, as identified in the Needs Assessment:

Facilities	Need	Expected Timing[11]
Group 1 Priority		
Main transformer station ("TS")	End-of-life of transformers T3 and T4, 115 kV line disconnect switches, installation of 115 kV Current Voltage Transformers	2021-2022
John TS	End-of-life of transformers T1, T2, T3, T4, T6, and 115 kV breakers	2024-2025
C5E/C7E 115kV underground transmission cables	End-of-life of underground cables from Esplanade TS to Terauley TS in downtown Toronto	2024-2025
H1L/H3L/H6LC/H8LC 115 kV overhead transmission lines	End-of-life of the overhead line sections between Bloor Street and Leaside Junction	2020-2021
L9C/L12C 115kV overhead transmission lines	End-of-life of the overhead line sections between Leaside TS and Balfour Junction	2021-2022
H2JK 115kV underground transmission cable H9EJ/H10EJ 115 kV overhead line section	Capacity on the underground cable H2JK between Don Fleet Junction and Esplanade TS Request to relocate the underground cable H2JK and overhead line H9EJ/H10EJ between Cherry Street and Don Fleet Junction due to Metrolinx Don Yard	2026 for line capacity need (timing to be updated based on demand outlook) Timing of possible relocation is to be determined

[10] Alectra Utilities, Veridian Connections and Hydro One Distribution are also supplied by feeders from Toronto. These utilities may also be involved in the regional plan, as needed.
[11] For end-of-life needs, the date refers to the anticipated timing that a solution will need to be in place. These timelines will be subject to further review and analysis in subsequent planning stages.

	Expansion	
Group 2 Priority		
Manby TS refurbishment	End-of-life of major station equipment including: autotransformers T7, T9, and T12, step-down transformer T13, and the 230 kV yard	2024-2025
Bermondsey TS	End-of-life of transformers T3 and T4	2022-2023
East Harbor / Port Lands Area and Basin TS	Area transformation capacity to accommodate city growth	2025+ (timing to be updated based on demand outlook)
Leaside TS 230/115kV autotransformers (six in total)	Transformation Capacity, and risk of voltage collapse affecting Leaside 115 kV subsystem	Beyond 2027 (timing to be updated based on demand outlook)
Group 3 Priority		
Transmission lines/circuits: C14L+C17L (Warden TS and Bermondsey TS); C5E+C7E (Terauley TS); and K3W+K1W (Fairbank TS and Wiltshire TS)	Ability to restore load following double circuit outages	To be determined based on demand outlook
Leaside TS to Wiltshire TS 115 kV transmission corridor	Line capacity to accommodate city growth	2034 (timing to be updated based on demand outlook)
Manby TS 230/115kV autotransformers (six in total)	Transformation capacity to accommodate city growth	Beyond 2035 (timing to be updated based on demand outlook)
Manby West to Riverside Junction 115kV transmission corridor	Line capacity to accommodate city growth	Beyond 2035 (timing to be updated based on demand outlook)

Other identified needs in the Needs Assessment not listed in the table above will proceed with Local Planning or Regional Infrastructure Planning as appropriate.

Since within the needs identified there are a number of inter-dependencies (i.e. it is possible that one solution could address multiple needs), the Working Group will consider these needs together when developing solutions. The Working Group will seek to find solutions for near and/or medium-term needs that can also address certain needs in the future. These inter-dependencies, or related needs, are listed as follows.

- Main TS (Group 1) <u>and</u> Leaside TS 230/115kV autotransformers (Group 2)
- C5E/C7E 115kV underground transmission cables (Group 1) <u>and</u> C5E+C7E load restoration (Group 3)
- H1L/H3L/H6LC/H8LC 115 kV overhead transmission lines (Group 1) <u>and</u> East Harbor / Port Lands Area and Basin TS (Group 2)

- Manby TS refurbishment (Group 2) and Manby TS 230/115kV autotransformers (Group 3)
- Bermondsey TS (Group 2) and C14L+C17L load restoration (Group 3)

Other inter-dependencies may be considered in the plan, such as reviewing together all transmission line and cable needs that facilitate load transfers between Manby and Leaside sub-systems.

3.2 Activities

The IRRP process will consist of the activities as listed below. The activities and anticipated timelines are summarized in Table A-1 at the end of this document. The first major planning activity following preparation of this Terms of Reference is the development of electricity demand outlooks to serve as the basis for conducting system assessments. The timing for initiating the assessment (Activity 3) and all subsequent plan development activities will be contingent on the Working Group agreeing on the demand outlooks to be used.

1) Develop an electricity demand outlook for the Toronto region. This outlook may be comprised of a number of electricity demand scenarios that account for uncertain elements that can affect (e.g., raise or lower) the need for electricity in the region.
    a. Summarize Toronto's committed long-term policy goals and plans, taking into account local and provincial policy goals, commitments, and climate change action plans.
    b. Develop a discussion paper to set context and seek informed advice on a vision for the electricity sector.
2) Confirm baseline technical assumptions including infrastructure ratings, system topology and relevant base cases for simulating the performance of the electric power system. Collect information on:
    a. Transformer, line and cable continuous ratings, long-term and short-term emergency ratings;
    b. Known reliability issues and load transfer capabilities;
    c. Customer load breakdown by transformer station;
    d. Historical and present CDM peak demand savings and installed/effective DER capacity, by transformer station.
3) Perform assessments of the capacity, reliability and security of the electric power system under each demand outlook scenario.
    a. Confirm and/or refine the needs listed earlier in this section using the demand outlook; establish the sensitivity of each need to different demand outlook scenarios.

   b. Identify additional infrastructure capacity needs and any additional load restoration needs; if new needs are discovered, determine the appropriate planning approach for addressing them.
4) Identify options for addressing the needs, including, non-wires and wires alternatives. Where necessary, develop portfolios of solutions comprising a number of options that, when combined, can address a need or multiple needs.
   a. Collect information about the attributes of each option: cost, performance, timing, risk, etc.
   b. Complete a local achievable potential study of CDM and DER at the transformer station level, for stations with an identified capacity need within the study period.
   c. Develop a methodology for calculating local avoided costs as a means of informing further evaluations of the local alternatives;[12]
   d. Seek cost-effective opportunities to manage growth first, by identifying opportunities to reduce electricity demand.
5) Evaluate options using criteria including, but not limited to the areas of: technical feasibility and timing, economics, reliability performance, risk, environmental, regulatory, and social factors. Evaluation criteria will be informed through community engagement activities and reflect attributes deemed important to the community-at-large.
6) Develop recommendations for actions and document in an implementation plan, to address needs in the near-term and medium-term.
7) Develop a long-term plan for the electricity system in Toronto to address the long-term needs that were identified, taking into account uncertainty inherent in long-term planning, local and provincial policy goals, commitments, and climate change action plans.
   a. Discuss possible ways the power system in Toronto could evolve to address potential long-term needs, support the achievement of Toronto's long-term policy goals and plans, and support the achievement of the long-term vision for the electricity sector.
   b. During the development of the plan, seek community and stakeholder input to confirm the long-term vision, expected impacts on the electricity system, and inform the recommended actions through engagement.
8) Complete an IRRP report documenting the near-term and medium-term needs, recommendations, and implementation actions; and long-term plan recommendations.

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[12] Local avoided (or "avoidable") costs are specific to a particular need or project, and are location and time-specific. They may not be generally applicable across a broader area (meaning that there is not likely to be a single average value that can be equally applied for Toronto). Further, these avoided costs will only be provided for planned investments that can practically be deferred or avoided. Determinations on the applicability and usefulness of local avoidable cost estimates will need to be made on a need or project-specific basis.

In order to carry out this scope of work, the working group will consider the data and assumptions outlined in section 4 below.

4. Data and Assumptions

The plan will consider the following data and assumptions:

- Demand Data
    - Historical coincident and non-coincident peak demand information and trends for the region
    - Historical weather correction, for median and extreme conditions
    - Gross peak demand forecast scenarios by TS, etc.
    - Coincident peak demand data
    - Identified potential future load customers, including transit expansions, electrification of personal vehicles, and possible impacts due to provincial and local GHG emissions reduction policies and targets

- Conservation and Demand Management
    - LDC CDM plans
    - Incorporation of verified LDC results and other CDM programs/opportunities in the area
    - Long-term conservation forecast for LDC customers, based on region's share of the Long-Term Energy Plan target
    - Conservation potential studies, if available
    - Potential for CDM at transmission-connected customers' facilities, if applicable
    - Load segmentation data for each TS based on customer type (residential, commercial, institutional, industrial)
    - Local building codes, energy performance requirements, etc.

- Local resources
    - Existing local generation resources, including distributed energy resources ("DER"), district energy resources, customer-based generation, and Non-Utility Generators, as applicable
    - Existing or committed renewable generation from Feed-in-Tariff ("FIT") and non-FIT procurements
    - Expected performance/dependability/output of local generation resources coincident with the local peak demand period
    - Future district energy plans, combined heat and power, energy storage, or other generation proposals, including requirements for on-site back-up and emergency generation

- Relevant local plans, as applicable
    - LDC Distribution System Plans

- Community Energy Plans and Municipal Energy Plans
    - City policies with an impact on electricity usage, including TransformTO
    - Municipal Growth Plans
    - Future transit plans impacting electricity use, including personal vehicle electrification

- Criteria, codes and other requirements
    - Ontario Resource and Transmission Assessment Criteria ("ORTAC")
        - Supply capability
        - Load security
        - Load restoration requirements
    - NERC Reliability Standards and NPCC Reliability Criteria and Directories, as applicable
    - OEB Transmission System Code
    - OEB Distribution System Code
    - Reliability considerations, such as the frequency and duration of interruptions to transmission delivery points
    - Other applicable requirements, including municipal requirements

- Existing system capability
    - Transmission line ratings as per transmitter records
    - System Limits as modelled, defined and determined by the IESO and incorporated into the IESO Power Flow base cases
    - Transformer station ratings (10-day LTR) as per asset owner
    - Load transfer capabilities
    - Technical and operating characteristics of local generation

- End-of-life asset considerations/sustainment plans
    - Transmission assets
    - Distribution assets, as applicable

- Other considerations, as applicable

5. Working Group

The core Working Group will consist of planning representatives from the following organizations:

- Independent Electricity System Operator *(Lead for the IRRP)*
- Toronto Hydro-Electric System Limited
- Hydro One Networks Inc. (Transmission)

Authority and Funding

Each entity involved in the study will be responsible for preparing regulatory applications and/or including in its regulatory applications the actions/tasks agreed upon for that entity under the implementation plan resulting from this IRRP. For the duration of the study process, each participant is responsible for their own funding.

5. Engagement

The Working Group will develop a comprehensive stakeholder engagement plan, taking into account the advice of the Local Advisory Committee, according to the Activities Timeline shown in Section 6.

Engagement activities will also be informed through meetings with municipal representatives within the planning area, Indigenous communities that may have an interest in the planning area, and the Métis Nation of Ontario. All will be invited to discuss regional planning, the development of the IRRP, and integrated solutions.

Table A-1 Summary of IRRP Timelines and Activities

	Activity	Lead Responsibility	Deliverable(s)	Timeframe
1	**Prepare Terms of Reference considering stakeholder input**	*IESO*	- Finalized Terms of Reference	Q1 2018
2	**Develop the Planning Outlooks / Forecasts**			
	- Establish historical coincident and non-coincident peak demand information	*IESO*	- Long-term planning forecast scenarios	Q1 2018
	- Establish historical weather correction, median and extreme conditions	*IESO*		
	- Establish gross peak demand outlook and scenarios accounting for uncertainty (coincident peak demand forecast at the transformer station level)	*LDC*		
	- Provide customer segmentation data, by peak demand share, for each transformer station	*LDC*		
	- Establish existing, committed and potential DER and historical DER performance	*IESO and LDC*		
	- Establish near- and long-term conservation forecasts based on LDC CDM plans and LTEP CDM targets	*IESO*		
	- Develop outlook scenarios - including the impacts of CDM, DER and extreme weather conditions	*IESO*		
3	**Provide information on load transfer capabilities under normal and emergency conditions**	*LDC*	- Load transfer capabilities under normal and emergency conditions	Q2 2018
4	**Provide and review relevant community plans and objectives**	*LDC and IESO*	- Summary of community plans, goals, objectives	Q2 2018
5	**Develop discussion paper/ white paper to inform discussions around a long-term vision for Toronto's electricity system**	*IESO*	- Discussion paper	Q3 2018
6	**Complete system studies to identify needs over the demand forecast period [13]** - Review and finalize base case, include bulk system assumptions as identified in the key assumptions - Apply reliability criteria as defined in ORTAC to demand forecast scenarios - Confirm and refine the need(s) and timing/load levels	*IESO, LDC, Hydro One Transmission*	- Summary of needs based on demand forecast scenarios for the planning horizon	Q3-Q4 2018

[13] The timing for initiating the assessment and all subsequent plan development activities will be contingent on the Working Group agreeing on the demand outlooks to be used.

<table>
<tr><th colspan="2">Activity</th><th>Lead Responsibility</th><th>Deliverable(s)</th><th>Timeframe</th></tr>
<tr><td rowspan="7">7</td><td>Develop Options and Alternatives (Near-term and Medium-term)</td><td></td><td rowspan="7">- Develop flexible planning options with timelines and key attributes, accounting for demand outlook scenarios</td><td rowspan="7">Q4 2018 - Q1 2019</td></tr>
<tr><td>Develop CDM options</td><td>IESO and LDC</td></tr>
<tr><td>Develop local generation and DER options</td><td>IESO and LDC</td></tr>
<tr><td>Develop transmission and distribution options</td><td>IESO, Hydro One, and LDC</td></tr>
<tr><td>Develop options involving other electricity initiatives (e.g., smart grid, storage)</td><td>IESO/ LDC with support as needed</td></tr>
<tr><td>Develop portfolios of integrated alternatives</td><td>All</td></tr>
<tr><td>Technical comparison and evaluation</td><td>All</td></tr>
<tr><td rowspan="4">8</td><td>Plan and Undertake Community & Stakeholder Engagement</td><td></td><td></td><td></td></tr>
<tr><td>- Engagement with local municipalities and Indigenous communities within study area with focus on needs</td><td>All</td><td rowspan="3">- Community and Stakeholder Engagement Plan
- Input from affected communities</td><td>Q4 2018</td></tr>
<tr><td>- Undertake community and stakeholder engagement on options</td><td>All</td><td rowspan="2">Q1 2019</td></tr>
<tr><td>- Summarize input and incorporate feedback, revise options</td><td>All</td></tr>
<tr><td>9</td><td>Develop recommendations to support actions to address near-term and medium-term needs
- Implementation plan</td><td>All</td><td>- Implementation plan
- Monitoring activities and identification of decision triggers
- Procedures for annual review</td><td>Q2-Q3 2019</td></tr>
<tr><td>10</td><td>Develop long-term recommendations
- Long-term vision for electric power system</td><td>All</td><td>- Long-term plan and supporting recommendations</td><td>Q2-Q3 2019</td></tr>
<tr><td>11</td><td>Prepare the IRRP report detailing the recommended near, medium and long-term plan for approval by all parties</td><td>IESO</td><td>- IRRP report</td><td>Q3 2019</td></tr>
</table>

Burlington to Nanticoke

REGIONAL INFRASTRUCTURE PLAN

February 7, 2017

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Prepared and supported by:

Company
Brantford Power Inc.
Burlington Hydro Inc.
Energy + Inc.
Alectra Utilities Corporation (former Horizon Utilities Inc.)
Hydro One Networks Inc. (Distribution)
Independent Electricity System Operator (IESO)
Oakville Hydro
Hydro One Networks Inc. (Lead Transmitter)

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Disclaimer

This Regional Infrastructure Plan (“RIP”) report was prepared for the purpose of developing an electricity infrastructure plan to address all near and mid-term needs (2015-2025) identified in previous planning phases and any additional needs identified based on new and/or updated information provided by the RIP Working Group.

The preferred solution(s) that have been identified in this report may be reevaluated based on the findings of further analysis. The load forecast and results reported in this RIP report are based on the information provided and assumptions made by the participants of the RIP Working Group.

Working Group participants, their respective affiliated organizations, and Hydro One Networks Inc. (collectively, “the Authors”) make no representations or warranties (express, implied, statutory or otherwise) as to the RIP report or its contents, including, without limitation, the accuracy or completeness of the information therein and shall not, under any circumstances whatsoever, be liable to each other, or to any third party for whom the RIP report was prepared (“the Intended Third Parties”), or to any other third party reading or receiving the RIP report (“the Other Third Parties”), for any direct, indirect or consequential loss or damages or for any punitive, incidental or special damages or any loss of profit, loss of contract, loss of opportunity or loss of goodwill resulting from or in any way related to the reliance on, acceptance or use of the RIP report or its contents by any person or entity, including, but not limited to, the aforementioned persons and entities.

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EXECUTIVE SUMMARY

THIS REGIONAL INFRASTRUCTURE PLAN (“RIP”) WAS PREPARED BY HYDRO ONE WITH PARTICIPATION AND INPUT FROM THE RIP WORKING GROUP IN ACCORDANCE WITH THE ONTARIO TRANSMISSION SYSTEM CODE REQUIREMENTS. IT IDENTIFIES INVESTMENTS IN TRANSMISSION FACILITIES, DISTRIBUTION FACILITIES, OR BOTH, THAT SHOULD BE PLANNED, DEVELOPED AND IMPLEMENTED TO MEET THE ELECTRICITY INFRASTRUCTURE NEEDS WITHIN THE BURLINGTON TO NANTICOKE REGION.

The participants of the RIP Working Group included members from the following organizations:

- Brantford Power Inc.
- Burlington Hydro Inc.
- Energy + Inc.
- Alectra Utilities Corporation (former Horizon Utilities Inc.)
- Hydro One Networks Inc. (Distribution)
- Independent Electricity System Operator (IESO)
- Oakville Hydro
- Hydro One Networks Inc. (Lead Transmitter)

In general, the RIP is the final phase of the regional planning process and, in this case, it follows the completion of the Integrated Regional Resource Plans (“IRRP”) for Brant Sub-Region and Bronte Sub-Region in March 2015 and June 2016, respectively, and the Burlington to Nanticoke Region’s Needs Assessment (“NA”) in May 2014. This RIP provides a consolidated summary of the needs and recommended plans for the Burlington to Nanticoke Region for the near-term (up to 5 years) and the mid-term (5 to 10 years).

It should be noted that this RIP, in addition to advancing the work from the aforementioned IRRPs, also identifies additional needs related to sustainment and end-of-life facilities in the Hamilton area. Built over 50 years ago, the transmission assets in the Hamilton area are some of the oldest installations in the province. At the time of the Burlington to Nanticoke Need Assessment and Scoping Assessment phases, done in 2014, the detailed information on the condition and end-of-life issues related to these assets was not available. As such, a decision was made by the Working Group at that time to not initiate a coordinated planning exercise for the Hamilton subsystem. Since then, through the RIP process, the extent and urgency of the sustainment work in the Hamilton area, and also in Oakville and Brantford, are better known to the Working Group.

This RIP discusses those needs and the projects developed to address those needs. Implementation to address some of these needs is underway. The plans presented in this RIP to address new end-of-life needs have been developed by Hydro One and needs also confirmed by the LDC. Further details are being formalized by Hydro One through assessment and consultation with the LDC to develop implementation plans. The plans for Beach TS, Birmingham TS, Gage TS and Kenilworth TS were later also reviewed by the IESO as part of an ongoing study for the Hamilton area. However, new near and mid-term needs namely Horning TS, Elgin TS, and Bronte TS were not fully identified earlier in the regional planning process and did not undergo a review by the IESO in the earlier phases due to their scope or project status.

The RIP report also identifies long-term needs associated with the revised and better defined sustainment plan.

The needs and/or plans in the near-term (2016-2020) and the mid- to long-term (beyond 2020) are provided below in Table 1 and Table 2, respectively, along with their planned in-service date and estimated cost, where applicable. Table 1 identifies both the stakeholders involved in each project's development and which formal regional planning process it originated from. The table also indicates the needs identified after the completion of the NA and SA (Scoping Assessment) processes.

Table 1: Near-Term Needs/Plans in Burlington to Nanticoke Region

No.	Needs	Plans	Status	I/S Date	Cost ($M)
Projects Developed in Local Planning or an IRRP					
1	115 kV B7/B8 Transmission Line Capacity	Bronte TS: Load Transfer	Planning	2018	1-3
2	115 kV B12/B13 Transmission Line Capacity	Install Brant Switching Station	Planning	2019	12
3	Two New Feeders at Dundas TS #2	Dundas TS: Load Transfer	Planning	2019	8
4	Cumberland TS – Power Factor Correction	LDC is developing distribution option	Planning	TBD (1)	-
5	Kenilworth TS – Power Factor Correction	LDC is developing distribution option	Planning	TBD (1)	-
Projects Developed by HONI & the LDC(s), Reviewed by IESO					
6	Kenilworth TS EOL transformers & switchgear (2)	Reconfigure from 2 DESNs to single DESN	Planning	2018	19
7	Beach TS – EOL T3/T4 DESN Transformers (2)	Replace Beach TS T3/T4 Transformers	Committed	2019	17
8	Gage TS – EOL transformers & switchgear	Gage TS: Reduce from 3 DESNs to 2 DESNs	Planning	2019	37
9	115 kV B7/B8 – EOL Line Section from Burlington TS to Nelson Jct. (2)	Refurbish the EOL B7/B8 line section	Planning	2020	2
Projects Developed by HONI & the LDC(s)					
10	115 kV B3/B4 – EOL Line Section from Horning Mountain Jct. to Glanford Jct. (2)	Refurbish the EOL B3/B4 line section conductor	Planning	2018	8
11	Horning TS EOL transformers & switchgears (2)	Replace EOL transformers & refurbish switchgears	Committed	2018	37
12	Bronte TS – EOL T5/T6 DESN (2)	Replace EOL transformers & refurbish switchgear	Committed	2019	34

No.	Needs	Plans	Status	I/S Date	Cost ($M)
13	Elgin TS – EOL transformers & switchgears	Replace transformers and switchgears and reduce 2 DESNs to 1 DESN	Committed	2019	58
14	Mohawk TS (T1/T2) – Station Capacity and EOL T1/T2 Transformers	Mohawk TS Transformers Replacement	Committed	2019	14

(1) To Be Decided
(2) New needs identified by HONI

Table 2: Mid- and Long-Term Needs/Plans in Burlington to Nanticoke Region

No.	Needs/Plans	Planned I/S Date	Cost ($M)
1	Birmingham TS: 2 Metal Clad Switchgear Refurbishment [1]	2021	14
2	Dundas TS: T1/T2 switchyard refurbishment	2021	10
3	Newton TS: Station Refurbishment	2021	36
4	LV Switchgear Refurbishment at Brantford TS, Lake TS and Stirton TS	2022	46
5	Beach TS: Replace EOL T7/T8 Autotransformers and refurbish T5/T6 DESN switchgear	2025	60
6	EOL 115 kV Cables: - H5K/ H6K - K1G/ K2G - HL3/ HL4	TBD [2]	TBD [2]

(1) Preliminarily reviewed by HONI, LDC and the IESO
(2) To Be Decided

Further details of needs, alternatives, and recommended plans for the above needs are provided in Section 7. The preliminary plans and needs identified in Table 2 will be further assessed in the next planning cycle. A summary of the current recommendations for these mid- and long-term needs is provided in Section 8.

The RIP Working Group recommends the following outcomes and next steps:

a) Hydro One will continue to implement the committed and near-term projects for addressing the above needs as discussed in this report, while keeping the Working Group apprised of project status, and

b) The RIP recommends that an expedited Needs Assessment report should be developed to list these already identified needs in the mid and long term or any new needs to be followed by Scoping Assessment, led by the IESO for further assessment under the Burlington to Nanticoke regional planning Working Group.

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1. INTRODUCTION

THIS REPORT PRESENTS THE REGIONAL INFRASTRUCTURE PLAN (“RIP”) TO ADDRESS THE ELECTRICITY NEEDS OF THE BURLINGTON TO NANTICOKE REGION.

The report was prepared by Hydro One Networks Inc. (“Hydro One”) and documents the results of the needs, assessments and recommended plan. The members of the RIP WG included representative from Brantford Power Inc. (“Brantford Power”), Burlington Hydro Inc. (“Burlington Hydro”), Energy + Inc. (“Energy +”), Alectra Utilities Corporation (former Horizon Utilities Inc. “Alectra Utilities”), Hydro One Distribution, the Independent Electricity System Operator (“IESO”) and Oakville Hydro Electricity Distribution Inc. (“Oakville Hydro”) in accordance with the Regional Planning process established by the Ontario Energy Board (“OEB”) in 2013.

The Burlington to Nanticoke region covers the City of Brantford, municipality of Hamilton, counties of Brant, Haldimand and Norfolk. The portions of Cities of Burlington and Oakville south of Dundas Street are included in the Burlington to Nanticoke region up to Third Line road in the east. Electrical supply to the Region is provided from thirty-one 230 kV and 115 kV step-down transformer stations. The summer 2015 load of the Region was about 1831 MW. The boundaries of the Region are shown in Figure 1-1 below.

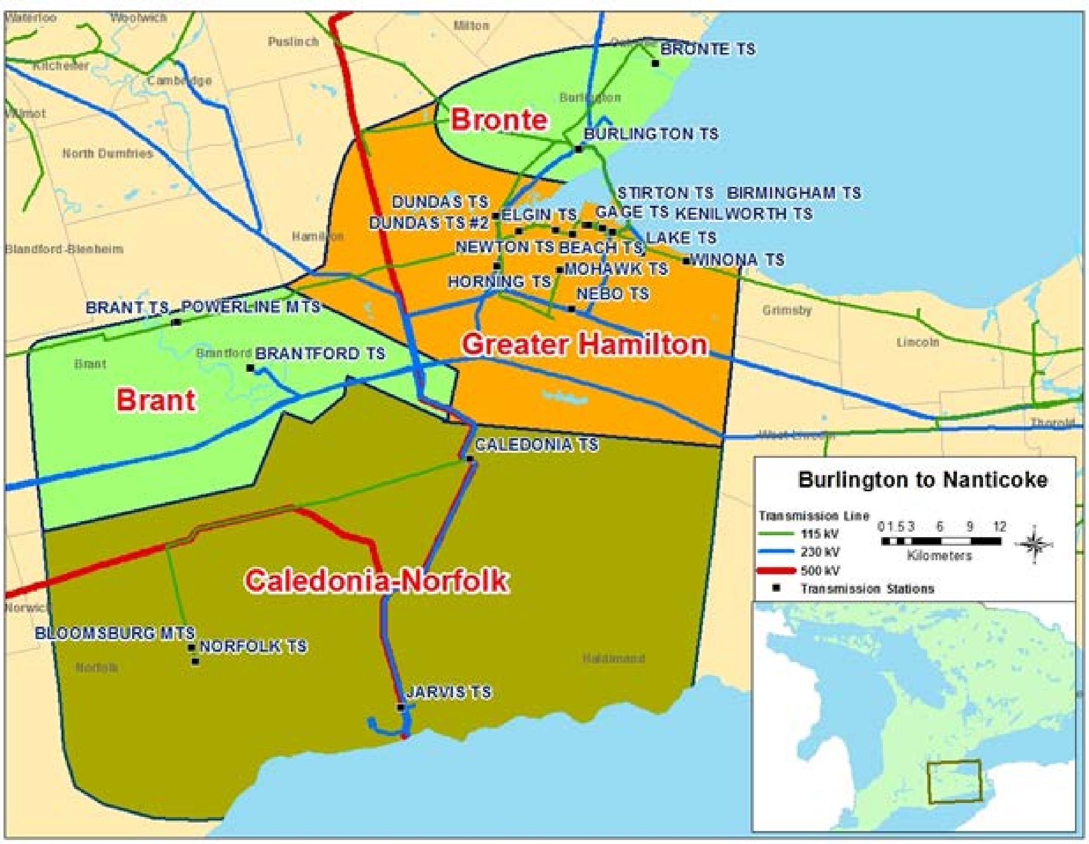

Figure 1-1 Burlington to Nanticoke Region

1.1 Objective and Scope

The RIP report examines the needs in the Burlington to Nanticoke Region. Its objectives are to:

- Provide a comprehensive summary of needs and wires plans to address the needs;
- Identify any new needs that may have emerged since previous planning phases e.g., Needs Assessment ("NA") and/or Integrated Regional Resource Plan("IRRP");
- Assess and develop a wires plan to address these new needs; and
- Identify investments in transmission and distribution facilities or both that should be developed and implemented on a coordinated basis to meet the electricity infrastructure needs within the region.

The RIP reviewed factors such as the load forecast, major high voltage sustainment issues emerging over the mid- and long-term, transmission and distribution system capability along with any updates with respect to local plans, conservation and demand management ("CDM"), renewable and non-renewable generation development, and other electricity system and local drivers that may impact the need and alternatives under consideration.

The scope of this RIP is as follows:

- A consolidated summary of the wires plan developed during LP (Local Planning), SA (Scoping Assessment), and/or as identified in IRRP.
- Discussion of any other major transmission infrastructure investment plans over the near and mid-term (0-10 years)
- Identification of any new needs and a wires plan to address these needs based on new and/or updated information.

1.2 Structure

The rest of the report is organized as follows:

- Section 2 provides an overview of the regional planning process.
- Section 3 describes the regional characteristics.
- Section 4 describes the transmission work completed over the last ten years.
- Section 5 describes the load forecast and study assumptions used in this assessment.
- Section 6 describes the results of the adequacy assessment of the transmission facilities and identifies needs.
- Section 7 discusses the needs and provides the alternatives and preferred solutions.
- Section 8 provides the conclusion and next steps.

2. REGIONAL PLANNING PROCESS

2.1 Overview

Planning for the electricity system in Ontario is done at essentially three levels: bulk system planning, regional system planning, and distribution system planning. These levels differ in the facilities that are considered and the scope of impact on the electricity system. Planning at the bulk system level typically looks at issues that impact the system on a provincial level, while planning at the regional and distribution levels looks at issues on a more regional or localized level.

Regional planning looks at supply and reliability issues at a regional or local area level. Therefore, it largely considers the 115 kV and 230 kV portions of the power system that supply various parts of the province.

2.2 Regional Planning Process

A structured regional planning process was established by the Ontario Energy Board ("OEB") in 2013 through amendments to the Transmission System Code ("TSC") and Distribution System Code ("DSC"). The process consists of four phases: the Needs Assessment [1] ("NA"), the Scoping Assessment ("SA"), the Integrated Regional Resource Plan ("IRRP"), and the Regional Infrastructure Plan ("RIP").

The regional planning process begins with the NA phase, which is led by the transmitter to determine if there are regional needs. The NA phase identifies the needs and the Working Group determines whether further regional coordination is necessary to address them. If no further regional coordination is required, further planning is undertaken by the transmitter and the impacted local distribution company ("LDC") or customer and develops a Local Plan ("LP") to address them. These needs are local in nature and can be best addressed by a straight forward wires solution.

In situations where identified needs require coordination at the regional or sub-regional levels, the IESO initiates the SA phase. During this phase, the IESO, in collaboration with the transmitter and impacted LDCs, reviews the information collected as part of the NA phase, along with additional information on potential non-wires alternatives, and makes a decision on the most appropriate regional planning approach. The approach is either a RIP, which is led by the transmitter, or an IRRP, which is led by the IESO. If more than one sub-region was identified in the NA phase, it is possible that a different approach could be taken for different sub-regions.

The IRRP phase will generally assess infrastructure (wires) versus resource (CDM and Distributed Generation) options at a higher or more macro level, but sufficient to permit a comparison of options. If the IRRP phase identifies that infrastructure options may be most appropriate to meet a need, the RIP phase will conduct detailed planning to identify and assess the specific wires alternatives and recommend

[1] Also referred to as Needs Screening

a preferred wires solution. Similarly, resource options that the IRRP identifies as best suited to meet a need are then further planned in greater detail by the IESO. The IRRP phase also includes IESO led stakeholder engagement with municipalities and establishes a Local Advisory Committee in the region or sub-region. The Brant Sub-Region IESO led IRRP was initiated prior to the new regional planning process and was completed in March 2015. The need for Bronte Sub-Region IRRP was identified during the Need Assessment for Burlington to Nanticoke region and was completed in June 2016.

The RIP phase is the fourth and final phase of the regional planning process and involves: discussion of previously identified needs and plans; identification of any new needs that may have emerged since the start of the planning cycle; and development of a wires plan to address the needs where a wires solution would be the best overall approach. This phase is led and coordinated by the transmitter and the deliverable is a comprehensive report of a wires plan for the region. Once completed, this report is also referenced in transmitter's rate filing submissions and as part of LDC rate applications with a planning status letter provided by the transmitter.

To efficiently manage the regional planning process, Hydro One has been undertaking wires planning activities in collaboration with the IESO and/or LDCs for the region as part of and/or in parallel with:

- Planning activities that were already underway in the region prior to the new regional planning process taking effect.
- The NA, SA, and LP phases of regional planning.
- Participating in and conducting wires planning as part of the IRRP for the region or sub-region.
- Working and planning for connection capacity requirements with the LDCs and transmission connected customers

Figure 2-1 illustrates the various phases of the regional planning process (NA, SA, IRRP, and RIP) and their respective phase trigger, lead, and outcome.

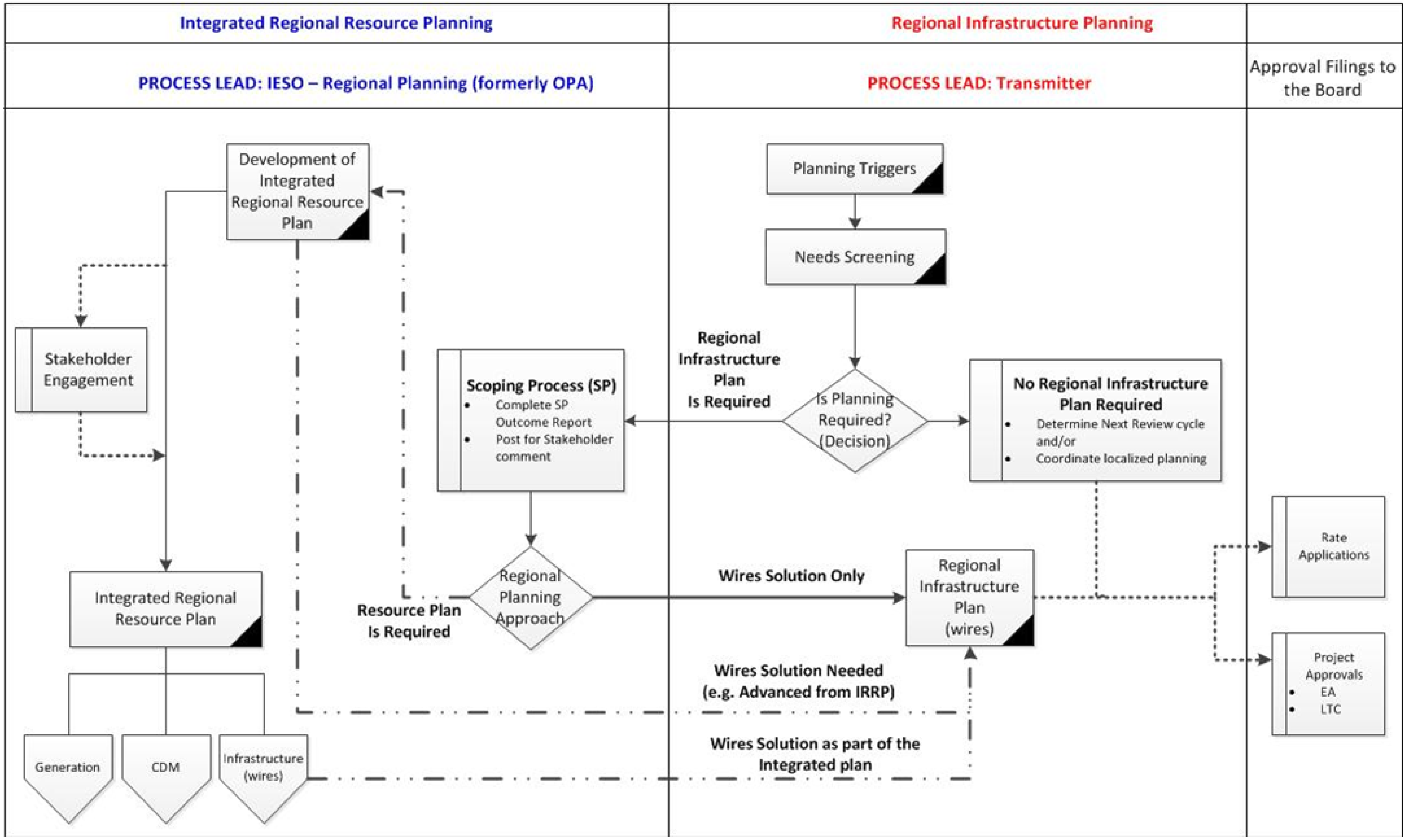

Figure 2-1 Regional Planning Process Flowchart

2.3 RIP Methodology

The RIP phase consists of a four step process (see Figure 2-2) as follows:

1. Data Gathering: The first step of the process is the review of planning assessment data collected in the previous phase of the regional planning process. Hydro One collects this information and reviews it with the Working Group to reconfirm or update the information as required. The data collected includes:
   - Net peak demand forecast at the transformer station level. This includes the effect of any distributed generation or conservation and demand management programs.
   - Existing area network and capabilities including any bulk system power flow assumptions.
   - Other data and assumptions as applicable such as asset conditions; load transfer capabilities, and previously committed transmission and distribution system plans.
2. Technical Assessment: The second step is a technical assessment to review the adequacy of the regional system including any previously identified needs. Depending upon the changes to load forecast or other relevant information, regional technical assessment may or may not be required or be limited to specific issue only. Additional near and mid-term needs may be identified in this phase.
3. Alternative Development: The third step is the development of wires options to address the needs and to come up with a preferred alternative based on an assessment of technical considerations, feasibility, environmental impact and costs.
4. Implementation Plan: The fourth and last step is the development of the implementation plan for the preferred alternative.

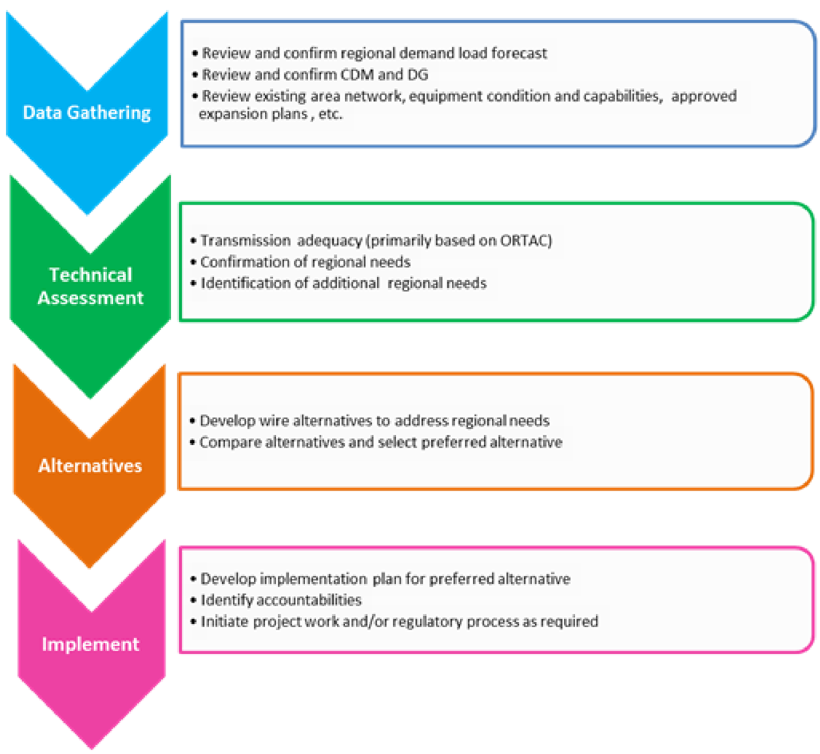

Figure 2-2 RIP Methodology

3. REGIONAL CHARACTERISTICS

THE BURLINGTON TO NANTICOKE REGION COVERS THE CITY OF BRANTFORD, MUNICIPALITY OF HAMILTON, COUNTIES OF BRANT, HALDIMAND AND NORFOLK. SOME OF THE ELECTRICAL INFRASTRUCTURE IN THE REGION IS ONE OF THE OLDEST INSTALLATIONS IN THE PROVINCE. THE PORTIONS OF CITIES OF BURLINGTON AND OAKVILLE SOUTH OF DUNDAS STREET ARE INCLUDED IN THE BURLINGTON TO NANTICOKE REGION UP TO THIRD LINE ROAD IN THE EAST.

Bulk electrical supply to the Burlington to Nanticoke Region is provided through the 500/230 kV Nanticoke TS and Middleport TS and 230 kV circuits from Middleport TS, Nanticoke TS and Beck TS. The 115 kV network is supplied by 230/115 kV autotransformers at Burlington TS, Beach TS and Caledonia TS. The area loads are supplied by a network of 230 kV and 115 kV transmission lines and step-down transformation facilities. The area has been divided into four sub-regions as shown in Figure 1-1 and described below:

- The Brant Sub-Region encompasses the County of Brant, City of Brantford and surrounding areas. Electricity supply to the sub-region is provided by:

  - Brant TS and Powerline MTS supplied by 115 kV double circuit line B12/B13.
  - Brantford TS supplied by the 230 kV double circuit transmission line M32W/M33W.

  The Brant Sub-Region transmission facilities are shown in Figure 3-1.

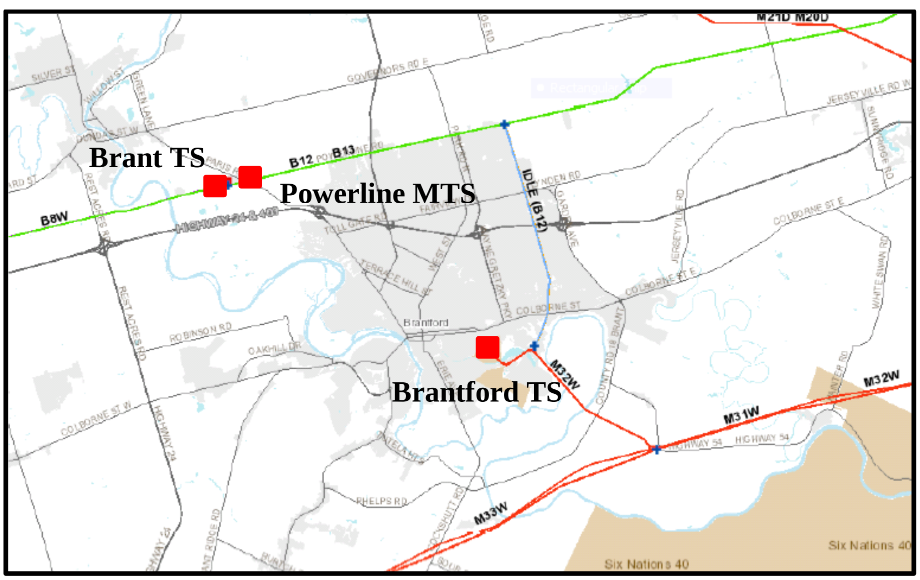

Figure 3-1 Brant Sub-Region

The total peak demand of the three stations was about 263 MW in 2015. Energy + Inc. and Brantford Power Inc. are the main LDCs that serve the electricity demand for the City of Brantford. Hydro One Distribution supplies load in the outlying areas of the sub-region. The electricity demand is comprised of residential, commercial and industrial customers.

- The Bronte Sub-Region covers the City of Burlington and the western part of the City of Oakville up to Third Line. Electricity supply to the sub-region is provided by:

  - Bronte TS supplied by 115 kV double circuit line B7/B8.
  - Burlington TS supplied by 230 kV double circuit line Q23BM/ Q25BM.
  - Cumberland TS supplied from 230 kV double circuit transmission line B40C/B41C.

  The Bronte Sub-Region transmission facilities are shown in Figure 3-2.

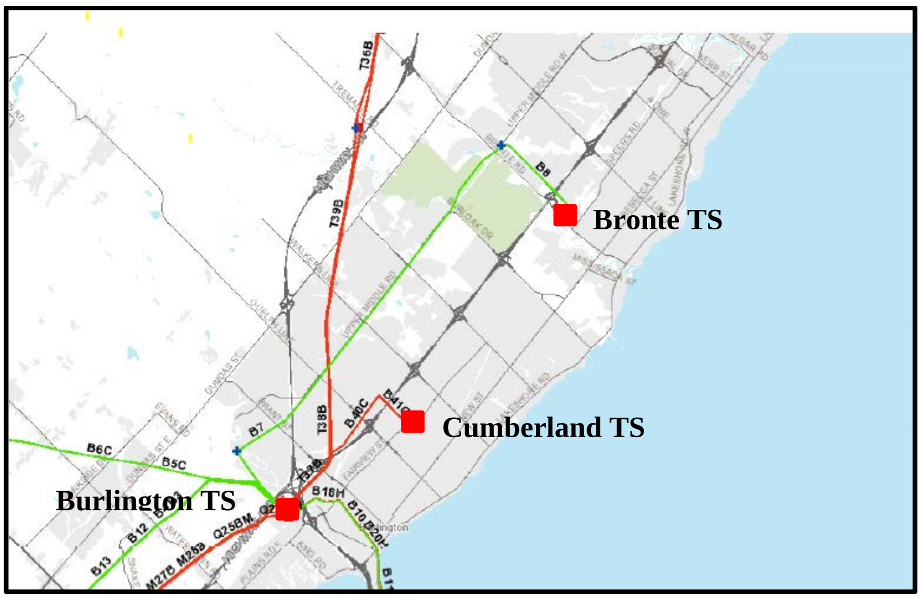

Figure 3-2 Bronte Sub-Region

The area is served by Burlington Hydro and Oakville Hydro. The electricity demand is comprised of residential, commercial and industrial customers. The total peak station demand of the three stations was about 402 MW in 2015.

- The Greater Hamilton Sub-Region encompasses the City of Hamilton that includes Townships of Flamborough and Glanbrook and towns of Dundas and Stoney Creek. Some of the electrical infrastructure in the sub-region was built over 50 years ago and is one of the oldest installations in the province. Electricity supply to the sub-region is grouped as follows:

  - Beach TS 115 kV area which includes five 115 kV step down stations Beach TS T3/T4 DESN, Birmingham TS, Kenilworth TS, Stirton TS, Winona TS and a CTS supplied from the 230/115 kV autotransformers at Beach TS.

- Burlington TS 115 kV area which includes Dundas TS, Dundas #2, Elgin TS, Gage TS, Mohawk TS, Newton TS and one customer owned CTS supplied from the 230/115 kV autotransformers at Burlington TS.

- 230 kV area which includes Beach TS T5/T6 DESN, Horning TS, Nebo TS, Lake TS and two customer owned stations supplied from 230 kV circuits connecting into Beach TS and Burlington TS.

The Greater Hamilton Sub-Region transmission facilities are shown in Figure 3-3.

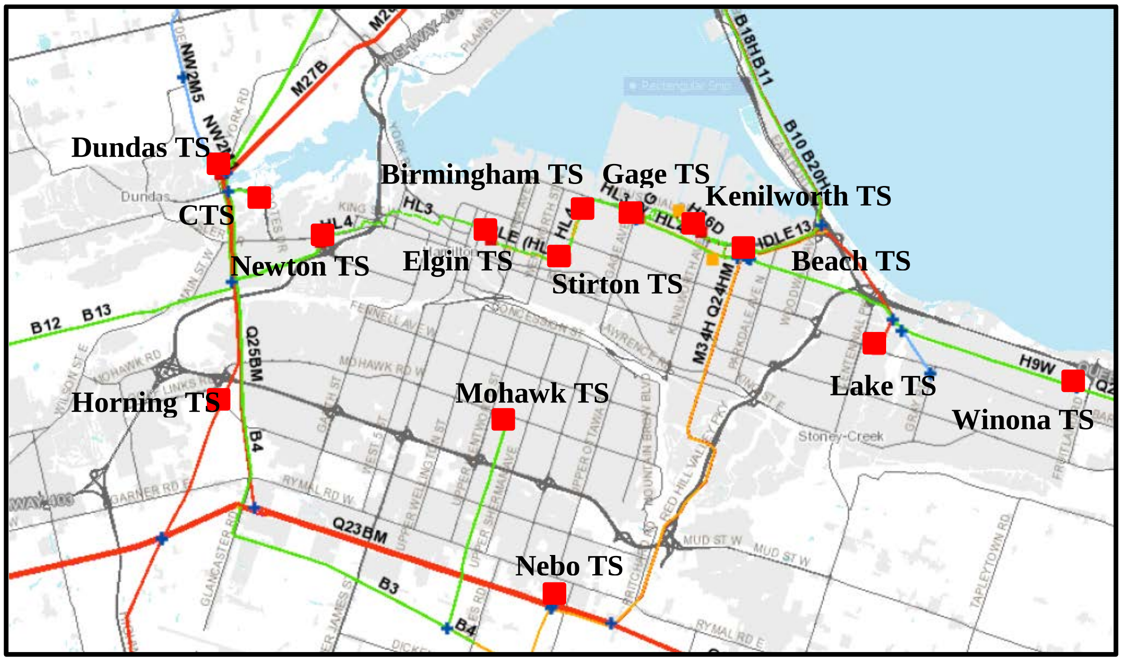

Figure 3-3 Greater Hamilton Sub-Region

The total peak station demand of the Greater Hamilton Sub-Region was about 1394 MW in 2015. The area is served by Alectra Utilities, Hydro One Distribution and CTSs comprises a significant number of large industrial customers along with commercial and residential customers.

- The Caledonia Norfolk Sub-Region covers the eastern part of Norfolk County and the western part of Haldimand County. Electricity supply to the Sub-region is provided by:

  - Caledonia TS supplied by 230 kV double circuit line N5M/S39M.
  - Jarvis TS supplied from the 230 kV double circuit line N21J/N22J.
  - Bloomsburg DS and Norfolk TS supplied from 115 kV double circuit transmission line C9/C12.

The Caledonia Norfolk Sub-Region transmission facilities are shown in Figure 3-4.

The area is served by Hydro One Distribution. The electricity demand mix is comprised of residential, commercial and industrial uses. The peak demand of the stations in the Sub-Region was approximately 334 MW in 2015.

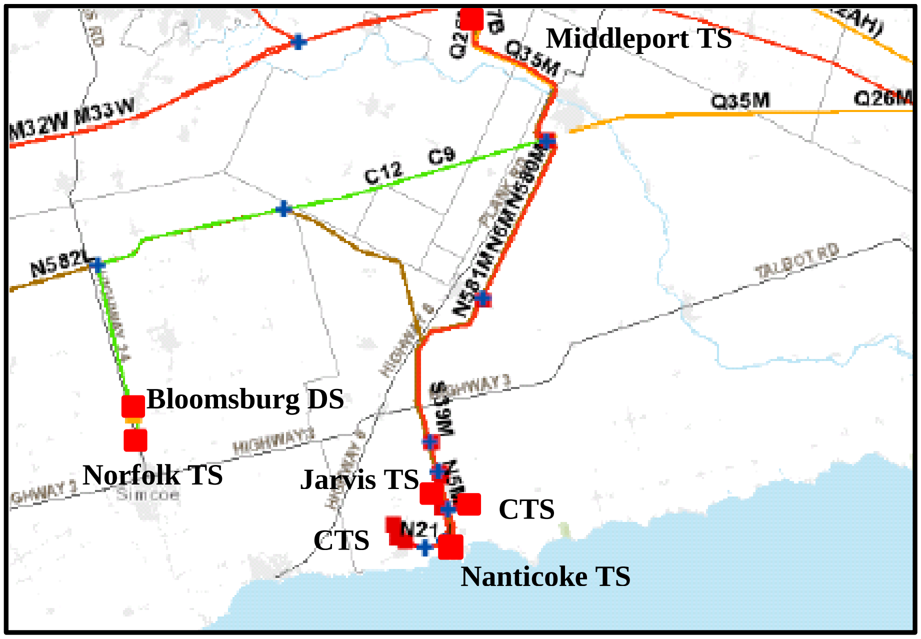

Figure 3-4 Caledonia Norfolk Sub-Region

Electrical single line diagrams for the Burlington to Nanticoke Region 500 kV/ 220 kV facilities and 115 kV facilities are shown below in Figure 3-5 and Figure 3-6.

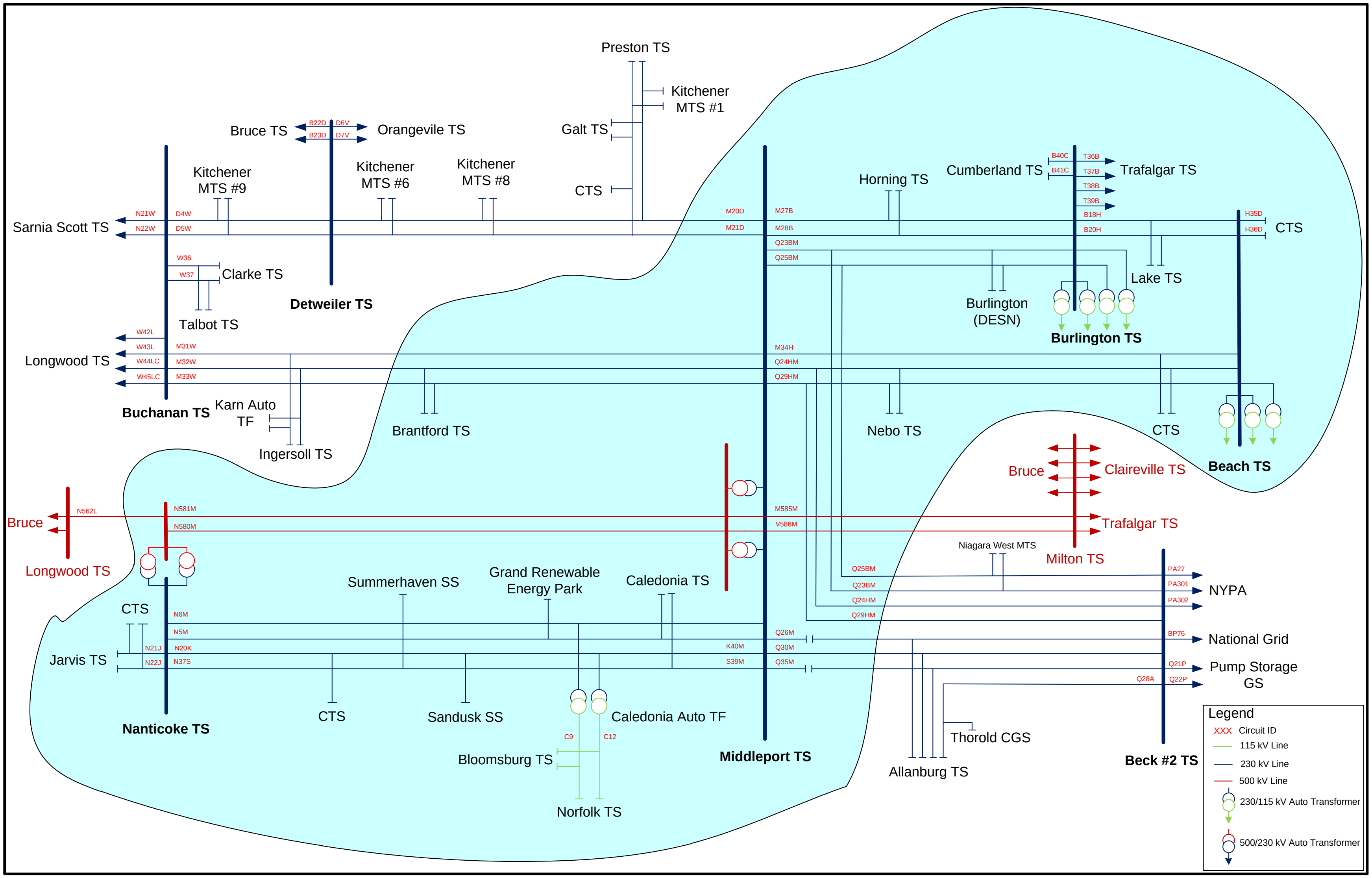

Figure 3-5 Burlington to Nanticoke Region 500 & 230 kV and Caledonia-Norfolk 115 kV Network

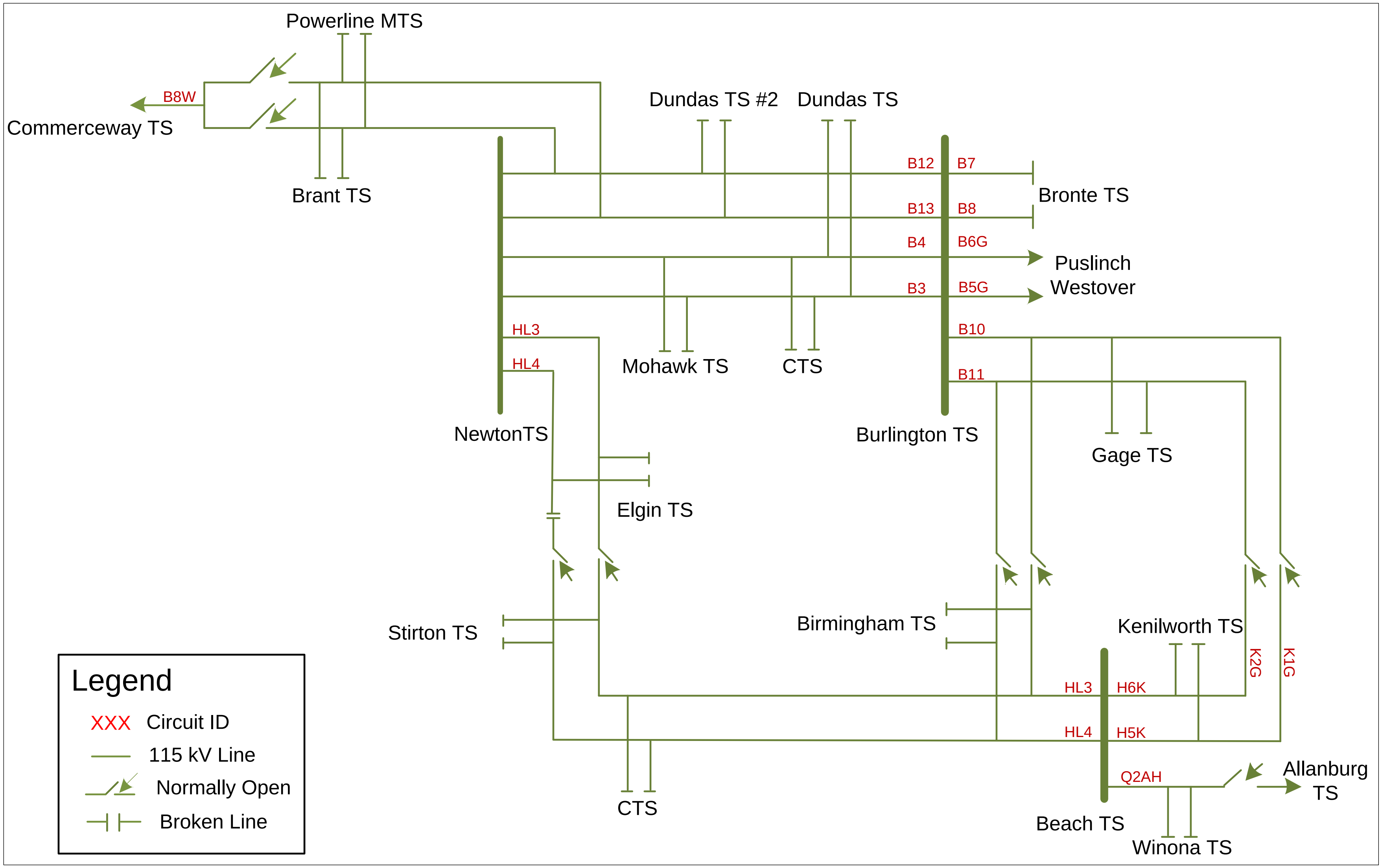

Figure 3-6 115 kV Network Supplied by Burlington TS and Beach TS

4. TRANSMISSION FACILITIES COMPLETED OVER LAST TEN YEARS

OVER THE LAST 10 YEARS A NUMBER OF TRANSMISSION PROJECTS HAVE BEEN PLANNED AND COMPLETED BY HYDRO ONE, IN CONSULTATION WITH THE LDCs AND/OR THE IESO, AIMED TO MAINTAIN OR IMPROVE THE RELIABILITY AND ADEQUACY OF SUPPLY IN THE BURLINGTON TO NANTICOKE REGION.

A brief listing of some of the major projects completed over the last ten years are as follows:

- Bronte TS (2008) - added a new low voltage breaker between T5/T6 DESN and T2 DESN units at Bronte TS.
- Burlington TS (2009) - replaced 230 kV/115 kV autotransformer T6 following failure.
- 2nd 115 kV Supply to Norfolk TS and Bloomsburg DS (2009) – Built 12 km of new 115 kV circuit to provide 2nd supply to Norfolk TS and Bloomsburg DS.
- Jarvis TS (2011) and Caledonia TS (2012) – installed LV reactors to reduce short circuit levels below the TSC limits and to allow increased generation connection capability at these stations.
- Nebo TS (2013) – replaced T1/T2 230 kV/ 27.6 kV transformers with larger size standard units and added six new breaker positions to meet customer needs.
- Burlington TS (2016) – installed an additional 230 kV circuit breaker to reduce probability of the simultaneous loss of two autotransformers at this station improving supply reliability to the stations supplied from 115 kV Burlington TS bus.
- Transformer replacement at stations: Bronte TS (2006), Norfolk TS (2009), Birmingham TS (2010), Cumberland TS (2012), Brantford TS (2013), Kenilworth TS (2014), Dundas TS (2015) and Brant TS (2016).
- Feeder Positions – added four new breaker positions at Horning TS (2006) and two new feeder breaker positions at Bronte TS (2008) to meet the customer needs.

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5. FORECAST AND OTHER STUDY ASSUMPTIONS

5.1 Load Forecast

The load in the Burlington to Nanticoke Region is growing at a slow rate with a decline of industrial loads in the region. Currently, load is forecast to increase at an average annual rate of approximately 0.24% up to 2035. The growth rate varies across the Region – with the highest growth rate of 1.37% in the Brant Sub Region.

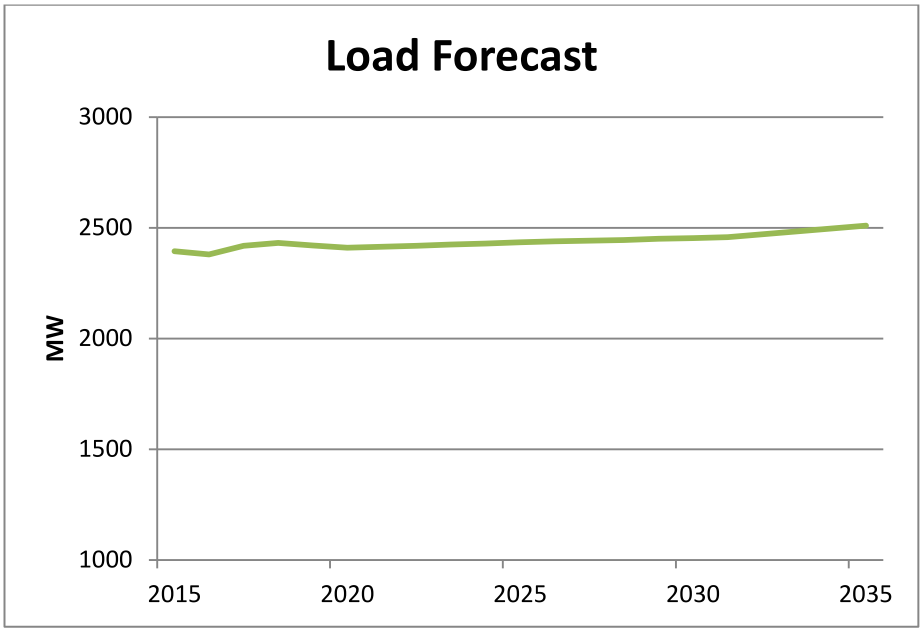

Figure 5-1 Burlington to Nanticoke Region Summer Extreme Weather Peak Forecast

Figure 5-1 shows the Burlington to Nanticoke Region peak summer non-coincident load forecast. This forecast is based on the 2015 extreme weather corrected loads. The non-coincident forecast represents the sum of the individual station's peak load and is used to determine the need for stations and line capacity. Regional non-coincident load forecast for the individual stations in the Burlington to Nanticoke Region is given in Appendix D.

The RIP load forecast was developed as follows:

- Load forecast for stations in the Bronte Sub region was taken from the IESO Bronte Sub- Region IRRP completed on June 30, 2016.
- Load forecast for Brant TS and Powerline MTS in the Brant Sub-Region was prepared by input and discussions with the LDCs recently (2016) as part of detailed planning for Brant switching station.
- Load forecast for the remaining stations was developed using the summer 2015 actual peak load adjusted for extreme weather and applying the station net growth rates provided by the LDCs. The net station loads account for CDM measures and connected DG in the region.

5.2 Other Study Assumptions

The following other assumptions are made in this report.

- The study period for the RIP assessments is 2015-2025.
- All planned facilities listed in Section 4 are assumed to be in-service.
- Where applicable, future industrial loads have been reduced based on historical information.
- Summer is the critical period with respect to line and transformer loadings. The assessment is therefore based on summer peak loads.
- Station capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity, assuming a 90% lagging power factor for stations having no low-voltage capacitor banks and 95% lagging power factor for stations having low-voltage capacitor banks.
- Normal planning supply capacity for transformer stations in this sub-region is determined by the Hydro One summer 10-Day Limited Time Rating (LTR).
- Adequacy assessment is conducted as per Ontario Resource Transmission Assessment Criteria (ORTAC).

6. ADEQUACY OF FACILITIES

THIS SECTION REVIEWS THE ADEQUACY OF THE EXISTING TRANSMISSION AND DELIVERY STATION FACILITIES SUPPLYING THE BURLINGTON TO NANTICOKE REGION OVER THE 2015-2025 PERIOD.

Within the current regional planning cycle three regional assessments have been conducted for the Burlington to Nanticoke Region. These studies are:

1) NA Report - Burlington to Nanticoke Region, May 23 , 2014
2) IRRP Report - Brant Sub-Region, April 28, 2015
3) Local Planning (“LP”) Report – Burlington to Nanticoke Region, October 28, 2015
4) IRRP Report - Bronte Sub-Region, June 30, 2016

The NA and IRRP reports identified a number of needs to meet the forecast load demands and EOL asset issues. A review of the loading on the transmission lines and stations in the Burlington to Nanticoke Region was also carried out as part of the RIP report using the latest regional forecast as given in Appendix D. Sections 6.1 to 6.5 present the results of this review. Further description of assessments, alternatives and preferred plan along with status is provided in Section 7.

6.1 500 and 230 kV Transmission Facilities

The 500 kV and most of the 230 kV transmission circuits in the Burlington to Nanticoke Region are classified as part of the Bulk Electricity System (“BES”). They connect the Region to the rest of Ontario’s transmission system. A number of these circuits also serve local area stations within the region and the power flow on them depends on the bulk system transfers as well as local area loads. In addition there are three 230 kV double circuit lines H35D/ H36D, B40C/ B41C and N21J/ N22J that supply only local loads. The circuits supplying local loads in the region are as follows (refer to Figure 3-5):

1. Middleport TS to Burlington TS 230 kV transmission circuits M27B/ M28B - supply Horning TS.
2. Middleport TS to Beck #2 TS to Burlington TS 230 kV transmission circuits Q23BM/ Q25BM /Q24HM/ Q29HM - supply Burlington (DESN) TS, Nebo TS and one customer owned CTS.
3. Middleport TS to Buchanan TS 230 kV transmission circuits M32W/ M33W - supply Brantford TS.
4. Middleport TS to Nanticoke TS 230 kV transmission circuits N5M/ S39M / N20K - supply Caledonia TS and one customer owned CTS.
5. Burlington TS to Beach TS 230 kV transmission circuits B18H/ B20H - supply Lake TS.
6. Nanticoke TS to Jarvis TS 230 kV transmission circuits N21J/ N22J - supply Jarvis TS and one customer owned CTS.
7. Beach TS to one customer owned CTS 230 kV transmission circuits H35D/ H36D.
8. Burlington TS to Cumberland TS 230 kV transmission circuits B40C/ B41C - supply Cumberland TS.

Bulk system planning is conducted by the IESO and is informed by government policy, including policy outlined in the long term energy plan ("LTEP"). Government engagement on the next LTEP is currently underway, with a new LTEP expected to be issued in Q2/Q3 2017. Bulk system needs, options and recommendations for Power System facilities serving this region will be determined by the IESO as part of the implementation plan for the 2017 LTEP.

6.2 230/115 kV Transformation Facilities

Almost half of the Region's load is supplied from the 115 kV transmission systems. The primary source of 115 kV supply is from three 230/115 kV autotransformers at Burlington TS, Beach TS and Caledonia TS.

Table 6-1 summarizes the loading levels for all three 230 /115 kV auto transformers in the Burlington to Nanticoke region.

Table 6-1 Adequacy of 230/115 kV Autotransformer Facilities

Overloaded Facilities	MVA Load Meeting Capability	2015 MVA Loading	Need Date
Burlington TS 230/115 kV autotransformers	912	745	-[1]
Beach TS 230/115 kV autotransformers	582	348	-[1]
Caledonia TS 230/115 kV autotransformer	187	88	-[1]

[1] Adequate over the study period (2015- 2025)

The autotransformers in the Burlington to Nanticoke region are of adequate capacity over the study period (2015-2025). The Needs Assessment identified a stuck breaker scenario at Burlington TS that could result in simultaneous loss of two of the four autotransformers at Burlington TS. This is a low probability scenario under which the loading on the remaining two autotransformers could exceed their short time emergency rating.

However, recently an additional 230 kV breaker has been added to the scheme reducing the possibility of simultaneous loss of two autotransformers at Burlington TS under a single contingency scenario. In addition, installation of the new 230/115 kV autotransformers at Cedar TS and 115 kV switching at Brant TS, to be in-service by 2019, will further reduce loading on the Burlington TS autotransformers.

The loading on the Burlington TS 230/115 kV autotransformers, for the simultaneous loss of two autotransformers, is therefore expected to remain within the short term rating of the two remaining in-service autotransformers at Burlington TS. No further action is required.

6.3 115 kV Transmission Facilities

The 115 kV transmission facilities can be divided in three main sections: Please see Figure 3-5 and 3-6 for the single line diagrams.

1. Burlington 115 kV – has twelve 115 kV circuits B3/B4, B5/B6, B7/B8, B10/B11, B12/B13 and HL3/ HL4. All circuits are adequate over the study period except for sections of the B7/B8 and B12/B13 circuits as given below in Table 6-2. These needs have been identified in the earlier phases of the regional planning process and are being addressed by Hydro One as per the recommendations in respective IRRPs and further discussed in this RIP (Section 7).

   The loading on the limiting sections of 115 kV circuits is summarized below in Table 6-2.

Table 6-2 Limiting Sections of 115 kV Circuits

Line Section	Overloaded Circuit	Reference Section	Capacity (MW)	Contingency	2015 Loading (MW)	Need Date
Palermo Jct. to Bronte TS	B7/ B8	Section 7.1	135	B7	129	2018
Horning Mountain Jct. to Brant TS	B12/B13	Section 7.5	125	B12/B13	119	2019

   The HL3/ HL4 115 kV double circuit cable consist of two sections:
   i. HL3/ HL4 Newton TS to Elgin TS
   ii. HL3/ HL4 Elgin TS to Stirton TS (HL4 is idle)

   These cables provide normal and backup supply to Elgin TS. The supply capacity of 115 kV HL3/ HL4 cables is adequate over the study period (2015-2025).

2. Beach 115 kV– has five 115 kV circuits H5K/ H6K, HL3/ HL4 and Q2AH expected to be adequate over the study period. There are two associated 115 kV double circuit cable sections:
   i. K1G/ K2G Kenilworth TS to Gage TS
   ii. H5K/ H6K Kenilworth TS to Beach TS

   These cables provide normal and backup supply to Kenilworth TS. The supply capacity of Beach 115 kV cables and lines is adequate over the study period (2015-2025).

3. Norfolk Caledonia – has two 115 kV circuits C9 and C12 supplying Norfolk TS and Bloomsburg DS. The need of additional supply capacity for C9/C12 double circuit line was identified during the earlier phases of the regional planning cycle.

   The updated load forecast and further assessment as part of this RIP shows that the combined load of Norfolk TS and Bloomsburg DS will remain below the supply capacity of 87 MW of C9/ C12 line during the study period and no further action is required.

The list of all the 230 kV and 115 kV circuits is given in Appendix A.

6.4 Step-Down Transformation Facilities

There are a total of 31 step-down transmission connected transformer stations in the Burlington to Nanticoke Region. The stations have been grouped based on the geographical area and supply configuration. The station loading in each area and the associated station capacity is provided in Table 6-3 below. The complete list of all the stations in the Burlington to Nanticoke region and their supply circuits is given in Appendix B.

Table 6-3 Adequacy of Step-Down Transformer Stations

Area/Supply	Capacity (MW)	2015 Loading (MW)	Need Date
Brant Sub-Region	403	263	-[2]
Bronte Sub-Region	530	402	-[2]
Greater Hamilton Sub-Region [1]	1919	1108	-[2]
Caledonia Norfolk Sub-Region [1]	351	211	-[2]

[1] Excludes Customer Transformer Stations (CTS)
[2] Adequate over the study period (2015-2025)

Dundas TS has two DESN units T1/T2 and T5/T6. During the earlier phases of the Regional Planning cycle T1/T2 DESN at Dundas TS was found to be loaded over its supply capacity due to unbalanced loading between the two Dundas TS DESNs. The current loading at both DESNs at Dundas TS is within each DESN's supply capacity. Further assessment as part of this RIP based on current forecast confirms that the loads on each of the Dundas TS DESNs will remain within its supply capacity during the study period. No further action is required.

Nebo TS 13.8 kV T3/T4 DESN was also identified as marginally over loaded during an earlier phase of the regional planning cycle. Further assessment as part of this RIP based on updated forecast confirms that the loads on the Nebo TS T3/T4 DESN will remain within its supply capacity during the study period. No further action is required.

6.5 System Reliability and Load Restoration

In case of contingencies on the transmission system, ORTAC provides the load restoration requirements relative to the amount of load affected. Planned system configuration must not exceed 600 MW of load curtailment/rejection. In all other cases, the following restoration times are provided for load to be restored for the outages caused by design contingencies.

a. All loads must be restored within 8 hours.
b. Load interrupted in excess of 150 MW must be restored within 4 hours.
c. Load interrupted in excess of 250 MW must be restored within 30 minutes.

It is expected that all loads can be restored within 8 hours in the Burlington to Nanticoke Region over the study period. None of the transmission circuits in the Burlington to Nanticoke region will be supplying total loads in excess of 250 MW. The following double circuit lines in the Burlington to Nanticoke Region are expected to supply the loads in excess of 150 MW at peak times:

- B12/ B13
- B3/ B4
- H35D/ H36D
- HL3/ HL4
- M32W/ M33W
- Q23BM/ Q25BM
- Q24HM/ Q29HM

Based on the historical performance and reliability data for these circuits in the region, the Working Group recommended that no action is required at this time.

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7. REGIONAL NEEDS & PLANS

THIS SECTION DISCUSSES THE ELECTRICAL INFRASTRUCTURE NEEDS FOR THE BURLINGTON TO NANTICOKE REGION AND SUMMARIZES THE REGIONAL PLANS FOR ADDRESSING THESE NEEDS. THESE NEEDS INCLUDE NEEDS PREVIOUSLY IDENTIFIED IN THE NEEDS ASSESSMENT, SCOPING ASSESSMENT, IRRPS FOR THE BRANT, AND BRONTE SUB-REGIONS, ASSESSMENTS CARRIED OUT IN SECTION 6 AS WELL AS EMERGING NEEDS DUE TO AGING INFRASTRUCTURE AND END OF LIFE ISSUES.

This section outlines and discusses infrastructure needs and plans identified for the Burlington to Nanticoke Region and recommended plans and/or next steps for the near-term (up to 5 years) and the mid-to long-term (beyond 5 years).

It should be noted that this RIP, in addition to advancing the work from the aforementioned IRRPs, also identifies additional needs related to sustainment and end-of-life facilities in the Hamilton area. Built over 50 years ago, the transmission assets in the Hamilton area are some of the oldest installations in the province. At the time of the Burlington to Nanticoke Need Assessment and Scoping Assessment phases, done in 2014, the detailed information on the condition and end-of-life issues related to these assets was not available. As such, a decision was made by the Working Group at that time to not initiate a coordinated planning exercise for the Hamilton subsystem. Since then, through the RIP process, the extent and urgency of the sustainment work in the Hamilton area, and also in Oakville and Brantford, are better known by the Working Group.

This RIP discusses those needs and the projects developed to address those needs. Implementation to address some of these needs is already or nearly underway. The plans presented in this RIP to address new end-of-life needs have been developed by Hydro One and needs also confirmed by the LDC. Further details are being formalized by Hydro One through assessment and consultation with the LDC to develop implementation plans. The plans for Beach TS, Birmingham TS, Gage TS and Kenilworth TS were later reviewed by the IESO as part of an ongoing study for the Hamilton area. However, new near and mid-term needs namely Horning TS, Elgin TS, and Bronte TS were not fully identified earlier in the regional planning process and did not undergo a review by the IESO in the earlier phases due to their scope or project status.

The RIP report also identifies long-term needs associated with the revised and better defined sustainment plan. These needs will be assessed in the next planning cycle. A summary of all of these needs in the near-term (2016-2020) and mid to long-term (beyond 2020) are listed in Table 7-1 and Table 7-2, respectively, along with their in-service date, where applicable. Table 7-1 identifies both the stakeholders involved in each project's development and which formal regional planning process it originated from and provide reference to sub-sections with further details for each of the need. The table also indicates the needs identified after the completion of the NA and SA processes.

Table 7-1 Identified Near-Term Needs in Burlington to Nanticoke Region

No.	Needs	Section	Timing
Projects Developed in Local Planning or an IRRP			
1	115 kV B7/B8 Transmission Line Capacity	7.1	2018
2	115 kV B12/B13 Transmission Line Capacity	7.2	2019
3	Two New Feeders at Dundas TS	7.3	2019
4	Cumberland TS – Power Factor Correction	7.4	TBD
5	Kenilworth TS – Power Factor Correction	7.5	TBD
Projects Developed by HONI & the LDC(s), Reviewed by IESO			
6	Kenilworth TS – EOL transformers & switchgear (1)	7.6	2018
7	Beach TS – EOL T3/T4 DESN Transformers (1)	7.7	2019
8	Gage TS – EOL transformers & switchgear	7.8	2019
9	115 kV B7/B8 – EOL Line Section from Burlington TS to Nelson Jct. (1)	7.9	2020
Projects Developed by HONI & the LDC(s)			
10	115 kV B3/B4 – EOL Line Section from Horning Mountain Jct. to Glanford Jct. (1)	7.10	2018
11	Horning TS – EOL transformers & switchgears (1)	7.11	2018
12	Bronte TS – EOL T5/T6 DESN (1)	7.12	2019
13	Elgin TS – EOL transformers & switchgears	7.13	2019
14	Mohawk TS (T1/T2) – Station Capacity & EOL T1/T2 Transformers	7.14	2019

(1) New needs identified by HONI

The mid- and long-term (2021-2025) electrical infrastructure needs in the Burlington to Nanticoke Region are summarized below in Table 7-2. Where available, a preliminary plan to address that need is provided in the corresponding sub-section.

Table 7-2 Identified Mid- and Long-Term Needs in Burlington to Nanticoke Region

No.	Needs	Section	Timing
1	Birmingham TS EOL Metalclad Switchgears	7.15	2021
2	Dundas TS EOL T1/T2 Switchgear	7.16	2021
3	Newton TS EOL Transformers, Switchgears, Breakers	7.17	2021
4	Brantford TS EOL Switchgear	7.18	2022
5	Lake TS EOL Switchgear	7.18	2022

No.	Needs	Section	Timing
6	Stirton TS EOL Switchgear	7.18	2022
7	Beach TS EOL T7/T8 Auto-transformers and T5/T6 Switchgear	7.19	2025
8	EOL Cables in Hamilton area: H5K/H6K, K1G/K2G, HL3/HL4	7.20	TBD

The needs identified in the Burlington to Nanticoke Region in the above Tables 7-1 and Table 7-2 are further discussed below.

7.1 115 kV Circuit B7/B8 Transmission Line Capacity (Burlington TS to Bronte TS)

7.1.1 Description

Bronte TS is radially supplied by the 115 kV double circuit B7/ B8 line from Burlington TS. The supply capacity of Bronte area is limited to 135 MW due to loading on B7/B8 exceeding its thermal capacity following a loss of either of the circuits starting in 2018. In 2021, the post contingency voltage drop for the loss of either circuit will also exceed the ORTAC limit of 10% at Bronte TS. The load in Bronte area is forecasted to exceed the 135 MW supply limit and reach about 150 MW during the study period.

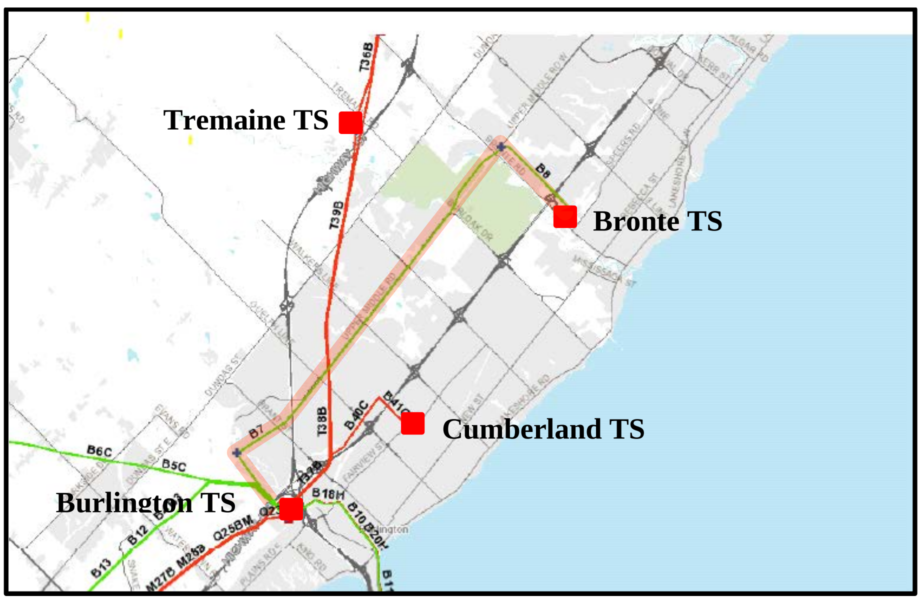

Figure 7-1 Bronte TS Supply Circuits B7/B8

7.1.2 Recommended Plan

The Working Group considered and reviewed different options to provide relief to the 115 kV circuits supplying Bronte TS as part of the Bronte area IRRP. The options included: a) upgrading of transmission system to mitigate the limitation on the 115 kV B7/ B8 circuits and b) Distribution option to transfer load from Bronte TS to neighboring station(s). Upgrading of transmission system was neither economical nor a practical solution.

Consistent with the WG recommendations in the IRRP, the most cost effective and preferred alternative is for LDC(s) to transfer loads from Bronte TS to other neighboring stations and to maintain Bronte TS loading below 135 MW.

Hydro One and the affected LDCs will develop a plan by the end of 2017 for transferring approximately 15 MW of load from Bronte TS to the neighboring station(s). The estimated cost of investments for the distribution load transfer is currently expected to be in the order of $1-3 million.

7.2 115 kV Circuit B12/B13 Transmission Line Capacity (Burlington TS to Brant TS)

7.2.1 Description

Brant TS and Powerline MTS in Brant County are supplied by the 115 kV double circuits B12/B13 line from Burlington TS. The Brant area is experiencing higher growth with a number of new industrial customers planning to connect over the next few years. The combined load of Brant TS and Powerline MTS was 119 MW in summer 2015 and exceeds the 104 MW supply capacity of the B12/B13 line.

7.2.2 Recommended Plan

As per the IRRP recommendations, first phase was to provide additional capacity for the Brant Area's 115 kV supply that included installation of 40 MVAR capacitor banks at Powerline MTS in July 2015. This has increased the line supply capacity to 125 MW.

In addition, the IRRP Working Group considered other options to provide additional 115 kV capacity to supply Brant TS and Powerline MTS to address future load growth over the near-term. The most economical option that was recommended by the WG is to install a three breaker switching station at Brant TS and using the existing backup supply from 115 kV circuit B8W (from Karn TS) as third supply. A single line diagram of the new switching facilities at Brant TS is shown below in Figure 7.2.

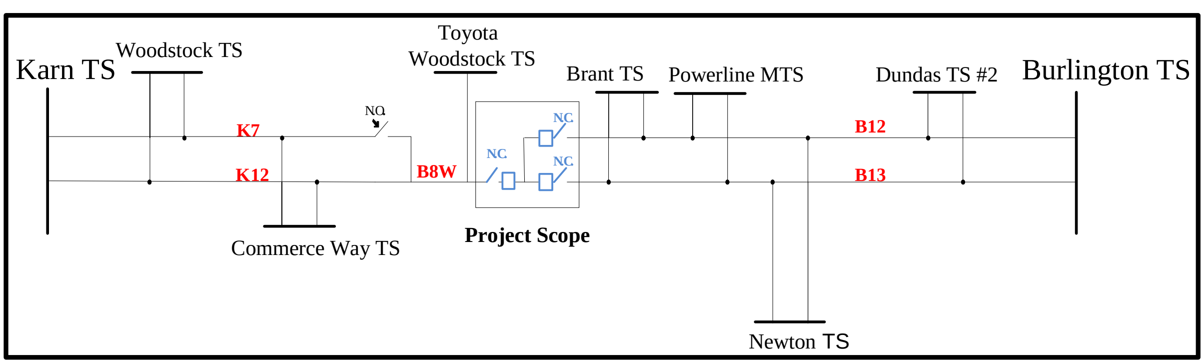

Figure 7-2 Brant Sub-Region Proposed Configuration

Hydro One has initiated detailed engineering work and design. The project is expected to be in-service by spring 2019 and is estimated to cost approximately $12 million. The installation of the switching station will reclassify some of the line connection assets as Network Assets. The project cost will be recoverable from the rate revenue and/or capital contribution from the LDCs in accordance with the TSC.

7.3 Two New Feeders at Dundas TS

7.3.1 Description

Dundas TS has two DESN units T1/T2 and T5/T6 with a total 2015 summer peak load of 148 MW and a station supply capacity of 188 MW. The station capacity is forecasted to be sufficient over and beyond the study period.

A LDC currently supplied from the T1/T2 DESN is planning to transfer load to T5/T6 DESN and supplied from two existing spare breaker positions to meet increased load needs. This will also help in balancing the loads between the two Dundas TS DESNs.

7.3.2 Alternatives, Recommended Plan and Current Status

The following alternatives were considered to address customer's needs:

- Maintain status quo: This alternative was considered and rejected as it does not address the customer's needs.
- Transfer customer load to T5/T6 DESN: Move portion of LDC customer loads from T1/T2 DESN to T5/T6 DESN utilizing two spare breaker positions at T5/T6 DESN. This will require reconfiguring of distribution assets by the LDC and will also help improving load balancing between two Dundas TS DESNs.

The preferred plan is to proceed with moving portion of the LDC's customer load from T1/T2 DESN to T5/T6 DESN utilizing two spare breaker positions. The transfer of load from T1/T2 DESN to T5/T6 DESN is planned to be completed in 2019 at an estimated cost of $8 million.

7.4 Cumberland TS Power Factor Correction

7.4.1 Description

The Cumberland TS supplies up to 123 MW of loads in the city of Burlington. The historical loading data of Cumberland TS indicated that under peak load conditions the power factor at Cumberland TS is lagging slightly below the ORTAC requirement of 0.9.

7.4.2 Recommended Plan and Current Status

The Needs Assessment identified this need and it was recommended that Burlington Hydro to work with their load customers supplied by Cumberland TS and install capacitor banks on distribution system as required to meet the minimum power factor requirements of 0.9.

Burlington Hydro is currently perusing different options to improve the power factor of customer loads supplied by Cumberland TS to meet ORTAC requirement. This issue will be further reviewed during the next regional planning cycle.

7.5 Kenilworth TS Power Factor Correction

7.5.1 Description

There are two supply stations inside Kenilworth TS T1/T4 and T2/T3 supplying about 60 MW of loads in the city of Hamilton. The historical loading data of Kenilworth TS indicated that under peak load conditions the power factor at Kenilworth TS is lagging below the ORTAC requirement of 0.9.

7.5.2 Alternatives and Recommended Plan

The Needs Assessment identified this need and it was recommended that Alectra Utilities to install capacitor bank on distribution system and/or work with load customers supplied by Kenilworth TS to meet ORTAC power factor requirement of 0.9.

Alectra Utilities is currently perusing option on cost and location to install equipment to improve power factor to meet ORTAC requirement. This issue will be further reviewed during the next regional planning cycle.

7.6 Kenilworth TS End of Life Assets

7.6.1 Description

There are two DESN units T1/T4 and T2/T3 inside Kenilworth TS supplying loads in the city of Hamilton and built in 1950’s and 1960’s respectively. The load at Kenilworth TS is currently about 60 MW. The T1/T4 transformers are rated at 67 MVA each while the T2/T3 transformers are 100MVA and 120 MVA, respectively, which are non-standard as per current standards. Non-standard and obsolete equipment results in complexity with failures and difficulty in getting similar spare equipment along with their installation. The original 120 MVA T2 transformer was replaced with a standard 100 MVA transformer unit in 2014 due to failure. In addition, one of the three metalclad switchgears at Kenilworth TS is presently out of service while the second in-service metalclad switchgear is approaching end of its useful life. As a result, near-term plan is developed to address the failure and EOL issues.

7.6.2 Alternatives and Recommended Plan

The following alternatives are considered to address end of life issue at Kenilworth TS:

- Maintain status quo: This alternative was considered and rejected as it does not address the risk of failure due to asset condition and would result in increased maintenance expenses and reduce supply reliability to the customers.
- "Like-for-Like" replacement of the assets: This alternative would require maintaining four transformers and the associated three switchgears which is not justifiable based on the load forecast.
- Station/load consolidation: Moving loads to neighboring station(s) and retiring Kenilworth TS. This alternative was considered but is not feasible due to: a) unique electrical characteristics and requirements of industrial costumer load in the area, and b) higher costs associated with reconfigurations and transfer of customer loads.
- Reconfiguration of the station reducing to two supply transformers and two switchgears: This option will reconfigure and adequately downsize the station. In this configuration, station will be reduced from four transformers to only two transformers supplying two switchgears.

The preferred plan is for Hydro One to proceed with the reconfiguration of the station and reduce it to two transformers and two switchgears only. The recently replaced transformer and one of the existing metalclad switchgear will be utilized while one transformer and switchgear will be required to be replaced. The new transformer will be a standard unit similar to T2 that was replaced in 2014. This refurbishment project is currently planned to be completed by the year 2018 at an estimated cost of $19 million.

7.7 Beach TS EOL T3/T4 DESN Transformers

7.7.1 Description

Beach TS has two DESN units T3/T4 and T5/T6 supplying loads in the city of Hamilton and built in 1950's and 1960's respectively. The T3/T4 DESN is supplied by the 115 kV bus while the T5/T6 DESN is supplied from the 230 kV bus at Beach TS. The 115/13.8 kV T3/T4 DESN transformers have been identified by Hydro One approaching the end of their useful life and require replacement. The load at Beach TS T3/T4 DESN is currently about 32 MW and is forecasted to stay at the same level in the foreseeable future.

7.7.2 Alternatives and Recommended Plan

The following alternatives are considered to address Beach TS T3/T4 supply transformer end of life issue:

- Continue to maintain the assets (status quo): This alternative was considered and rejected as it does not address the risk of failure due to asset condition and would result in increased maintenance expenses and reduce supply reliability to the customers.
- "Like-for-Like" replacement of the assets: Replacing existing EOL 115/ 13.8 kV T3/T4 DESN transformers with similarly sized units.

- Reconfigure 115 kV T3/T4 transformers to a 230 kV configuration by replacing the existing non-standard 115/ 13.8 kV (67 MVA + 75 MVA) transformers with standard 100 MVA 230/13.8 kV units.

Keeping the existing supply configuration at 115 kV of T3/T4 transformers at Beach TS is not possible as it does not meet safety clearance requirements. In light of this and the fact that moving the transformer supply configuration from 115 kV to 230 kV bus is similar in cost plus has other long-term advantages, such as the 230 kV supply option will result in reduced loading levels of 230/115 kV Beach TS autotransformers resulting in freeing up capacity and improve supply reliability.

The preferred plan is for Hydro One to proceed with reconfiguring the 115 kV T3/T4 DESN to a 230 kV configuration by replacing the existing non-standard transformers with standard 100 MVA 230/13.8 kV units is the most suitable option. The project is currently underway, and is expected to be completed in 2019. The cost of this investment is currently estimated at about $17 million.

7.8 Gage TS End of Life T3/T4/T5/T6 Transformers and a Switchgear

7.8.1 Description

Gage TS has three DESNs (T3/T4, T5/T6, and T8/T9) predominantly supplying large industrial customer loads in Hamilton. T3/T4 and T5/T6 DESNs were built in the 1940's with each transformer rated at 63 MVA LTR, while T8/T9 DESN was built in 1960's with each transformer rated at 137 MVA LTR. These transformers are non-standard with unique electrical characteristics with high short circuit requirements of the customer. The transformers T3, T4, T5, and T6, as well as T5/T6 DESN at Gage TS have been identified by Hydro One at their EOL and have been previously deferred to better understand customer load requirements. Transformer T5 has failed multiple times and breakers in the T5/T6 DESN have experienced recurring problems. No issues or refurbishment needs have been identified at T8/T9 DESN at this time.

The load at Gage TS has reduced over the years to approximately 48 MW, and is currently expected to stay at this level over the study period. The existing station capacity (of the three DESNs) is about 240 MW. Although there seems to be over-capacity at Gage TS, unique short-circuit and connection requirements of industrial loads at this station limits the feasibility of some of the alternatives/solutions.

7.8.2 Alternatives, Recommended Plan and Current Status

The following alternatives were considered to address end of life issues at Gage TS:

- Maintain status quo: This alternative was considered and rejected as it does not address the risk of failure due to asset condition, safety issues and would result in increased maintenance expenses and will not meet Hydro One's obligation to provide reliable supply to the customers.
- "Like-for-Like" replacement of the assets: This alternative would continue maintaining six transformers and the associated three switchgears. This option is extremely costly and cannot be justified since the load has significantly reduced at this station.

- Station/load consolidation: Moving loads to neighboring station(s) and retiring Gage TS. This alternative is not feasible due to: a) unique costumer load requirements (i.e., high short circuit currents are required to operate customer's large arc furnaces and large motors without significant impact to power quality), and b) higher costs associated with reconfigurations of LV cables and transfer of customer loads to other stations.
- Reconfiguration of the station and downsize the station from three DESN to two DESN station: In this option, the station will be reconfigured and downsized from the existing six transformers to four transformers.

The preferred plan is for Hydro One to proceed with the reconfiguration of the station and reduce it from 3 DESNs to 2 DESNs. Under this plan, T3/T4 and T5/T6 DESNs will be replaced by a single T10/T11 DESN with two 100 MVA standard units and switchgear currently supplied by T5/T6 transformers will also be replaced. This option will also provide future flexibility to eliminate T8/T9 DESN when it approached EOL.

The refurbishment of Gage TS is currently expected to be completed in 2019 at an estimated cost of $37 million.

7.9 115 kV Circuit B7/B8 End of Life Section (Burlington TS to Nelson Junction)

7.9.1 Description

The 115 kV double circuit line B7/B8 line supplies about 130 MW of Burlington and Oakville area loads through Bronte TS. The line section from Burlington TS to Nelson junction (about 2.3 km) was built in 1920's. Hydro One has identified that the conductor on this line section from Burlington TS to Nelson junction has reached end of useful life.

7.9.2 Alternatives and Recommended Plan

The following alternatives are considered to address 115 kV B7/B8 end of life line section from Burlington TS to Nelson junction:

- Maintain status quo: This alternative was considered and rejected as it does not address the EOL issue, risk of failures resulting in poor supply reliability and would result in increased maintenance expenses.
- Refurbishment of EOL line section: Refurbish 2.3 km of EOL line conductor section of B7/B8 line section.

The preferred plan is to proceed with the refurbishment of the 115 kV B7/ B8 line section from Burlington TS to Nelson junction supplying Bronte TS using similar ACSR conductor. The refurbishment work is planned to be completed by the year 2020 and estimated to cost approximately $2 million.

7.10 115 kV B3/B4 End of Life Line Section (Horning Mountain Jct. to Glanford Jct.)

7.10.1 Description

The 115 kV B3/B4 line supplies Hamilton area loads through Dundas TS (T1/T2 DESN), a CTS and Mohawk TS. Mohawk TS is supplied from B3/B4 line through about 16 km long line-tap supplying about 84 MW of load. A section of this line tap has a solid copper conductor from Horning Mountain Jct. to Glanford Jct. which is approximately 100 year old and has reached end of useful life.

7.10.2 Alternatives and Recommended Plan

The following alternatives are considered to address the above need:

- Continue to maintain the assets (status quo): This alternative was considered and rejected as it does not address the frequent failure, increased maintenance expenses and poor supply reliability.
- Refurbishment of EOL line section: Replace EOL copper conductor with 605 kcmil ACSR conductor Mohawk TS line tap section.

The preferred plan is for Hydro One to replace this EOL copper conductor with 605 kcmil ACSR from Horning Mountain Jct. to Glanford Jct. supplying Mohawk TS. This work is currently planned to be completed by 2018 at an estimated cost of $8 million.

7.11 Horning TS End of Life Assets

7.11.1 Description

Horning TS is a 230/13.8 kV DESN station built in 1967 and supplies Alectra Utilities loads in the Hamilton area. It has two station supply transformers of 100 MVA each supplying load through its two metalclad switchgears. Recent equipment failures in 2016 due to aging low voltage switchgear have adversely impacted supply to customers in the Hamilton area along with safe operations.

In addition, both the transformers and both low voltage switchgears at Horning TS are approaching end of expected useful life and have been identified by Hydro One for replacement. The load at Horning TS is currently about 70 MW and is forecasted to stay at the same level during the study period.

7.11.2 Alternatives and Recommended Plan

The following alternatives are considered to address Horning TS end of life issue:

- Continue to maintain the assets (status quo): This alternative was considered and rejected as it does not address the risk of failure due to asset condition and would result in increased maintenance expenses and reduce supply reliability to the customers.

- “Like-for-Like” replacement of the assets: This alternative would continue maintaining current station configuration and only replace existing transformers will similar units and refurbish both metalclad switchgears.

The preferred plan is for Hydro One to proceed with Like-for-Like replacements replacing supply transformers with similar 100 MVA units and refurbishing EOL low voltage metalclad switchgears. The new replaced transformers and refurbished switchgear will provide sufficient capacity to serve the load over the study period. The project is currently underway, and is expected to be completed in 2018. The cost of this investment is estimated to be about $37 million.

7.12 Bronte TS End of Life T5/T6 DESN

7.12.1 Description

Bronte TS was placed in service in 1963 and is radially supplied from Burlington TS via 115 kV B7/ B8 circuits. The total load at Bronte TS is currently about 129 MW and is forecasted to stay at about 135 MW with load transfers as proposed in section 7.1.

There are three transformers, T2 (single transformer configuration), and T5/T6 DESN (83 MVA), at Bronte TS supplying loads in the cities of Oakville and Burlington. Transformer T2 was replaced in 2006 and the T5/T6 DESN transformers at Bronte TS and LV switchgear is approaching end of expected useful life. Hydro One has identified that these transformers require replacement.

7.12.2 Alternatives and Recommended Plan

The following alternatives are considered to address end of life Bronte TS T5/T6 DESN refurbishment:

- Continue to maintain the assets (status quo): This alternative was considered and rejected as it does not address the risk of failure due to asset condition and would result in increased maintenance expenses and reduce supply reliability to the customers.
- “Like-for-Like” replacement of the assets: Replacing existing EOL 115/ 27.6 kV T5/T6 DESN transformers with similar size standard units and refurbish switchgear.

The preferred plan is for Hydro One to proceed with Like-for-Like replacement. This will include replacing existing 83 MVA T5/T6 transformers with similar units and refurbishing associated switchgear. This investment is estimated to be approximately $34 million with planned in-service of 2019.

7.13 Elgin TS End of Life Assets

7.13.1 Description

Elgin TS has two DESNs (T1/T2 and T3/T4) built in 1960’s supplying loads in the city of Hamilton through three switchgears. The current load at Elgin TS is approximately 85 MW, and is currently expected to stay at this level over the study period.

The T1/T2 transformers are 75 MVA units while the T3/T4 units are non-standard 33 MVA units. All existing four transformers (T1, T2, T3, and T4) and three switchgears at Elgin TS have been identified by Hydro One as approaching end of their useful life. This need was identified in the Needs Assessment phase.

7.13.2 Alternatives, Recommended Plan and Current Status

The following alternatives were considered to address end of life issues at Elgin TS:

- Maintain status quo: This alternative was considered and rejected as it does not address the risk of failure due to asset condition, safety issues and would result in increased maintenance expenses and will not meet Hydro One's obligation to provide reliable supply to the customers.
- "Like-for-Like" replacement of the assets: This alternative would continue maintaining four transformers and the associated three switchgears. This option is extremely costly and cannot be justified with load forecast not showing any growth at this station.
- Reconfiguration and downsize the station from two DESNs to one DESN station: In this option, the station will be reconfigured and downsized from the existing four transformers to two transformers.

The preferred plan is for Hydro One to proceed with the reconfiguration of the station and reduce it to two transformers and two switchgears only. Under this plan, T1/T2 and T3/T4 DESNs will be replaced by a single T5/T6 DESN with two 100 MVA standard units and four new switchgears. This will maintain adequate supply capacity to the loads through the four new switchgears. The cost of this investment is expected to be $58 million with a planned in service of 2019.

7.14 Mohawk TS Station Supply Capacity & End of Life T1/T2 Transformers

7.14.1 Description

Mohawk TS is a 115/13.8 kV step down transformer station supplied from 115 kV circuit B3/B4 from Burlington TS supplying loads in the city of Hamilton. The station supply capacity is limited to 80 MW by the LTR of transformers. The 2015 summer peak load was 84 MW and the station is marginally over its supply limits during peak load periods. In addition, transformers at Mohawk TS are over 50 years old and condition assessment has identified Mohawk TS transformers approaching end of their useful life.

7.14.2 Alternatives and Recommended Plan

The following alternatives were considered to address Mohawk TS end of life transformer issue:

- Maintain status quo: This alternative was considered and rejected as it does not address the risk of failure due to asset condition, poor supply reliability and would result in increased maintenance expenses. In addition option will not address the capacity needs at the station,
- Transformer replacement: Replacing the existing non-standard (67 MVA) end of life transformers with new standard (75 MVA) units.

The preferred plan is for Hydro One to proceed with the replacement of existing nonstandard supply transformers at Mohawk TS with the standard 75 MVA units. This will address the issue of: a) EOL transformers, b) replace non-standard equipment with standard units, and c) will provide sufficient station supply capacity. In the interim, Alectra Utilities will manage the overloads (under contingency) by distribution loads transfers. The transformer replacement project is currently expected to be in service by 2019 at an estimated cost of $14 million.

7.15 Birmingham TS End of Life Switchgear

7.15.1 Description

Birmingham TS is located in the city of Hamilton having two DESN units T1/T2 and T3/T4 of 75 MVA each. Both the DESNs at Birmingham TS can supply a total load of about 185 MVA (LTR). The Birmingham TS currently supplies a large industrial customer with unique connection requirements. The load at Birmingham TS is forecasted at about 75 MW.

At this time transformers and/or other HV equipment at this station has not been identified as EOL over the study period. However, two 13.8 kV LV metalclad switchgears are at EOL and have been identified by Hydro One for refurbishment.

7.15.2 Recommended Plan

The two end of life 13.8 kV LV end of life metalclad switchgears at Birmingham TS are required to be replaced to meet the unique connection needs of the customer at this station. Not replacing the end of life switchgears will increase the risk of failure due to asset condition and adversely impact supply to a large industrial customer. Currently Hydro One plans to complete this by 2021. This need will be further reviewed in the next regional planning cycle.

7.16 Dundas TS End of Life Switchgear

7.16.1 Description

Dundas TS has two DESN units T1/T2 and T5/T6 with a total 2015 summer peak load of 148 MW and station capacity of 188 MW. The station capacity is forecasted to be sufficient over and beyond the study period. The T1/T2 transformers at Dundas TS have recently been replaced in 2015. The Dundas TS T1/T2 27.6 kV MV switchgear has been identified by Hydro One at end of life requiring refurbishment.

7.16.2 Alternatives and Recommended Plan

Hydro One has identified MV 27.6 kV T1/T2 switchgear at Dundas TS at end of life requiring refurbishment. Keeping status quo not refurbishing this switchgear will increase the risk of failure due to asset condition reducing supply reliability to the customers and would result in increased maintenance expenses.

The refurbishment switchgear is currently planned by Hydro One to be completed by 2021. This need is recommended to be further reviewed in the next regional planning cycle.

7.17 Newton TS End of Life Transformers and Switchgear

7.17.1 Description

Newton TS is a 115 kV/ 13.8 kV DESN station having transformers built in 1956 and supplies Alectra Utilities loads in the city of Hamilton. It has two station supply transformer of 67 MVA each supplying loads through its 13.8 kV switchyards. The customer load at the station is about 50 MW and is forecasted to stay at the same level in the foreseeable future. Hydro One in initial assessment has identified that both transformers and switchgear requiring refurbishment. The scope of refurbishment is subject to final asset condition assessment of Newton TS to be completed in 2017.

7.17.2 Alternatives and Recommended Plan

The following alternatives are considered to address Newton TS end of life asset issue:

- Maintain status quo: This alternative was considered and rejected as it does not address the risk of failure due to asset condition and would result in increased maintenance cost.
- Replacement of the assets: Replace existing EOL non-standard transformers with similarly sized units and refurbish switchgear to current standards.

The current plan is to refurbish Newton TS with new equipment built to current standards including two 75 MVA units replacing existing 67 MVA transformers and LV switchgear. This is the preferred alternative since it addresses the needs at Newton TS and maintaining station’s operability and reliability of supply. This refurbishment work at Newton TS is planned by Hydro One to be completed by 2021. This need is recommended to be further reviewed in the next regional planning cycle.

7.18 Mid-Term End of Life LV Switchyard Refurbishment

7.18.1 Description

Hydro One has identified the LV switchyards reaching end-of-life by 2022 and need to be refurbished at the following stations:

1. Brantford TS
2. Lake TS
3. Stirton TS

7.18.2 Recommended Plan

The Working Group is recommending that these needs to be further reviewed in the next regional planning cycle.

7.19 Beach TS End of Life T7/T8 Autotransformers and T5/T6 DESN LV Switchgear

7.19.1 Description

Beach TS is a major switching and transformer station in East Hamilton. Station facilities include a 230 kV switchyard, three 230/115 kV autotransformers (T1/T7/T8), a 115 kV switchyard, a 230/13.8 kV DESN T5/T6 and a 115/13.8 kV DESN T3/T4.

Hydro One has determined that autotransformers T7 and T8 and the T5/T6 DESN LV Metalclad switchgear are expected to reach end of life by 2025 and will need to be replaced.

7.19.2 Recommended Plan

The Working Group is recommending that this need be further reviewed in the next regional planning cycle.

7.20 End of Life Cables in Hamilton Area: HL3/HL4, K1G/K2G, H5K/H6K

Underground cables in Hamilton area (listed below) are expected to be approaching end-of-life over the next 10 years or so.

- 115 kV H5K/H6K Cable (Beach TS to Kenilworth TS)
- 115 kV K1G/K2G Cable (Kenilworth TS to Gage TS)
- 115 kV HL3/HL4 Cable (Newton TS to Elgin TS)
- 115 kV HL3/HL4 Cable (Elgin TS to Stirton TS)

In light that replacement of the high voltage underground cables can be complicated, affect upstream transmission system and expensive requires alternative/s to be developed and assessed ahead of time. The WG has recommended further review of the cable replacement needs and development of a tentative plan in the next regional planning cycle.

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8. CONCLUSION AND NEXT STEPS

THIS REGIONAL INFRASTRUCTURE PLAN (RIP) REPORT CONCLUDES THE REGIONAL PLANNING PROCESS FOR THE BURLINGTON TO NANTICOKE REGION.

A list and summary of all the needs and/or plans in the near-term (2016-2020) and mid to long term (beyond 2020) is provided below in Table 8-1 and Table 8-2, respectively, along with their in-service date and estimated cost, where applicable. Where available, preliminary plans to address the mid- to long-term needs were also provided.

Table 8-1 Near-Term Needs/Plans in Burlington to Nanticoke Region

No.	Needs	Plans	Status	I/S Date	Cost ($M)
Projects Developed in Local Planning or an IRRP					
1	115 kV B7/B8 Transmission Line Capacity	Bronte TS: Load Transfer	Planning	2018	1-3
2	115 kV B12/B13 Transmission Line Capacity	Install Brant Switching Station	Planning	2019	12
3	Two New Feeders at Dundas TS	Dundas TS: Load Transfer	Planning	2019	8
4	Cumberland TS – Power Factor Correction	LDC is developing distribution option	Planning	TBD	-
5	Kenilworth TS – Power Factor Correction	LDC is developing distribution option	Planning	TBD	-
Projects Developed by HONI & the LDC(s), Reviewed by IESO					
6	Kenilworth TS EOL transformers & switchgear (1)	Reconfigure from 2 DESNs to single DESN	Planning	2018	19
7	Beach TS – EOL T3/T4 DESN Transformers (1)	Replace Beach TS T3/T4 DESN Transformers	Committed	2019	17
8	Gage TS – EOL transformers & switchgear	Gage TS: Reduce from 3 DESNs to 2 DESNs	Planning	2019	37
9	115 kV B7/B8 – EOL Line Section from Burlington TS to Nelson Jct. (1)	Refurbish the EOL B7/B8 line section	Planning	2020	2
Projects Developed by HONI & the LDC(s)					
10	115 kV B3/B4 – EOL Line Section from Horning Mountain Jct. to Glanford Jct. (1)	Refurbish the EOL B3/B4 line section conductor	Planning	2018	8
11	Horning TS EOL transformers & switchgears (1)	Replace EOL transformers & refurbish switchgears	Committed	2018	37

No.	Needs	Plans	Status	I/S Date	Cost ($M)
12	Bronte TS – EOL T5/T6 DESN [1]	Replace EOL transformers & refurbish switchgear	Committed	2019	34
13	Elgin TS – EOL transformers & switchgears	Replace transformers and reduce 2 DESNs to 1 DESN	Committed	2019	58
14	Mohawk TS (T1/T2) – Station Capacity and EOL T1/T2 Transformers	Mohawk TS Transformers Replacement	Committed	2019	14

(1) New needs identified by HONI

Table 8-2 Mid- and Long-Term Needs/Plans in Burlington to Nanticoke Region

No.	Needs/Plans	Planned I/S Date	Cost ($M)
1	Birmingham TS: 2 Metal Clad Switchgear Refurbishment [1]	2021	14
2	Dundas TS: T1/T2 switchyard refurbishment	2021	10
3	Newton TS: Station Refurbishment	2021	36
4	LV Switchgear Refurbishment at Brantford TS, Lake TS and Stirton TS	2022	46
5	Beach TS: Replace EOL T7/T8 Autotransformers and refurbish T5/T6 DESN switchgear	2025	60
6	EOL 115 kV Cables: - H5K/ H6K - K1G/ K2G - HL3/ HL4	TBD [2]	TBD [2]

(1) Preliminarily reviewed by HONI, LDC and the IESO
(2) To Be Decided

It is the recommendation of RIP Working Group:

a) Hydro One will continue to implement the committed and near-term projects for addressing the above needs as discussed in this report, while keeping the Working Group apprised of project status, and

b) The RIP recommends that an expedited Needs Assessment report should be developed to list these already identified needs in the mid and long term or any new needs to be followed by Scoping Assessment, led by the IESO for further assessment under the Burlington to Nanticoke regional planning Working Group.

9. REFERENCES

[1]. Independent Electricity System Operator, “Brant Area Integrated Regional Resource Plan”, 28 April 2015.
http://www.ieso.ca/Documents/Regional-Planning/Burlington_to_Nanticoke/2015-Brant-IRRP-Report.pdf

[2]. Bronte Sub region Integrated Regional Resource Planning (IRRP) Report
http://www.ieso.ca/Pages/Ontario%27s-Power-System/Regional-Planning/Burlington-to-Nanticoke/Bronte.aspx

[3]. Hydro One, “Needs Screening Report, Burlington to Nanticoke Region”, 23 May 2014.
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[4]. Hydro One, “Local Planning Report – Burlington to Nanticoke Region”, 28 October 2015.
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[5]. Hydro One, “OPA Letter – Brant Area Regional Planning”, 06 February 2014.
http://www.hydroone.com/RegionalPlanning/Burlington/Documents/OPA%20Letter%20-%20Burlington%20Nanticoke%20-%20Brant.pdf

[6]. Independent Electricity System Operator, “Review of Ontario Interties”, 14 October 2014.
http://www.ieso.ca/Documents/IntertieReport-20141014.pdf

APPENDIX A: TRANSMISSION LINES IN THE BURLINGTON TO NANTICOKE REGION

No.	Location	Circuit Designations	Voltage (kV)
1	Beach TS - CTS	H35D, H36D	230
2	Beach TS - Burlington TS	B18H, B20H	230
3	Beach TS - Middleport TS	M34H	230
4	Beach TS - Middleport TS - Beck #2 TS	Q24HM, Q29HM	230
5	Burlington TS - Cumberland TS	B40C, B41C	230
6	Burlington TS - Middleport TS	M27B, M28B	230
7	Burlington TS - Middleport TS - Beck #2 TS	Q23BM, Q25BM	230
8	Middleport TS - Beck #2 TS	Q30M	230
9	Middleport TS - Buchanan TS	M31W, M32W, M33W	230
10	Middleport TS - Detweiler TS	M20D, M21D	230
11	Middleport TS - Nanticoke TS	N5M, N6M	230
12	Middleport TS - Summerhaven SS	S39M	230
13	Middleport TS - Sandusk SS	K40M	230
14	Nanticoke TS - Jarvis TS	N21J, N22J	230
15	Summerhaven SS - Nanticoke TS	N37S	230
16	Sandusk SS - Nanticoke TS	N20K	230
17	Beach TS - Gage TS	B10, B11	115
18	Beach TS - Kenilworth TS	H5K, H6K	115
19	Beach TS - Newton TS	HL3, HL4	115
20	Beach TS - Winona TS	Q2AH	115
21	Beach TS - CSS	H9W	115
22	Burlington TS - Brant TS	B12, B13	115
23	Burlington TS - Bronte TS	B7, B8	115
24	Burlington TS - Cedar TS	B5G, B6G	115
25	Burlington TS - Newton TS	B3, B4	115
26	Caledonia TS - Norfolk TS	C9, C12	115
27	Kenilworth TS - Gage TS (Idle)	K1G, K2G	115

APPENDIX B: STATIONS IN THE BURLINGTON TO NANTICOKE REGION

No.	Station	Voltage (kV)	Supply Circuits
1	CTS	230	H35D, H36D
2	Beach TS	230	Beach TS 230 kV Bus (1)
3	Beach TS	115	Beach TS 115 kV Bus (2)
4	Birmingham TS	115	HL3, HL4
5	Bloomsburg DS	115	C9, C12
6	Brant TS	115	B12, B13
7	Brantford TS	230	M32W, M33W
8	Bronte TS	115	B7, B8
9	Burlington TS DESN	230	Q23BM, Q25BM
10	Caledonia TS	230	N5M, S39M
11	Cumberland TS	230	B40C, B41C
12	CTS	230	Q24HM, Q29HM
13	Dundas TS	115	B3, B4
14	Dundas TS #2	115	B12, B13
15	Elgin TS	115	HL3, HL4
16	Gage TS	115	B10, B11
17	Horning TS	230	M27B, M28B
18	CTS	230	N20K
19	Jarvis TS	230	N21J, N22J
20	Kenilworth TS	115	H5K, H6K
21	Lake TS	230	B18H, B20H
22	CTS	115	B3, B4
23	Mohawk TS	115	B3, B4
24	Nebo TS	230	Q24HM, Q29HM
25	Newton TS	115	Newton TS 115 kV Bus (3)
26	Norfolk TS	115	C9, C12
27	Powerline MTS	115	B12, B13
28	CTS	115	HL3, HL4
29	Stirton TS	115	HL3, HL4
30	CTS	230	N21J, N22J
31	Winona TS	115	Q2AH

(1) Beach TS 230 kV bus is supplied by five 230 kV B18H, B20H, Q24HM, Q29HM and M34H circuits

(2) Beach TS 115 kV bus is supplied by three 230 kV/ 115 kV autotransformers at Beach TS

(3) Newton TS 115 kV bus is supplied by four 115 kV B3, B4, B12 and B13 circuits

APPENDIX C: DISTRIBUTORS IN THE BURLINGTON TO NANTICOKE REGION

Distributor Name	Station Name	Connection Type
Energy + Inc.	Brant TS	Dx, Tx
	Brantford TS	Dx
Brantford Power Inc.	Brant TS	Tx
	Brantford TS	Tx
Brantford Power Inc. and Energy + Inc.	Powerline MTS	Tx
Burlington Hydro Inc.	Bronte TS	Tx
	Burlington TS	Tx
	Cumberland TS	Tx
Haldimand County Hydro Inc.	Caledonia TS	Dx, Tx
	Jarvis TS	Dx, Tx
Alectra Utilities Corporation	Beach TS	Tx
	Birmingham TS	Tx
	Dundas TS	Dx, Tx
	Dundas TS #2	Tx
	Elgin TS	Tx
	Gage TS	Tx
	Horning TS	Tx
	Kenilworth TS	Tx
	Lake TS	Dx, Tx
	Mohawk TS	Tx
	Nebo TS	Dx, Tx
	Newton TS	Tx
	Stirton TS	Tx
	Winona TS	Tx
Hydro One Networks Inc.	Brant TS	Tx
	Caledonia TS	Tx
	Dundas TS	Tx
	Dundas TS #2	Tx
	Jarvis TS	Tx
	Lake TS	Tx
	Nebo TS	Tx
	Norfolk TS	Dx, Tx
	Bloomsburg DS	Dx, Tx
Oakville Hydro Electricity Distribution Inc.	Bronte TS	Tx

APPENDIX D: AREA STATIONS NON COINCIDENT NET LOAD FORECAST (MW)

Sub-Region	Station	LTR	2015	2016	2017	2018	2019	2020	2021	2023	2025	2027	2029	2031	2033	2035
Brant 115 kV	Brant TS	101	59	61	63	67	68	69	70	72	74	76	79	81	84	86
	Powerline MTS	114	69	67	70	71	72	73	75	77	80	83	86	89	92	95
	Total	215	128	128	134	138	140	143	145	149	154	159	165	170	175	181
Brant 230 kV	Brantford TS	188	135	134	153	156	156	156	156	157	157	158	159	160	163	165
	Total	188	135	134	153	156	156	156	156	157	157	158	159	160	163	165
Bronte 115 kV	Bronte TS (T2)	75	59	60	62	63	64	65	66	67	68	68	68	68	69	70
	Bronte TS (T5/T6)	96	70	71	72	74	75	76	77	79	80	80	80	80	81	82
	Total	171	129	131	134	138	139	141	143	146	148	148	148	148	150	152
Bronte 230 kV	Burlington (DESN) TS	185	151	153	154	154	155	156	157	159	160	163	165	168	170	171
	Cumberland TS	174	123	122	122	122	123	124	124	126	127	129	131	133	135	136
	Total	359	273	275	276	277	278	279	281	284	288	291	296	301	304	307
Greater Hamilton 115 kV	Beach TS (T3/T4)	75	32	32	32	31	31	31	31	31	30	30	30	30	30	30
	Birmingham TS (T1/T2)	76	32	31	31	31	31	30	30	30	30	30	30	29	30	30
	Birmingham TS (T3/T4)	91	46	46	46	45	45	45	44	44	44	44	43	43	43	43
	Dundas TS	99	85	91	93	93	93	84	84	84	84	85	85	85	86	87
	Dundas TS #2	89	63	65	68	70	72	72	71	71	71	70	70	69	70	70
	Elgin TS (T1/T2)	80	63	62	62	62	61	59	58	58	58	57	57	57	57	57
	Elgin TS (T3/T4)	42	22	22	22	21	21	21	21	21	21	21	21	20	21	21
	Gage TS (T3/T4)	60	22	22	22	21	21	21	21	21	21	21	21	20	21	21
	Gage TS (T5/T6)	57	11	11	11	11	11	11	11	10	10	10	10	10	10	10
	Gage TS (T8/T9)	123	15	15	15	15	15	15	15	15	14	14	14	14	14	14
	Kenilworth TS (T1/T4)	36	29	28	28	28	28	28	28	27	27	27	27	27	27	27
	Kenilworth TS (T2/T3)	64	31	31	31	31	30	30	30	30	30	30	29	29	29	29
	Mohawk TS	80	84	83	83	83	83	82	82	82	81	81	80	79	80	80
	Newton TS	78	47	47	48	47	47	47	47	46	46	46	45	45	45	46
	Stirton TS	112	50	50	50	49	49	49	49	48	48	48	47	47	47	48
	Winona TS	89	46	48	51	51	50	50	50	49	49	49	49	48	48	49
	Total CTS		59	59	60	60	61	61	61	61	61	61	61	61	61	61
	Total		736	745	752	750	749	735	732	729	726	723	719	715	719	723
Greater Hamilton 230 kV	Beach TS (T5/T6)	91	41	44	43	43	47	47	47	46	46	46	46	45	45	46
	Horning TS	102	71	73	76	76	76	75	75	75	74	74	73	73	73	73
	Lake TS (T1/T2)	94	57	57	56	56	55	55	55	54	54	54	53	53	53	54
	Lake TS (T3/T4)	113	55	54	54	55	55	54	54	54	54	53	53	53	53	53
	Nebo TS (T1/T2)	178	119	113	116	119	123	123	124	127	129	131	133	136	140	144
	Nebo TS (T3/T4)	51	50	49	50	51	51	50	50	50	50	49	49	49	49	49
	Total CTS		265	265	265	265	244	244	244	244	244	244	244	244	244	244
	Total		658	655	661	665	651	650	650	650	651	652	652	652	658	663
Caledonia Norfolk 115 kV	Norfolk TS	97	59	56	55	55	54	54	54	53	53	53	52	52	52	52
	Bloomsburg DS	56	42	30	29	27	27	27	27	27	27	27	27	27	27	27
	Total	153	101	87	85	82	82	81	81	80	80	80	79	78	79	80
Caledonia Norfolk 230 kV	Caledonia TS	99	45	41	42	42	42	42	43	44	45	45	46	47	48	50
	Jarvis TS	99	66	62	61	61	61	61	61	62	62	63	63	63	64	66
	Total CTS		123	123	123	123	123	123	123	123	123	123	123	123	123	123
	Total		233	226	226	226	226	226	227	228	230	231	232	233	235	238
Regional Total			2394	2379	2419	2432	2421	2411	2415	2425	2434	2442	2450	2458	2483	2509

APPENDIX E: LIST OF ACRONYMS

Acronym	Description
A	Ampere
BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
CIA	Customer Impact Assessment
CGS	Customer Generating Station
CSS	Customer Switching Station
CTS	Customer Transformer Station
DCF	Discounted Cash Flow
DESN	Dual Element Spot Network
DG	Distributed Generation
DSC	Distribution System Code
GATR	Guelph Area Transmission Reinforcement
GS	Generating Station
GTA	Greater Toronto Area
HV	High Voltage
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
LDC	Local Distribution Company
LP	Local Plan
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low Voltage
MTS	Municipal Transformer Station
MW	Megawatt
MVA	Mega Volt-Ampere
MVAR	Mega Volt-Ampere Reactive
NA	Needs Assessment
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.
NUG	Non-Utility Generator
OEB	Ontario Energy Board
OPA	Ontario Power Authority
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Plan
ROW	Right-of-Way
SA	Scoping Assessment
SIA	System Impact Assessment
SPS	Special Protection Scheme
SS	Switching Station
TS	Transformer Station
TSC	Transmission System Code
UFLS	Under Frequency Load Shedding
ULTC	Under Load Tap Changer
UVLS	Under Voltage Load Rejection Scheme

Hydro One Networks Inc.
483 Bay Street
13th Floor, North Tower
Toronto, ON M5G 2P5
www.HydroOne.com

Tel: (416) 345.5420
Ajay.Garg@HydroOne.com

Niagara

Regional Infrastructure Plan ("RIP")

March 28th 2017

Canadian Niagara Power Inc.
Grimsby Power Inc.
Alectra Utilities
Hydro One Networks Inc. (Distribution)
Niagara Peninsula Energy Inc.
Niagara-On-the-Lake Hydro Inc.
Welland Hydro-Electric System Corporation

The Niagara Region includes the municipalities of City of Port Colborne, City of Welland, City of Thorold, City of Niagara Falls, Town of Niagara-On-The-Lake, City of St. Catharines, Town of Fort Erie, Town of Lincoln, Township of West Lincoln, Town of Grimsby, Township of Wainfleet, and Town of Pelham.

The Needs Assessment ("NA") report for the Niagara Region was completed on April 30th, 2016 (see attached). The report concluded that there were only two needs in the Region and that they should be addressed as follows:

- Thermal overloading of 115kV circuit Q4N: Addressed in a Local Plan ("LP") report.

The loading constraints on 115kV circuit Q4N was addressed in a LP report led by Hydro One Networks Inc. and published on November 11th, 2016. The report concluded that Hydro One already has plans to replace the existing section of conductor between Sir Adam Beck SS #1 and Portal JCT with a 910A continuous rating conductor at 93°C as part of their Beck #1 SS Refurbishment project. The expected in-service date for this conduction section upgrade is December 2019.

Consistent with a process established by an industry working group[1] created by the OEB the Regional Infrastructure Plan ("RIP") is the last phase of the planning process. In view that no further regional coordination was required, the attached NA and LP reports will be deemed to form the RIP for the Niagara Region.

The next planning cycle for the region will take place within five years of the start of this cycle (2021) or earlier, should there be a new need identified in the region.

Sincerely,

Ajay Garg | Manager, Regional Planning Co-ordination
Hydro One Networks Inc.

[1] Planning Process Working Group (PPWG) Report to the
Ontario Energy Board available at the OEB website www.ontarioenergyboard.ca

Hydro One Networks Inc.
483 Bay Street
Toronto, Ontario
M5G 2P5

Needs Assessment Report

Region: Niagara

Date: April 30th 2016

Prepared by: Niagara Region Study Team

Niagara Study Team
Hydro One Networks Inc. (Lead Transmitter)
Independent Electricity System Operator
Hydro One Networks Inc. (Distribution)
Canadian Niagara Power Inc.
Grimsby Power Inc.
Haldimand County Hydro Inc.
Horizon Utilities Corp.
Niagara Peninsula Energy Inc.
Niagara on the Lake Hydro Inc.
Welland Hydro Electric System Corp.

DISCLAIMER

This Needs Assessment Report was prepared for the purpose of identifying potential needs in the Niagara region and to assess whether those needs require further coordinated regional planning. The potential needs that have been identified through this Needs Assessment Report may be studied further through subsequent regional planning processes and may be reevaluated based on the findings of further analysis. The load forecast and results reported in this Needs Assessment Report are based on the information and assumptions provided by study team participants.

Study team participants, their respective affiliated organizations, and Hydro One Networks Inc. (collectively, "the Authors") make no representations or warranties (express, implied, statutory or otherwise) as to the Needs Assessment Report or its contents, including, without limitation, the accuracy or completeness of the information therein and shall not, under any circumstances whatsoever, be liable to each other, or to any third party for whom the Needs Assessment Report was prepared ("the Intended Third Parties"), or to any other third party reading or receiving the Needs Assessment Report ("the Other Third Parties"), for any direct, indirect or consequential loss or damages or for any punitive, incidental or special damages or any loss of profit, loss of contract, loss of opportunity or loss of goodwill resulting from or in any way related to the reliance on, acceptance or use of the Needs Assessment Report or its contents by any person or entity, including, but not limited to, the aforementioned persons and entities.

NEEDS ASSESSMENT EXECUTIVE SUMMARY

Region	Niagara (the "Region")		
Lead	Hydro One Networks Inc. ("Hydro One")		
Start Date	October 15, 2015	End Date	April 30th 2016

1. INTRODUCTION

The purpose of this Needs Assessment (NA) report is to undertake an assessment of the Niagara Region and determine if there are regional needs that require coordinated regional planning. Where regional coordination is not required, and a "localized" wires solution is necessary, such needs will be addressed between relevant Local Distribution Companies (LDCs) and Hydro One and other parties as required.

For needs that require further regional planning and coordination, IESO will initiate the Scoping Assessment (SA) process to determine whether an IESO-led Integrated Regional Resource Planning (IRRP) process, or the transmitter-led Regional Infrastructure Plan (RIP) process (wires solution), or whether both are required.

2. REGIONAL ISSUE / TRIGGER

The NA for the Niagara Region was triggered in response to the Ontario Energy Board's (OEB) Regional Infrastructure Planning process approved in August 2013. To prioritize and manage the regional planning process, Ontario's 21 regions were assigned to one of three groups. The NA for Group 1 and 2 regions is complete and has been initiated for Group 3 Regions. The Niagara Region belongs to Group 3. The NA for this Region was triggered on October 15, 2015 and was completed on April 30th 2016

3. SCOPE OF NEEDS ASSESSMENT

The scope of the NA study was limited to 10 years as per the recommendations of the Planning Process Working Group (PPWG) Report to the Board. As such, relevant data and information was collected up to the year 2025. Needs emerging over the next 10 years and requiring coordinated regional planning may be further assessed as part of the IESO-led SA, which will determine the appropriate regional planning approach: IRRP, RIP, and/or local planning. This NA included a study of transmission system connection facilities capability, which covers station loading, thermal and voltage analysis as well as a review of system reliability, operational issues such as load restoration, and assets approaching end-of-useful-life.

4. INPUTS/DATA

Study team participants, including representatives from LDCs, the Independent Electricity System Operator (IESO), and Hydro One transmission provided information for the Niagara Region. The information included: historical load, load forecast, conservation and demand management (CDM) and distributed generation (DG) information, load restoration data, and performance information including major equipment approaching end-of-useful life.

5. NEEDS ASSESSMENT METHODOLOGY

The assessment's primary objective was to identify the electrical infrastructure needs and system performance issues in the Region over the study period (2015 to 2024). The assessment reviewed available information, load forecasts and included single contingency analysis to confirm needs, if and when required. See Section 5 for further details.

6. RESULTS

Transmission Needs

A. Transmission Lines & Ratings

The 230kV and 115kV lines are adequate over the study period with a section of 115kV circuit Q4N being the exception.

B. 230 kV and 115 kV Connection Facilities

The 230kV and 115kV connection facilities in this region are adequate over the study period.

System Reliability, Operation and Restoration Review

There are no known issues with system reliability, operation and restoration in the Niagara region.

Aging Infrastructure / Replacement Plan

Within the regional planning time horizon, the following sustainment work is currently planned by Hydro One in the region:

- DeCew Falls SS: Circuit Breaker Replacement (2017)
- Sir Adam Beck SS #1: 115kV Refurbishment Project (2018)
- 115kV Q11/Q12S Line Refurbishment from Glendale TS to Beck SS #1 (2019)
- Carlton TS: Switchgear Replacement (2020)
- Sir Adam Beck SS #2: 230kV Circuit Breakers Replacement (2020)
- Glendale TS: Station Refurbishment and Reconfiguration (2021)
- Stanley TS: Station Refurbishment (2021)
- Thorold TS: Transformer Replacement (2021)
- Crowland TS: Transformer Replacement (2021)

Based on the findings of the Needs Assessment, the study team recommends that thethermal overloading of 115kV circuit Q4N shouldbe further assessed as part of a Local Plan. No further regional coordination or planning is required.

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1 Introduction

This Needs Assessment (NA) report provides a summary of needs that are emerging in the Niagara Region ("Region") over the next ten years. The development of the NA report is in accordance with the regional planning process as set out in the Ontario Energy Board's (OEB) Transmission System Code (TSC) and Distribution System Code (DSC) requirements and the "Planning Process Working Group (PPWG) Report to the Board".

The purpose of this NA is to undertake an assessment of the Niagara Region to identify any near term and/or emerging needs in the area and determine if these needs require a "localized" wires only solution(s) in the near-term and/or a coordinated regional planning assessment. Where a local wires only solution is necessary to address the needs, Hydro One, as transmitter, with Local Distribution Companies (LDC) or other connecting customer(s), will further undertake planning assessments to develop options and recommend a solution(s). For needs that require further regional planning and coordination, the Independent Electricity System Operator (IESO) will initiate the Scoping Assessment (SA) process to determine whether an IESO-led Integrated Regional Resource Planning (IRRP) process, or the transmitter-led Regional Infrastructure Plan (RIP) process (wires solution), or both are required. The SA may also recommend that local planning between the transmitter and affected LDCs be undertaken to address certain local type of needs if straight forward wires solutions can address a need. Ultimately, assessment and findings of the local plans are incorporated in the RIP for the region.

This report was prepared by the Niagara Region NA study team (Table 1) and led by the transmitter, Hydro One Networks Inc. The report captures the results of the assessment based on information provided by LDCs, and the Independent Electricity System Operator (IESO).

Table 1: Study Team Participants for Niagara Region

No.	Company
1	Hydro One Networks Inc. (Lead Transmitter)
2	Independent Electricity System Operator
3	Canadian Niagara Power Inc.
4	Grimsby Power Inc.
5	Haldimand County Hydro Inc
6	Horizon Utilities Corp.
7	Hydro One Networks Inc. (Distribution)
8	Niagara Peninsula Energy Inc.
9	Niagara on the Lake Hydro Inc.
10	Welland Hydro Electric System Corp.

2 Regional Issue / Trigger

The NA for the Niagara Region was triggered in response to the OEB's Regional Infrastructure Planning process approved in August 2013. To prioritize and manage the regional planning process, Ontario's 21 regions were assigned to one of three groups. The NA for Group 1 Regions is complete and has been initiated for Group 2 Regions. The Niagara Region belongs to Group 3.

3 Scope of Needs Assessment

This NA covers the Niagara Region over an assessment period of 2015 to 2024. The scope of the NA includes a review of transmission system connection facility capability which covers transformer station capacity, thermal capacity, and voltage performance. System reliability, operational issues such as load restoration, and asset replacement plans were also briefly reviewed as part of this NA.

3.1 Niagara Region Description and Connection Configuration

For regional planning purposes, the Niagara region includes the City of Port Colborne, City of Welland, City of Thorold, City of Niagara Falls, Town of Niagara-on-the-Lake, City of St. Catharines, Town of Fort Erie, Town of Lincoln, Township of West Lincoln, Town of Grimsby, Township of Wainfleet, and Town of Pelham. Haldimand County has also been included in the regional infrastructure planning needs assessment for Niagara region. A map of the region is shown below in Figure 1.

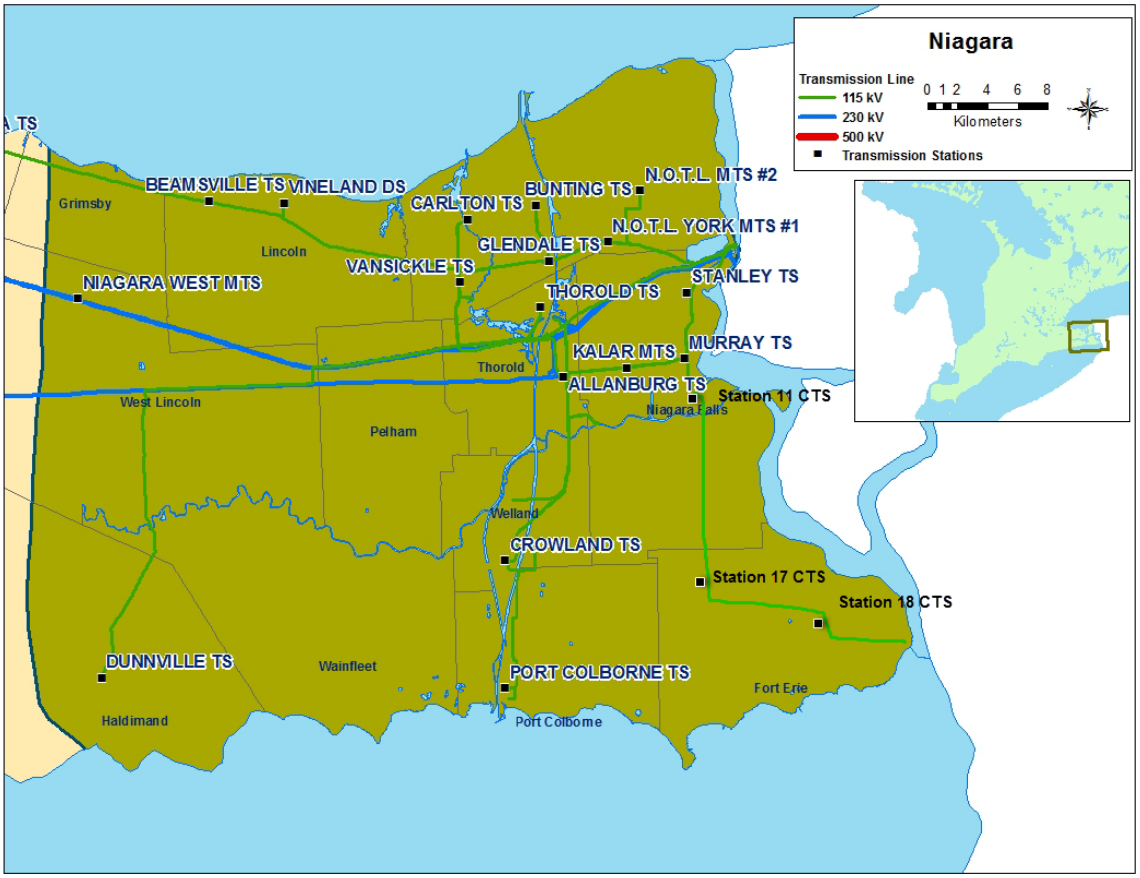

Figure 1: Niagara Region Map

Electrical supply for this region is provided through a network of 230kV and 115kV transmission circuits supplied mainly by the local generation from Sir Adam Beck #1, Sir Adam Beck #2, Decew Falls GS, Thorold GS and the autotransformers at Allanburg TS.

Bulk supply is provided through the 230kV circuits (Q23BM, Q24HM, Q25BM, Q26M, Q28A, Q29HM, Q30M, and Q35M) from Sir Adam Beck #2 SS. These circuits connect this region to Hamilton/Burlington.

The Niagara Region has the following local distribution companies (LDC):

- Canadian Niagara Power Inc.
- Grimsby Power Inc.
- Haldimand County Hydro Inc.
- Horizon Utilities
- Hydro One Distribution Inc.
- Niagara Peninsula Energy Inc.
- Niagara on the Lake Hydro Inc.
- Welland Hydro Electric System Corporation

Large transmission connected customers in the area will not actively participate in the regional planning process, however their load forecasts will used in determining regional supply needs.

Table 2: Transmission Lines and Stations in Niagara Region

115kV circuits	230kV circuits	Hydro One Transformer Stations	Customer Transformer Stations
Q3N, Q4N, Q11S, Q12S, Q2AH, A36N, A37N, D9HS, D10S, D1A, D3A, A6C, A7C,C1P, C2P	Q23BM, Q24HM, Q25BM, Q26M, Q28A, Q29HM, Q30M, Q35M, Q21P, Q22P	Allanburg TS*, Stanley TS, Niagara Murray TS, Thorold TS, Vansickle TS, Carlton TS, Glendale TS, Bunting TS, Dunville TS, Vineland TS, Beamsville TS, Sir Adam Beck SS #1, Sir Adam Beck SS #2, Crowland TS, Port Colborne TS	Niagara on the Lake #1 and #2 MTS, CNPI Station 11 , CNPI Station 17, CNPI Station 18, Kalar MTS, Niagara West MTS

Stations with Autotransformers installed

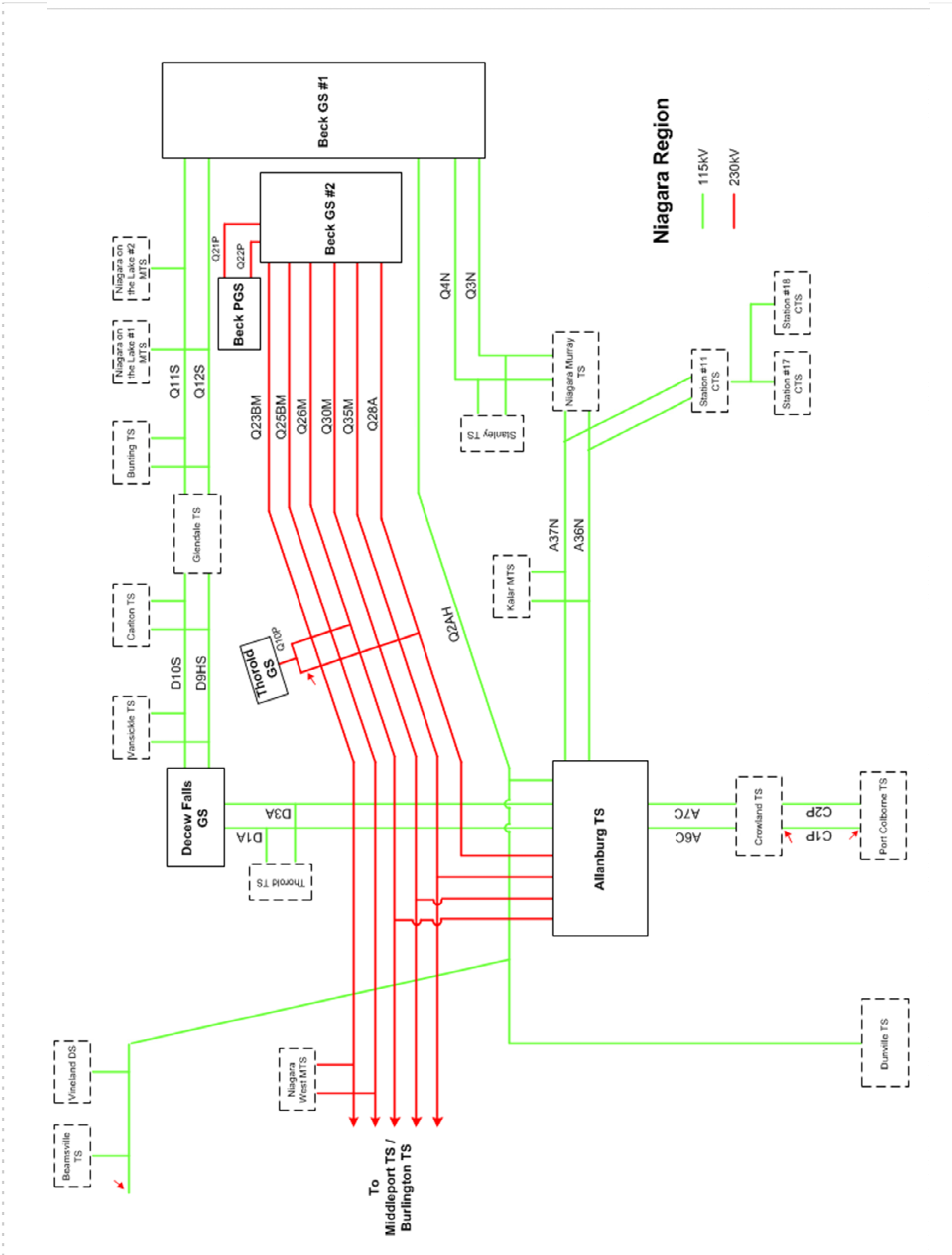

Figure 2: Simplified Niagara Regional Planning Electrical Diagram

4 Inputs and Data

In order to conduct this Needs Assessment, study team participants provided the following information and data to Hydro One:

- Actual 2013 regional coincident peak load and station non-coincident peak load provided by IESO;
- Historical (2012-2014) net load and gross load forecast (2015-2024 provided by LDCs and other Transmission connected customers;
- Conservation and Demand Management (CDM) and Distributed Generation (DG) data provided by IESO;
- Any known reliability and/or operating issues conditions identified by LDCs or the IESO;
- Planned transmission and distribution investments provided by the transmitter and LDCs, etc.

4.1 Load Forecast

As per the data provided by the study team, the gross load in region is expected to grow at an average rate of approximately 0.61% annually from 2015-2024.

The net load forecast takes the gross load forecast and applies the planned CDM targets and DG contributions. With these factors in place, the total regional load is expected to decrease at an average rate of approximately 0.26% annually from 2015-2024.

5 Needs Assessment Methodology

The following methodology and assumptions are made in this Needs Assessment:

1. The Region is summer peaking so this assessment is based on summer peak loads.
2. Forecast loads are provided by the Region's LDCs.
3. Load data for the industrial customers in the region were assumed to be consistent with historical loads.
4. Accounting for (2), (3), above, the gross load forecast and a net load forecast were developed. The gross load forecast is used to develop a worst case scenario to identify needs. Where there are issues, the net load forecast which accounts for CDM and DG are analyzed to determine if the needs can be deferred. A gross and net non-coincident peak load forecast was used to perform the analysis for this report.

5. Review impact of any on-going and/or planned development projects in the Region during the study period.
6. Review and assess impact of any critical/major elements planned/identified to be replaced at the end of their useful life such as autotransformers, cables, and stations.
7. Station capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity assuming a 90% lagging power factor for stations having no low-voltage capacitor banks or the historical low voltage power factor, whichever is more conservative. For stations having low-voltage capacitor banks, a 95% lagging power factor was assumed or the historical low-voltage power factor, whichever is more conservative. Normal planning supply capacity for transformer stations in this Region is determined by the summer 10-Day Limited Time Rating (LTR). Summer LTR ratings were reviewed to assess the worst possible loading scenario from a ratings perspective.
8. Extreme weather scenario factor at 1.037 was also assessed for capacity planning over the study term.
9. To identify emerging needs in the Region and determine whether or not further coordinated regional planning should be undertaken, the study was performed observing all elements in service and only one element out of service.
10. Transmission adequacy assessment is primarily based on, but is not limited to, the following criteria:
    - With all elements in service, the system is to be capable of supplying forecast demand with equipment loading within continuous ratings and voltages within normal range.
    - With one element out of service, the system is to be capable of supplying forecast demand with circuit loading within their summer long-term emergency (LTE) ratings. Thermal limits for transformers are acceptable using summer loading with summer 10-day LTR.
    - All voltages must be within pre and post contingency ranges as per Ontario Resource and Transmission Assessment Criteria (ORTAC) criteria.
    - With one element out of service, no more than 150 MW of load is lost by configuration. With two elements out of service, no more than 600 MW of load is lost by configuration.

- With two elements out of service, the system is capable of meeting the load restoration time limits as per ORTAC criteria.

6 Results

6.1 Transmission Capacity Needs

230/115 kV Autotransformers

The 230/115kV transformers supplying the region are adequate for loss of single unit.

Transmission Lines & Ratings

The 230 kV circuits supplying the Region are adequate over the study period for the loss of a single 230 kV circuit in the Region.

The 115 kV circuits supplying the Region are adequate over the study period with Q4N as an exception between Sir Adam Beck SS #1 x Portal Junction.

230 kV and 115 kV Connection Facilities

A station capacity assessment was performed over the study period for the 230 kV and 115 kV transformer stations in the Region using the station summer peak load forecast provided by the study team. All stations in the area have adequate supply capacity for the study period even in the event of extreme weather scenario.

6.2 System Reliability, Operation and Restoration

6.2.1 Load Restoration

Load restoration is adequate in the area and meet the ORTAC load restoration criteria.

The needs assessment did not identify any additional issues with meeting load restoration as per the ORTAC load restoration criteria.

6.2.2 Thermal Overloading on Q4N Section

Under high generation scenarios at Sir Adam Beck GS #1, the loading on the *Beck SS #1 x Portal Junction* section (egress out from the GS) of 115kV circuit Q4N can exceed circuit ratings. Hydro One already has plans to address this issue as part of the Beck SS #1 Refurbishment Project.

6.2.3 Power Factor at Thorold TS

A few instances (<54 hours / year) of power factor below 0.9 (between 0.89 - 0.9) were observed at the HV side of Thorold TS. Hydro One Distribution will investigate these instances and work with Distribution customers to address.

7 Aging Infrastructure and Replacement Plan of Major Equipment

Hydro One reviewed the sustainment initiatives that are currently planned for the replacement of any autotransformers and power transformers during the study period. At this time, the following sustainment work is planned at the following stations:

- DeCew Falls SS Circuit Breaker Replacement (2017)
- Sir Adam Beck SS #1 115kV Refurbishment Project (2018)
- 115kV Q11/Q12S Line Refurbishment from Glendale TS to Beck SS #1 (2019)
- Carlton TS; Switchgear Replacement (2020)
- Sir Adam Beck SS #2 230kV Circuit Breakers Replacement (2020)
- Glendale TS; Station Refurbishment and Reconfiguration (2021)
- Stanley TS; Station Refurbishment (2021)
- Thorold TS; Transformer Replacement (2021)
- Crowland TS; Transformer Replacement (2021)

8 Recommendations

Based on the findings and discussion in Section 6 and 7 of this report, the study team recommends that no further regional coordination or further planning is required. The region will be reassessed within five years as part of the next planning cycle.

9 Next Steps

No further Regional Planning is required at this time. The Niagara Region Regional Planning will be reassessed during the next planning cycle or at any time should unforeseen conditions or needs warrant to initiate the regional planning for the region.

10 References

i) Planning Process Working Group (PPWG) Report to the Board: The Process for Regional Infrastructure Planning in Ontario – May 17, 2013

ii) IESO 18-Month Outlook: March 2014 – August 2015

iii) IESO Ontario Resource and Transmission Assessment Criteria (ORTAC) – Issue 5.0

Appendix A: Non-Coincident Winter Peak Load Forecast

Transformer Station Name	Customer Data (MW)	Historical Data (MW)			Near Term Forecast (MW)					Medium Term Forecast (MW)				
		2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Allanburg TS	Net Load Forecast	33.4	35.4	29.6										
Hydro One	Gross Peak Load				31.1	31.3	31.4	31.6	32.0	32.4	32.6	32.7	32.9	33.1
NPEI - Embedded	Gross Peak Load - DG - CDM				30.8	30.7	30.6	30.4	30.4	30.5	30.5	30.5	30.5	30.5
Beamsville TS	Net Load Forecast	53.6	55.9	49.0										
Hydro One	Gross Peak Load				54.9	55.6	56.8	58.0	59.2	59.4	59.6	59.8	60.0	60.2
Grimsby Power, NPEI - Embedded	Gross Peak Load - DG - CDM				54.1	54.2	55.0	55.5	56.1	55.8	55.6	55.5	55.4	55.3
Bunting TS	Net Load Forecast	58.3	55.9	49.6										
Horizion Utilities	Gross Peak Load				53.1	53.3	53.4	53.5	53.7	53.8	53.9	54.1	54.2	54.3
	Gross Peak Load - DG - CDM				52.5	52.1	51.8	51.4	51.0	50.7	50.5	50.3	50.2	50.1
Carlton TS	Net Load Forecast	100.1	98.3	76.7										
Horizion Utilities	Gross Peak Load				78.4	79.5	79.7	79.9	80.1	80.3	80.5	80.7	80.9	81.1
	Gross Peak Load - DG - CDM				77.6	77.8	77.5	76.8	76.1	75.7	75.4	71.6	71.4	71.2
Crowland TS	Net Load Forecast	89.1	93.6	74.6										
Welland Hydro	Gross Peak Load				75.2	77.5	78.5	80.0	81.0	82.0	83.0	84.0	85.0	86.0
Hydro One, CNPI - Embedded	Gross Peak Load - DG - CDM				70.4	71.9	72.3	72.9	73.0	73.3	73.8	74.2	74.8	75.3
Dunnville TS	Net Load Forecast	25.3	27.0	24.1										
Haldimand County Hydro	Gross Peak Load				24.1	24.3	24.4	24.5	24.7	24.9	25.0	25.1	25.2	25.4
Hydro One - Embedded	Gross Peak Load - DG - CDM				19.8	19.7	19.6	19.4	19.4	19.3	19.3	19.3	19.3	19.3
Glendale TS	Net Load Forecast	61.5	59.1	60.1										
Horizion Utilities	Gross Peak Load				66.5	62.5	62.6	62.8	62.9	63.1	63.2	63.4	63.5	63.7
	Gross Peak Load - DG - CDM				65.7	61.0	60.7	60.2	59.7	59.3	59.1	58.9	58.8	58.6
Kalar MTS	Net Load Forecast	39.5	38.6	33.9										
NPEI	Gross Peak Load				39.8	40.0	40.2	40.4	40.6	40.8	41.0	41.2	41.4	41.6
	Gross Peak Load - DG - CDM				39.4	39.2	39.1	38.8	38.6	38.5	38.4	38.4	38.4	38.4

Transformer Station Name	Customer Data (MW)	Historical Data (MW)			Near Term Forecast (MW)					Medium Term Forecast (MW)				
		2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Niagara Murray TS	Net Load Forecast	97.0	101.7	90.2										
Hydro One	Gross Peak Load				89.7	90.0	90.4	90.7	91.0	91.4	91.7	92.0	92.4	92.7
NPEI - Embedded	Gross Peak Load - DG - CDM				88.9	88.3	88.0	87.4	86.9	86.5	86.3	86.2	86.1	86.0
Niagara On the Lake #1 MTS	Net Load Forecast	23.8	22.3	22.3										
Niagara On the Lake	Gross Peak Load				24.9	25.3	25.7	26.1	26.5	26.9	27.3	27.7	28.1	28.5
	Gross Peak Load - DG - CDM				24.7	24.8	25.0	25.1	25.2	25.3	25.6	25.8	26.1	26.3
Niagara On the Lake #2 MTS	Net Load Forecast	20.7	22.6	18.3										
Niagara On the Lake	Gross Peak Load				18.9	19.2	19.5	19.8	20.1	20.4	20.7	21.0	21.3	21.7
	Gross Peak Load - DG - CDM				18.8	18.8	19.0	19.0	19.1	19.2	19.4	19.6	19.8	20.0
Niagara West MTS	Net Load Forecast	47.5	43.5	35.7										
Grimsby Power	Gross Peak Load				35.8	35.9	36.1	36.5	36.7	37.0	37.2	37.6	37.8	38.1
NPEI Embedded	Gross Peak Load - DG - CDM				34.4	34.2	34.0	34.0	33.8	31.2	31.2	31.4	31.4	31.5
Stanley TS	Net Load Forecast	59.8	58.9	52.4										
NPEI	Gross Peak Load				52.7	52.9	53.1	53.3	53.5	53.7	53.9	54.1	54.3	54.5
	Gross Peak Load - DG - CDM				52.1	51.7	51.5	51.1	50.8	50.5	50.4	50.3	50.3	50.2
Station 17 TS	Net Load Forecast		16.1	16.6										
CNP	Gross Peak Load				16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6
	Gross Peak Load - DG - CDM				16.4	16.2	16.1	15.9	15.8	15.6	15.5	15.5	15.4	15.3
Station 18 TS	Net Load Forecast		32.3	35.2										
CNP	Gross Peak Load				35.2	37.7	40.2	40.2	40.2	40.2	40.2	40.2	40.2	40.2
	Gross Peak Load - DG - CDM				34.8	36.9	39.1	38.6	38.2	37.9	37.7	37.4	37.3	37.1
Port Colborne TS	Net Load Forecast		40.2	35.7										
CNP	Gross Peak Load				30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8
	Gross Peak Load - DG - CDM				30.3	30.0	29.8	29.4	29.1	28.9	28.7	28.5	28.4	28.2

Transformer Station Name	Customer Data (MW)	Historical Data (MW)			Near Term Forecast (MW)					Medium Term Forecast (MW)				
		2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Thorold TS	Net Load Forecast	20.1	21.3	18.4										
Hydro One	Gross Peak Load				21.3	21.5	21.6	21.7	22.0	22.2	22.4	22.5	22.6	22.7
	Gross Peak Load - DG - CDM				21.1	21.1	20.9	20.8	20.9	20.9	20.9	20.9	20.9	20.9
Vansickle TS	Net Load Forecast	46.3	53.3	43.7										
Horizion Utilities	Gross Peak Load				44.1	44.5	44.6	44.8	44.9	45.0	45.1	45.2	45.3	45.4
	Gross Peak Load - DG - CDM				43.7	43.6	43.4	43.0	42.7	42.4	42.2	42.1	42.0	41.9
Vineland TS	Net Load Forecast	17.4	17.0	17.0										
Hydro One	Gross Peak Load				21.9	22.3	22.4	22.7	23.1	23.5	23.8	24.0	24.3	24.5
NPEI - Embedded	Gross Peak Load - DG - CDM				21.7	21.8	21.8	21.8	22.0	22.2	22.3	22.4	22.5	22.6

Appendix B: Acronyms

BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
CIA	Customer Impact Assessment
CGS	Customer Generating Station
CTS	Customer Transformer Station
DESN	Dual Element Spot Network
DG	Distributed Generation
DSC	Distribution System Code
GS	Generating Station
HVDS	High Voltage Distribution Station
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Planning
kV	Kilovolt
LDC	Local Distribution Company
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low-voltage
MW	Megawatt
MVA	Mega Volt-Ampere
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.
NA	Needs Assessment
OEB	Ontario Energy Board
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Planning
SIA	System Impact Assessment
SS	Switching Station
TS	Transformer Station
TSC	Transmission System Code
ULTC	Under Load Tap Changer

Hydro One Networks Inc.
483 Bay Street
Toronto, Ontario
M5G 2P5

Local Planning Report

Q4N Thermal Overload

Region: Niagara

Revision: Final
Date: November 11th 2016

Prepared by: Niagara Region Study Team

Niagara Region Local Planning Study Team
Hydro One Networks Inc. (Lead Transmitter)
Hydro One Networks Inc. (Distribution)
Canadian Niagara Power Inc.
Grimsby Power Inc.
Haldimand County Hydro Inc.
Horizon Utilities Corp.
Niagara Peninsula Energy Inc.
Niagara on the Lake Hydro Inc.
Welland Hydro Electric System Corp.

Disclaimer

This Local Planning Report was prepared for the purpose of developing wires options and recommending a preferred solution(s) to address the local needs identified in the Needs Assessment (NA) report for the Niagara Region that do not require further coordinated regional planning. The preferred solution(s) that have been identified through this Local Planning Report may be reevaluated based on the findings of further analysis. The load forecast and results reported in this Local Planning Report are based on the information and assumptions provided by study team participants.

Study team participants, their respective affiliated organizations, and Hydro One Networks Inc. (collectively, "the Authors") make no representations or warranties (express, implied, statutory or otherwise) as to the Local Planning Report or its contents, including, without limitation, the accuracy or completeness of the information therein and shall not, under any circumstances whatsoever, be liable to each other, or to any third party for whom the Local Planning Report was prepared ("the Intended Third Parties"), or to any other third party reading or receiving the Local Planning Report ("the Other Third Parties"), for any direct, indirect or consequential loss or damages or for any punitive, incidental or special damages or any loss of profit, loss of contract, loss of opportunity or loss of goodwill resulting from or in any way related to the reliance on, acceptance or use of the Local Planning Report or its contents by any person or entity, including, but not limited to, the aforementioned persons and entities.

LOCAL PLANNING EXECUTIVE SUMMARY

REGION	Niagara Region ("Region")		
LEAD	Hydro One Networks Inc. ("Hydro One")		
START DATE	16 May 2016	**END DATE**	1 November 2016

1. INTRODUCTION

The purpose of this Local Planning ("LP") report is to develop and recommend a preferred wires solution that will address the local needs identified in the Needs Assessment (NA) report for the Niagara Region. The development of the LP report is in accordance with the regional planning process as set out in the Planning Process Working Group ("PPWG") Report to the Ontario Energy Board's ("OEB") and mandated by the Transmission System Code ("TSC") and Distribution System Code ("DSC").

2. LOCAL NEEDS REVIEWED IN THIS REPORT

This report reviewed the potential thermal rating violation for the Beck SS #1 x Portal Junction section of the 115kV Q4N circuit (egress out from Sir Adam Beck GS #1).

3. OPTIONS CONSIDERED

The following options were considered:

- Option 1: Status Quo
- Option 2: Uprate Circuit Section

4. PREFERRED SOLUTIONS

Option 2 is the preferred option. The uprating of limiting section of the circuit is included in Hydro One's Sustainment plan.

5. RECOMMENDATIONS

It is recommended that the circuit section upgrade proceed with current with an expected in-service date of December 2019.

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LIST OF FIGURES

1 Introduction

The Needs Assessment (NA) for the Niagara Region ("Region") was triggered in response to the Ontario Energy Board's (OEB) Regional Infrastructure Planning process approved in August 2013. The NA for the Niagara Region was prepared jointly by the study team, including LDCs, Independent Electric System Operator (IESO) and Hydro One. The NA report can be found on Hydro One's Regional Planning website. The study team identified needs that are emerging in the Region over the next ten years (2015 to 2024) and recommended that they should be further assessed through the transmitter-led Local Planning (LP) process.

As part of the NA report for the Niagara Region, it identified that under high generation scenarios at Sir Adam Beck GS #1, the loading on the Beck SS #1 x Portal Junction section (egress out from the GS) of 115kV circuit Q4N can exceed circuit ratings in IESO's System Impact Assessment for the Sir Adam Beck-1 GS – Conversion of units G1 and G2 to 60 Hz

This Local Planning report was prepared by Hydro One Networks Inc. ("HONI"). This report captures the results of the assessment based on information provided by LDCs and HONI.

2 Regional Description and Circuit Q4N Description

Sir Adam Beck GS #1 is an 115kV hydroelectric generating station located on the Niagara Escarpment north of Niagara Falls in Queenston. Geographically, it roughly borders Highway 405 and the Canadian-American border via the Niagara River.

Electrical supply from Sir Adam Beck GS #1 is currently provided through eight (8) OPG generators connected to Hydro One's 115kV solid 'E' bus inside the station. Supply to the local 115kV area is delivered via five (5) Hydro One circuits (Q2AH, Q3N, Q4N, Q11S, Q12S) from 115kV 'E' bus within the power house. The 115 kV 'E' bus serves as a switching station for the Hydro One network as well as a connection facility for OPGI's generators. The generators, transformers and circuits on the 'E' bus are sectionalized via switches.

A single line diagram is shown of the 115 kV system originating from the 115kV Sir Adam Beck GS #1 in Figure 1.

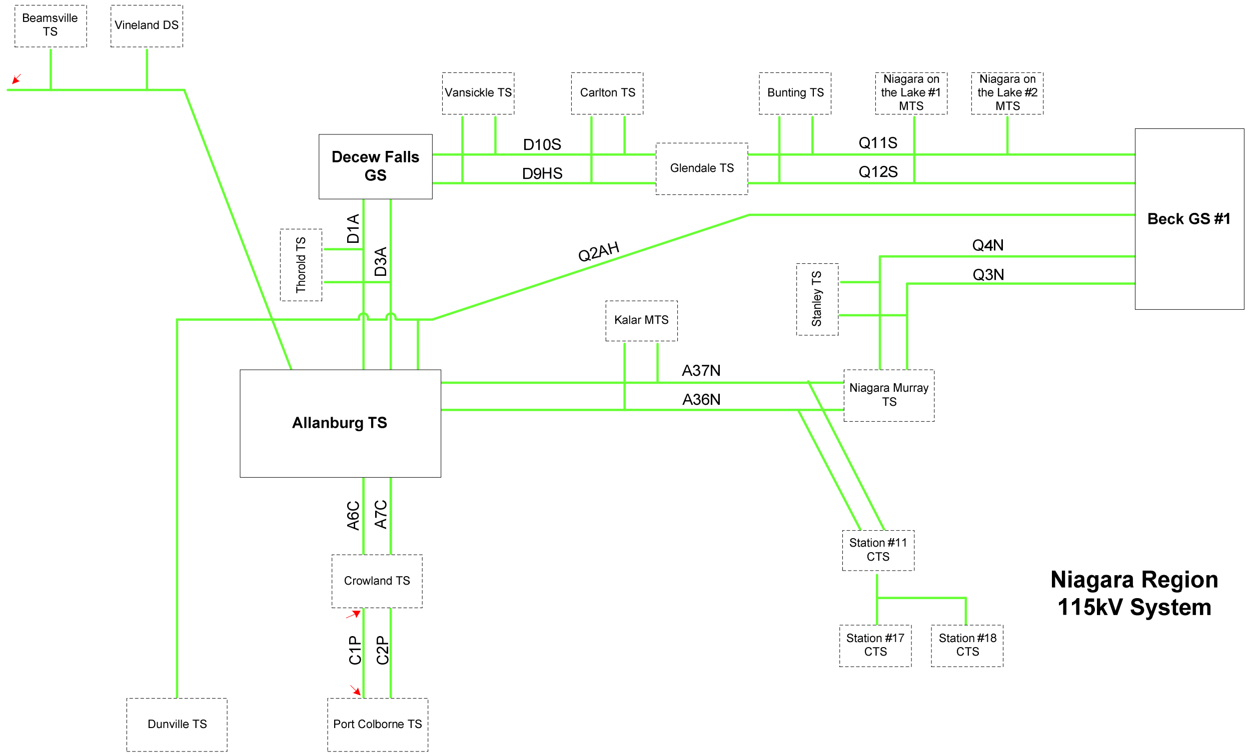


Figure 1: Single Line Diagram – Niagara Region 115kV System

From the NA report for the Niagara Region, a possible thermal limit issue on a section of the circuit Q4N was identified. Q4N is an approximately 9 km long, 115kV radial circuit from Sir Adam Beck GS #1, supplying Stanley TS and Niagara Murray TS.

The section of Q4N identified in the NA comprises of the section from Sir Adam Beck GS #1 to Portal Junction. This section of circuit is shown in Figure 2.

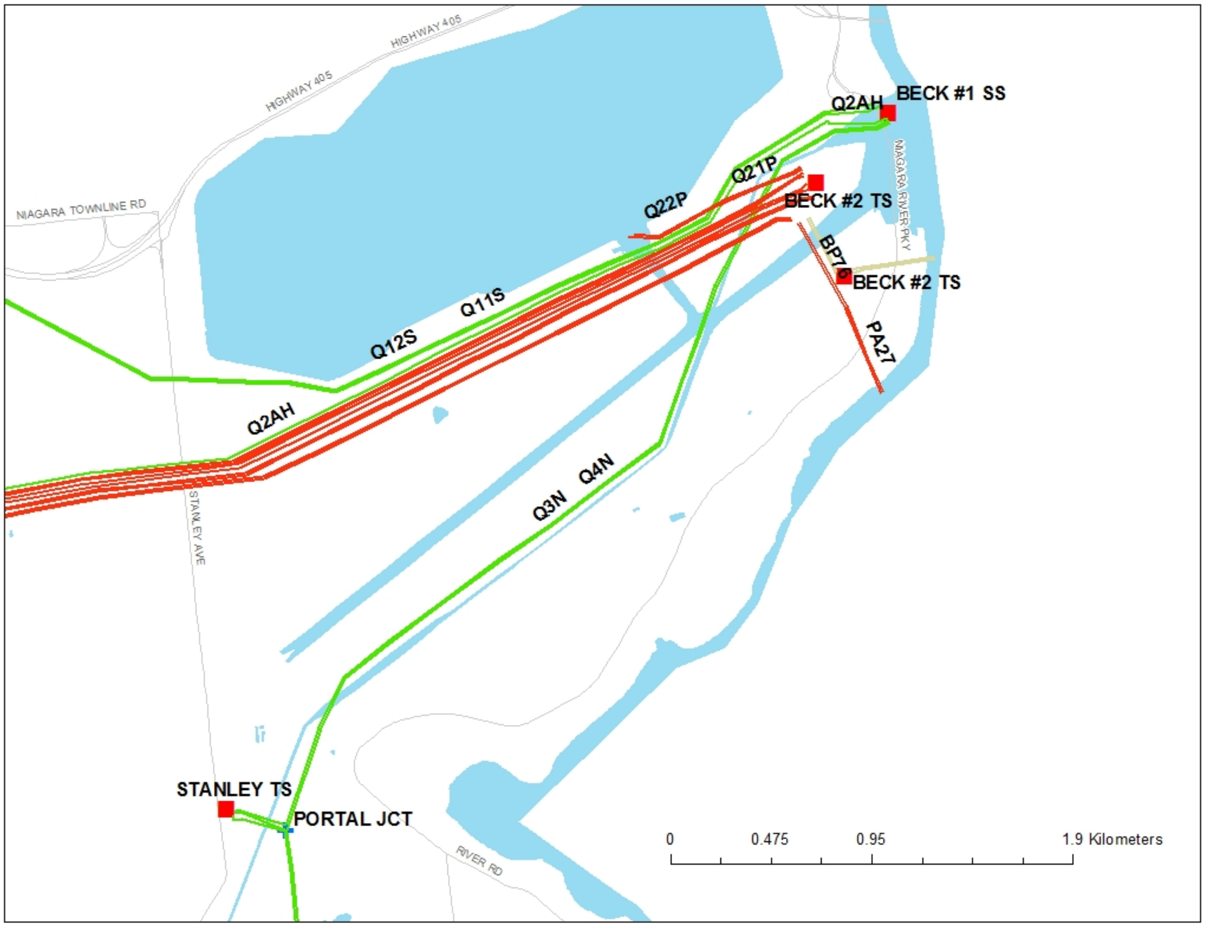


Figure 2: Single Line Diagram – Q4N from Beck #1 SS to Portal Junction

3 Local Niagara Need (Q4N)

In the past decade, OPG has been steadily increasing the power output of their generators with station upgrades.

In the IESO SIA for "Sir Adam Beck-1 GS – Conversion of units G1 and G2 to 60 Hz" it was identified that the thermal loading on circuit section Q4N from Beck #1 SS to Portal junction exceeds its continuous rating by 109.6% at total generation output of Sir Adam Beck #1 GS. This study was based on 2018 summer peak demand with high generation dispatch in the 115 kV transmission system in the vicinity with the existing 8 generators and 2 future generators (G1 and G2) at full output. This thermal loading is based on an ambient 35ºC temperature condition with 4 km/hr wind speed during daytime.

Reducing the generation output of Sir Adam Beck #1 GS from its maximum capacity of 556 MW to 509 MW reduces the loading on Q4N (Beck #1 SS by Portal Junction) to below its continuous rating.

4 Study Result / Options Considered

The conductor on a 64m section of the 115kV circuit Q4N between Sir Adam Beck SS #1 and Portal Jct. is comprised of 605.0 kcmil aluminum, 54/7 ACSR. The continuous rating for this type of conductor at 93^{o}C is 680A. The options considered are outlined below.

4.1 Option 1: Status Quo

Status Quo is not an option because there is a risk that for maximum generation dispatch in extreme weather conditions. Under these conditions generation would have to be curtailed to meet line thermal rating requirements and thus causing financial losses to customer.

4.2 Option 2: Uprate Conductor Section

Hydro One has plans already in place to replace the existing section of conductor with a 910A continuous rated conductor at 93^{o}C as part of their Beck #1 SS Refurbishment project. This will enable this section of circuit to meet all pre and post contingency thermal limits during max generation and under extreme weather conditions.

5 Recommendations

It is recommended that Hydro One continues with their sustainment plans (Option 2) on replacing the section of the 115kV circuit Q4N between Sir Adam Beck SS #1 and Portal Jct. with a larger ampacity conductor (increase of 680A to 910A).

The expected in-service date for this conduction section upgrade is December 2019.

6 References

i) Planning Process Working Group (PPWG) Report to the Board: The Process for Regional Infrastructure Planning in Ontario – May 17, 2013

ii) IESO Ontario Resource and Transmission Assessment Criteria (ORTAC) – Issue 5.0

iii) Needs Assessment Report Niagara Region

Appendix A: Load Forecast

Transformer Station Name	Customer Data (MW)	Historical Data (MW)			Near Term Forecast (MW)					Medium Term Forecast (MW)				
		2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Allanburg TS	Net Load Forecast	33.4	35.4	29.6										
Hydro One, NPEI - Embedded	Gross Peak Load				31.1	31.3	31.4	31.6	32.0	32.4	32.6	32.7	32.9	33.1
	Gross Peak Load - DG - CDM				30.8	30.7	30.6	30.4	30.4	30.5	30.5	30.5	30.5	30.5
Beamsville TS	Net Load Forecast	53.6	55.9	49.0										
Hydro One & NPEI, Grimsby Power, NPEI - Embedded	Gross Peak Load				54.9	55.6	56.8	58.0	59.2	59.4	59.6	59.8	60.0	60.2
	Gross Peak Load - DG - CDM				54.1	54.2	55.0	55.5	56.1	55.8	55.6	55.5	55.4	55.3
Bunting TS	Net Load Forecast	58.3	55.9	49.6										
Horizion Utilities	Gross Peak Load				53.1	53.3	53.4	53.5	53.7	53.8	53.9	54.1	54.2	54.3
	Gross Peak Load - DG - CDM				52.5	52.1	51.8	51.4	51.0	50.7	50.5	50.3	50.2	50.1
Carlton TS	Net Load Forecast	100.1	98.3	76.7										
Horizion Utilities	Gross Peak Load				78.4	79.5	79.7	79.9	80.1	80.3	80.5	80.7	80.9	81.1
	Gross Peak Load - DG - CDM				77.6	77.8	77.5	76.8	76.1	75.7	75.4	71.6	71.4	71.2
Crowland TS	Net Load Forecast	89.1	93.6	74.6										
Welland Hydro & Hydro One, CNPI - Embedded	Gross Peak Load				75.2	77.5	78.5	80.0	81.0	82.0	83.0	84.0	85.0	86.0
	Gross Peak Load - DG - CDM				70.4	71.9	72.3	72.9	73.0	73.3	73.8	74.2	74.8	75.3
Dunnville TS	Net Load Forecast	25.3	27.0	24.1										
Hydro One	Gross Peak Load				24.1	24.3	24.4	24.5	24.7	24.9	25.0	25.1	25.2	25.4
	Gross Peak Load - DG - CDM				19.8	19.7	19.6	19.4	19.4	19.3	19.3	19.3	19.3	19.3

Transformer Station Name	Customer Data (MW)	Historical Data (MW)			Near Term Forecast (MW)					Medium Term Forecast (MW)				
		2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Glendale TS	Net Load Forecast	61.5	59.1	60.1										
Horizion Utilities	Gross Peak Load				66.5	62.5	62.6	62.8	62.9	63.1	63.2	63.4	63.5	63.7
	Gross Peak Load - DG - CDM				65.7	61.0	60.7	60.2	59.7	59.3	59.1	58.9	58.8	58.6
Kalar MTS	Net Load Forecast	39.5	38.6	33.9										
NPEI	Gross Peak Load				39.8	40.0	40.2	40.4	40.6	40.8	41.0	41.2	41.4	41.6
	Gross Peak Load - DG - CDM				39.4	39.2	39.1	38.8	38.6	38.5	38.4	38.4	38.4	38.4
Niagara Murray TS	Net Load Forecast	97.0	101.7	90.2										
Hydro One & NPEI	Gross Peak Load				89.7	90.0	90.4	90.7	91.0	91.4	91.7	92.0	92.4	92.7
	Gross Peak Load - DG - CDM				88.9	88.3	88.0	87.4	86.9	86.5	86.3	86.2	86.1	86.0
Niagara On the Lake #1 MTS	Net Load Forecast	23.8	22.3	22.3										
Niagara On the Lake	Gross Peak Load				24.9	25.3	25.7	26.1	26.5	26.9	27.3	27.7	28.1	28.5
	Gross Peak Load - DG - CDM				24.7	24.8	25.0	25.1	25.2	25.3	25.6	25.8	26.1	26.3
Niagara On the Lake #2 MTS	Net Load Forecast	20.7	22.6	18.3										
Niagara On the Lake	Gross Peak Load				18.9	19.2	19.5	19.8	20.1	20.4	20.7	21.0	21.3	21.7
	Gross Peak Load - DG - CDM				18.8	18.8	19.0	19.0	19.1	19.2	19.4	19.6	19.8	20.0
Niagara West MTS	Net Load Forecast	47.5	43.5	35.7										
Grimsby Power, NPEI Embedded	Gross Peak Load				35.8	35.9	36.1	36.5	36.7	37.0	37.2	37.6	37.8	38.1
	Gross Peak Load - DG - CDM				34.4	34.2	34.0	34.0	33.8	31.2	31.2	31.4	31.4	31.5

Transformer Station Name	Customer Data (MW)	Historical Data (MW)			Near Term Forecast (MW)					Medium Term Forecast (MW)				
		2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Stanley TS	Net Load Forecast	59.8	58.9	52.4										
NPEI	Gross Peak Load				52.7	52.9	53.1	53.3	53.5	53.7	53.9	54.1	54.3	54.5
	Gross Peak Load - DG - CDM				52.1	51.7	51.5	51.1	50.8	50.5	50.4	50.3	50.3	50.2
Station 17 TS	Net Load Forecast		16.1	16.6										
CNP	Gross Peak Load				16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6
	Gross Peak Load - DG - CDM				16.4	16.2	16.1	15.9	15.8	15.6	15.5	15.5	15.4	15.3
Station 18 TS	Net Load Forecast		32.3	35.2										
CNP	Gross Peak Load				35.2	37.7	40.2	40.2	40.2	40.2	40.2	40.2	40.2	40.2
	Gross Peak Load - DG - CDM				34.8	36.9	39.1	38.6	38.2	37.9	37.7	37.4	37.3	37.1
Port Colborne TS	Net Load Forecast		40.2	35.7										
CNP	Gross Peak Load				30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8
	Gross Peak Load - DG - CDM				30.3	30.0	29.8	29.4	29.1	28.9	28.7	28.5	28.4	28.2
Thorold TS	Net Load Forecast	20.1	21.3	18.4										
Hydro One	Gross Peak Load				21.3	21.5	21.6	21.7	22.0	22.2	22.4	22.5	22.6	22.7
	Gross Peak Load - DG - CDM				21.1	21.1	20.9	20.8	20.9	20.9	20.9	20.9	20.9	20.9
Vansickle TS	Net Load Forecast	46.3	53.3	43.7										
Horizion Utilities	Gross Peak Load				44.1	44.5	44.6	44.8	44.9	45.0	45.1	45.2	45.3	45.4
	Gross Peak Load - DG - CDM				43.7	43.6	43.4	43.0	42.7	42.4	42.2	42.1	42.0	41.9
Vineland DS	Net Load Forecast	17.4	17.0	17.0										
Hydro One, NPEI - Embedded	Gross Peak Load				21.9	22.3	22.4	22.7	23.1	23.5	23.8	24.0	24.3	24.5
	Gross Peak Load - DG - CDM				21.7	21.8	21.8	21.8	22.0	22.2	22.3	22.4	22.5	22.6

Appendix B: Acronyms

BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
CIA	Customer Impact Assessment
CGS	Customer Generating Station
CTS	Customer Transformer Station
DESN	Dual Element Spot Network
DG	Distributed Generation
DSC	Distribution System Code
GS	Generating Station
GTA	Greater Toronto Area
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Planning
kV	Kilovolt
LDC	Local Distribution Company
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low-voltage
MW	Megawatt
MVA	Mega Volt-Ampere
NA	Needs Assessment
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.
OEB	Ontario Energy Board
OPA	Ontario Power Authority
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Planning
SIA	System Impact Assessment
SS	Switching Station
TS	Transformer Station
TSC	Transmission System Code
ULTC	Under Load Tap Changer

Hydro One Networks Inc.
483 Bay Street
Toronto, Ontario
M5G 2P5

NEEDS ASSESSMENT REPORT

Kitchener - Waterloo - Cambridge - Guelph (KWCG) Region

Date: December 19, 2018

Prepared by: KWCG Region Study Team

Disclaimer

This Needs Assessment Report was prepared for the purpose of identifying potential needs in the KWCG Region and to recommend which need may require further assessment and/or regional coordination to develop a preferred plan. The results reported in this Needs Assessment are based on the input and information provided by the Study Team.

The Study Team participants, their respective affiliated organizations, and Hydro One Networks Inc. (collectively, "the Authors") shall not, under any circumstances whatsoever, be liable to each other, to any third party for whom the Needs Assessment Report was prepared ("the Intended Third Parties") or to any other third party reading or receiving the Needs Assessment Report ("the Other Third Parties"). The Authors, Intended Third Parties and Other Third Parties acknowledge and agree that: (a) the Authors make no representations or warranties (express, implied, statutory or otherwise) as to this document or its contents, including, without limitation, the accuracy or completeness of the information therein; (b) the Authors, Intended Third Parties and Other Third Parties and their respective employees, directors and agents (the "Representatives") shall be responsible for their respective use of the document and any conclusions derived from its contents; (c) and the Authors will not be liable for any damages resulting from or in any way related to the reliance on, acceptance or use of the document or its contents by the Authors, Intended Third Parties or Other Third Parties or their respective Representatives.

Executive Summary

REGION	Kitchener - Waterloo - Cambridge - Guelph (KWCG) Region		
LEAD	Hydro One Networks Inc. ("HONI")		
START DATE	September 17, 2018	**END DATE**	December 19, 2018

1. INTRODUCTION

The first cycle of the Regional Planning process for the KWCG Region an Integrated Regional Resource Plan ("IRRP") was published in April 2015 which identified a number of near- and mid-term needs in the KWCG region. The planning process was completed in December 2015 with the publication of the Regional Infrastructure Plan ("RIP") which provided a description of needs and recommendations of preferred wires plans to address near-term needs. The RIP also identified some near- and mid-term needs that will be reviewed during this Regional Planning cycle.

The purpose of this Needs Assessment ("NA") is to identify any new needs and to reaffirm needs identified in the previous KWCG Regional Planning cycle.

2. REGIONAL ISSUE/TRIGGER

In accordance with the Regional Planning process, the regional planning cycle should be triggered at least every five years. In light of the timing of the needs identified in the previous Integrated Regional Resource Plan ("IRRP") and RIP reports as well as new replacement/ refurbishment needs in the KWCG Region, the 2nd Regional Planning cycle was triggered for this Region.

3. SCOPE OF NEEDS ASSESSMENT

The scope of this NA includes:

- Review and reaffirm needs/plans identified in the previous RIP; and
- Identification and assessment of system capacity, reliability, operation, and aging infrastructure needs.

The Study Team may also identify additional needs during the next phases of the planning process, namely Scoping Assessment ("SA"), IRRP and RIP, based on updated information available at that time.

4. INPUTS/DATA

The Study Team representatives from Local Distribution Companies ("LDC"), the Independent Electricity System Operator ("IESO"), and Hydro One provided input and relevant information for the KWCG Region regarding capacity needs, reliability needs, operational issues, and major assets/facilities approaching end-of-life ("EOL"). In addition, community energy plans in the region have also been scanned and reviewed.

5. ASSESSMENT METHODOLOGY

The assessment's primary objective is to identify the electrical infrastructure needs, recommend further mitigation or action plan(s) to address these needs, and determine whether further regional coordination or broader study would be beneficial.

The assessment reviewed available information including load forecasts, conservation and demand management ("CDM") and distributed generation ("DG") forecasts, reliability needs, operational issues, and major high voltage equipment identified to be at or near the end of their useful life and requiring replacement/refurbishment. A technical assessment of needs was undertaken based on:

- Current and future station capacity and transmission adequacy;
- Reliability needs and operational concerns; and
- Any major high voltage equipment reaching the end of its useful life.

6. NEEDS

I. Station & Transmission Supply Capacity

- Campbell TS (T3/T4) DESN Overloading is forecasted in the 2021-2022.
- Future need for Waterloo North Hydro MTS #4
- Future need for Energy+ MTS #2

A contingency analysis was performed and due to reduced forecasts no issues were found.

II. System Reliability & Operation

- D10H 115 kV line reliability and restoration of Elmira TS loads.

III. Aging Infrastructure – Transformer Replacements and line Section Refurbishment

- Projects in execution:
  - i. Campbell TS – T1 (2018)
  - ii. Detweiler TS -Auto T2 &T4 (2021-2022)
  - iii. 115 kV B5C/ B6C Circuits (2019-2020) [1]
- New projects:
  - i. 115 kV D7F/ D9F Circuits (2019-2020)[2]
  - ii. 230 kV D6V/ D7V Circuits (2019- 2020)[3]
  - iii. Hanlon TS - T1 & T2 (2023-2024)
  - iv. Kitchener MTS #5 - T9 & T10 (2023-2024)
  - v. Cedar TS - T7 & T8 (2024-2025)
  - vi. Scheifele MTS - T1 & T2 (2024-2026)
  - vii. Preston TS - T3 & T4 (2025-2026)

IV. Other Planning Considerations

The local municipalities in the region are extremely engaged and actively pursuing innovative ways to manage and/or reduce their energy needs over the next 10-20 Years. For example, several community energy plans have been developed in the region.

[1] Burlington TS to a CTS Line Section
[2] Tower 157 to Freeport Switching Station Line Section
[3] Guelph North Junction to Fergus TS Line Section

7. RECOMMENDATIONS

The Study Team's recommendations for the above identified needs are as follows:

a) The replacement of EOL station supply transformers at Campbell TS, Hanlon TS, Cedar TS, Kitchener MTS #5 and Preston TS along with the EOL auto transformers at Detweiler to proceed. Hydro One and the concerned LDCs will coordinate replacement of above equipment and develop replacement plans.

b) The refurbishment of EOL line sections 115 kV B5C/ B6C, D7F/ D9F and 230 kV D6V/ D7V to proceed. Hydro One will coordinate refurbishment of these line sections with affected LDCs/ Customer.

c) Hydro One will continue to work with Waterloo North Hydro Inc. to address the supply reliability issue at Elmira TS.

d) The Study Team has recommended that Hydro One Transmission and the Guelph Hydro Electric System Inc. to closely monitor the loading at the T3/T4 Campbell TS DESN and to balance the loads between these DESNs when required.

e) The Study Team recommends that the supply capacity needs with regards to Energy + MTS #2 and WNH MTS #4 be further assessed for optimization in the SA phase of regional planning. Once the optimization options are complete, Waterloo North Hydro and Energy+ shall conduct a technical and economic assessment in consultation with Hydro One.

f) The Study Team has recommended that community energy plans will be further considered in the SA phase of the regional planning process.

TABLE OF CONTENTS

List of Tables and Figures

1 INTRODUCTION

The first cycle of the Regional Planning process for the KWCG Region was completed in December 2015 with the publication of the Regional Infrastructure Plan ("RIP"). The RIP provided a description of needs and recommendations of preferred wires plans to address near- and medium-term needs. Waterloo North Hydro MTS #4 was the only need to be reviewed in this planning cycle.

The purpose of this Needs Assessment ("NA") is to identify new needs and to reconfirm needs identified in the previous KWCG regional planning cycle. Since the previous regional planning cycle, some new needs in the region have been identified.

This report was prepared by the KWCG Region Study Team ("Study Team"), led by Hydro One Networks Inc. Participants of the Study Team are listed below in Table 1. The report presents the results of the assessment based on information provided by the Hydro One, the Local Distribution Companies ("LDC") and the Independent Electricity System Operator ("IESO").

Table 1: KWCG Region Study Team Participants

Company
Centre Wellington Hydro
Energy+
Guelph Hydro Electric System Inc.
Halton Hills Hydro
Hydro One Networks Inc. (Lead Transmitter)
Hydro One Networks Inc. (Distribution)
Independent Electricity System Operator ("IESO")
Kitchener Wilmot Hydro Inc.
Milton Hydro
Waterloo North Hydro Inc.
Wellington North Power Inc.

2 REGIONAL ISSUE/TRIGGER

In accordance with the Regional Planning process, the Regional Planning cycle should be triggered at least every five years. In light of the timing of the needs identified in the previous IRRP and RIP reports as well as new replacement/ refurbishment identified needs in the KWCG Region, the 2nd Regional Planning cycle was triggered for the KWCG region.

3 SCOPE OF NEEDS ASSESSMENT

The scope of this NA covers the KWCG Region and includes:

- Identification of new needs based on latest information provided by the Study Team; and,
- Confirmation/updates of existing needs and/or plans identified in the previous planning cycle.

The Study Team may identify additional needs during the next phases of the regional planning process, namely Scoping Assessment ("SA"), Local Planning ("LP"), IRRP, and/or RIP.

4 REGIONAL DESCRIPTION AND CONNECTION CONFIGURATION

The KWCG Region covers the cities of Kitchener, Waterloo, Cambridge and Guelph, portions of Oxford and Wellington counties and the townships of North Dumfries, Puslinch, Woolwich, Wellesley and Wilmot. Electrical supply to the Region is provided from eleven 230 kV and thirteen 115 kV step-down transformer stations. The summer 2018 non-coincident regional loads were about 1390 MW. The approximate boundaries of the KWCG Region are shown below in Figure 1.

The main sources of electricity into the KWCG Region are from five Hydro One stations: Middleport TS, Buchanan TS, Detweiler TS, Orangeville TS and Burlington TS. At these stations electricity is transformed from 500 kV and 230 kV to 230 kV and 115 kV levels, respectively. Electricity is then delivered to the end users of LDCs and directly-connected industrial customers through 26 (TS/ MTS/ CTS) step-down transformer stations. Figure 2 illustrates these stations as well as the four major regional sub-systems: Waterloo-Guelph 230 kV sub-system, Cambridge-Kitchener 230 kV sub-system, Kitchener-Guelph 115 kV sub-system and South-Central Guelph 115 kV sub-system.

The summer non-coincident regional load forecast is provided as Appendix A. Appendix B lists all step-down transformer stations, Appendix C transmission circuits and Appendix D LDCs in the KWCG Region.

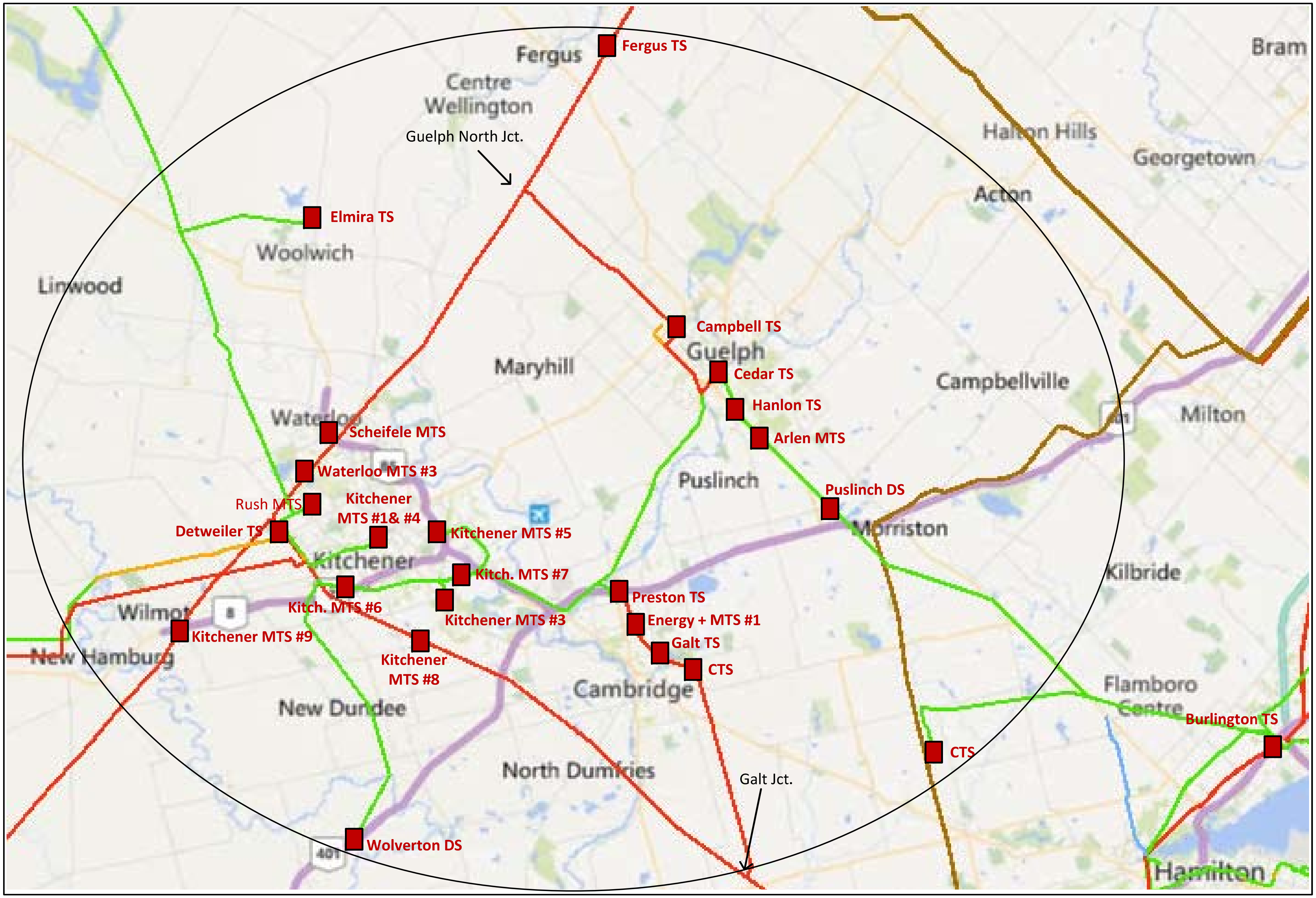


Figure 1: Geographical Area of the KWCG Region with Electrical Layout

An electrical single line diagram for the KWCG Region facilities is shown below in Figure 2.

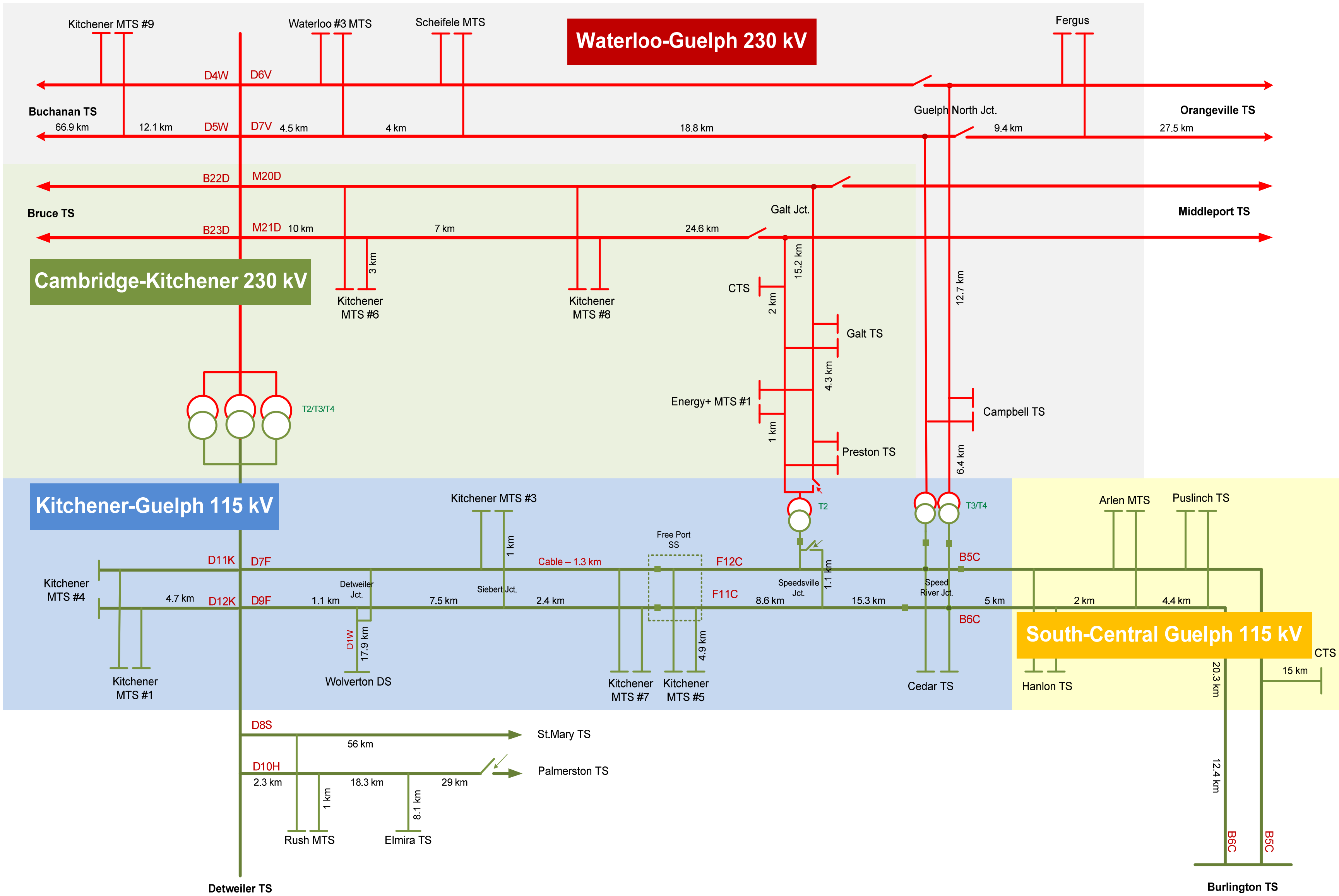


Figure 2: KWCG Region (Single Line Diagram)

5 INPUTS AND DATA

Study Team participants, including representatives from LDCs, IESO, and Hydro One provided information and input for the KWCG Region NA. The information provided includes the following:

- KWCG Load Forecast for all supply stations;
- Known capacity and reliability needs, operating issues, and/or major assets approaching the end of their useful life ("EOL"); and
- Planned/foreseen transmission and distribution investments that are relevant to regional planning for the KWCG Region.

6 ASSESSMENT METHODOLOGY

The following methodology and assumptions are made in this Needs Assessment:

Information gathering included:

i. Load forecast: The relevant LDCs provided load forecasts for all the stations supplying their loads in the KWCG region for the 10 year study period. The IESO provided a Conservation and Demand Management ("CDM") and Distributed Generation ("DG") forecast for the KWCG region. The region's extreme summer non-coincident peak gross load forecast for each station were prepared by applying the LDC load forecast load growth rates to the actual 2018 summer peak extreme weather corrected loads. The extreme summer weather correction factors were provided by Hydro One. The net extreme weather summer load forecasts were produced by reducing the gross load forecasts for each station by the % age CDM and then by the amount of effective DG capacity provided by the IESO for that station. These extreme weather summer load forecast for the individual stations in the KWCG region is given in Appendix A;

ii. Relevant information regarding system reliability and operational issues in the region; and

iii. List of major HV transmission equipment planned and/or identified to be refurbished and/or replaced due to the end of their useful life which is relevant for regional planning purposes. This includes HV transformers, autotransformers, HV Breakers, HV underground cables and overhead lines.

A technical assessment of needs was undertaken based on:

- Current and future station capacity and transmission adequacy;
- System reliability and operational concerns; and
- Any major high voltage equipment reaching the end of its useful life.

In addition, Hydro One has reviewed the Community Energy Plans in the region. It is worth noting that there are several community energy plans in the region and some of them are meant to sustain at the current level or reduce the community's reliance on the provincial electric system by meeting future electricity needs with local, distributed resources and/or community-based solutions. These plans may have potential to supplement and/or defer future transmission infrastructure development needs.

7 NEEDS

This section describes emerging needs identified in the KWCG Region, and also reaffirms the near, mid, and long-term needs already identified in the previous regional planning cycle.

The recent load forecast prepared for this report is lower than that of the previous cycle of regional planning. A contingency analysis was performed for the region and due to reduced load forecasts, as expected; no new system needs were identified.

The newly identified/emerging needs pertaining to this NA will be discussed further in the following sub-sections, while the status of the previously identified needs is summarized in Table 2 below.

Table 2: Needs Identified in the Previous Regional Planning Cycle

Type of Needs identified in the previous RP cycle	Needs Details	Current Status
115kV System Supply Capacity	**GATR Project** Two new additional 230/115kV autotransformers at Cedar TS to reinforce supply to both 115kV sub-systems in the region.	Completed
230kV Load Restoration Needs	**GATR Project** Two new additional 230 kV in-line switches on D6V/D7V circuits to improve restoration capability of Waterloo-Guelph 230 kV sub-system.	Completed
	Galt Junction Two new additional 230kV in-line switches on M20D/M21D circuits to improve restoration capability of the Cambridge-Kitchener 230 kV sub-system.	Completed
Station Short Circuit Capacity	**Arlen MTS** Install 13.8 kV series reactors to mitigate LV bus short circuit levels.	Completed
Station Transformation Capacity	New Waterloo North Hydro: MTS #4 (2024).	Need is now expected beyond 2029.

7.1 End-Of-Life (EOL) Equipment Needs

Hydro One and LDCs have provided high voltage asset information under the following categories that have been identified at this time and are likely to be replaced over the next 10 years:

- Autotransformers
- Power transformers
- HV breakers
- Transmission line requiring refurbishment where an uprating is being considered for planning needs and require Leave to Construct (i.e., Section 92) application and approval
- HV underground cables where an uprating is being considered for planning needs and require EA and Leave to Construct (i.e., Section 92) application and approval

Accordingly, following major high voltage equipment has been identified as approaching its end of useful life over the next 10 years.

Table 3: End-of-Life Equipment – KWCG Region

EOL Asset Replacement/ Refurbishment	Replacement/ Refurbishment Timing	Details
Projects in Execution		
Campbell TS (T1/T2 DESN): T1 Supply Transformer	2018	These Project are discussed further in Section 7.1.1
Detweiler TS: 230/ 115 kV T2/ T4 Auto-transformers	2021-2022	
115 kV B5C/ B6C: Burlington TS to Westover CTS Line Sections	2019-2020	
New Identified Projects		
115 kV D7F/ D9F : Tower #157 to Freeport SS Line Section	2019-2020	These Project are discussed further in Section 7.1.2
230 kV D6V/ D7V: Guelph North Jct. to Fergus Jct. Line Section	2019-2020	
Kitchener MTS #5[1]: T9/T10 Supply Transformers	2023-2024	
Hanlon TS: T1/T2 Supply Transformers	2023-2024	
Cedar TS: T7/T8 Supply Transformers	2024-2025	
Scheifele MTS[1]- T1/T2 Supply Transformers	2024-2026	
Preston TS: T3/T4 Supply Transformers	2025-2026	

[1] LDC owned assets

The end-of-life assessment for the above high voltage equipment typically included consideration of the following options:

1. Maintaining the status quo;
2. Replacing equipment with similar equipment of lower ratings and built to current standards;
3. Replacing equipment with lower ratings and built to current standards by transferring some load to other existing facilities;
4. Eliminating equipment by transferring all of the load to other existing facilities;
5. Replacing equipment with similar equipment and built to current standards (i.e., “like-for-like” replacement);
6. Replacing equipment with higher ratings and built to current standards; and
7. Station reconfiguration

Maintaining status quo is not an option for any of the above EOL autotransformer, station transformer or line sections due to risk of equipment failure, would result in increased maintenance cost and customer outages. Replacing “Like-for-Like” with nonstandard transformers would result in complexity with failures and difficulty in getting similar spare equipment along with their installation. Nonstandard equipment also poses serious safety risk for employees under normal and emergency situations.

No other lines or HV station equipment in the KWCG region have been identified for major replacement/ refurbishment at this time. If and when new and/or additional information is available, it will be provided during the next planning phase underway at the time.

7.1.1 Projects in Execution

The following end-of-life refurbishment needs are under execution. This region was deemed to be in transition and NA for this region was deemed complete. Hence, following projects were not listed or discussed in the first cycle of regional planning and are currently in execution:

Campbell TS – T1 Transformer

Campbell TS is located in the city of Guelph supplying Guelph Hydro Electric System Inc. loads. Campbell TS has two 230/ 13.8 kV DESNs T1/T2 and T3/T4 of 75 MVA transformers with an LTR of 105 MVA (94 MW @ 0.9 PF) and 63 MVA (56 MW @ 0.9 PF) respectively. The loads on these two DESNs are currently forecasted to be about 87 MW and 66 MW respectively by the end of study period.

The 75 MVA T1/T2 DESN transformer T2 failed in 2017 and was replaced with a new standard 100 MVA unit and transformer T1 is also being replaced with a similar unit. In 2021-2022, Hydro One in addition plans to replace the secondary equipment limiting the station LTR. This will result in sufficient LTR of about 130 MVA for T1/T2 DESN, over the study period.

The replacement of T1 transformer is currently in execution and expected to be completed by the end of year 2018.

Detweiler TS - T2 & T4 Autotransformers

Detweiler TS is a Bulk System, major switching and autotransformer station located in the city of Kitchener. Detweiler TS facilities include a 230 kV switchyard, three 230/115 kV autotransformers (T2/T3/T4) and a 115 kV switchyard.

The Detweiler TS autotransformers T2/T3/ T4 were built in 1959, 2004 and 1963 respectively. The condition assessment has identified T2 and T4 autotransformers as EOL requiring replacement. At this time none of other HV equipment at this station has been identified as approaching EOL over the next 5-10 years.

Not replacing these auto transformers would increase risk of failure due to asset condition, maintenance expenses and reduce supply reliability to the customers. The replacement of both the EOL Detweiler TS T2 and T4 autotransformers with similar units is in execution expected to be completed in 2021-22. This will address the 230/ 115 kV transformation needs at Detweiler TS and maintain station's operability and reliability of supply.

Any Detweiler TS 230 kV system reconfiguration needs will be studied under bulk system planning expected to commence in early 2019.

115 kV B5C/ B6C Line Sections

The 115 kV B5C/B6C circuits consist of about 45 km of double circuit line and 15 km of single circuit line supplying South-Central Guelph 115 kV loads. About 12 km of double circuit line section from Burlington TS to Harper's Jct. and about 15 km B5C 115 kV line tap from Harper's Jct. to a Westover Jct. requires refurbishment.

Not refurbishing these line sections would increase risk of failure due to asset condition, maintenance expenses and reduce supply reliability to the customers.

The refurbishment of this 27 km long 115 kV B5C/B6C line sections from Burlington TS to a CTS is currently under execution and the work is planned to be completed by the end of year 2019.

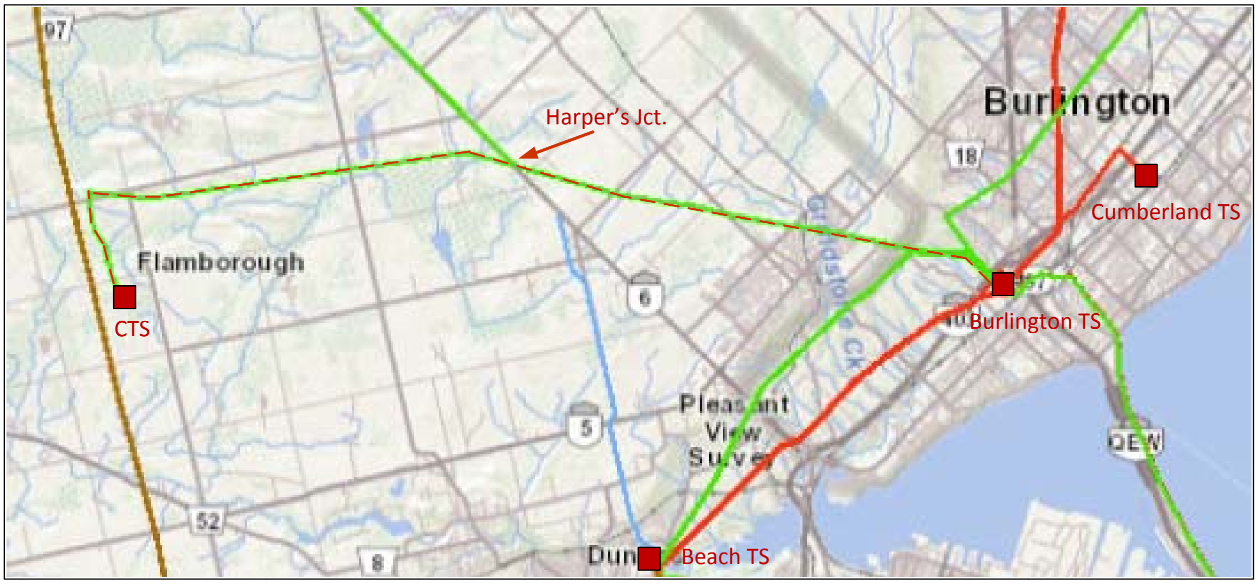


Figure 3: Burlington TS to Harper's Jct. to CTS B5C/ B6C Line Sections

7.1.2 New Needs

The following end-of-life refurbishment needs have been identified in this regional planning cycle:

115 kV D7F/D9F Line Section

The 115 kV D7F/ D9F double circuit line is about 12 km long supplying Kitchener- Guelph 115 kV loads. The 115 kV D7F/ D9F double circuit 450 meter line section from Tower 157 to Freeport Switching Station was built in 1951. It is approaching end of life and requires refurbishment.

Not refurbishing this line section would increase risk of failure due to asset condition, maintenance expenses and reduce supply reliability to the customers.

Therefore the Study Team recommends Hydro One to continue with refurbishment of the 450 meter long 115 kV D7F/ D9F end of life line section from Tower 157 to Freeport Switching Station. This project is currently under estimating and is planned to be completed by the end of year 2019.

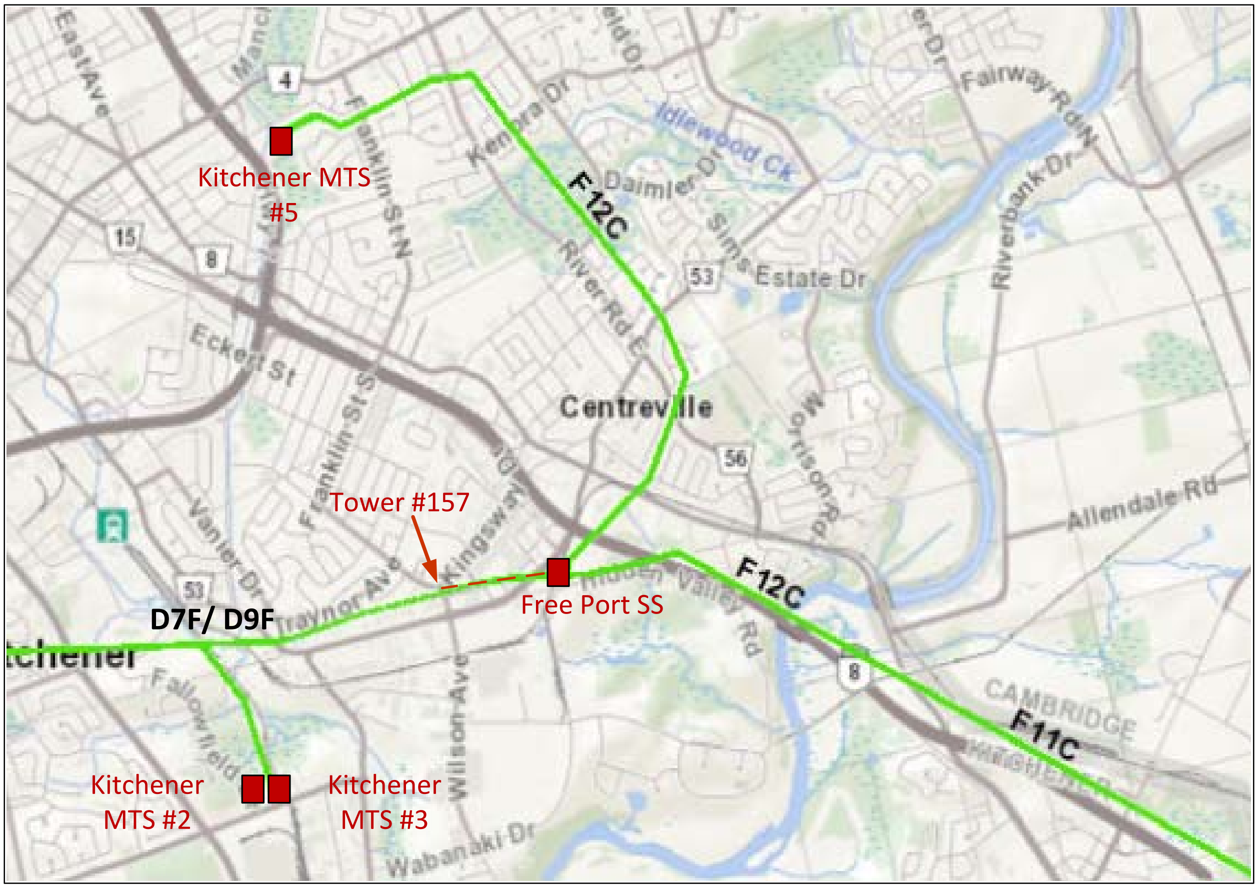


Figure 4: Tower #157 Jct. to Freeport SS F11C/ F12C Line Section

230 kV D6V/D7V Line Section

The 230 kV D6V/D7V double circuit line is about 84 km long and is part of bulk power system supplying loads in the Waterloo Guelph 230kV and South Central Guelph 115 kV loads. A 230 kV D6V/ D7V 9.5 km double circuit line section from Guelph North junction to Fergus TS was built in 1950's and its conductor is approaching end of life. It requires refurbishment.

Not refurbishing this line section would increase risk of failure due to asset condition, maintenance expenses and reduce supply reliability to the customers.

Therefore the Study Team recommends to refurbish this the 9.5 km long 230 kV D6V/D7V end of life line section from Guelph North Junction to Fergus TS. This project is currently under estimating and is planned to be completed by the end of year 2019.

Figure 5: Guelph North Jct. to Fergus TS D6V/ D7V Line Section

Kitchener MTS #5 T9/T10 Transformers

Kitchener MTS #5 is located in the city of Kitchener supplying Kitchener-Wilmot Hydro Inc. loads. Kitchener MTS #5 is a 115/ 13.8 kV single T9/T10 DESN station of 83 MVA nonstandard transformers having a LTR of 89 MVA (80 MW @ 0.9 PF), currently supplying 67 MW of peak load. The loads at Kitchener MTS #5 are currently forecasted to remain flat over the entire study period. The supply capacity of this station is therefore expected to be sufficient over and beyond the study period.

Both the T9/T10 transformers at this station have been identified as approaching end of life requiring replacement. At this time none of other HV/LV equipment at this station has been identified as approaching EOL over the next 5-10 years.

The station cannot be downsized or eliminated because there is no nearby supply station/s to Kitchener MTS #5 having surplus capacity where this station's loads can be transferred. The Study Team recommends replacing the T9/T10 nonstandard transformers with standard units of similar size is the preferred option. Kitchener-Wilmot Hydro Inc. and Hydro One will coordinate the replacement plan of these transformers. The replacement of the EOL equipment is expected to be completed by 2023-2024.

Hanlon TS T1/T2 Transformer

Hanlon TS is located south of the city of Guelph supplying Guelph Hydro Electric System Inc. loads. Hanlon TS is a single T1/T2 DESN station of 33 MVA nonstandard transformers having a LTR of 48

MVA (43 MW @ 0.9 PF). This station is currently supplying about 27 MW of peak load. The loads at Hanlon TS are currently forecasted to remain flat over the entire study period. The supply capacity of this station is therefore expected to be sufficient over and beyond the study period.

The T1/T2 transformers are of 1955/ 56 built and have been identified as EOL requiring replacement. At this time none of other HV/LV equipment at this station has been identified as approaching EOL over the next 5-10 years.

There is no nearby supply station/s to Hanlon TS having surplus capacity where this station's loads can be transferred therefore Hydro One plans to replace these EOL transformers with standard size units of 42 MVA in 2023-2024.

Cedar TS – T7/ T8 Transformers

Cedar TS is located in the city of Guelph supplying Guelph Hydro Electric System Inc. loads. Cedar TS has two 115/ 13.8 kV DESN units T1/T2 and T7/T8 of 75 MVA with a LTR of 115 MVA (103 MW @ 0.9 PF) and 37 MVA with a LTR of 44 MVA (40 MW @ 0.9 PF), currently supplying 67 MW and 36 MW of peak loads respectively. The loads at both Cedar TS DESNs are currently forecasted to remain almost flat over the entire study period. The supply capacity of this station is therefore expected to be sufficient over and beyond the study period.

The T7/T8 DESN 38 MVA nonstandard transformers are of 1958 built have been identified for replacement. The T1/T2 transformers are relatively newer and were built in early 1990s. At this time none of other HV/LV equipment at this station has been identified as approaching EOL over the next 5-10 years.

The station cannot be downsized or eliminated because there is no nearby supply station/s to Cedar TS having surplus capacity where this station's loads can be transferred therefore Hydro One plans to replace these EOL transformers with standard size units of 42 MVA in 2024-2025 timeframe.

Cedar TS and Hanlon TS Optimization with Neighbouring Stations

After performing an analysis of the current distribution situation, it was determined that there are not enough spare feeder positions at HONI and GHESI stations to reallocate DESN loads in the sub-system without significant distribution system and neighboring station upgrades.

Over loading of Campbell DESN T3/T4 will be effectively managed by load transfer to DESN T1/T2 after 2021/22. Following that there will be no additional capacity at these two DESNs.

Secondly, Hanlon TS DESN has eight (8) feeders with three (3) being dedicated underground infrastructure to existing customers, two (2) feeders supplying the industrial load in the Hanlon Industrial Park, two (2) feeder circuits supplying residential load north of Hanlon TS and one (1) feeder to be utilized for planned future load growth at Gordon/ Clair. In addition, due to technical limitations at 13.8 kV distribution voltage and density of load on certain feeders sections, it is not possible to supply existing loads from any other station without significant transmission and distribution investments. Therefore there are little or no significant optimization opportunity is present at this point in time. Option considered for load transfer will require significant new investment; for example:

- The two residential distribution feeders supplying loads north of Hanlon TS could be transferred to existing feeders out of Cedar TS. These load transfers will result in increased line losses and reduced capacity (due to voltage drop)
- Another option could be transferring remaining Hanlon TS load to Arlen MTS. This load transfer will require an additional DESN and underground infrastructure at Arlen MTS.

Hence, the Study Team recommends that Hydro One undertakes replacement of Cedar TS T7/T8 and Hanlon TS T1/T2 transformers with 42 MVA standard size units, being technically and economical most suitable solution. The replacement of EOL equipment is expected to be completed by 2023-2025 timeframe for both stations.

Scheifele MTS – T1/ T2 Transformers

Scheifele MTS is located in the city of Waterloo supplying Waterloo North Hydro Inc. loads. Scheifele MTS has four 230/ 13.8 kV transformers T1 and T2 of 67 MVA, and T3 and T4 of 83 MVA currently supplying 145 MW of peak loads. The load at this station is forecasted to remain almost flat over the entire study period. The total supply capacity of Scheifele MTS is 161 MW expected to be sufficient over the study period.

The T1/T2 transformers based on their age have been identified by Waterloo North Hydro Inc. as approaching end of life potentially requiring replacement in the 2024- 2026 timeframe. Waterloo North Hydro will be monitoring the condition of these transformers to assess their replacement need. At this time none of other HV/LV equipment at this station has been identified as approaching EOL over the next 5-10 years.

The station cannot be downsized or eliminated because there is no nearby supply station/s to Scheifele MTS having surplus capacity where this station's loads can be transferred. The Study Team recommends that Waterloo North Hydro continue monitoring the condition of these T1/T2 transformers at Scheifele MTS and this need to be reassessed in the next regional planning cycle.

Preston TS T3/T4 Transformers

Preston TS (DESN) is located in the city of Cambridge supplying Energy+ loads. Preston TS is a single T3/T4 DESN station of 125 MVA transformers with no additional LTR capability available i.e. 125 MVA (113 MW @ 0.9 PF). This station is currently supplying about 92 MW of peak load. The loads at Preston TS are currently forecasted to peak at about 102 MW during the study period.

The T3/T4 transformers are almost 50 years old, having been built in 1968. Condition assessment has identified that both T3/T4 transformers at their EOL requiring replacement. At this time none of other HV/LV equipment at this station has been identified as EOL over the next 5-10 years.

The station cannot be downsized or eliminated because there is no nearby supply station/s to Preston TS having spare supply capacity where this station's loads can be transferred. The Study Team recommends replacing the existing 125 MVA 230/ 27.6 kV T3/T4 transformers at Preston TS with 125 MVA standard units. This will also result in an increased supplying capacity at Preston TS required to meet the future Energy+ needs in the Cambridge distribution area. The replacement plan for the equipment will be developed by Hydro One and coordinated with the affected LDC and/or customers and it is expected to be completed by 2025-2026.

7.2 Supply Reliability Needs

Supply reliability of Elmira TS –D10H 115 kV Line

The 115 kV D10H circuit between Detweiler TS and Hanover TS supplies loads at Rush MTS, Elmira TS and Palmerston TS. The D10H circuit has a normally open point just south of Palmerston TS through a motorized disconnect switch. The northern section of D10H is supplied from Hanover TS radially supplying Palmerston TS loads. The southern section of D10H supplied from Detweiler TS radially supplies Waterloo North Hydro's 34 MW Elmira TS peak loads. D10H also supplies Rush MTS which is also supplied by 115 kV D8S circuit from Detweiler TS.

The normally open motorized switch near Palmerston TS helps restore the loads at Elmira TS from Hanover TS in-case supply from Detweiler TS is interrupted and similarly helps restoring Palmerston TS loads from Detweiler if supply from Hanover is interrupted.

In last three years, supply to Elmira TS from Detweiler TS resulted in 3 outages due to faults on the D10H line section between Elmira TS tap and Detweiler TS. The Elmira TS load restoration from Hanover TS is slower due to manually operated disconnect switches at Elmira TS tap location.

Hydro One is currently assessing the condition of line and will continue to work with Waterloo North Hydro to address the supply reliability at Elmira TS. The developed mitigation plan to improve supply reliability of Elmira TS loads will be included in the final RIP report.

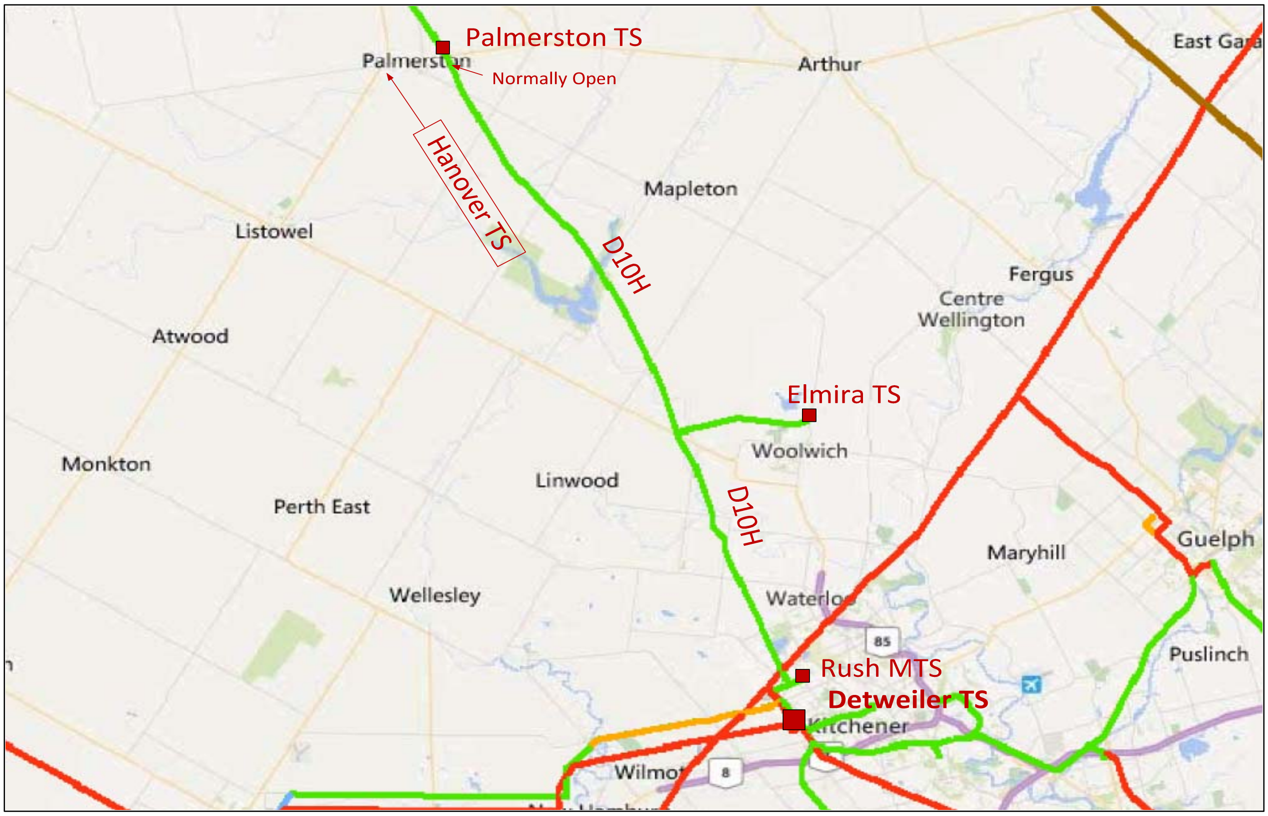


Figure 6: D10H 115 kV Line (Burlington TS to Elmira TS)

7.3 Station and Transmission Capacity Needs in the KWCG Region

The following Station and Transmission supply capacities needs have been identified in the KWCG region during the study period of 2019 to 2028.

7.3.1 Campbell TS (T3/T4) DESN Overloading

There are two DESN stations inside Campbell TS boundary. Both the T1/T2 and T3/T4 DESNs are 230 kV/ 13.8 kV having supply capacities of 94 MW and 56 MW, currently supplying 84 MW and 52 MW of loads respectively. The 75 MVA transformer T2 recently failed and was replaced with a Hydro One standard 100 MVA unit. The transformer T1 is also being replaced with a similar 100 MVA unit by the end of 2018. The load at T3/T4 DESN is forecasted to exceed its supply capacity of 56 MW in the 2021-2022 timeframe.

At Campbell TS, after replacement of T1 transformer and secondary equipment there will be sufficient spare supply capacity on T1/T2 DESN where excess T3/T4 DESN loads can be transferred. Hydro One Transmission and the Guelph Hydro Electric System Inc. will monitor the loading at the T3/T4 Campbell TS DESN and will balance the loads between the two DESNs, when required. The Study Team therefore recommends that no further action is required at this time.

7.3.2 Waterloo North Hydro MTS #4

During the last regional planning cycle a need for a new MTS #4 DESN was identified in the 2024 timeframe. The current load forecast defers this need beyond the needs assessment study period.

7.3.3 Energy+ MTS #2

Energy+ has initially identified a future need for a new DESN station (MTS #2) in the city of Cambridge near Preston TS. This station need is due to a potential new load center growth in their service territory. The additional supply capacity due to EOL transformer replacement and available new feeder positions at Preston TS, will defer this new MTS need beyond the study period of current regional planning cycle.

<u>WNH MTS #4 and Energy+ MTS #2 Optimization</u>

The Preston TS like-for-like transformer replacement is critical for local supply needs and will proceed according to the current plan. However, study team recommends that the supply capacity needs with regards to Energy + MTS #2 and WNH MTS #4 be further assessed for optimization in the next phases of regional planning. Once the optimization options are complete, Waterloo North Hydro and Energy+ shall conduct a technical and economic assessment in consultation with Hydro One.

7.4 Other Planning Considerations in the KWCG Region

Municipalities in KWCG region have developed their community energy plans with a primary focus to reduce their energy consumption by local initiatives over next 25 to 30 years. With respect to electricity, these communities are planning for an increased reliance on community energy sources such as distributed generation, generation behind the meters like rooftop solar systems and local battery storage systems to reduce cost and for improved reliability of electricity supply.

There are situations where behind the meter battery storage cannot be connected due to technical constraints. The LDCs in this region and Hydro One, outside the regional planning forum, can undertake the task of exploring the issue to assess technical constraints and /or other solutions that can facilitate connection of additional battery storage.

Communities are also working towards self-sufficiency by improving efficiencies of existing local energy systems i.e. reducing energy consumption and losses by means of utilizing smarter buildings, houses, efficient heating, cooling, appliances, equipment, and processes for all community needs. Ultimately, the objective of these energy plans in the region is to be a net zero carbon community.

Community energy plans may have potential to supplement and/or defer future transmission infrastructure development needs. The Study Team therefore recommends reviewing the community energy plans in the SA phase.

8 CONCLUSION AND RECOMMENDATIONS

Hydro One and Waterloo North Hydro Inc. will develop a supply reliability improvement plan for Elmira TS loads. The developed local plan to improve supply reliability of Elmira TS loads will be included in the final RIP report.

At Campbell TS, after replacement of T1 transformer and addressing the secondary equipment limitations there will be sufficient spare supply capacity on T1/T2 DESN to accommodate T3/T4 DESN overloading. Hydro One and the LDC will work together to balance loads between the two Campbell TS DESNs, when required.

The distribution system in the Cedar TS, Hanlon TS and Arlen MTS supply area is already optimized and there are not enough spare feeder positions at any of the stations to reallocate DESN loads without significant distribution system investments and upgrades at neighboring stations.

The Study Team's recommendations for the above identified needs are as follows:

a) The replacement of EOL station supply transformers at Campbell TS, Hanlon TS, Cedar TS, Kitchener MTS #5 and Preston TS along with the EOL auto transformers at Detweiler to proceed. Hydro One and the concerned LDCs will coordinate replacement of above equipment and develop replacement plans.

b) The refurbishment of EOL line sections 115 kV B5C/ B6C, D7F/ D9F and 230 kV D6V/ D7V to proceed. Hydro One will coordinate refurbishment of these line sections with affected LDCs/ Customer.

c) Hydro One will continue to work with Waterloo North Hydro Inc. to address the supply reliability issue at Elmira TS.

d) The Study Team has recommended that Hydro One Transmission and the Guelph Hydro Electric System Inc. to closely monitor the loading at the T3/T4 Campbell TS DESN and to balance the loads between these DESNs when required.

e) The Study Team recommends that the supply capacity needs with regards to Energy + MTS #2 and WNH MTS #4 be further assessed for optimization in the SA phase of regional planning. Once the optimization options are complete, Waterloo North Hydro and Energy+ shall conduct a technical and economic assessment in consultation with Hydro One.

f) The Study Team has recommended that community energy plans will be further considered in the SA phase of the regional planning process.

9 REFERENCES

[1] KWCG Regional Infrastructure Plan - December 2015

[2] Planning Process Working Group Report to the Ontario Energy Board - May 2013

[3] Ontario Resource and Transmission Assessment Criteria (ORTAC) – Issue 5.0 -August 2007

Appendix A: KWCG Region Non-Coincident Summer Load Forecast

* LTR based on 0.9 power factor

Transformer Station		Summer 10 Day LTR*	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Arlen MTS	Gross	45	24.44	25.17	25.92	26.70	27.50	28.33	29.18	30.05	30.95	31.88	32.84	33.82
	CDM		0.00	0.22	0.28	0.44	0.57	0.79	1.12	1.50	2.05	2.71	3.40	3.99
	DG		0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
	Net		24.42	24.94	25.64	26.25	26.92	27.53	28.04	28.54	28.89	29.16	29.43	29.83
Campbell TS (T1/T2)	Gross	94	83.46	84.71	85.98	87.27	88.58	89.91	91.26	92.63	94.02	95.43	96.86	98.31
	CDM		0.00	0.72	0.91	1.44	1.83	2.50	3.51	4.63	6.22	8.11	10.03	11.59
	DG		0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
	Net		83.45	83.98	85.06	85.82	86.75	87.40	87.74	87.99	87.78	87.30	86.82	86.72
Campbell TS (T3/T4)	Gross	56	51.62	53.42	55.29	57.23	59.23	61.30	63.45	65.67	67.97	70.35	72.81	75.36
	CDM		0.00	0.46	0.59	0.94	1.22	1.70	2.44	3.28	4.50	5.98	7.54	8.88
	DG		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Net		51.62	52.97	54.71	56.28	58.01	59.60	61.01	62.39	63.47	64.37	65.27	66.48
Cedar TS (T1/T2)	Gross	103	67.35	67.69	68.03	68.37	68.71	69.05	69.40	69.75	70.09	70.44	70.80	71.15
	CDM		0.00	0.58	0.72	1.13	1.42	1.92	2.67	3.49	4.64	5.99	7.33	8.38
	DG		0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
	Net		67.30	67.06	67.26	67.19	67.24	67.09	66.68	66.21	65.40	64.41	63.42	62.72
Cedar TS (T7/T8)	Gross	40	35.63	35.80	35.98	36.16	36.34	36.53	36.71	36.89	37.08	37.26	37.45	37.63
	CDM		0.00	0.31	0.38	0.60	0.75	1.01	1.41	1.85	2.45	3.17	3.88	4.44
	DG		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Net		35.63	35.50	35.60	35.57	35.59	35.51	35.29	35.05	34.62	34.09	33.57	33.20
Elmira TS	Gross	55	34.19	34.62	35.04	35.38	35.73	36.06	36.39	36.71	37.05	37.40	37.75	38.10
	CDM		0.00	0.30	0.37	0.58	0.74	1.00	1.40	1.84	2.45	3.18	3.91	4.49
	DG		0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
	Net		34.17	34.31	34.65	34.78	34.98	35.04	34.97	34.86	34.58	34.20	33.83	33.60
Energy+ MTS #1	Gross	102	84.03	84.87	85.72	86.58	87.44	88.53	89.64	90.76	91.90	93.05	94.21	95.39
	CDM		0.00	0.73	0.91	1.43	1.80	2.46	3.45	4.54	6.08	7.91	9.75	11.24
	DG		0.32	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49
	Net		83.71	83.65	84.31	84.65	85.15	85.58	85.70	85.73	85.32	84.64	83.96	83.65
Fergus TS	Gross	154	87.52	88.57	89.62	90.27	90.96	91.52	92.07	92.62	93.20	93.83	94.45	95.05
	CDM		0.00	0.76	0.95	1.49	1.87	2.54	3.54	4.63	6.17	7.98	9.78	11.20
	DG		0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
	Net		87.47	87.77	88.62	88.73	89.03	88.92	88.48	87.94	86.98	85.80	84.62	83.80
Galt TS	Gross	169	113.56	114.69	115.84	117.00	118.17	119.64	121.14	122.65	124.19	125.74	127.31	128.90
	CDM		0.00	0.98	1.23	1.93	2.44	3.32	4.66	6.14	8.22	10.69	13.18	15.19
	DG		0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21
	Net		113.35	113.51	114.40	114.86	115.53	116.11	116.27	116.31	115.76	114.84	113.93	113.51
Hanlon TS	Gross	43	26.85	27.25	27.66	28.08	28.50	28.93	29.36	29.80	30.25	30.70	31.16	31.63
	CDM		0.00	0.23	0.29	0.46	0.59	0.80	1.13	1.49	2.00	2.61	3.23	3.73
	DG		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Net		26.85	27.02	27.37	27.62	27.91	28.12	28.23	28.31	28.25	28.09	27.94	27.90
Kitchener MTS # 1	Gross	54	31.31	33.64	34.72	35.81	36.90	37.76	38.60	39.46	40.31	41.16	42.02	42.87
	CDM		0.00	0.29	0.37	0.59	0.76	1.05	1.49	1.97	2.67	3.50	4.35	5.05
	DG		0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
	Net		31.28	33.33	34.33	35.19	36.11	36.68	37.09	37.47	37.62	37.64	37.65	37.79
Kitchener MTS # 3	Gross	108	46.73	45.03	45.34	46.05	46.78	47.49	48.22	48.93	49.64	50.37	51.08	51.81
	CDM		0.00	0.38	0.48	0.76	0.96	1.32	1.86	2.45	3.29	4.28	5.29	6.11
	DG		0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
	Net		46.71	44.63	44.83	45.27	45.79	46.15	46.34	46.46	46.34	46.06	45.77	45.68

Transformer Station		Summer 10 Day LTR*	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Kitchener MTS # 4	Gross	90	58.39	59.76	60.63	61.49	62.36	63.05	63.73	64.41	65.09	65.77	66.46	67.13
	CDM		0.00	0.51	0.64	1.01	1.29	1.75	2.45	3.22	4.31	5.59	6.88	7.91
	DG		0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
	Net		58.34	59.19	59.93	60.43	61.02	61.24	61.22	61.14	60.73	60.12	59.52	59.17
Kitchener MTS #5	Gross	80	66.56	67.94	68.82	69.70	70.58	71.28	71.96	72.66	73.35	74.03	74.73	75.42
	CDM		0.00	0.58	0.73	1.15	1.45	1.98	2.77	3.63	4.86	6.29	7.74	8.89
	DG		0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
	Net		66.50	67.31	68.03	68.49	69.07	69.24	69.14	68.97	68.43	67.68	66.94	66.47
Kitchener MTS #6	Gross	90	64.17	62.22	62.97	63.71	64.47	65.21	65.96	66.70	67.44	68.19	68.93	69.68
	CDM		0.00	0.53	0.67	1.05	1.33	1.81	2.54	3.34	4.46	5.80	7.14	8.21
	DG		0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09
	Net		64.08	61.60	62.21	62.57	63.04	63.30	63.33	63.27	62.88	62.30	61.70	61.38
Kitchener MTS #7	Gross	54	42.79	43.98	44.69	45.38	46.08	46.77	47.47	48.16	48.85	49.55	50.24	50.95
	CDM		0.00	0.38	0.48	0.75	0.95	1.30	1.83	2.41	3.23	4.21	5.20	6.00
	DG		0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
	Net		42.77	43.59	44.19	44.61	45.11	45.45	45.63	45.73	45.60	45.32	45.03	44.92
Kitchener MTS #8	Gross	54	38.68	39.94	41.18	42.44	43.70	45.62	47.53	49.45	51.38	53.30	55.21	57.13
	CDM		0.00	0.34	0.44	0.70	0.90	1.27	1.83	2.47	3.40	4.53	5.71	6.73
	DG		0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
	Net		38.62	39.54	40.69	41.68	42.74	44.30	45.65	46.92	47.92	48.71	49.44	50.34
Kitchener MTS #9	Gross	90	30.16	30.72	31.28	31.83	32.39	32.94	33.50	34.05	34.61	35.17	35.73	36.27
	CDM		0.00	0.26	0.33	0.52	0.67	0.92	1.29	1.70	2.29	2.99	3.70	4.27
	DG		0.23	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50
	Net		29.94	29.96	30.45	30.80	31.22	31.53	31.71	31.85	31.82	31.68	31.53	31.50
Preston TS	Gross	113	92.38	95.15	98.00	100.94	103.97	105.27	106.59	107.92	109.27	110.63	112.02	113.42
	CDM		0.00	0.81	1.04	1.67	2.14	2.92	4.10	5.40	7.23	9.41	11.60	13.37
	DG		0.00	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19
	Net		92.38	94.14	96.76	99.08	101.63	102.15	102.29	102.33	101.84	101.03	100.23	99.86
Puslinch DS	Gross	56	28.49	29.24	30.01	30.45	30.92	31.30	31.68	32.05	32.45	32.88	33.31	33.72
	CDM		0.00	0.25	0.32	0.50	0.64	0.87	1.22	1.60	2.15	2.80	3.45	3.97
	DG		0.02	0.02	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15
	Net		28.47	28.98	29.54	29.80	30.14	30.29	30.31	30.30	30.16	29.94	29.71	29.60
Rush MTS	Gross	68	45.33	46.24	47.16	48.11	49.07	50.05	51.05	52.07	53.11	54.17	55.26	56.36
	CDM		0.00	0.40	0.50	0.79	1.01	1.39	1.97	2.60	3.52	4.61	5.72	6.64
	DG		0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
	Net		45.30	45.81	46.63	47.28	48.03	48.63	49.06	49.44	49.57	49.54	49.51	49.69
Scheifele MTS	Gross	161	144.78	146.96	149.16	151.39	153.67	155.98	158.32	160.69	163.11	165.55	168.04	170.56
	CDM		0.00	1.26	1.59	2.50	3.17	4.33	6.10	8.04	10.80	14.08	17.39	20.10
	DG		0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08
	Net		144.70	145.62	147.49	148.81	150.42	151.56	152.14	152.57	152.23	151.40	150.56	150.38
WNH MTS #3	Gross	77	56.29	57.42	58.57	59.74	60.93	62.15	63.39	64.66	65.95	67.27	68.62	69.99
	CDM		0.00	0.49	0.62	0.99	1.26	1.73	2.44	3.23	4.37	5.72	7.10	8.25
	DG		0.06	0.06	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15
	Net		56.23	56.87	57.80	58.61	59.53	60.28	60.81	61.28	61.44	61.41	61.37	61.60
Wolverton DS	Gross	54	18.42	18.73	19.05	19.19	19.35	19.47	19.59	19.71	19.83	19.98	20.12	20.25
	CDM		0.00	0.16	0.20	0.32	0.40	0.54	0.75	0.99	1.31	1.70	2.08	2.39
	DG		0.00	0.00	0.00	0.00	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19
	Net		18.41	18.57	18.84	18.87	18.76	18.74	18.64	18.53	18.33	18.08	17.84	17.67
CTS	Net		9.80	9.80	9.80	9.80	9.80	9.80	9.80	9.80	9.80	9.80	9.80	9.80

Appendix B: Lists of Step-Down Transformer Stations

Sr. No.	Transformer Stations
1.	Arlen MTS
2.	Campbell TS (T1/T2)
3.	Campbell TS (T3/T4)
4.	Cedar TS (T1/T2)
5.	Cedar TS (T7/T8)
6.	Elmira TS
7.	Energy+ MTS #1
8.	Fergus TS
9.	Galt TS
10.	Hanlon TS
11.	Kitchener MTS # 1
12.	Kitchener MTS # 3
13.	Kitchener MTS # 4
14.	Kitchener MTS #5
15.	Kitchener MTS #6
16.	Kitchener MTS #7
17.	Kitchener MTS #8
18.	Kitchener MTS #9
19.	Preston TS
20.	Puslinch DS
21.	Rush MTS
22.	Scheifele MTS
23.	Waterloo North MTS 3
24.	Wolverton DS
25.	CTS - 1
26.	CTS - 2

Appendix C: Lists of Transmission Circuits

Sr. No.	Circuit ID	From Station	To Station	Voltage (kV)
1.	D6V/ D7V	Detweiler TS	Orangeville TS	220
2.	M20D/ M21D	Detweiler TS	Middleport TS	220
3.	D4W/ D5W	Detweiler TS	Buchanan TS	220
4.	B22D/ B23D	Detweiler TS	Bruce TS	220
5.	D7F/ D9F	Detweiler TS	Free Port SS	115
6.	F11C/ F12C	Free Port SS	Cedar TS	115
7.	B5C/ B6C	Cedar TS	Burlington TS	115
8.	D11K/ D12K	Detweiler TS	Kitchener MTS #4	115
9.	D8S	Detweiler TS	St. Mary TS	115
10.	D10H	Detweiler TS	Hanover TS	115

Appendix D: Lists of LDCs in the KWCG Region

Sr. No.	Company	Connection Type (TX/DX)
1.	Centre Wellington Hydro	Dx
2.	Energy+	Tx/ Dx
3.	Guelph Hydro Electric System Inc.	Tx/ Dx
4.	Halton Hills Hydro	Dx
5.	Hydro One Networks Inc. (Distribution)	Tx/ Dx
6.	Kitchener Wilmot Hydro Inc.	Tx
7.	Milton Hydro	Dx
8.	Waterloo North Hydro Inc.	Tx/ Dx
9.	Wellington North Power Inc.	Dx

Appendix E: Acronyms

Acronym	Description
A	Ampere
BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
CIA	Customer Impact Assessment
CGS	Customer Generating Station
CSS	Customer Switching Station
CTS	Customer Transformer Station
DESN	Dual Element Spot Network
DG	Distributed Generation
DS	Distribution Station
GS	Generating Station
HV	High Voltage
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
LDC	Local Distribution Company
LP	Local Plan
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low Voltage
MTS	Municipal Transformer Station
MW	Megawatt
MVA	Mega Volt-Ampere
MVAR	Mega Volt-Ampere Reactive
NA	Needs Assessment
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.
NUG	Non-Utility Generator
OEB	Ontario Energy Board
OPA	Ontario Power Authority
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Plan
SA	Scoping Assessment
SIA	System Impact Assessment
SPS	Special Protection Scheme
SS	Switching Station
STG	Steam Turbine Generator
TS	Transformer Station

Appendix I

Hydro One Networks Inc. - Planning Status Letter

Alectra Utilities

Distribution System Plan (2020-2024)

Hydro One Networks Inc.
483 Bay Street
13th Floor, North Tower
Toronto, ON M5G 2P5
www.HydroOne.com

Tel: (416) 345-5420
Fax: (416) 345-4141
Ajay.Garg@HydroOne.com

April 5th, 2019

Riaz Shaikh
Manager, Distribution System Planning
Alectra Utilities Corporation
2185 Derry Rd W,
Mississauga, ON L5N 7A6,

Dear Mr. Shaikh,

Subject: Regional Planning Status

As per your request, this Planning Status letter is provided to meet one of the requirements of your upcoming Rate Application to the Ontario Energy Board (OEB).

As you are aware, the province of Ontario is divided into 21 Regions for the purpose of Regional Planning (RP), and these regions have been split into three (3) groups for the purposes of prioritizing and managing the RP process. A map of Ontario showing the 21 Regions and the list of LDCs in each of the Region are attached as Appendix A and B respectively.

Alectra Utilities Corporation's service territory extends to parts of Burlington to Nanticoke, GTA North, GTA West, Kitchener-Waterloo-Cambridge-Guelph (KWCG) and Toronto regions in Group 1, South Georgian Bay / Muskoka region in Group 2 and Niagara region in Group 3, where Hydro One Networks Inc. (Hydro One) is the lead transmitter.

This letter confirms that the first cycle of RP for all the 21 regions was completed in 2017. Since then, the second cycle of regional planning is in progress for Burlington to Nanticoke, Greater Ottawa, GTA North, GTA West, KWCG, Toronto and Windsor Essex regions. An overview of the RP process is available on Hydro One's RP homepage[1], which also includes these region's current status and corresponding reports. The current RP status for the regions impacting Alectra Utilities is summarized below:

Burlington to Nanticoke Region

The first cycle of RP for this Region was completed in February 2017 and the second cycle Needs Assessment (NA) report was completed and published in May 2017.

[1] https://www.hydroone.com/about/corporate-information/regional-plans

The first cycle Regional Infrastructure Plan (RIP) identified additional needs related to end-of-life transmission assets in the Hamilton area. The plans to address these end-of-life needs are being developed by Hydro One in coordination with Alectra and other impacted LDCs in the region.

The project to install 115kV switching facilities at Brant TS was identified as one of the transmission infrastructure investments required for the region. This project along with investments at Beach TS for Transformer (T3/T4) replacement; and at Bronte TS for Transformer (T5/T6) and DESN refurbishment, are continuing to be developed and are expected to be in-service in 2019.

In response to the remaining RIP recommendations, the following investments are planned to commence over the 2020 to 2024 period:

- Beach TS: Auto-Transformer (T7/T8) Replacement and DESN Switchgear
- Birmingham TS: MV Metalclad Switchgear Refurbishment
- Dundas TS: MV Switchyard Refurbishment
- Dundas TS #2: Two New Feeder Positions
- Elgin TS: Transformer and DESN Reconfiguration
- Gage TS: Transformer and DESN Reconfiguration
- Kenilworth TS: Transformer and DESN Reconfiguration
- Lake TS: LV Switchyard Refurbishment
- Newton TS: Station Refurbishment
- 115kV B3/B4 Transmission Line: Refurbish line sections from Horning Mountain Junction to Glanford Junction and
- 115kV B7/B8 Transmission Line: Refurbish line sections from Burlington TS to Nelson Junction

The second cycle NA reaffirmed the needs identified in the first cycle RIP and has identified the following additional needs resulting from aging infrastructure over the 2020 to 2024 period:

- Burlington TS: LV Switchyard Refurbishment and
- Norfolk TS: LV Switchyard Refurbishment

Hydro One is developing scope of work and will continue to coordinate with Alectra Utilities and impacted customers for the effective execution of these projects. The above projects are expected to improve the overall reliability performance in the region. Hydro One is expecting that there will be little or no capital contribution from Alectra Utilities Corporation for the above projects in the Burlington to Nanticoke Region consistent with the Transmission System Code (TSC).

<u>GTA North Region</u>

The GTA North region was divided into two sub-regions: a) Western Sub-Region and b) York Sub-Region. This letter confirms that the first cycle of RP for GTA North Region was completed in February 2016 and the second cycle NA report was completed and published in March 2018.

The first cycle RIP identified three transmission infrastructure investments over the 2017 to 2018 period.

These investments have been completed and placed in-service, including the connection of a new load station Vaughan MTS #4 owned and operated by Alectra Utilities; the installation of breakers and switches at Holland TS; and the installation of two inline switches on the 230kV circuits V71P/V75P at Grainger Junction.

The second cycle NA has identified the need for the following investments over the 2020 to 2024 period:

- Connection of a new load station Markham #5 MTS and
- Woodbridge TS: Transformer (T5) Replacement

Based on the latest load forecast and Conservation and Demand Side Management (CDM) impact, the targeted completion date for the MTS#5 has been revised to 2026. The above projects are expected to strengthen the electrical system and improve the overall reliability performance in the region. The connection of Markham MTS #5 is projected to be beyond 2024 and may require capital contribution from Alectra Utilities Corporation consistent with the TSC.

GTA West Region

The first cycle of RP for GTA West Region was completed in January 2016 and the second cycle NA phase is expected to be completed by Q2 2019.

In response to the first cycle RIP recommendations, the following investments are planned over the 2020 to 2024 period:

- Connection of a new load station Halton TS #2
- Station Expansion and Connection of 230kV circuits at Milton Switching Station (SS) and
- Reconductoring 230kV H29/H30 Transmission Line

Hydro One is expecting little or no capital contribution from Alectra Utilities Corporation for the above projects in the GTA West Region consistent with the TSC.

Kitchener – Waterloo – Cambridge - Guelph Region

The KWCG region includes the municipalities of Kitchener, Waterloo, Cambridge and Guelph, as well as portions of Perth and Wellington Counties and the Townships of Wellesley, Woolwich, Wilmot and North Dumfries. This letter confirms that the first cycle of RP for KWCG Region was completed in December 2015 and the second cycle NA report was completed and published in December 2018.

The following transmission projects were completed by Hydro One to address needs that were recommended in the first cycle RIP:

- The Guelph Area Transmission Refurbishment Project (GATR), placed into service since Q4 2016.
- The switching facilities work at Galt Junction to improve supply reliability for the Cambridge-Kitchener 230 kV Sub-system, placed into service in Oct 2017.

The second cycle NA has identified following new projects to address aging Infrastructure needs in the region:

- Near Term (1-5 years)
    - Campbell TS – T1 (2018)
    - Detweiler TS -Auto T2 &T4 (2021-2022)
    - 115 kV B5C/ B6C Circuits (2019-2020)
    - 115 kV D7F/ D9F Circuits (2019-2020)
    - 230 kV D6V/ D7V Circuits (2019- 2020)
- Mid-term (5-10 years)
    - Hanlon TS - T1 & T2 (2023-2024)
    - Cedar TS - T7 & T8 (2024-2025)
    - Preston TS - T3 & T4 (2025-2026)

It is expected that there will be little or no capital contributions required from Alectra Utilities for the above transmission projects undertaken by Hydro One consistent with the TSC.

Other two distribution projects addressing the end-of-life needs emerging over next 5-10 years as outlined in the 2nd cycle NA report are being planned and managed by the LDCs:

- Scheifele MTS - T1 & T2 (2024-2026) for Waterloo North Hydro
- Kitchener MTS #5 - T9 & T10 (2023-2024) for Kitchener Wilmot Hydro Inc.

The above projects are expected to improve the overall reliability performance in the region. The future system capacity need for Waterloo North Hydro MTS #4 and the new future system capacity need for Energy+ MTS #2 will be studied during the next phases of second cycle regional planning.

Toronto Region

This letter confirms that the first cycle of RP for Toronto (formerly referred to as Metro Toronto) region has been completed in January 2016 and the second cycle of RP is in progress. The second cycle NA was completed in October 2017.

The first cycle RIP identified several near-term transmission infrastructure investments for the region, including:

- Addition of a second transformer station at Horner TS
- Manby TS, Autotransformer overload protection scheme
- Runnymede TS, Expansion of transformer station and reconductoring the 115kV circuits and
- Southwest GTA Transmission Reinforcement

The investments at Runnymede TS and Manby TS were completed and placed in-service in 2018. The other two investments, along with the connection for Copeland MTS Phase 2, are expected to be in-service over the 2020 to 2024 period.

The second cycle NA reaffirmed the needs identified in the first cycle RIP and also identified the following additional investments to address aging infrastructure issues over the 2020 to 2024 period:

- Bermondsey TS Transformer (T3/T4) Replacement
- Bridgman TS: Transformer (T11-T13) Replacement
- Charles TS: Transformer (T3/T4) Replacement
- Duplex TS: Transformer (T1/T2) Replacement
- Fairbank TS: Transformer (T1-T4) Replacement
- Fairchild TS: Transformer (T1/T2) Replacement
- John TS: Station Reinvestment
- Leslie TS: Transformer (T1) Replacement
- Main TS: Transformer (T3/T4) Replacement
- Manby TS: Transformer (T7/T9/T12/T13) and 230kV Component Replacement
- Runnymede TS: Transformer (T3/T4) Replacement
- Sheppard TS: Transformer (T3/T4) Replacement
- Strachan TS: Transformer (T12) Replacement
- 115kV C5E/C7E Underground Cables: Refurbish cable sections from Esplanade TS to Terauley TS
- 115kV H1L/H3L/H6LC/H8LC Transmission Lines: Refurbish line sections from Leaside Junction to Bloor St. Junction and
- 115kV L9C/L12C Transmission Lines: Refurbish line sections from Leaside TS to Balfour Junction

These investments will require little or no contribution from Alectra Utilities Corporation.

<u>South Georgian Bay / Muskoka Region</u>

This letter confirms that the first cycle of Regional Planning for South Georgian Bay/Muskoka Region has been completed in August 2017 and the second cycle of Regional planning is currently expected to commence in Q4 of 2019.

In response to the RIP recommendations, the following investments are being planned over the 2020 to 2024 period:

- Barrie Area Transmission Upgrade
- Minden TS: Transformer Replacement, LV Switchyard Rebuild
- Orangeville TS: Transformer (T1/T2) Replacement
- Parry Sound TS: Transformer Replacement

These projects are expected to maintain and/or improve the reliability performance and provide additional capacity in the region. Barrie Area Transmission Upgrade project is still under development and contribution from LDCs, if any, will be consistent with the requirements of Transmission System Code. It is currently expected that these investments will require little or no contribution from Alectra Utilities Corporation.

Niagara Region

The first cycle of Regional Planning for Niagara Region was completed in March 2017 and the second cycle of Regional planning is expected to commence in Q3 of 2019.

The Regional Infrastructure Plan identified that the needs for this region were strictly local in nature. Local plans have been implemented by Hydro One to address thermal overloading of the 115kV circuit (Q4N) by upgrading the conductor on a section of Q4N from Beck 1 SS to Portal Junction. At this time the following infrastructure investments are contemplated over the 2020 to 2024 planning period in the Niagara Region

- Carlton TS Switchgear Replacement (2021)
- Glendale TS Transformer and component Replacement (2023)
- Thorold Transformer and Component Replacement (2022)
- Stanley TS Transformer and Component Replacement (2021)
- Crowland TS Transformer and Component Replacement (2023)

Links to all the first cycle Regional Infrastructure Plans (RIPs) and the second cycle Needs Assessment (NA) reports, where applicable in order of regional description provided above, can be found in Appendices C and D respectively. Further planning details will be communicated and discussed with Study Team Members as they become available. It is expected that these investments will require little or no contribution from Alectra Utilities Corporation.

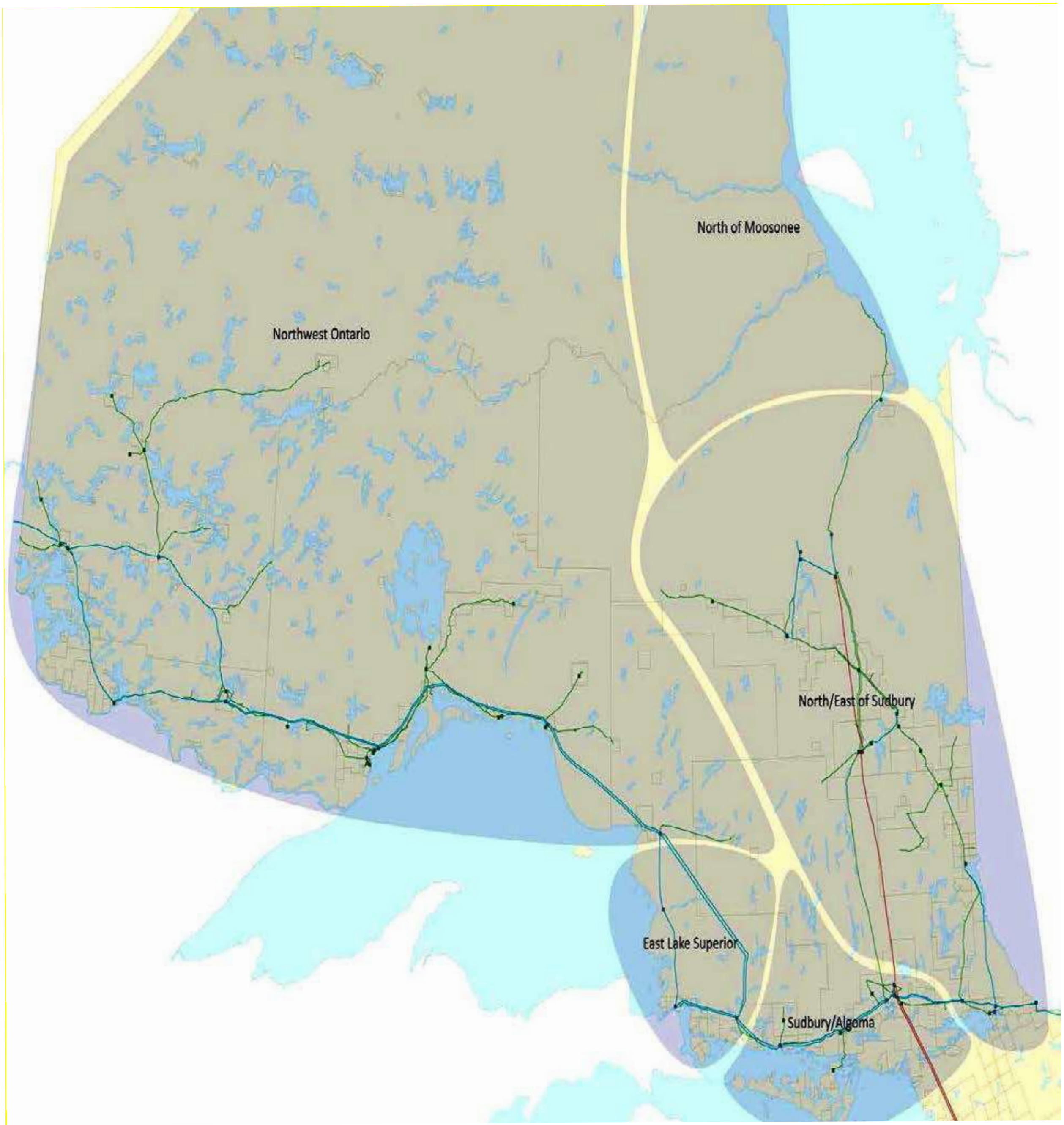
Alectra Utilities Corporation is an active participating member on the regional Study Teams and Hydro One is looking forward to continue working with Alectra Utilities in executing the regional planning process. Please feel free to contact me if you have any questions.

Sincerely,

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

Appendix A: Map of Ontario's Planning Regions

Northern Ontario



Southern Ontario

Greater Toronto Area (GTA)

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

Appendix B: List of LDCs for Each Region

[Hydro One as Upstream Transmitter]

Region	LDCs
1. Burlington to Nanticoke	• Energy+ Inc. • Brantford Power Inc. • Burlington Hydro Inc. • Haldimand County Hydro Inc.** • Alectra Utilities Corporation • Hydro One Networks Inc. • Norfolk Power Distribution Inc.** • Oakville Hydro Electricity Distribution Inc.
2. Greater Ottawa	• Hydro 2000 Inc. • Hydro Hawkesbury Inc. • Hydro One Networks Inc. • Hydro Ottawa Limited • Ottawa River Power Corporation • Renfrew Hydro Inc.
3. GTA North	• Alectra Utilities Corporation • Hydro One Networks Inc. • Newmarket-Tay Power Distribution Ltd. • Toronto Hydro Electric System Limited • Veridian Connections Inc.
4. GTA West	• Burlington Hydro Inc. • Alectra Utilities Corporation • Halton Hills Hydro Inc. • Hydro One Networks Inc. • Milton Hydro Distribution Inc. • Oakville Hydro Electricity Distribution Inc.
5. Kitchener- Waterloo-Cambridge-Guelph ("KWCG")	• Energy+ Inc. • Centre Wellington Hydro Ltd. • Alectra Utilities Corporation • Halton Hills Hydro Inc. • Hydro One Networks Inc. • Kitchener-Wilmot Hydro Inc. • Milton Hydro Distribution Inc. • Waterloo North Hydro Inc. • Wellington North Power Inc.

6. Toronto	• Alectra Utilities Corporation • Hydro One Networks Inc. • Toronto Hydro Electric System Limited • Veridian Connections Inc.
7. Northwest Ontario	• Atikokan Hydro Inc. • Chapleau Public Utilities Corporation • Fort Frances Power Corporation • Hydro One Networks Inc. • Kenora Hydro Electric Corporation Ltd. • Sioux Lookout Hydro Inc. • Thunder Bay Hydro Electricity Distribution Inc.
8. Windsor-Essex	• E.L.K. Energy Inc. • Entegrus Power Lines Inc. [Chatham- Kent] • EnWin Utilities Ltd. • Essex Powerlines Corporation • Hydro One Networks Inc.
9. East Lake Superior	N/A → This region is not within Hydro One's territory
10. GTA East	• Hydro One Networks Inc. • Oshawa PUC Networks Inc. • Veridian Connections Inc. • Whitby Hydro Electric Corporation
11. London area	• Entegrus Power Lines Inc. [Middlesex] • Erie Thames Power Lines Corporation • Hydro One Networks Inc. • London Hydro Inc. • Norfolk Power Distribution Inc.** • St. Thomas Energy Inc. • Tillsonburg Hydro Inc. • Woodstock Hydro Services Inc.**
12. Peterborough to Kingston	• Eastern Ontario Power Inc. • Hydro One Networks Inc. • Kingston Hydro Corporation • Lakefront Utilities Inc. • Peterborough Distribution Inc. • Veridian Connections Inc.

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

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

**This Local Distribution Company (LDC) has been acquired by Hydro One Networks Inc.

Appendix C: Links to Regional Infrastructure Plans

Burlington to Nanticoke

GTA North

GTA West

Kitchener-Waterloo-Cambridge-Guelph (KWCG)

Toronto

South Georgian Bay / Muskoka

Niagara

Appendix D: Links to Needs Assessment Reports

Burlington to Nanticoke

GTA North

Kitchener-Waterloo-Cambridge-Guelph (KWCG)

Toronto

Appendix J

Asset Depreciation Study for the Ontario Energy Board

Kinectrics Inc. Report No: K-418033-RA-001-R000 (July 8, 2010)

Alectra Utilities

Distribution System Plan (2020-2024)

Asset Depreciation Study for the Ontario Energy Board

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

July 8, 2010

Kinectrics Inc.
800 Kipling Avenue, Unit 2
Toronto, ON Canada M8Z 6C4
www.kinectrics.com

DISCLAIMER

The views expressed in this report are those of Kinectrics Inc. and do not necessarily represent the views of, and should not be attributed to the Ontario Energy Board, any individual Board member, or Board staff.

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	USEFUL LIFE: TUL	USEFUL LIFE: MAX UL	FACTORS **: MC	EL	EN	OP	MP	NPF
OH	1	Fully Dressed Wood Poles	Overall		35	45	75	H	L	M	NI	L	L
			Cross Arm	Wood	20	40	55						
				Steel	30	70	95						
	2	Fully Dressed Concrete Poles	Overall		50	60	80	H	L	M	NI	L	NI
			Cross Arm	Wood	20	40	55						
				Steel	30	70	95						
	3	Fully Dressed Steel Poles	Overall		60	60	80	H	M	L	NI	L	NI
			Cross Arm	Wood	20	40	55						
				Steel	30	70	95						
	4	OH Line Switch			30	45	55	L	L	L	L	M	L
	5	OH Line Switch Motor			15	25	25	L	NI	L	L	M	L
	6	OH Line Switch RTU			15	20	20	NI	NI	L	L	L	M
	7	OH Integral Switches			35	45	60	L	M	M	M	L	H
	8	OH Conductors			50	60	75	M	L	M	NI	NI	L
	9	OH Transformers & Voltage Regulators			30	40	60	L	M	M	NI	NI	M
	10	OH Shunt Capacitor Banks			25	30	40	-	-	-	-	-	-
	11	Reclosers			25	40	55	L	L	L	M	L	M
TS & MS	12	Power Transformers	Overall		30	45	60	NI	M	M	L	L	NI
			Bushing		10	20	30						
			Tap Changer		20	30	60						
	13	Station Service Transformer			30	45	55	NI	L	M	L	NI	L
	14	Station Grounding Transformer			30	40	40	-	-	-	-	-	-
	15	Station DC System	Overall		10	20	30	NI	M	L	L	M	M
			Battery bank		10	15	15						
			Charger		20	20	30						
	16	Station Metal Clad Switchgear	Overall		30	40	60	L	L	M	M	M	M
			Removable Breaker		25	40	60						
	17	Station Independent Breakers			35	45	65	M	M	M	M	M	M
	18	Station Switch			30	50	60	M	L	M	M	M	L

* **OH = Overhead Lines System** **TS & MS = Transformer and Municipal Stations**

** MC = Mechanical Stress EL = Electrical Loading OP = Operating Practices EN = Environmental Conditions
MP = Maintenance Practices NPF=Non-Physical Factors
H=High M=Medium L=Low NI=No Impact

PARENT*	#	ASSET DETAILS Category| Component | Type		USEFUL LIFE MIN UL	TUL	MAX UL	FACTORS ** MC	EL	EN	OP	MP	NPF
TS & MS	19	Electromechanical Relays		25	35	50	NI	NI	NI	NI	NI	H
	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).

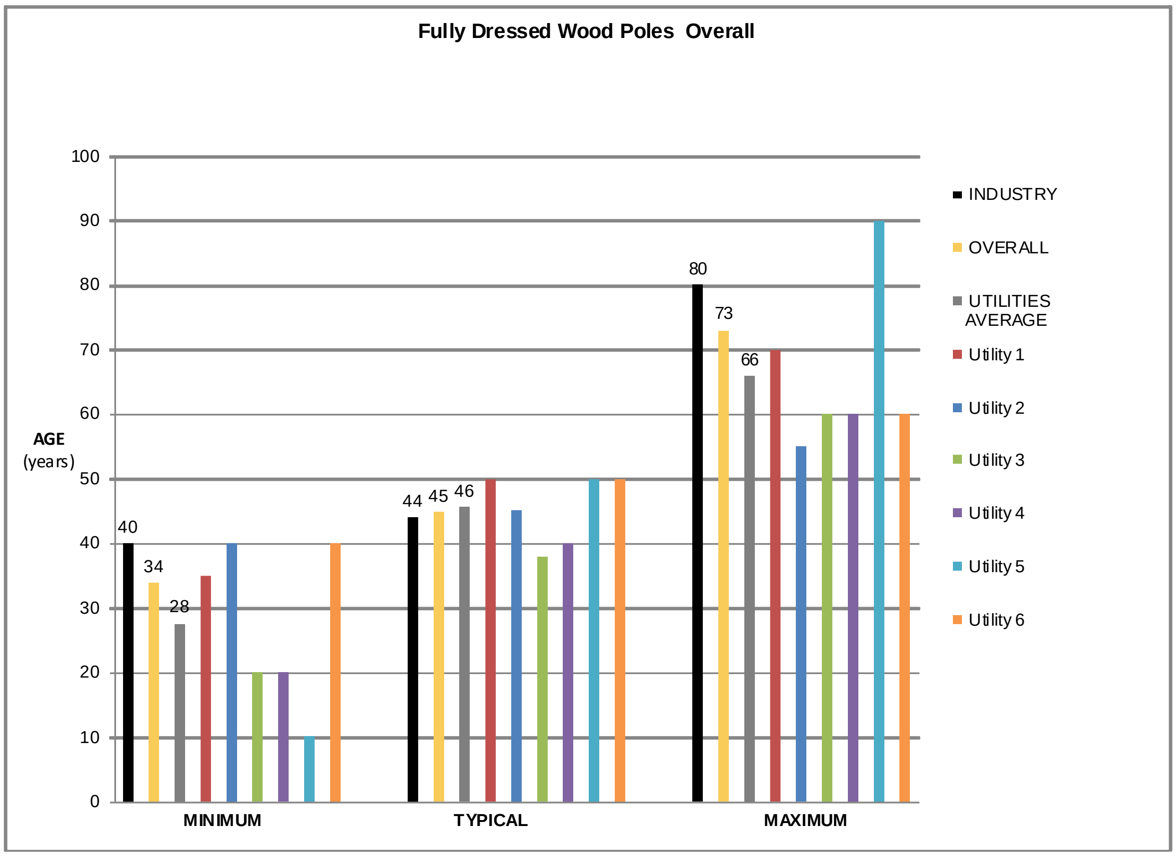


Figure 1-1 Useful Life Values for Fully Dressed Wood Poles

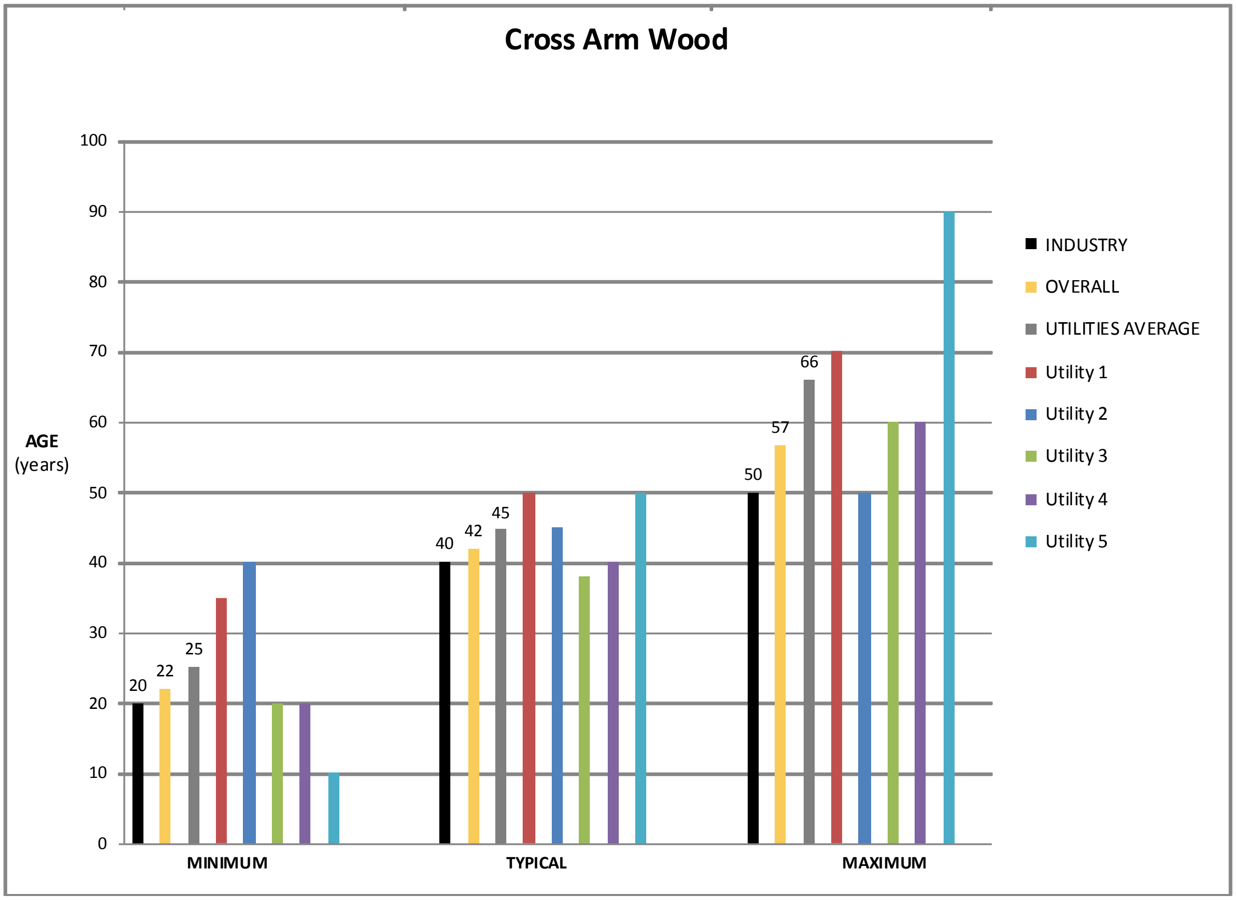


Figure 1-2 Useful Life Values for Fully Dressed Wood Poles – Cross Arm – Wood

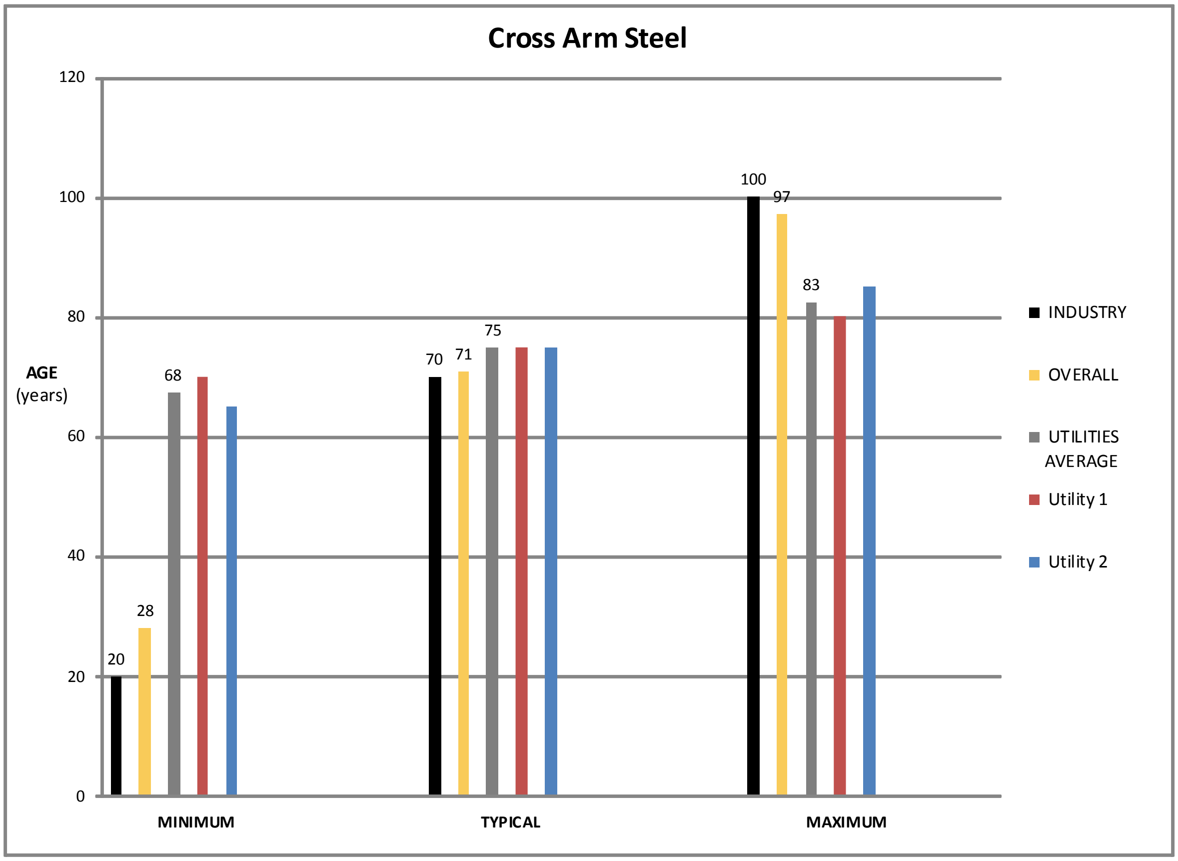


Figure 1-3 Useful Life Values for Fully Dressed Wood Poles – Cross Arm - Steel

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.

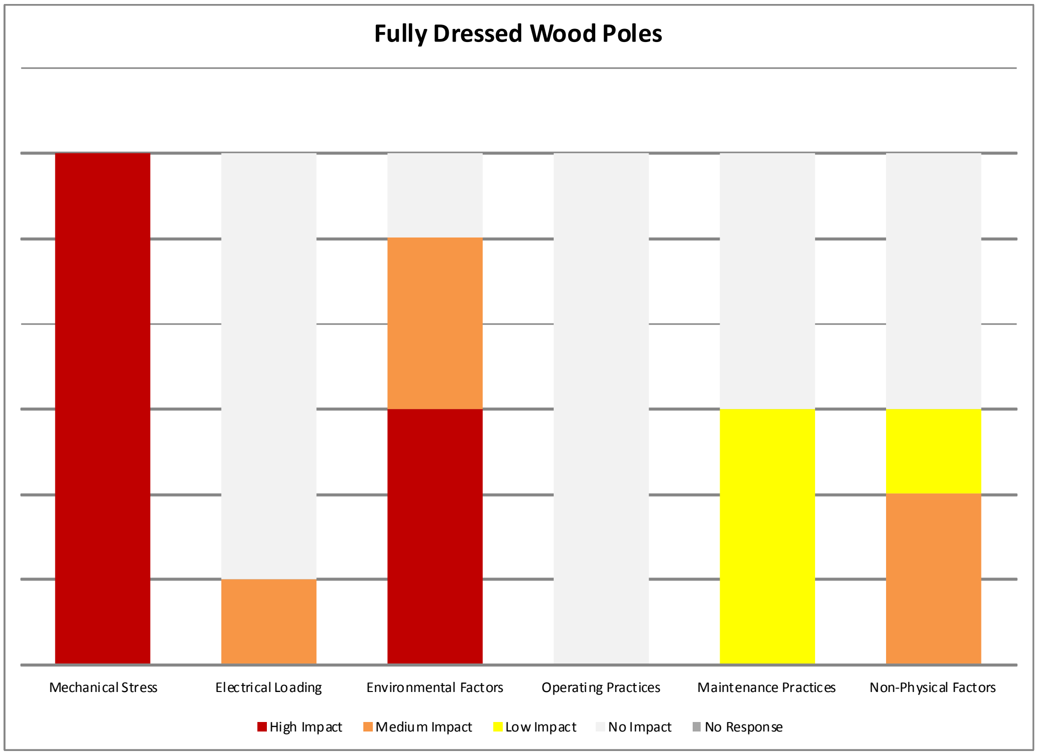


Figure 1-4 Impact of Utilization Factors of the Useful Life of Fully Dressed Wood Poles

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.

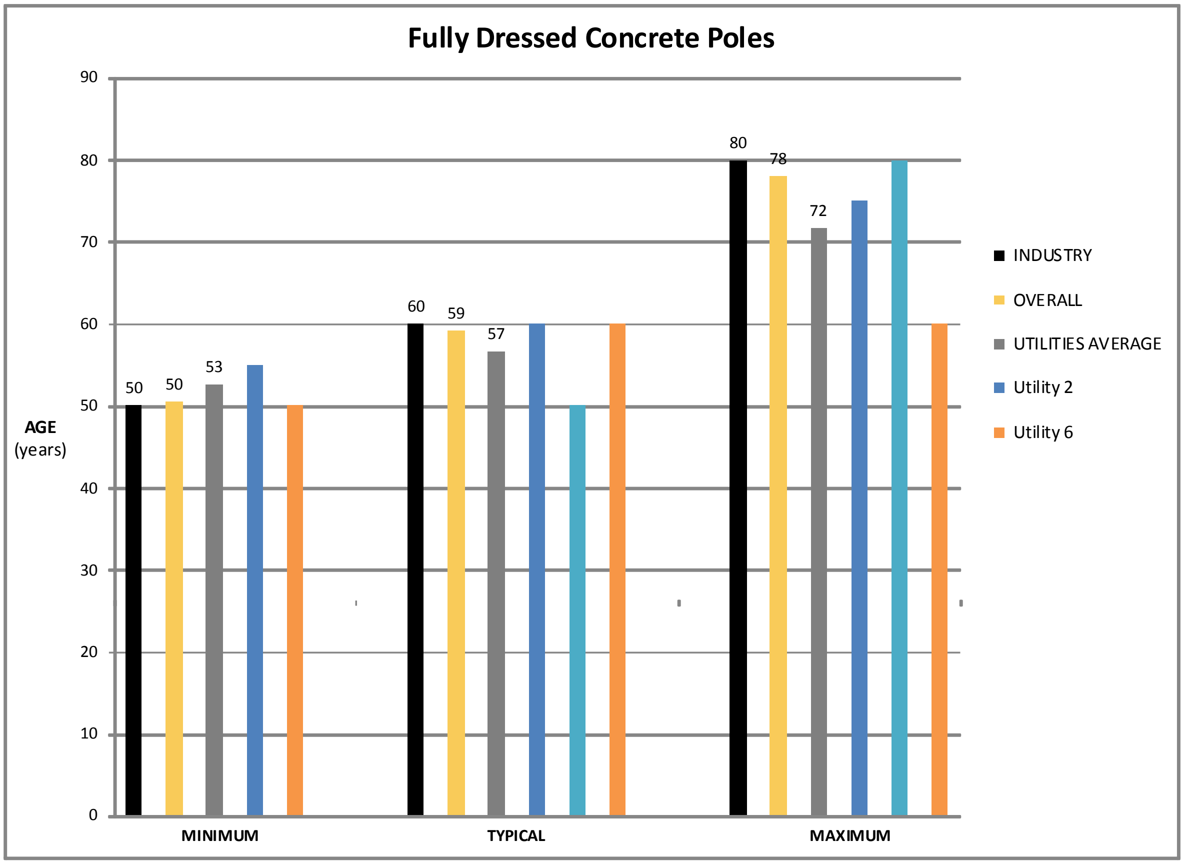


Figure 2-1 Useful Life Values for Fully Dressed Concrete Poles

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).

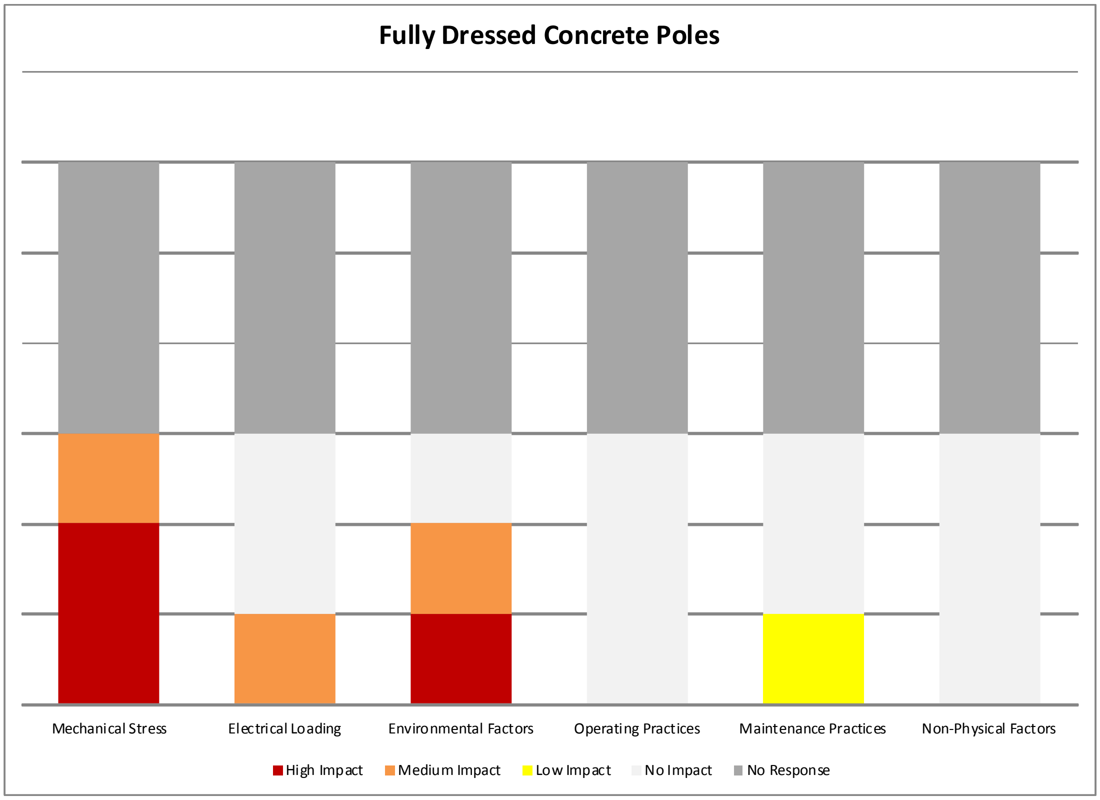


Figure 2-2 Impact of Utilization Factors on the Useful Life of Fully Dressed Concrete Poles

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.

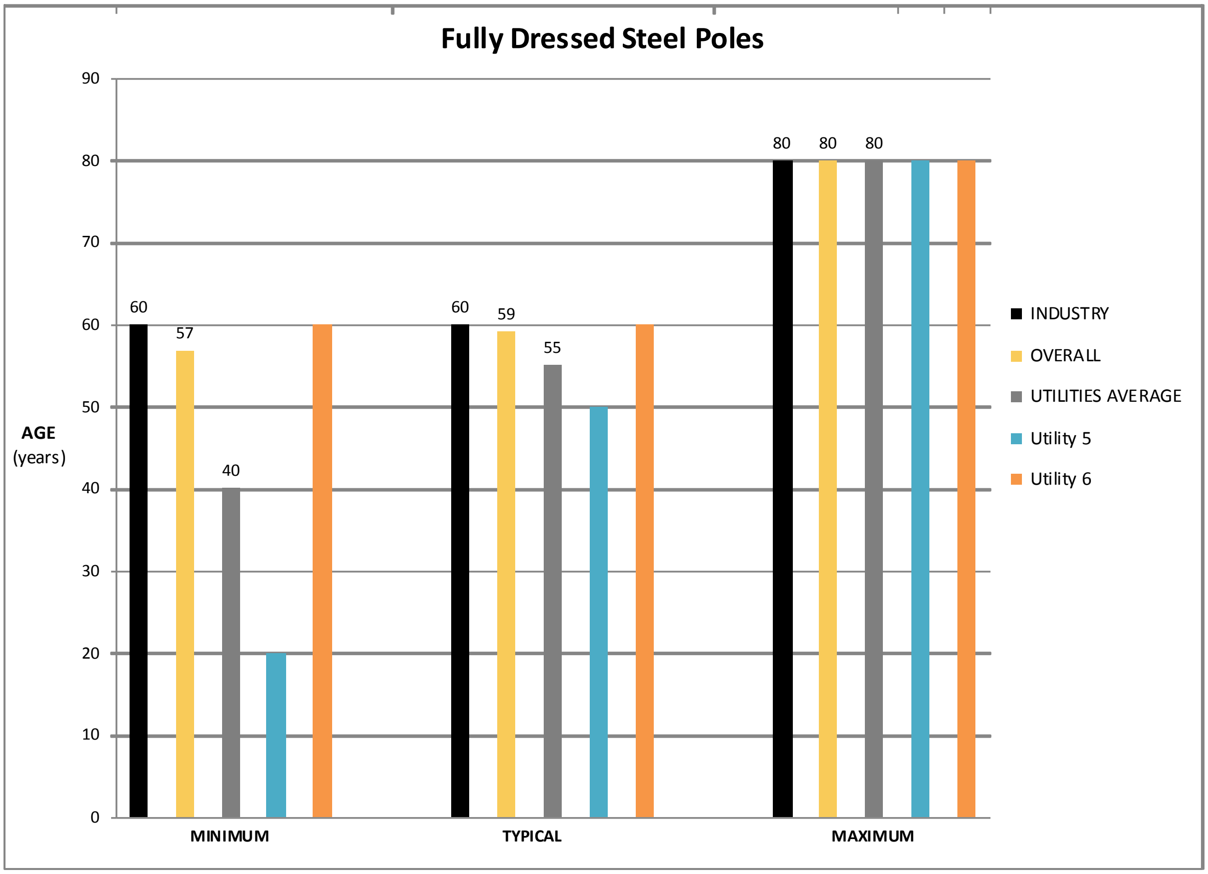


Figure 3-1 Useful Life Values for Fully Dressed Steel Poles

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).

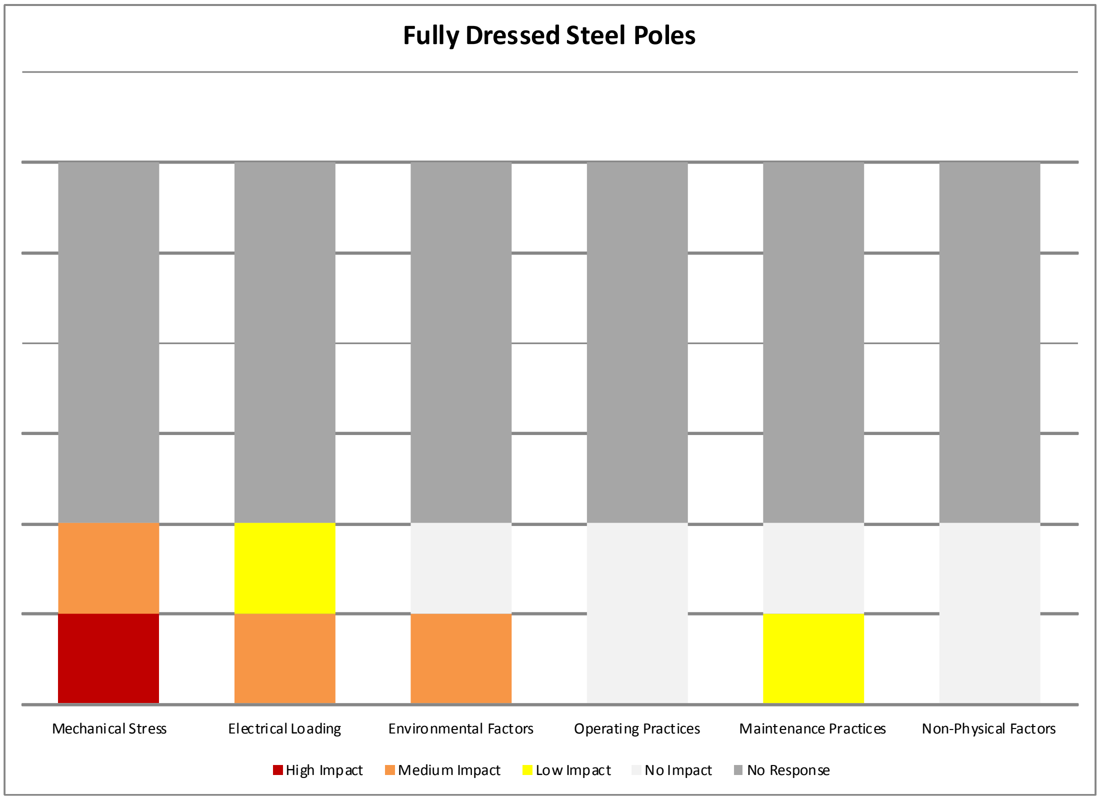


Figure 3-2 Impact of Utilization Factors on the Useful Life of Fully Dressed Steel Poles

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).

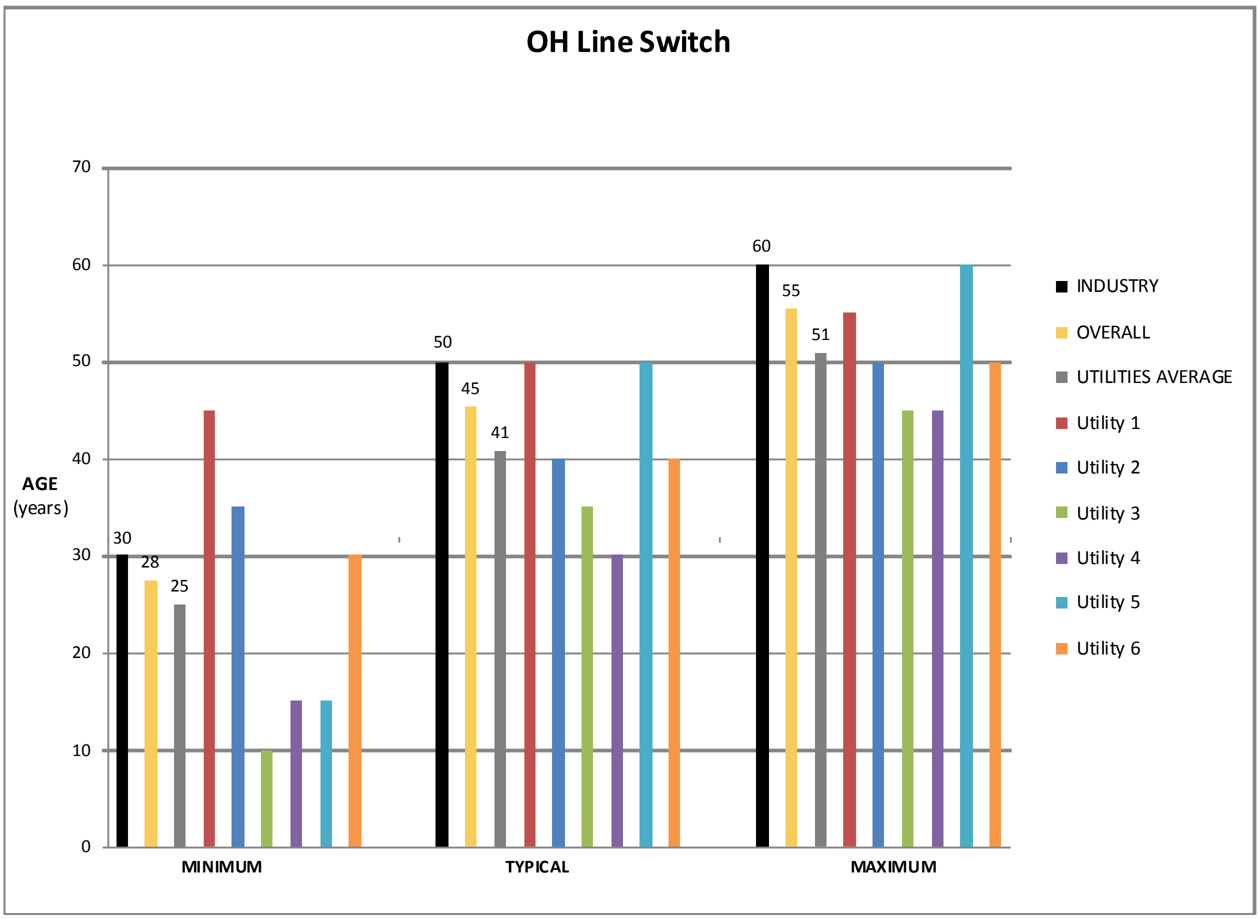


Figure 4-1 Useful Life Values for Overhead Line Switch

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).

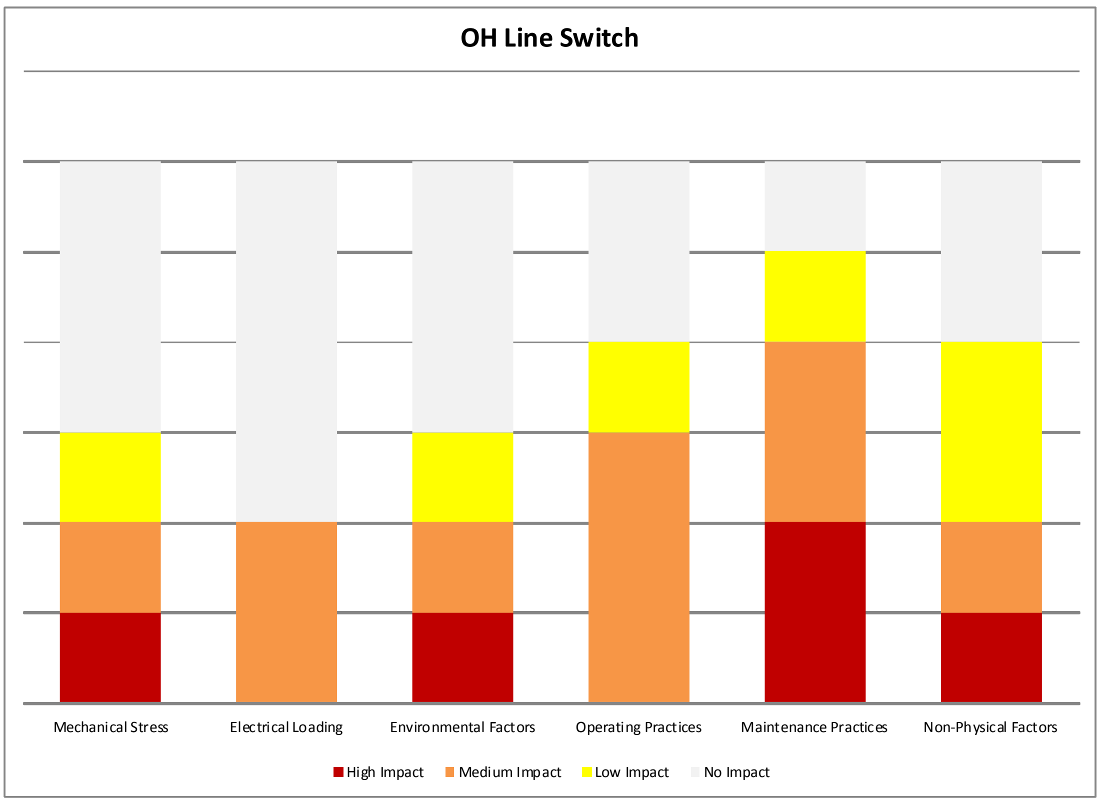


Figure 4-2 Impact of Utilization Factors on the Useful Life of Overhead Line Switch

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).

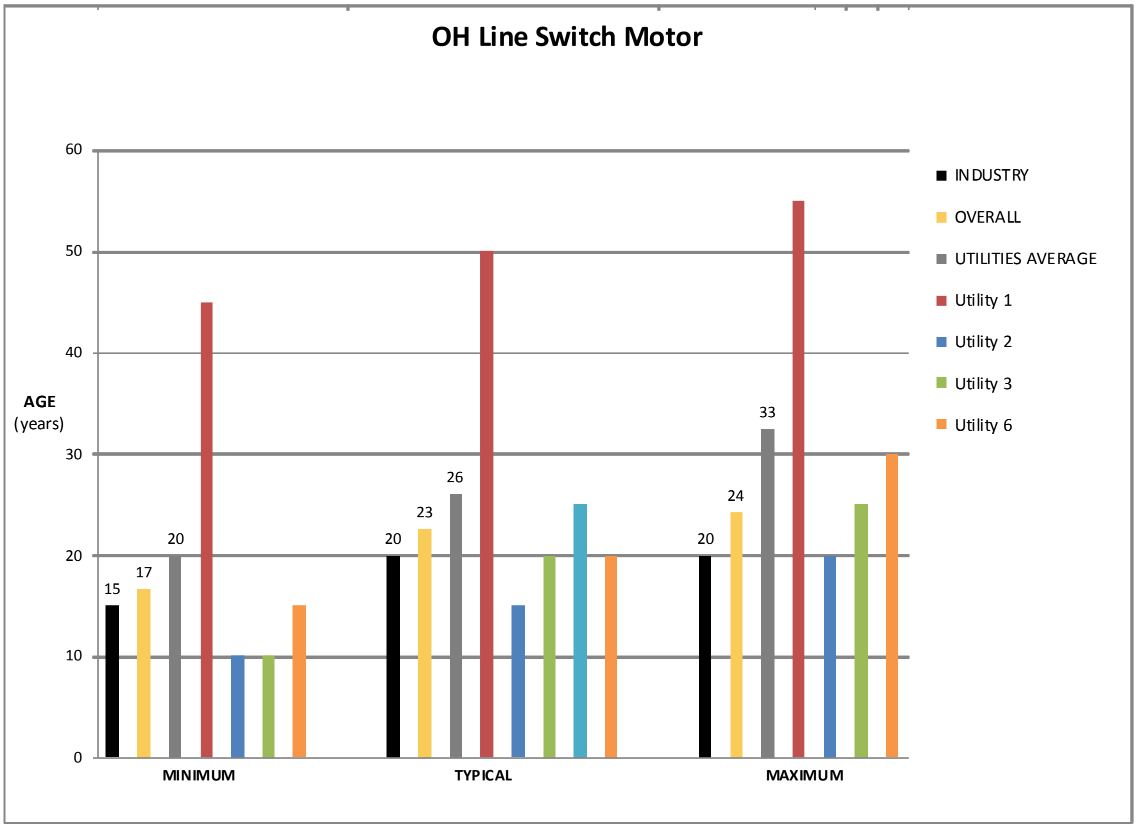


Figure 5-1 Useful Life Values for Overhead Line Switch Motor

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).

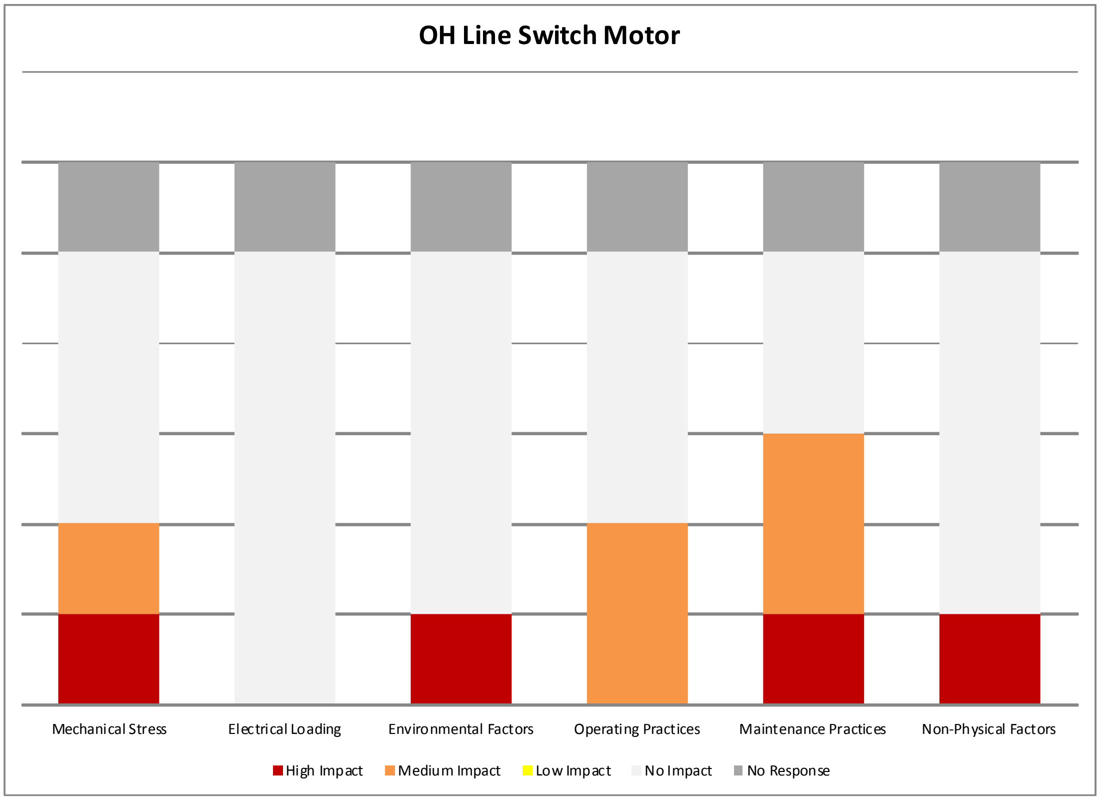


Figure 5-2 Impact of Utilization Factors on the Useful Life of Overhead Line Switch Motor

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).

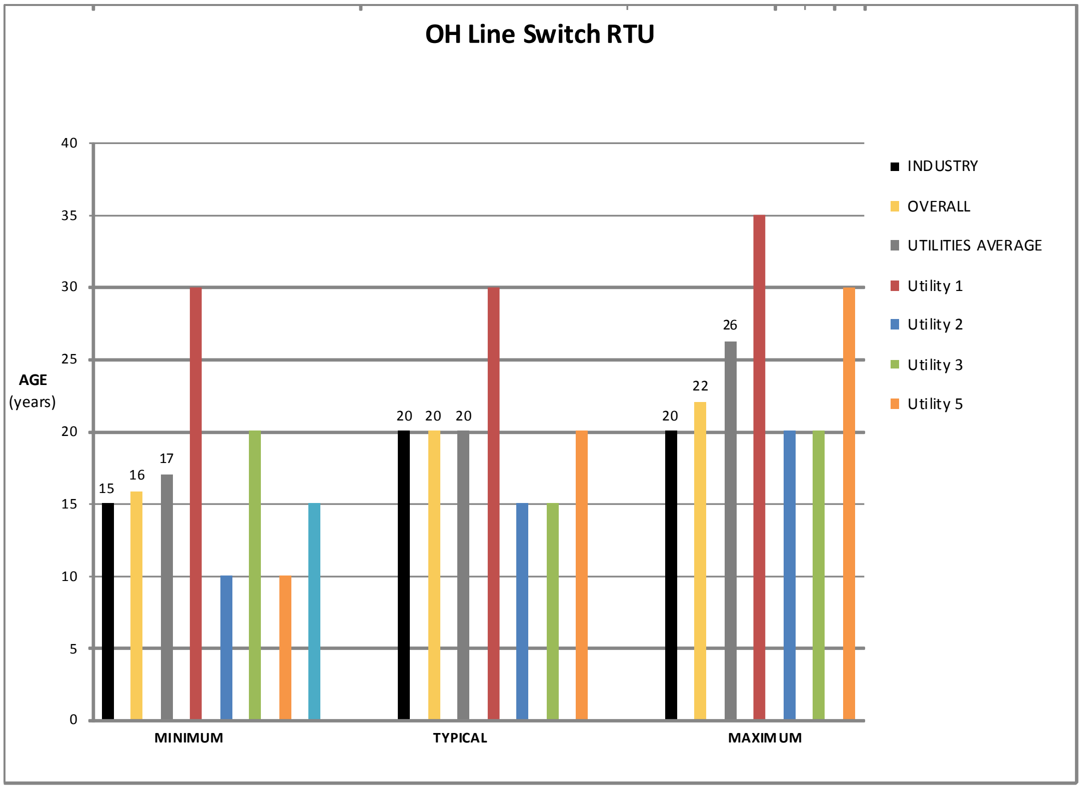


Figure 6-1 Useful Life Values for Overhead Line Switch Remote Terminal Unit

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).

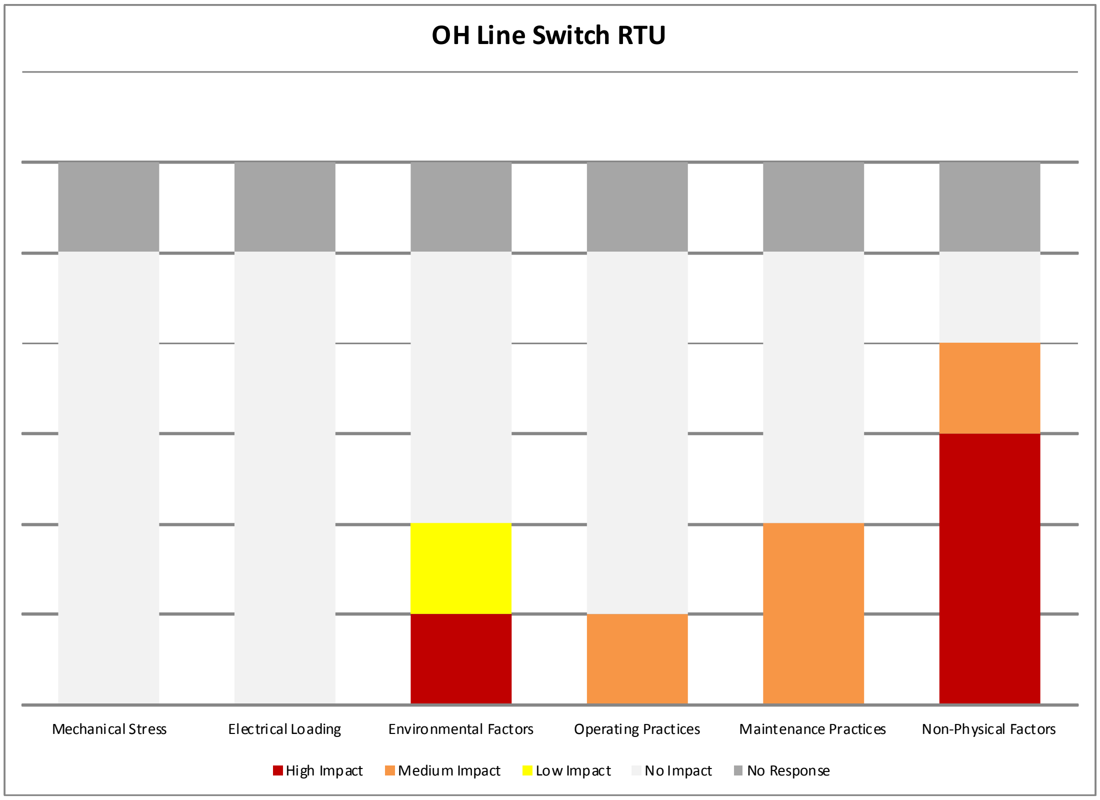


Figure 6-2 Impact of Utilization Factors on the Useful Life of Overhead Line Switch Remote Terminal Unit

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).

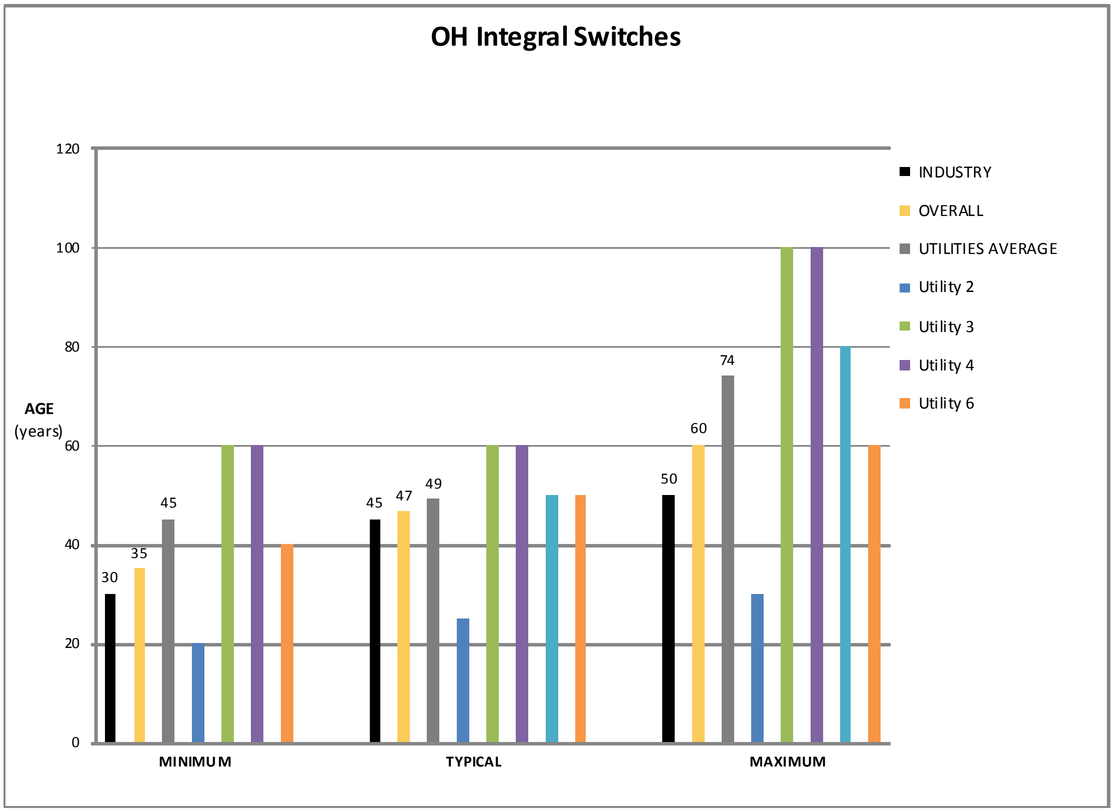


Figure 7-1 Useful Life Values for Overhead Integral Switch

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).

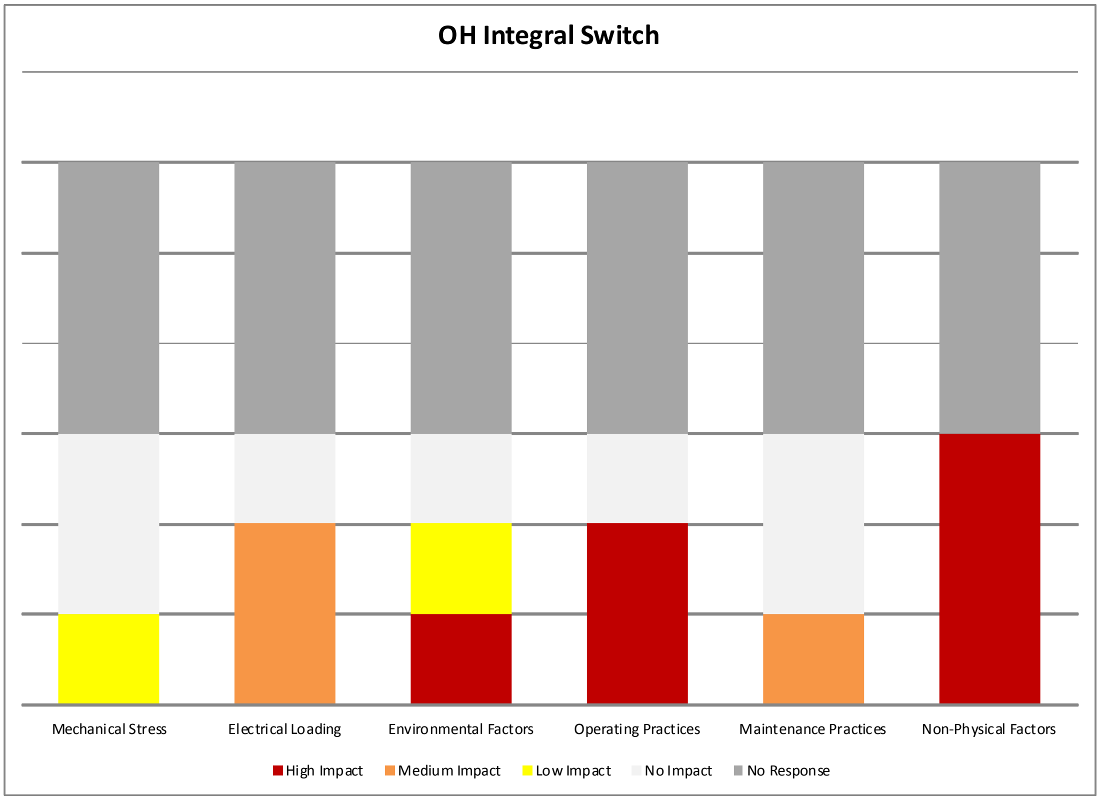


Figure 7-2 Impact of Utilization Factors on the Useful Life of Overhead Integral Switch

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).

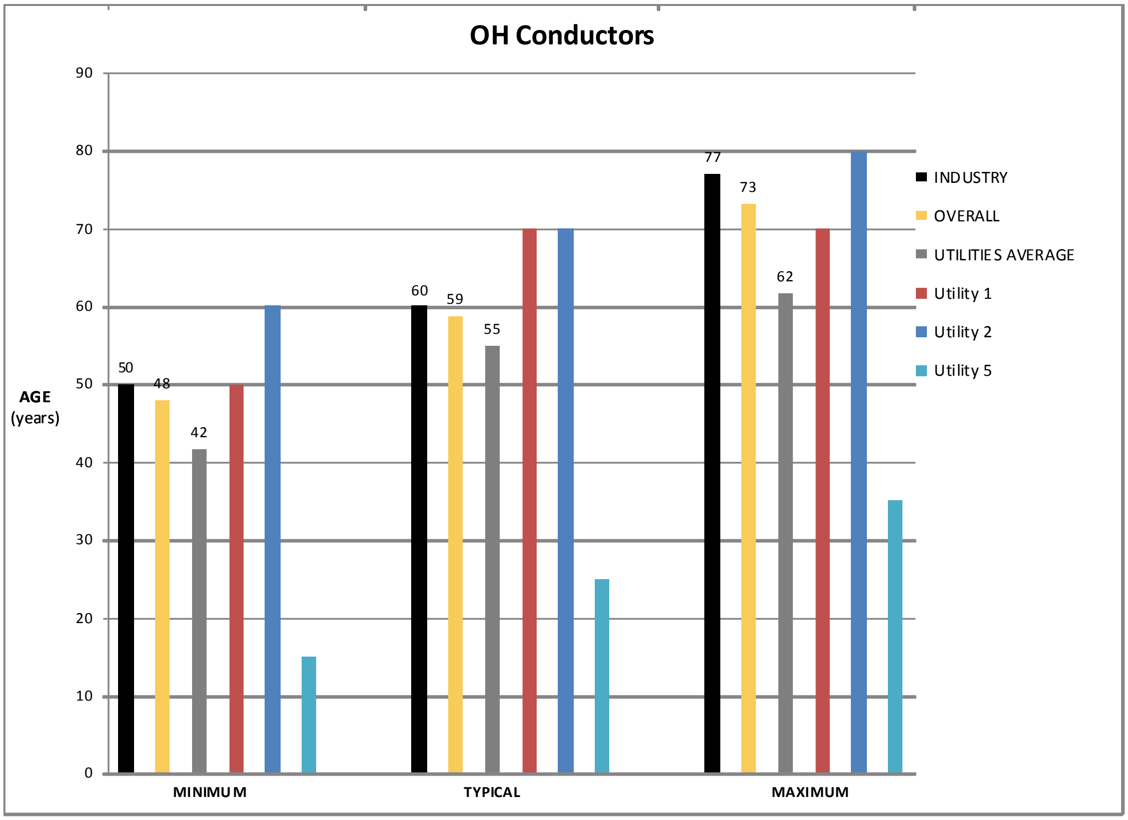


Figure 8-1 Useful Life Values for Overhead Conductors

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).

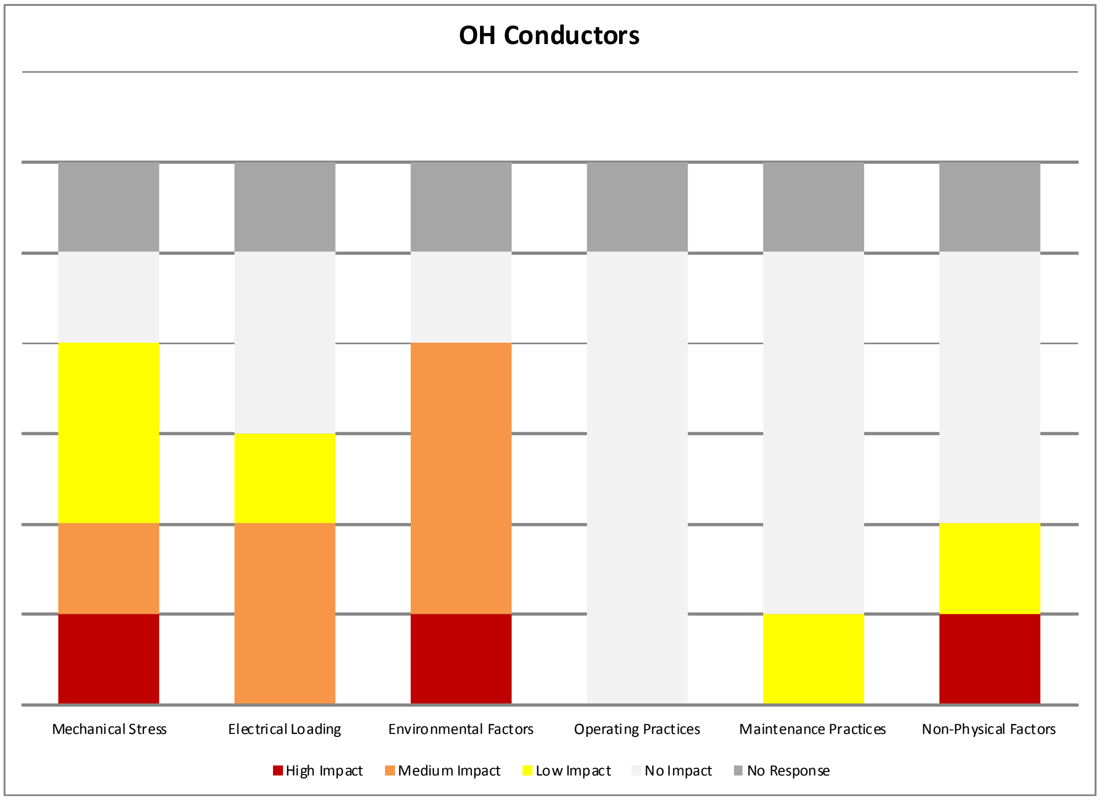


Figure 8-2 Impact of Utilization Factors on the Useful Life of Overhead Conductors

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).

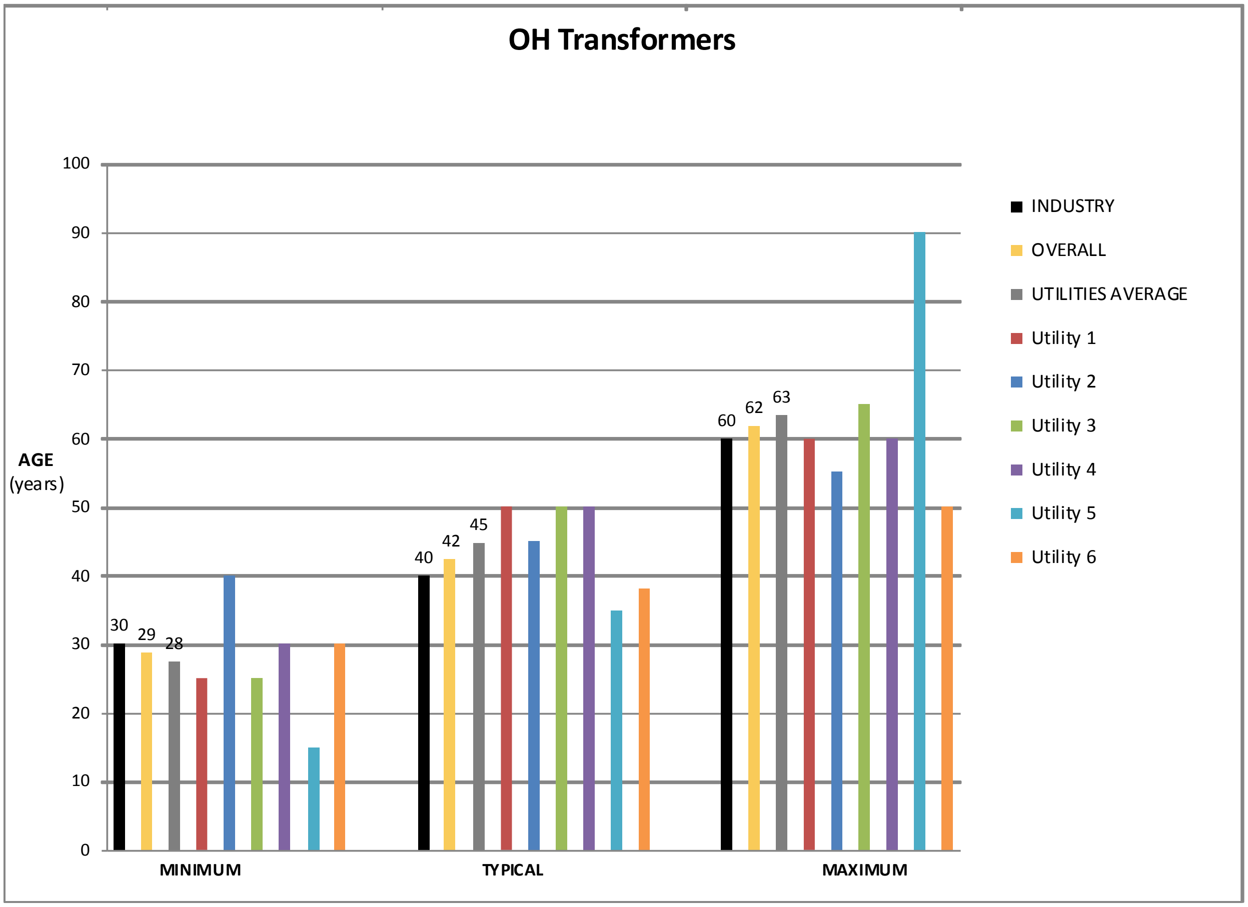


Figure 9-1 Useful Life Values for Overhead Transformers and Voltage Regulators

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).

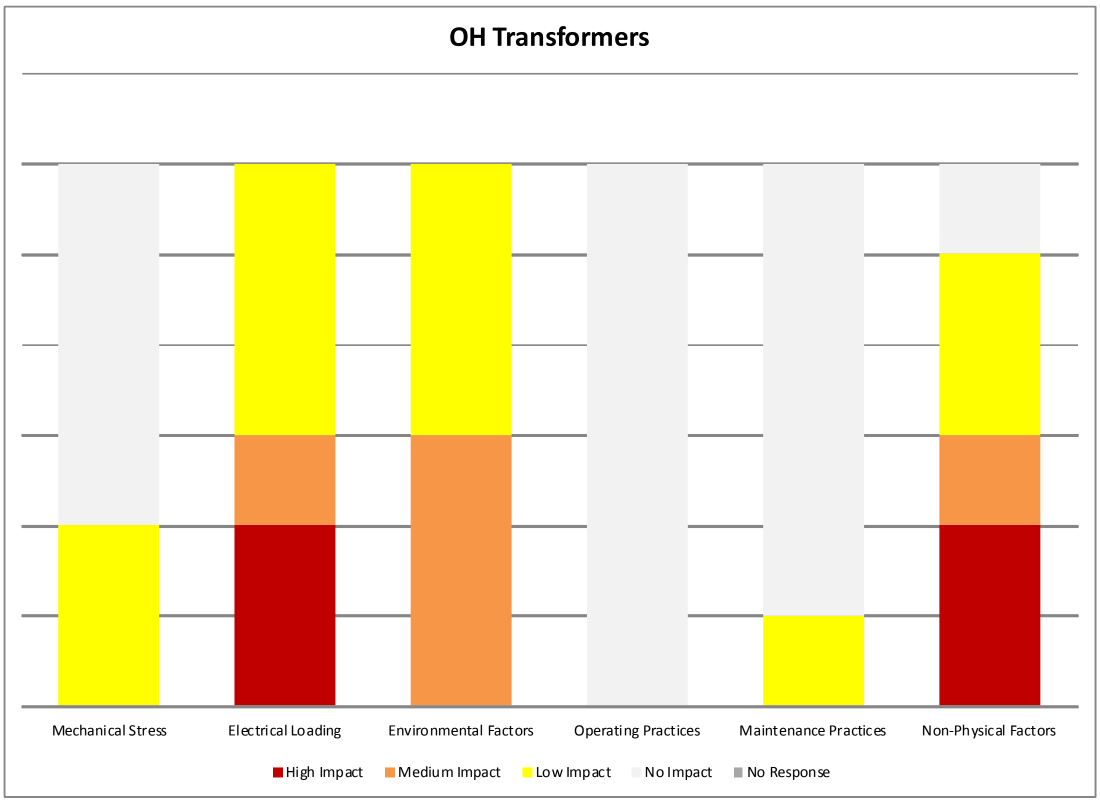


Figure 9-2 Impact of Utilization Factors on the Useful Life of Overhead Transformers and Voltage Regulators

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).

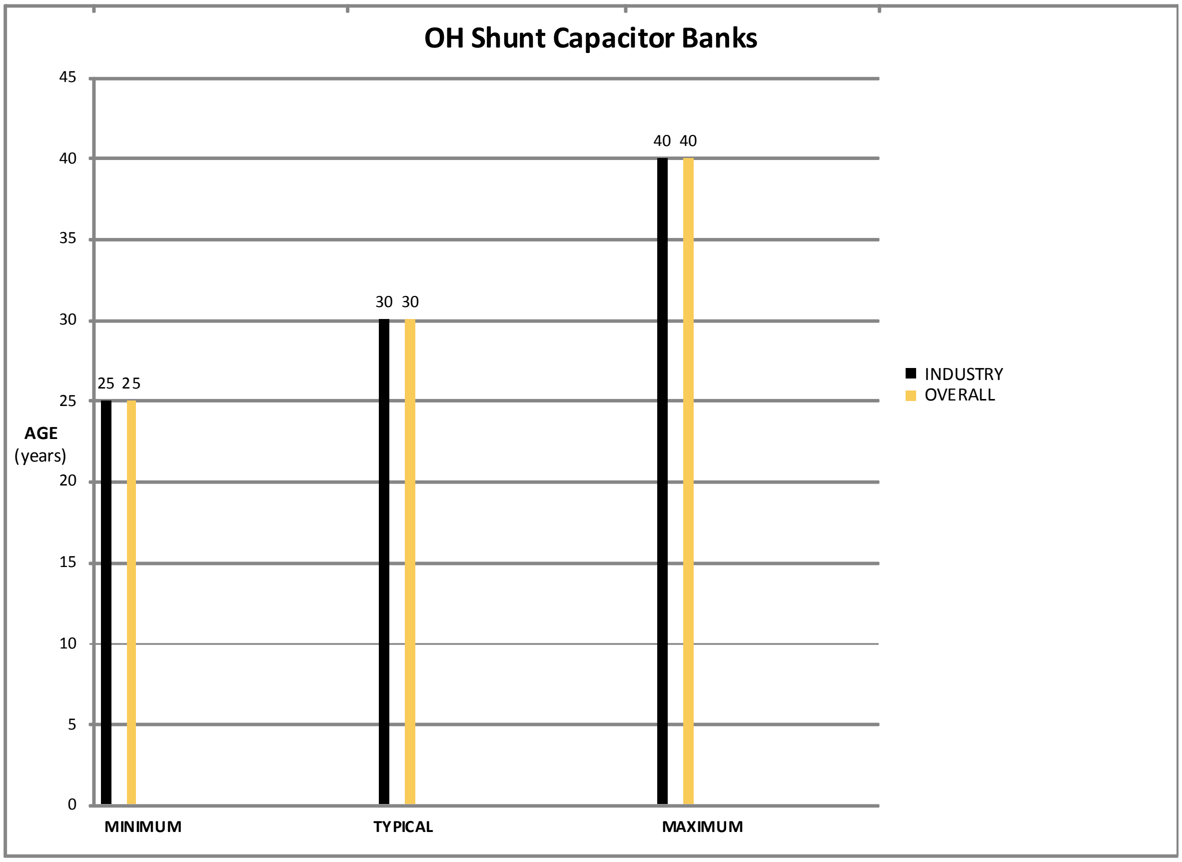


Figure 10-1 Useful Life Values for Overhead Shunt Capacitor Banks

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).

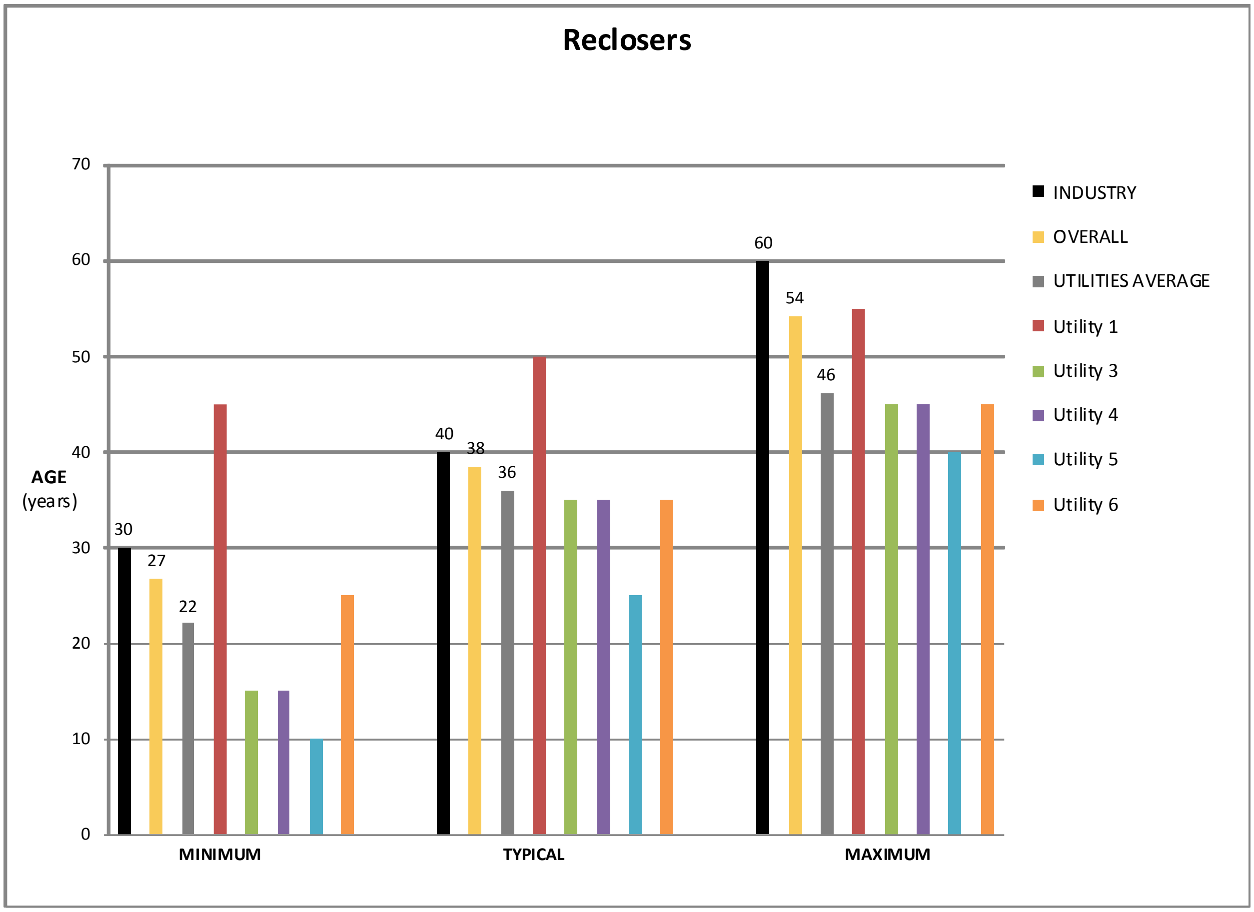


Figure 11-1 Useful Life Values for Reclosers

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).

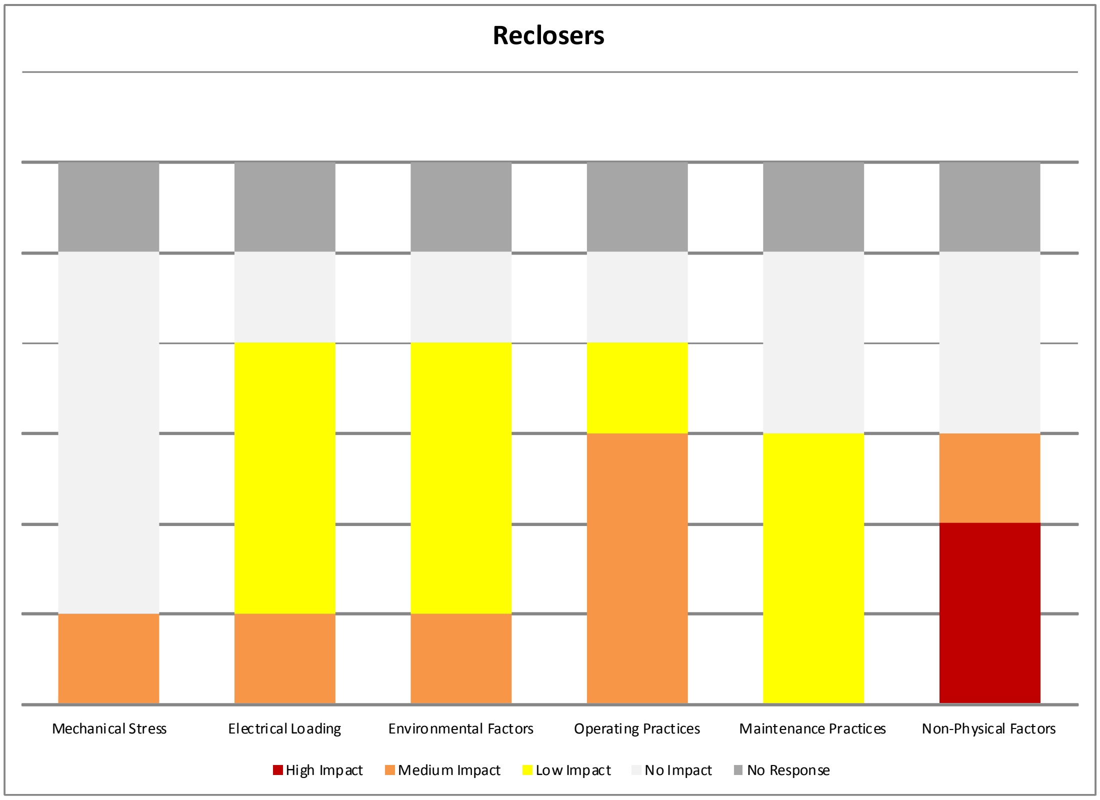


Figure 11-2 Impact of Utilization Factors on the Useful Life of Reclosers

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).

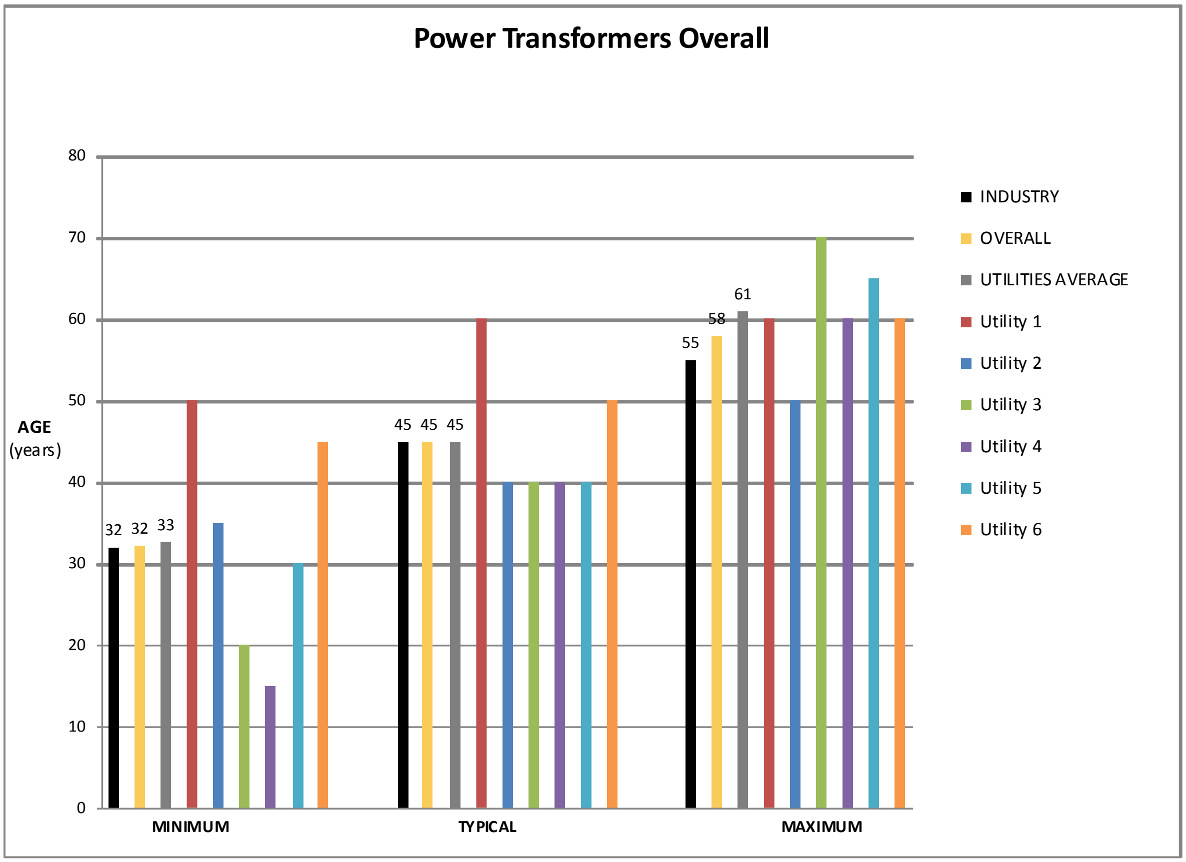


Figure 12-1 Useful Life Values for Power Transformers

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).

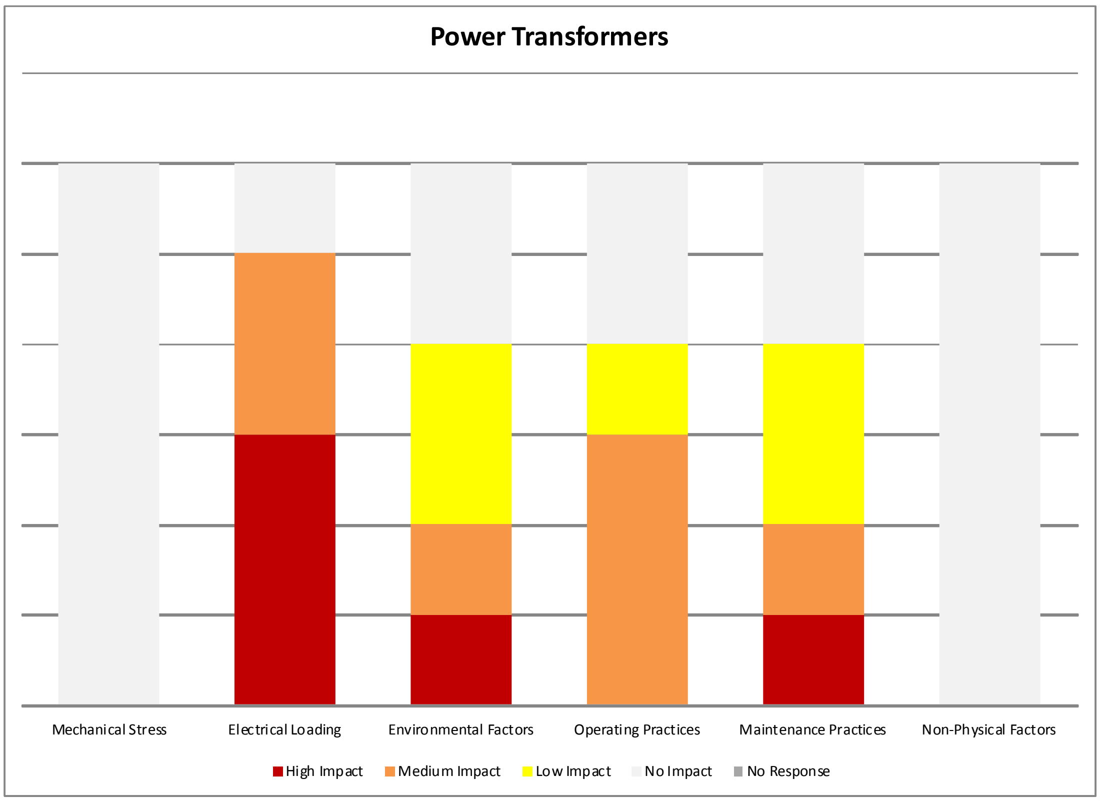


Figure 12-2 Impact of Utilization Factors on the Useful Life of Power Transformers

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).

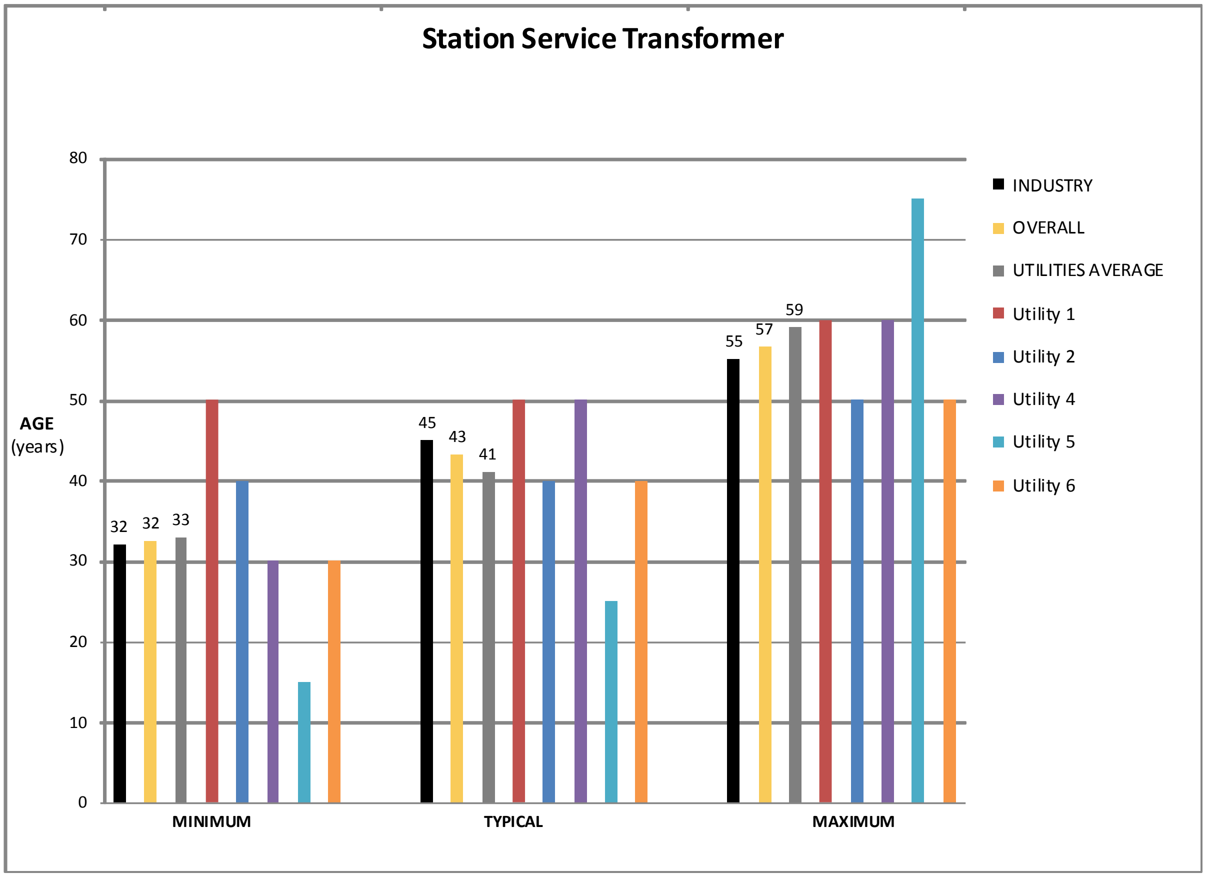


Figure 13-1 Useful Life Values for Station Service Transformers

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).

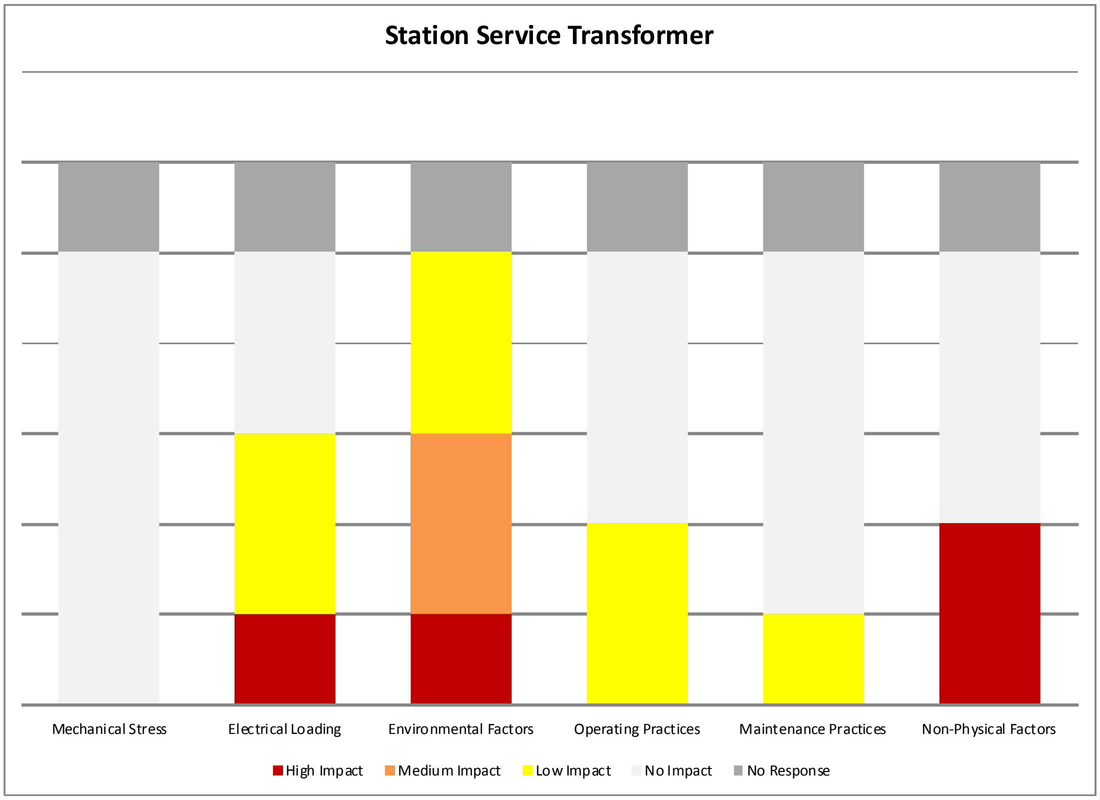


Figure 13-2 Impact of Utilization Factors on the Useful Life of Station Service Transformers

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).

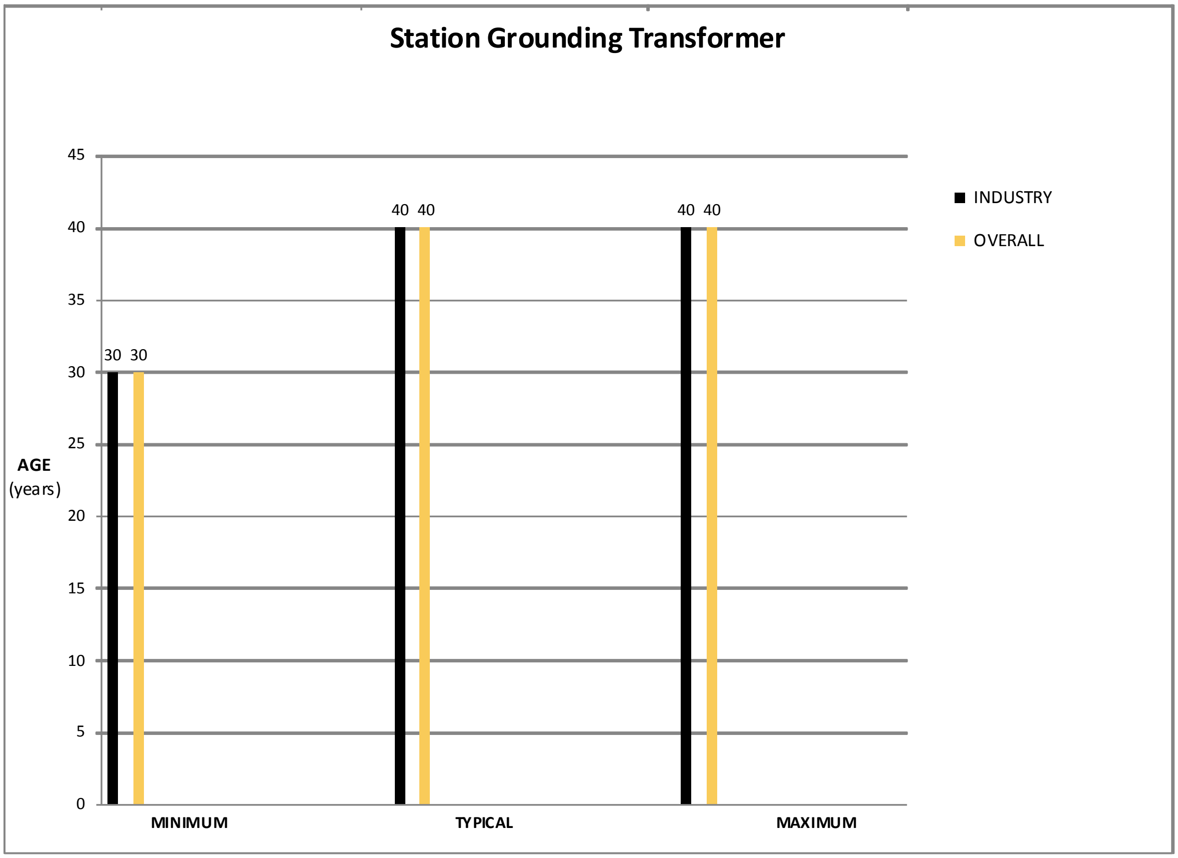


Figure 14-1 Useful Life Values for Station Grounding Transformers

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).

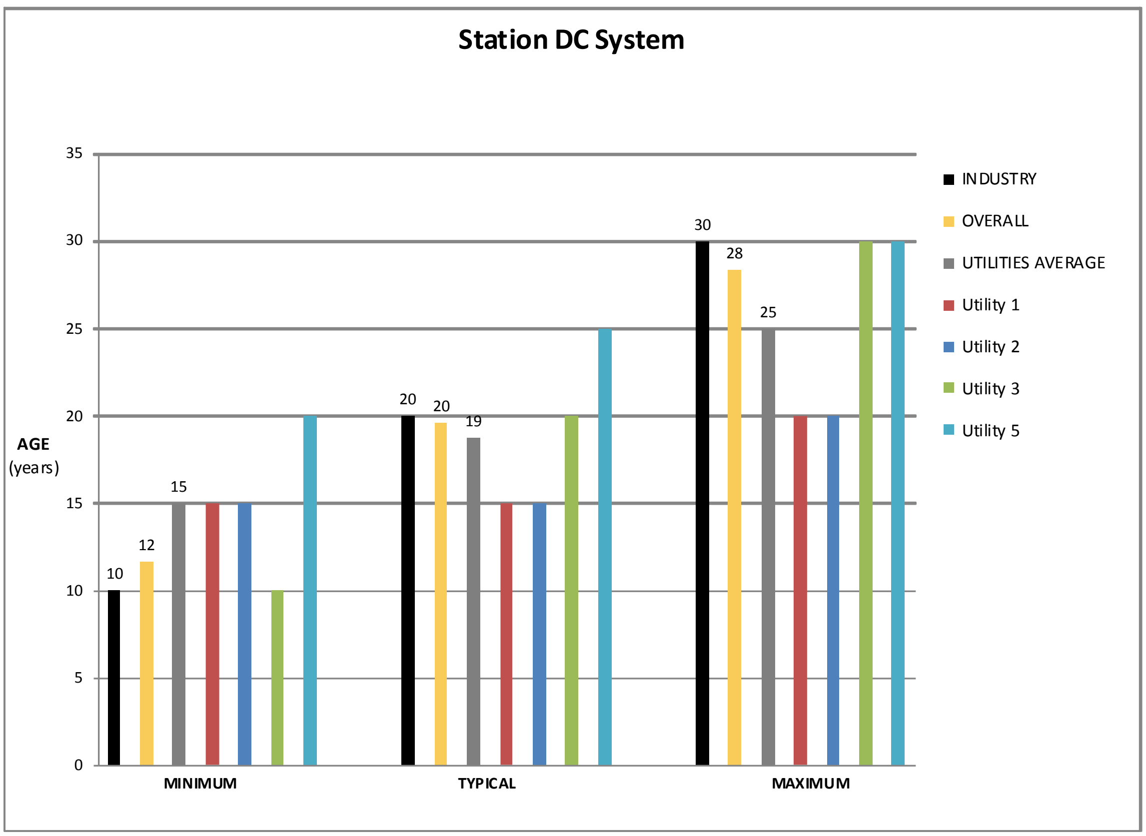


Figure 15-1 Useful Life Values for Station Direct Current System

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).

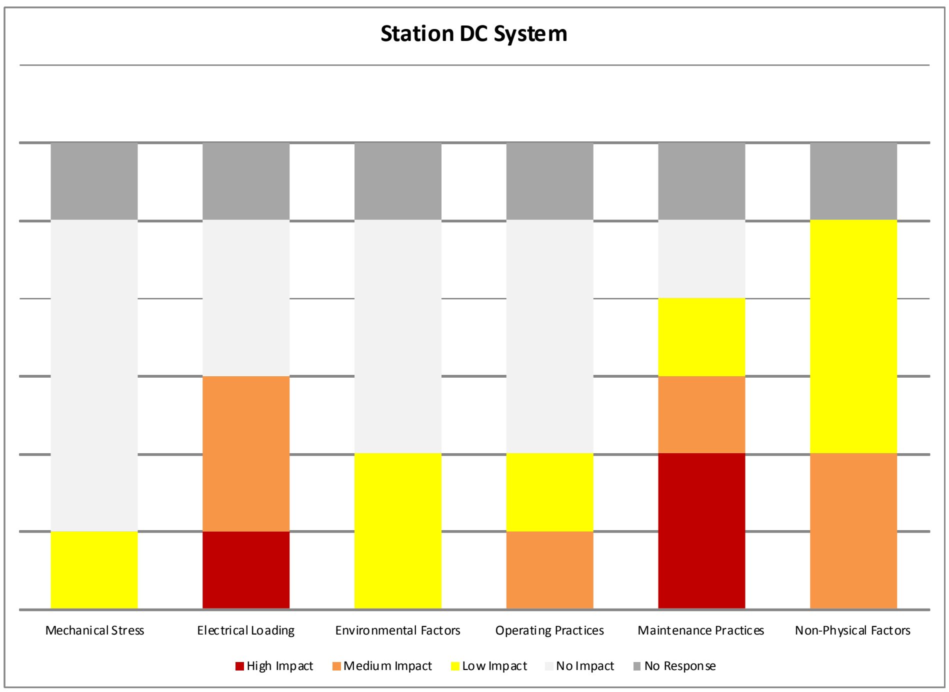


Figure 15-2 Impact of Utilization Factors on the Useful Life of Station Direct Current System

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).

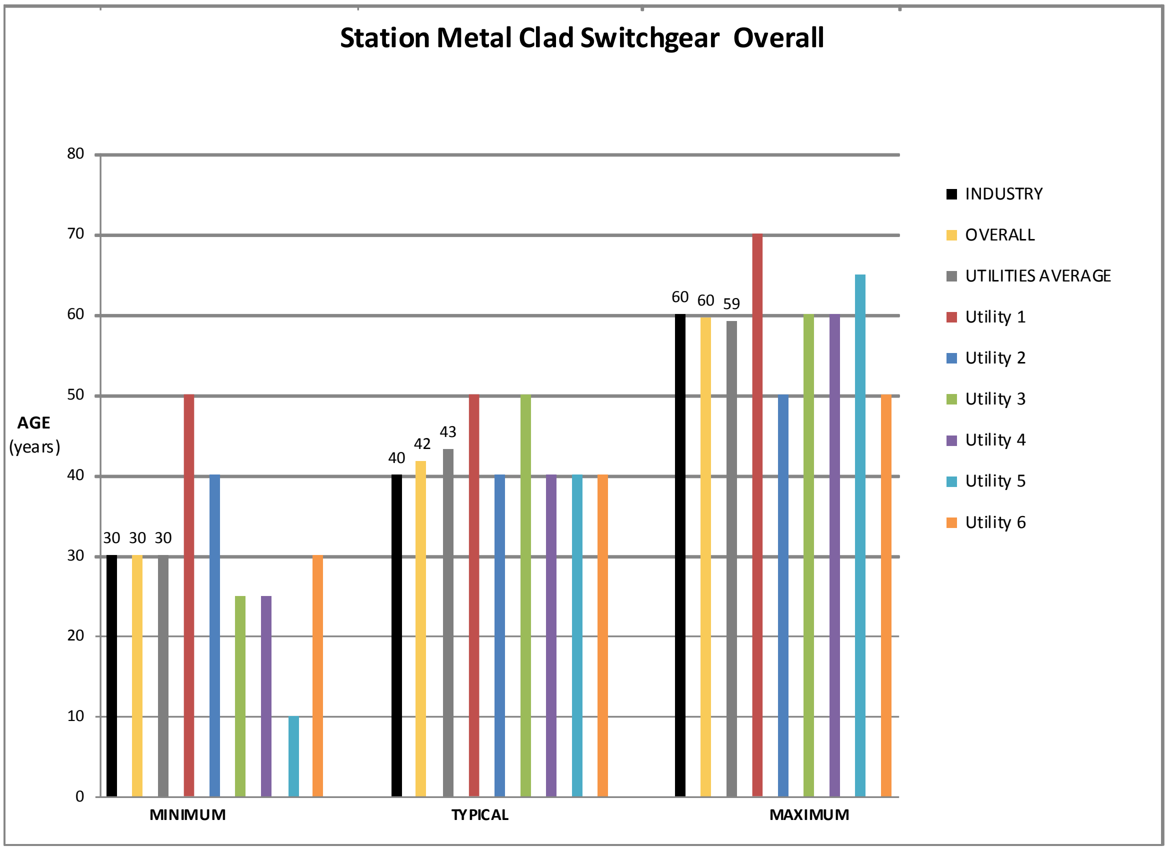


Figure 16-1 Useful Life Values for Station Metal Clad Switchgear

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).

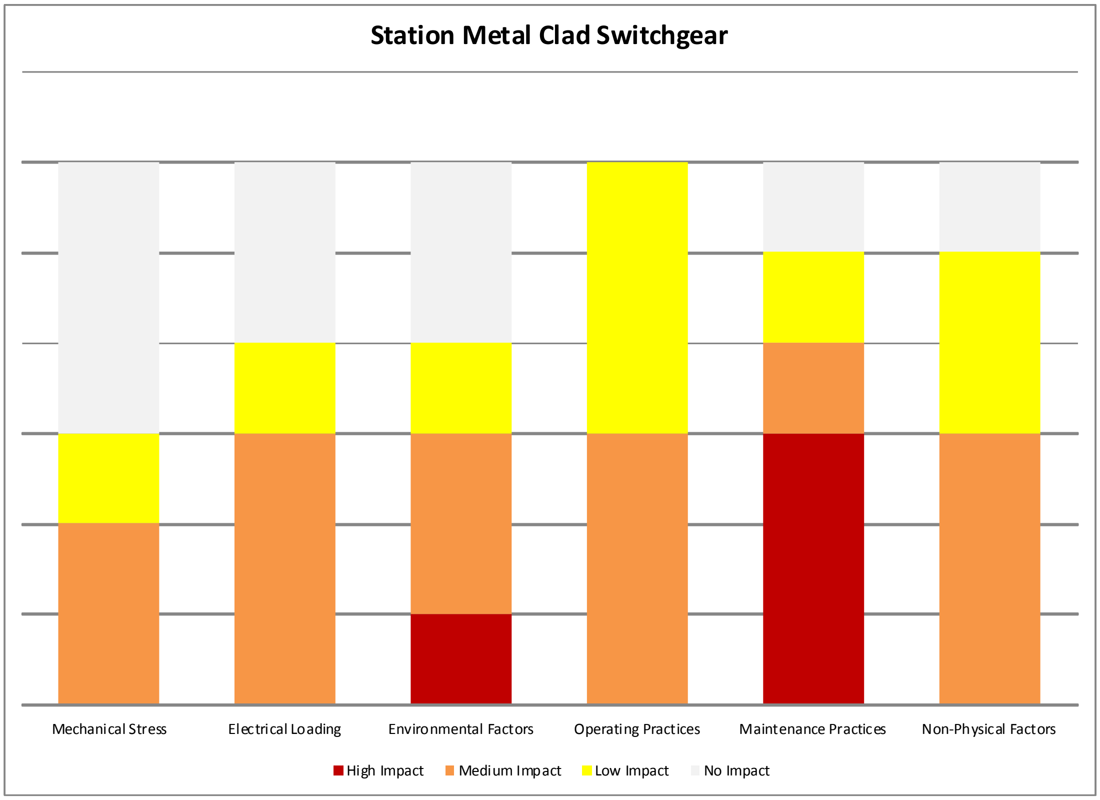


Figure 16-2 Impact of Utilization Factors on the Useful Life of Station Metal Clad Switchgear

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).

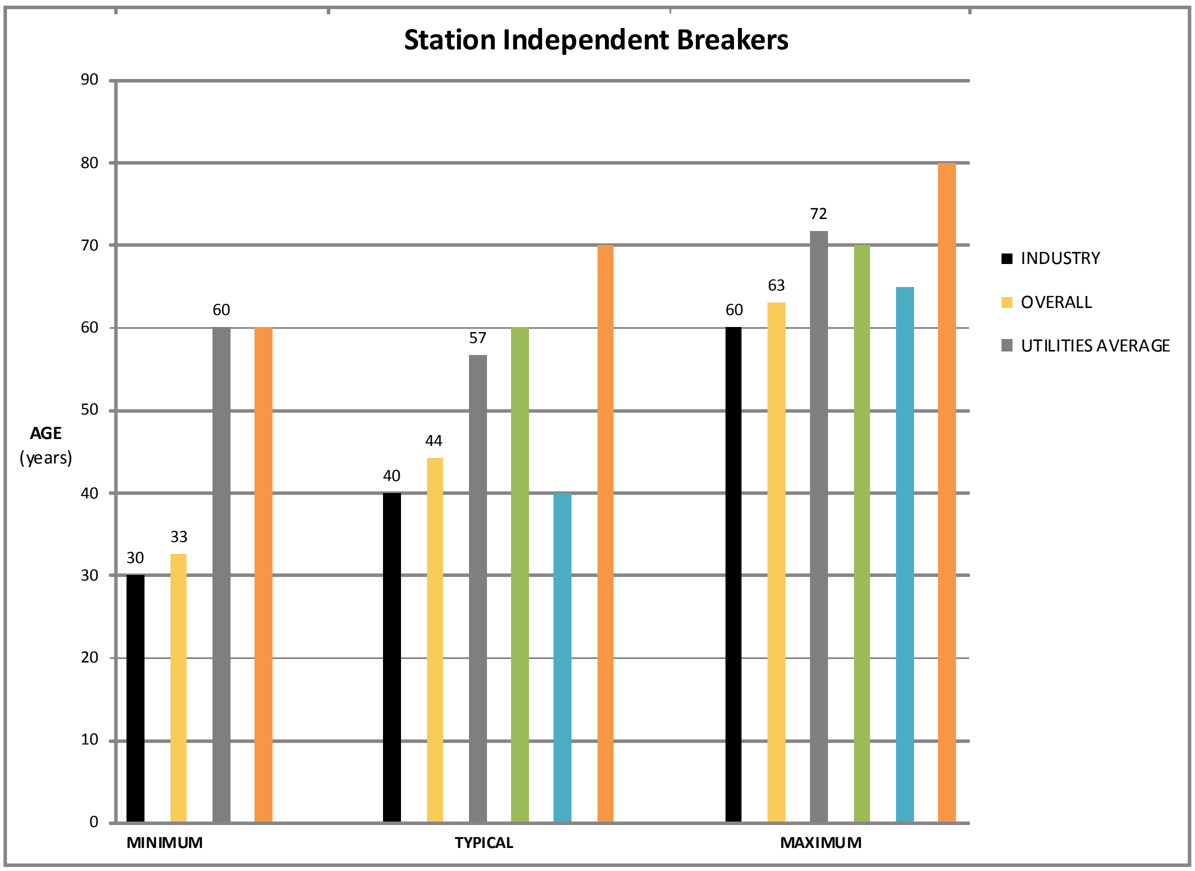


Figure 17-1 Useful Life Values for Station Independent Breakers

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).

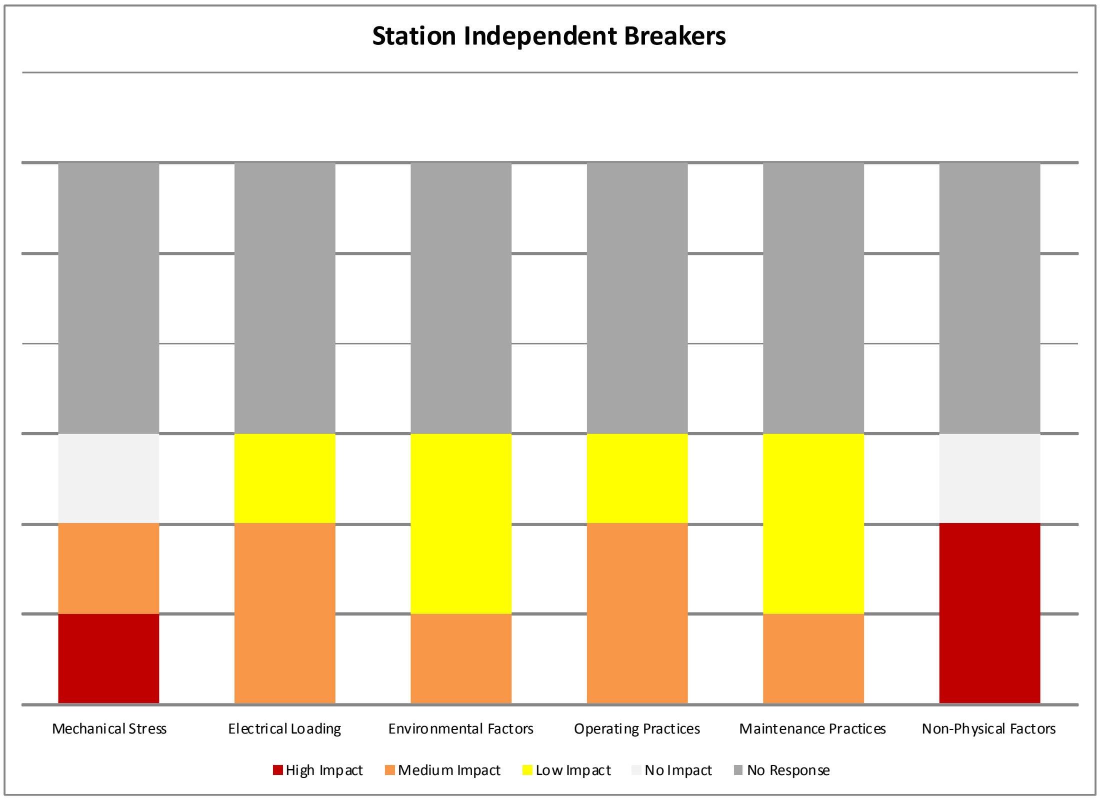


Figure 17-2 Impact of Utilization Factors on the Useful Life of Station Independent Breakers

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).

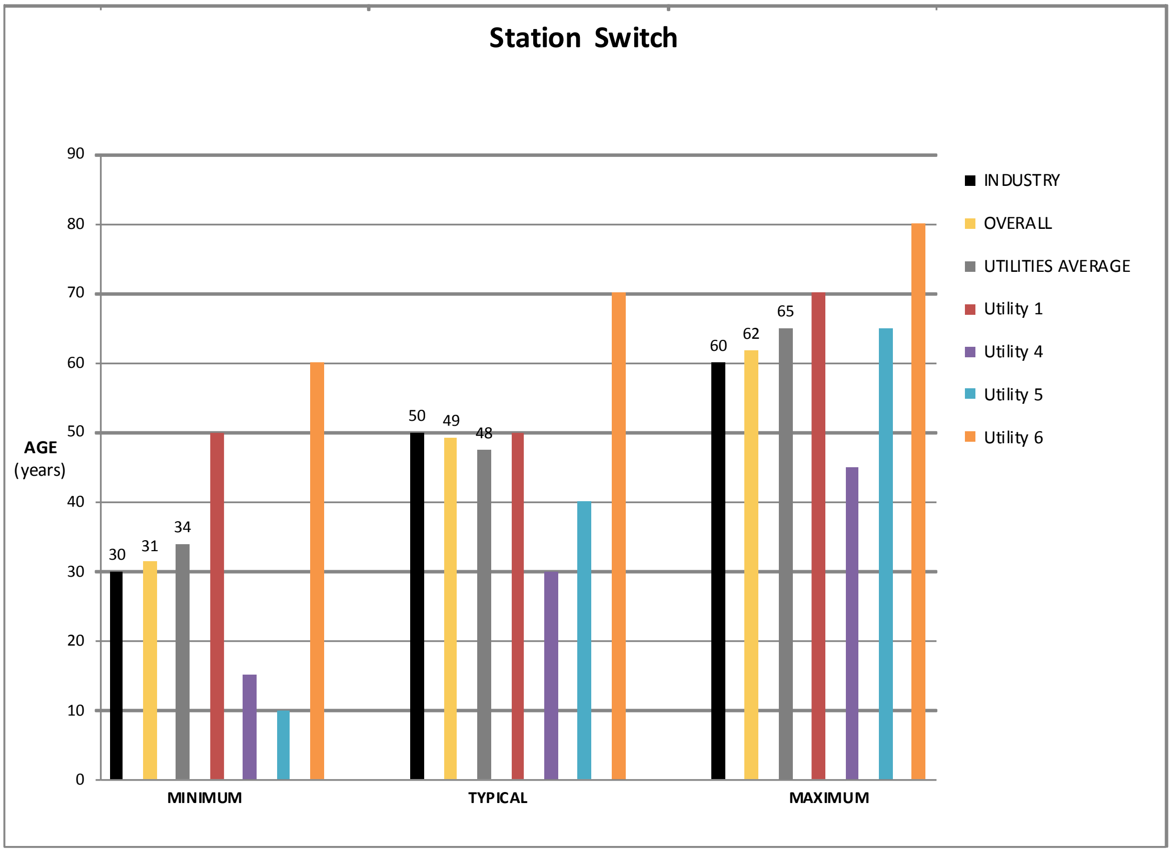


Figure 18-1 Useful Life Values for Station Switch

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).

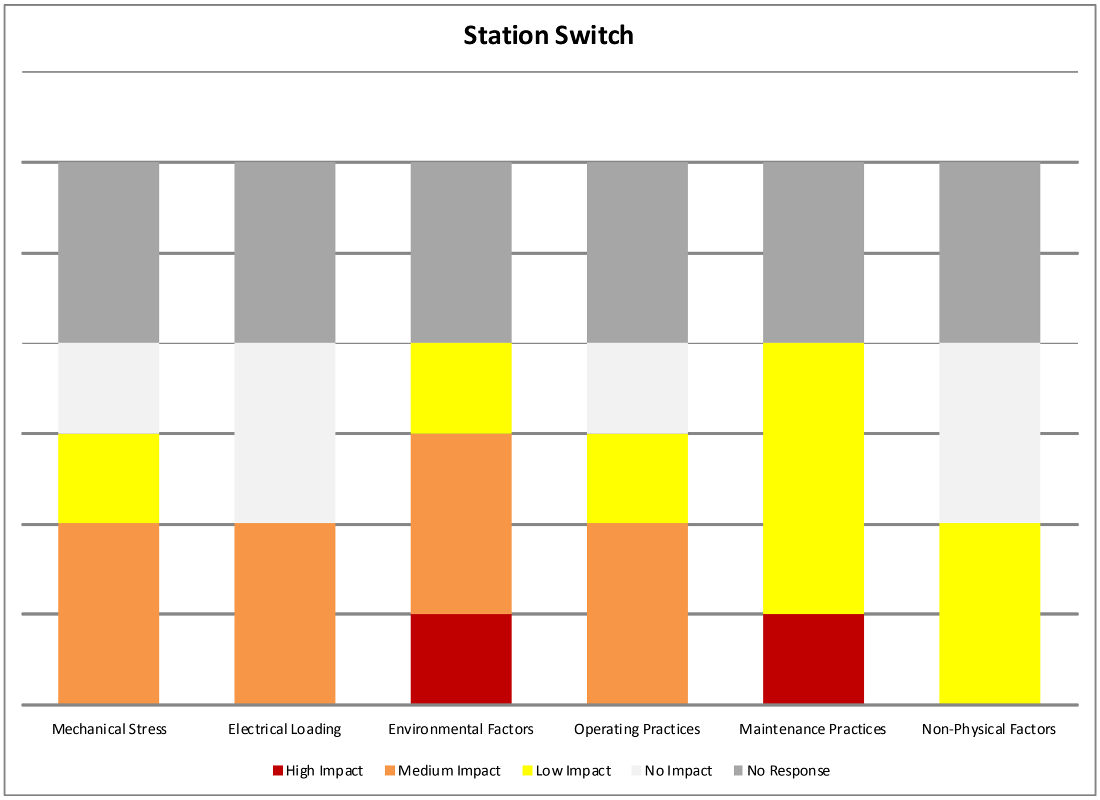


Figure 18-2 Impact of Utilization Factors on the Useful Life of Station Switch

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).

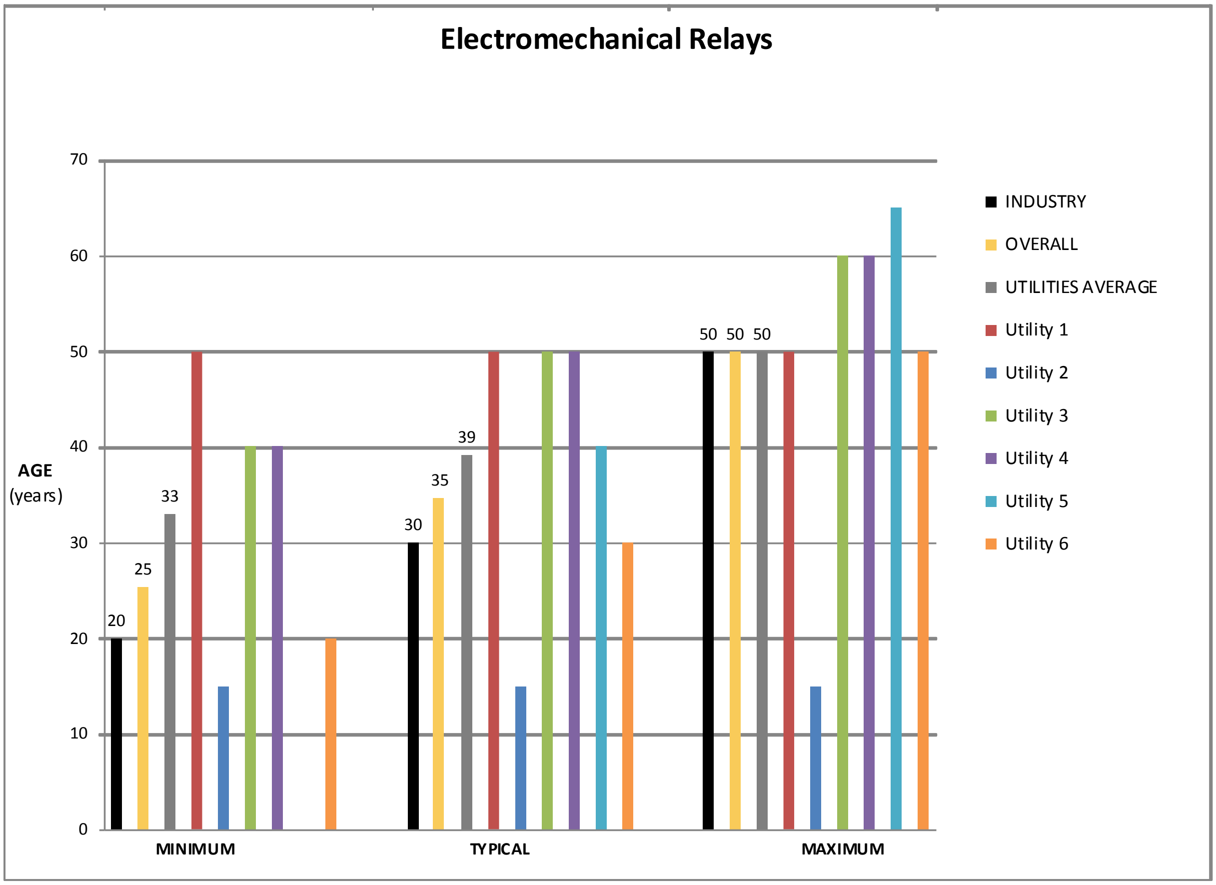


Figure 19-1 Useful Life Values for Electromechanical Relays

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).

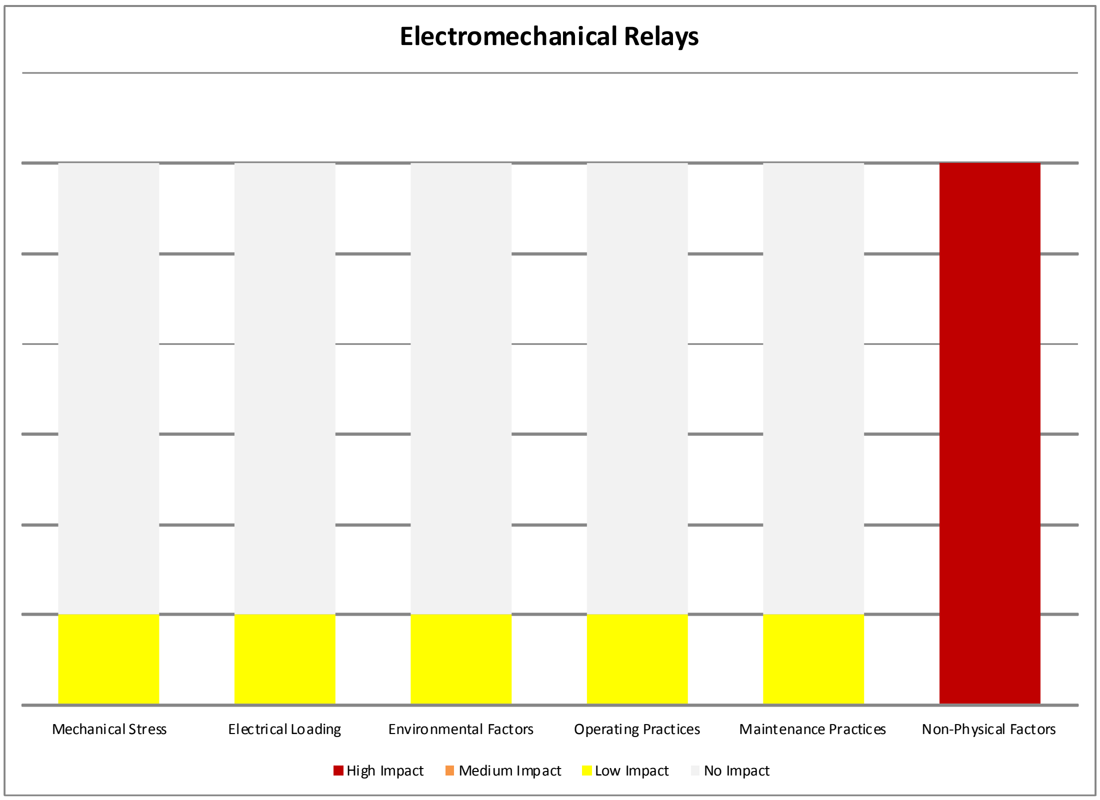


Figure 19-2 Impact of Utilization Factors on the Useful Life of Electromechanical Relays

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).

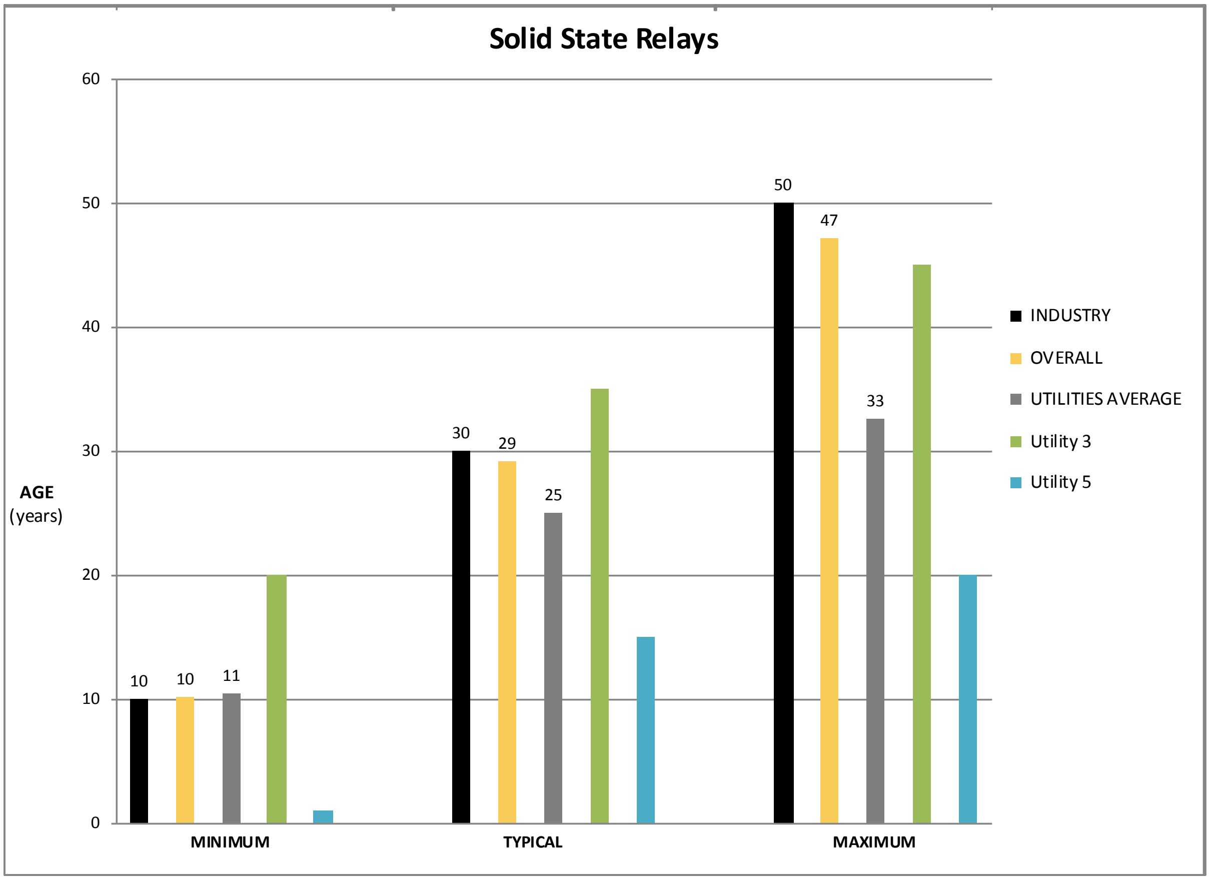


Figure 20-1 Useful Life Values for Solid State Relays

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).

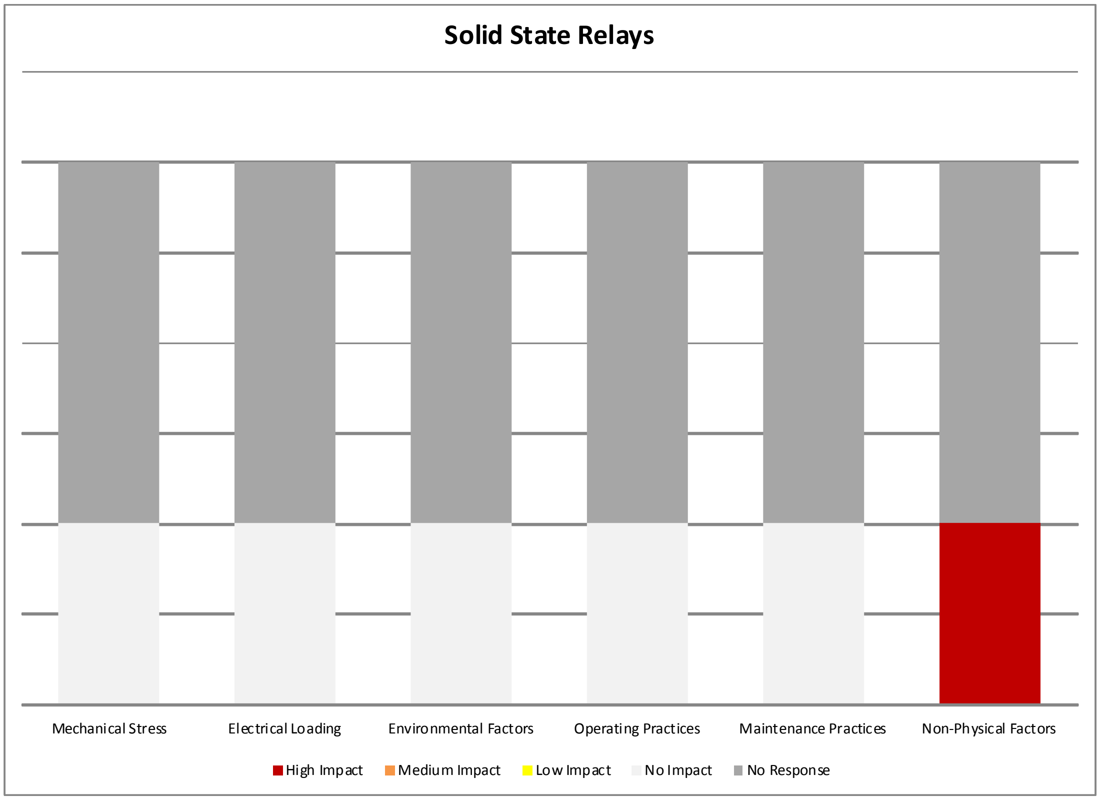


Figure 20-2 Impact of Utilization Factors on the Useful Life of Solid State Relays

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).

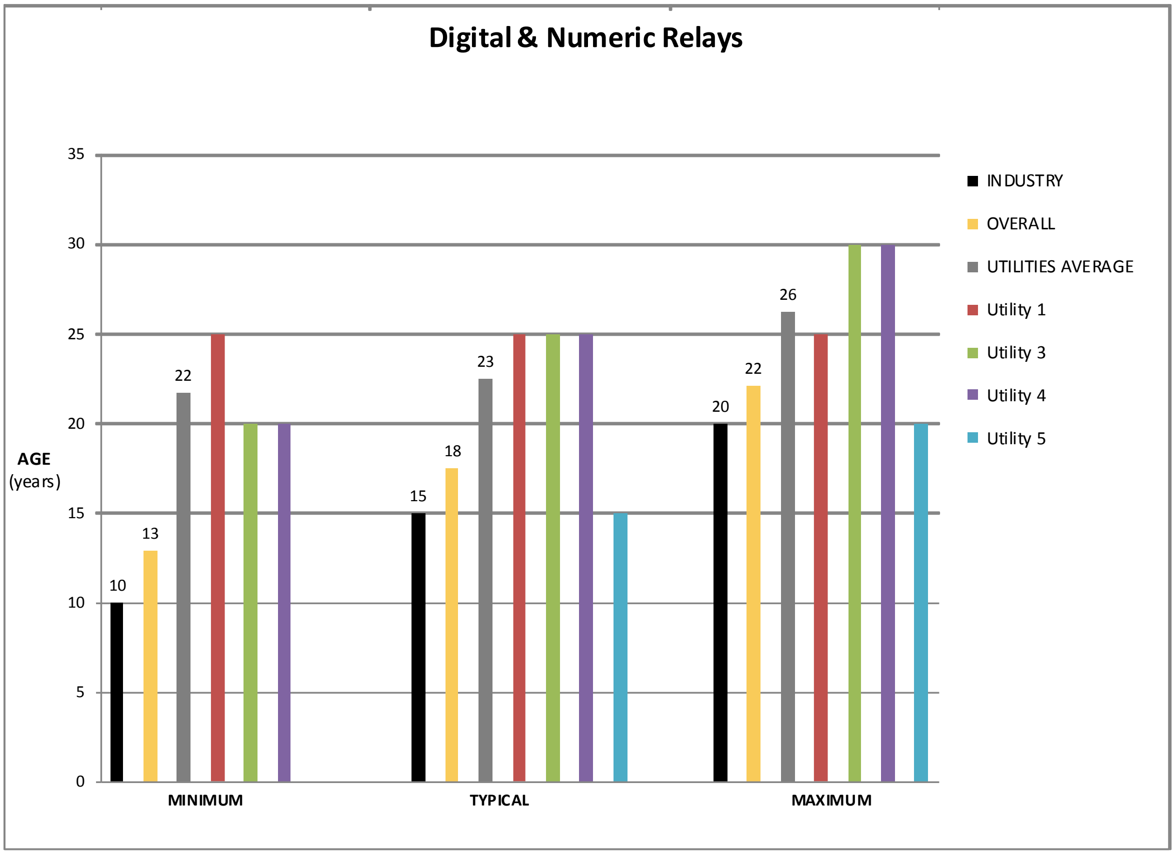


Figure 21-1 Useful Life Values for Digital Microprocessor Relays

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).

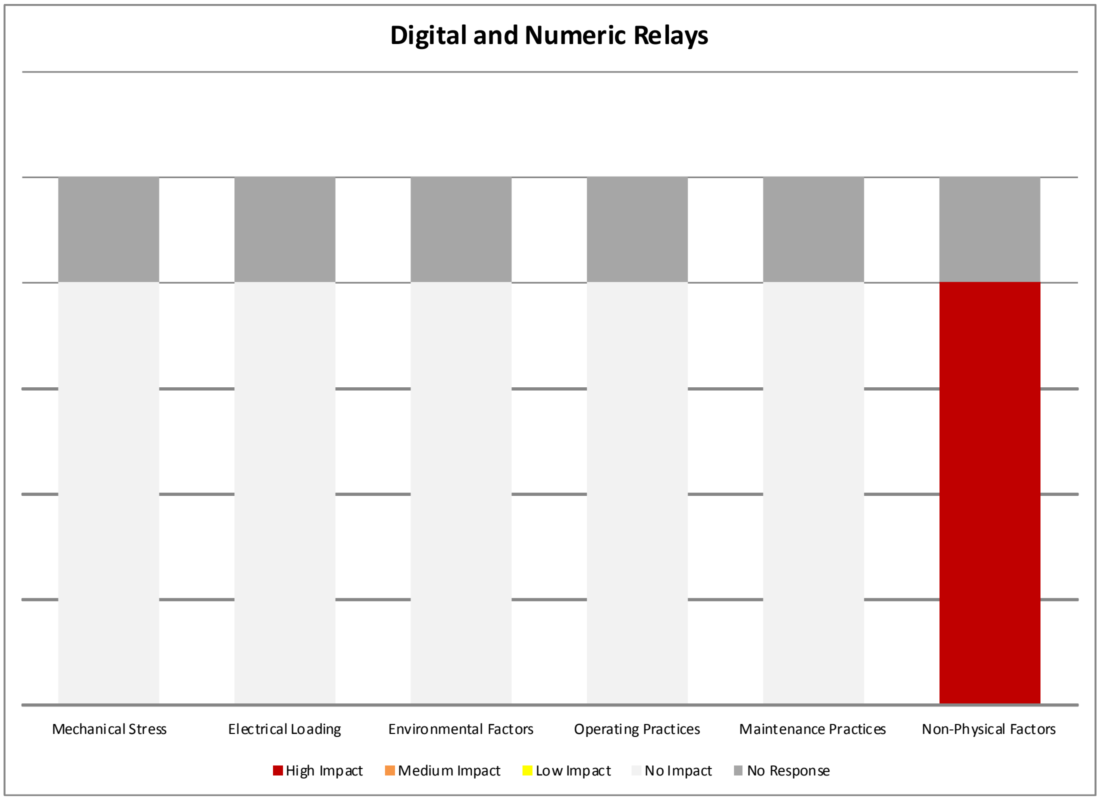


Figure 21-2 Impact of Utilization Factors on the Useful Life of Digital Microprocessor Relays

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).

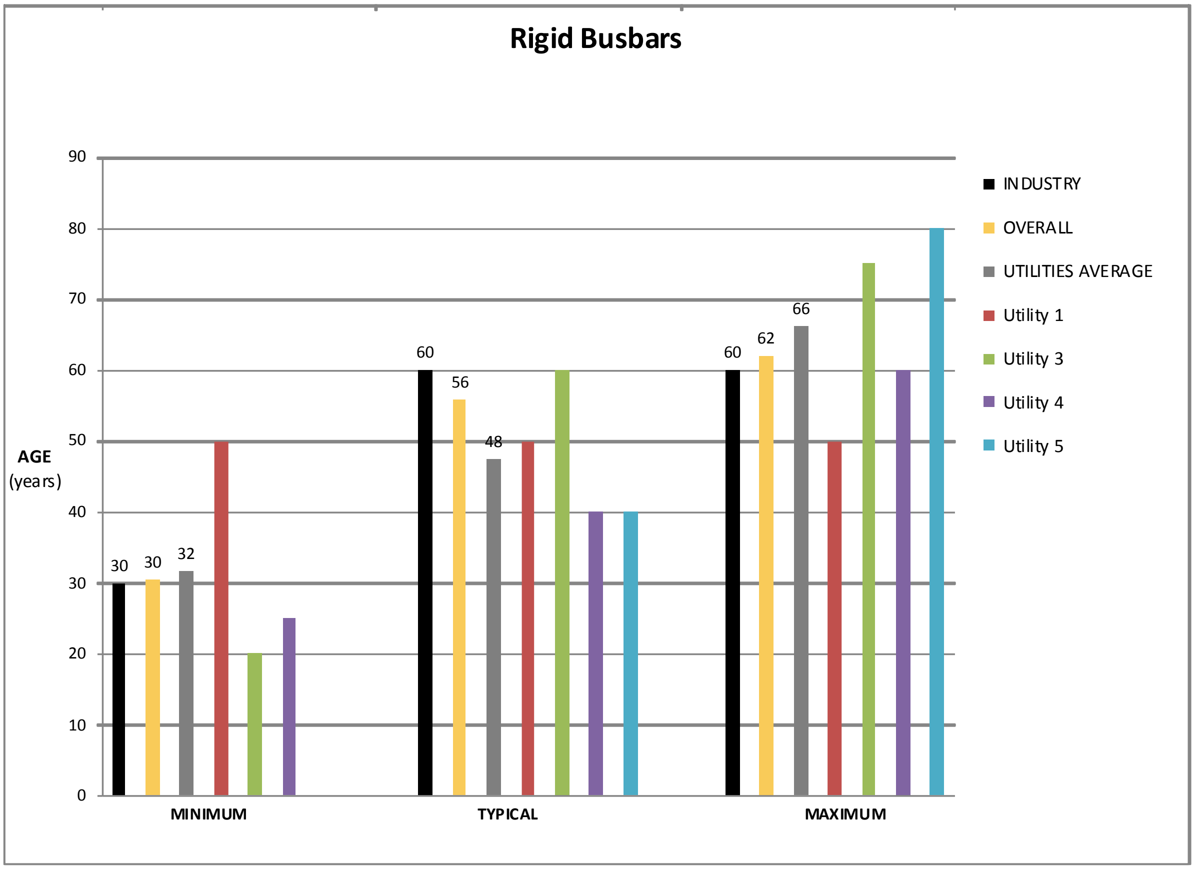


Figure 22-1 Useful Life Values for Rigid Busbars

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).

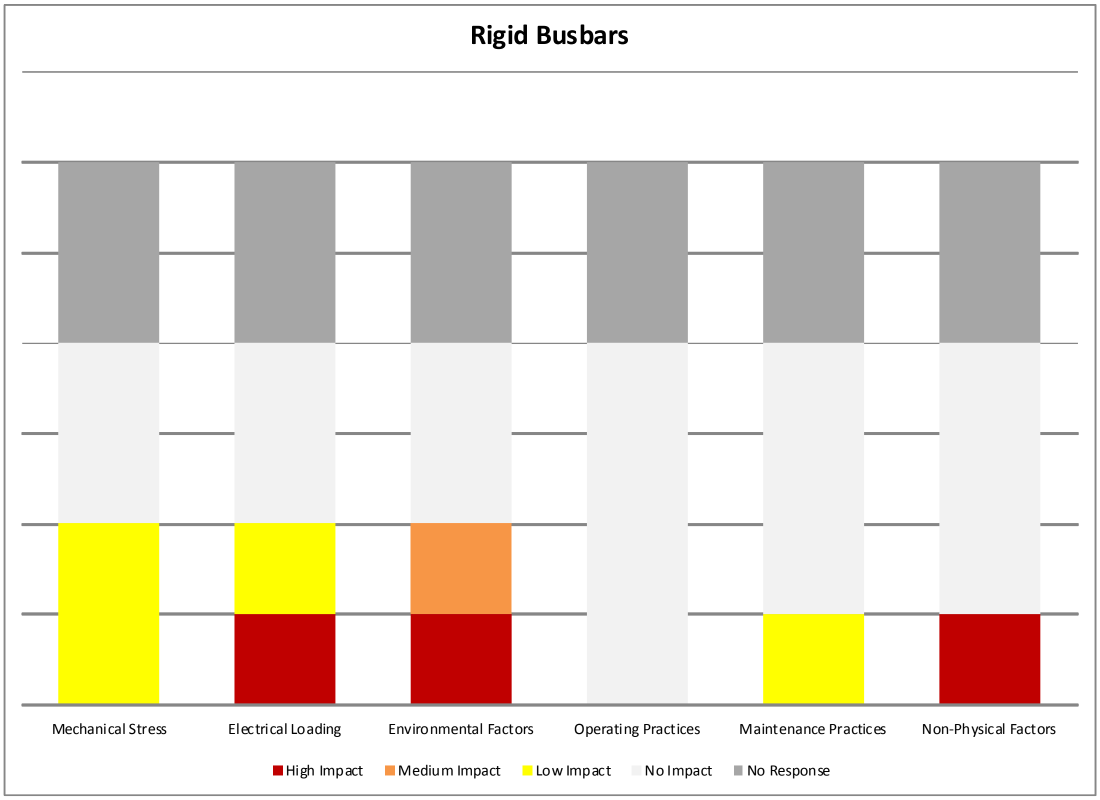


Figure 22-2 Impact of Utilization Factors on the Useful Life of Rigid Busbars

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).

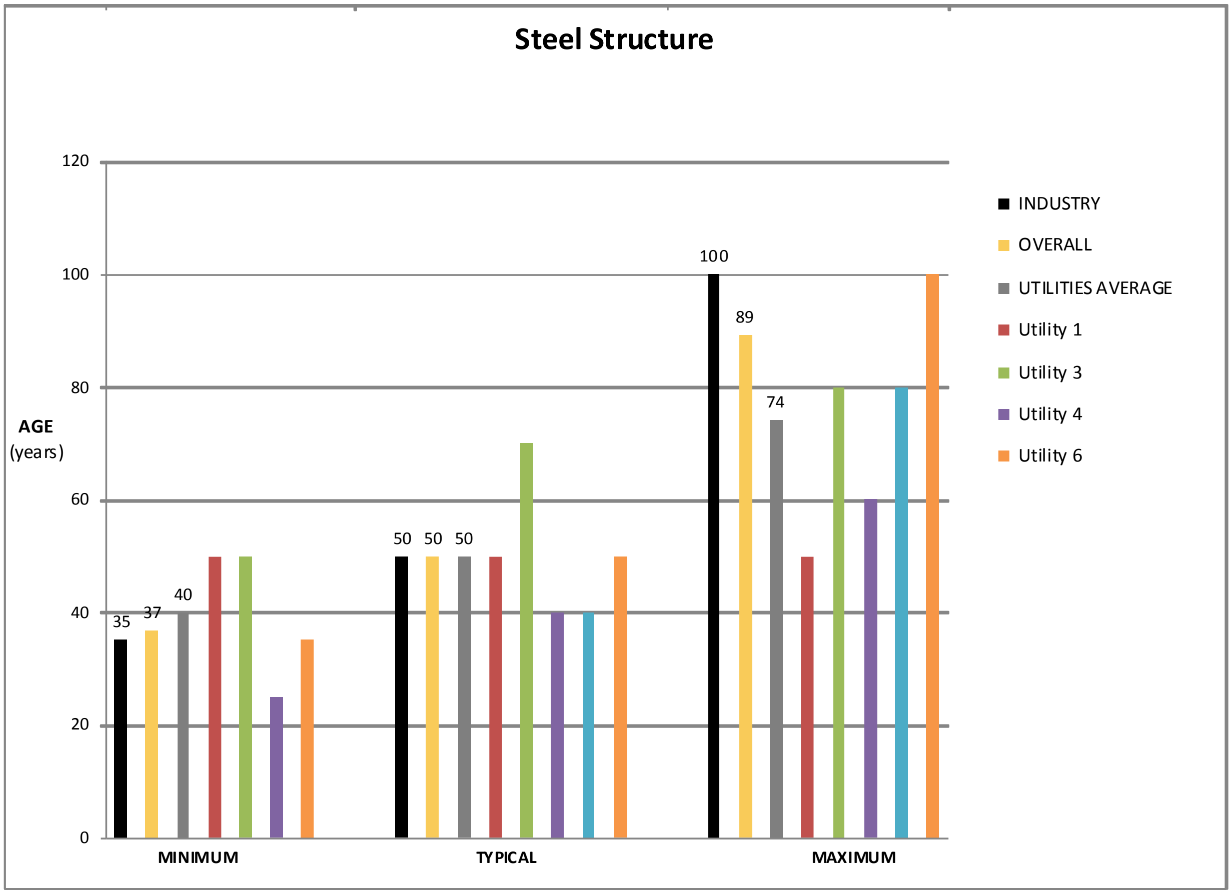


Figure 23-1 Useful Life Values for Steel Structure

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).

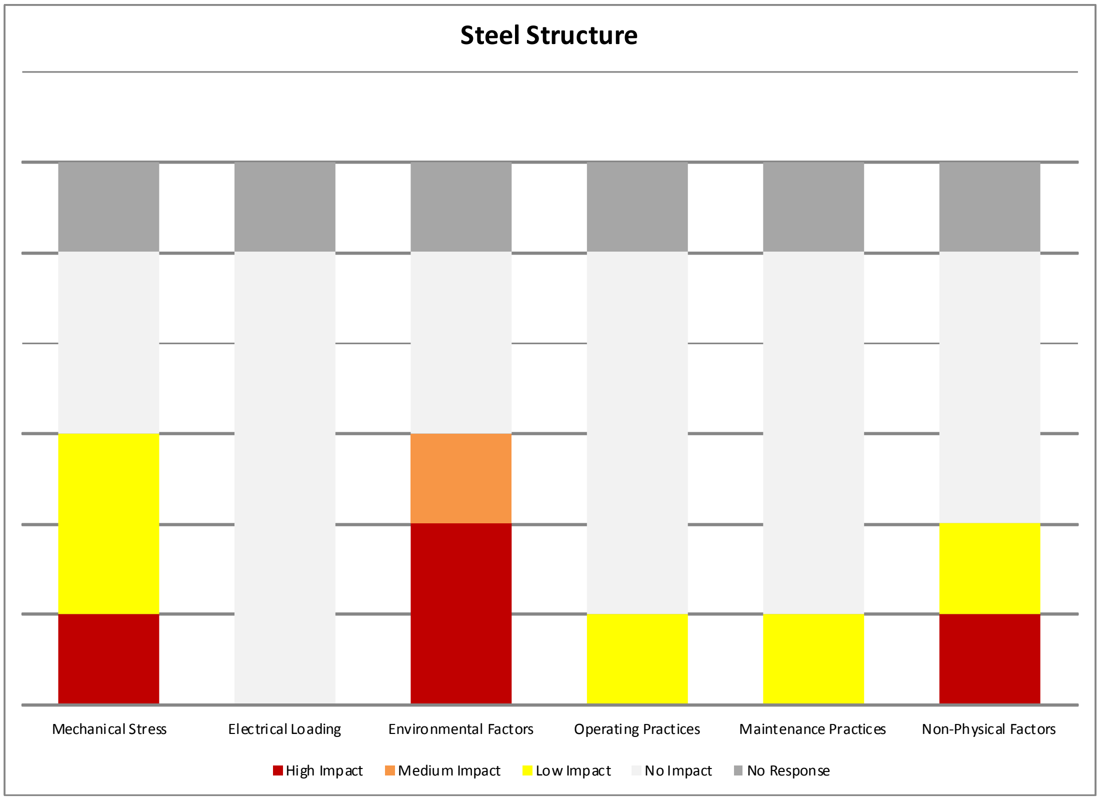


Figure 23-2 Impact of Utilization Factors on the Useful Life of Steel Structure

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).

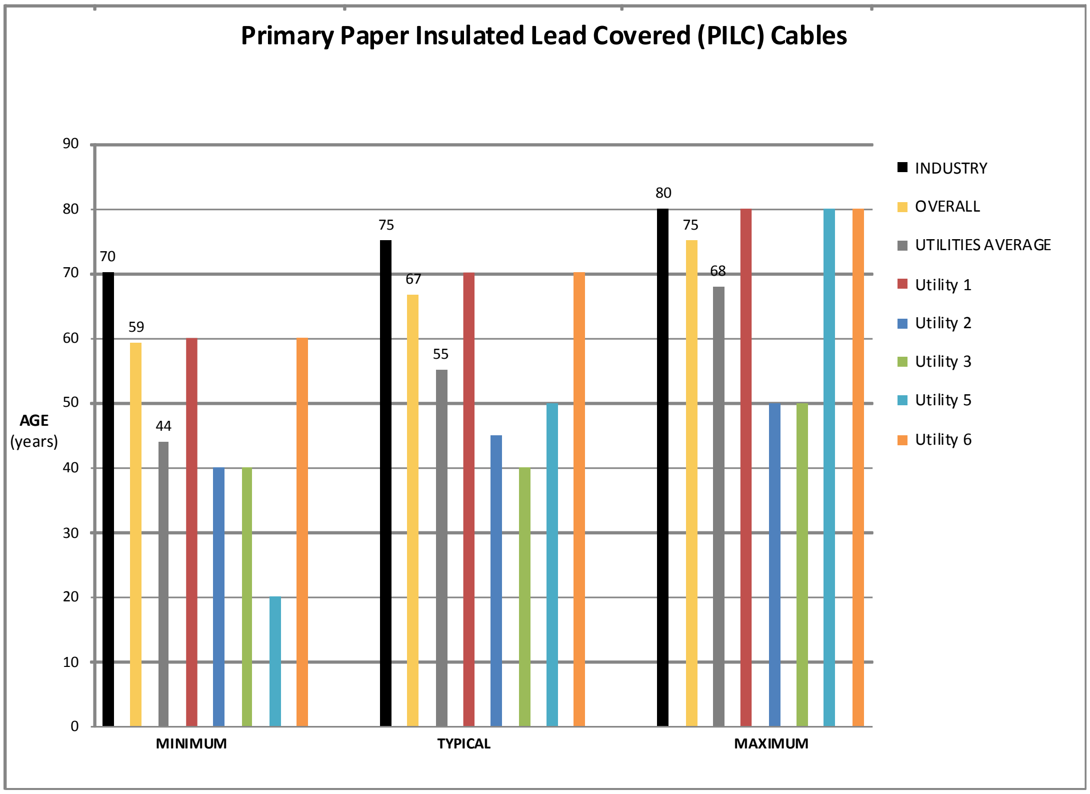


Figure 24-1 Useful Life Values for Primary Paper Insulated Lead Covered Cables

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).

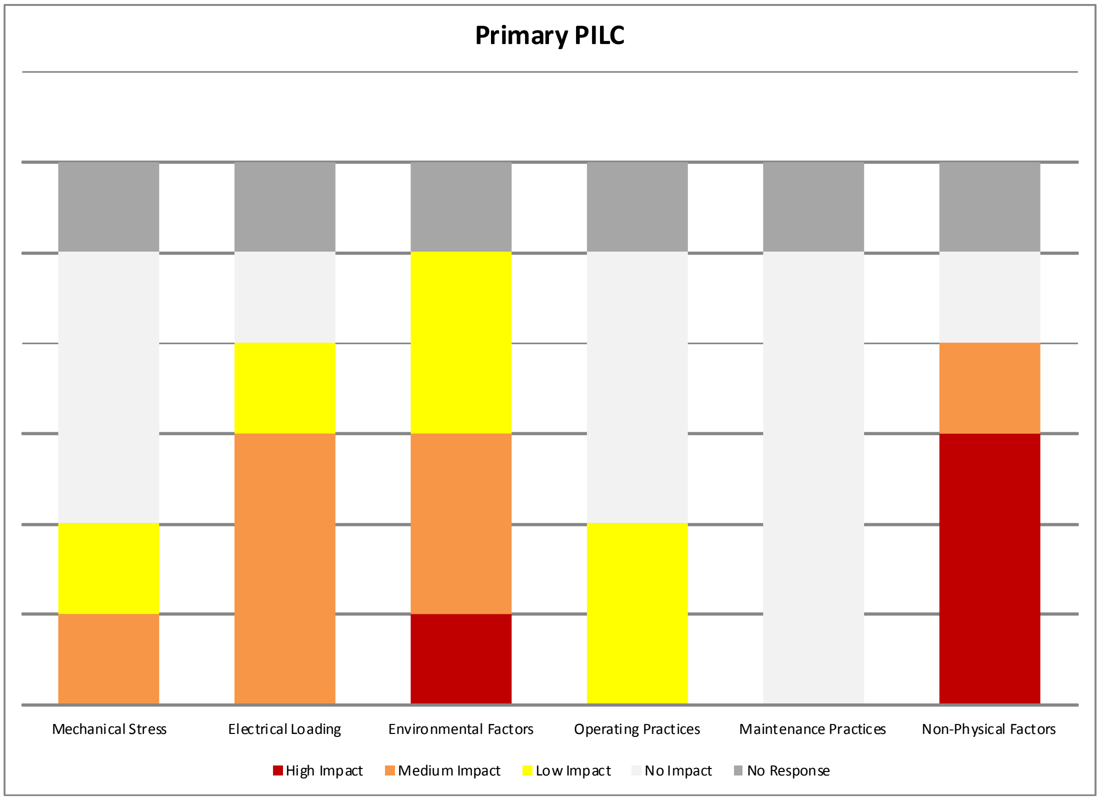


Figure 24-2 Impact of Utilization Factors on the Useful Life of Primary Paper Insulated Lead Covered Cables

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).

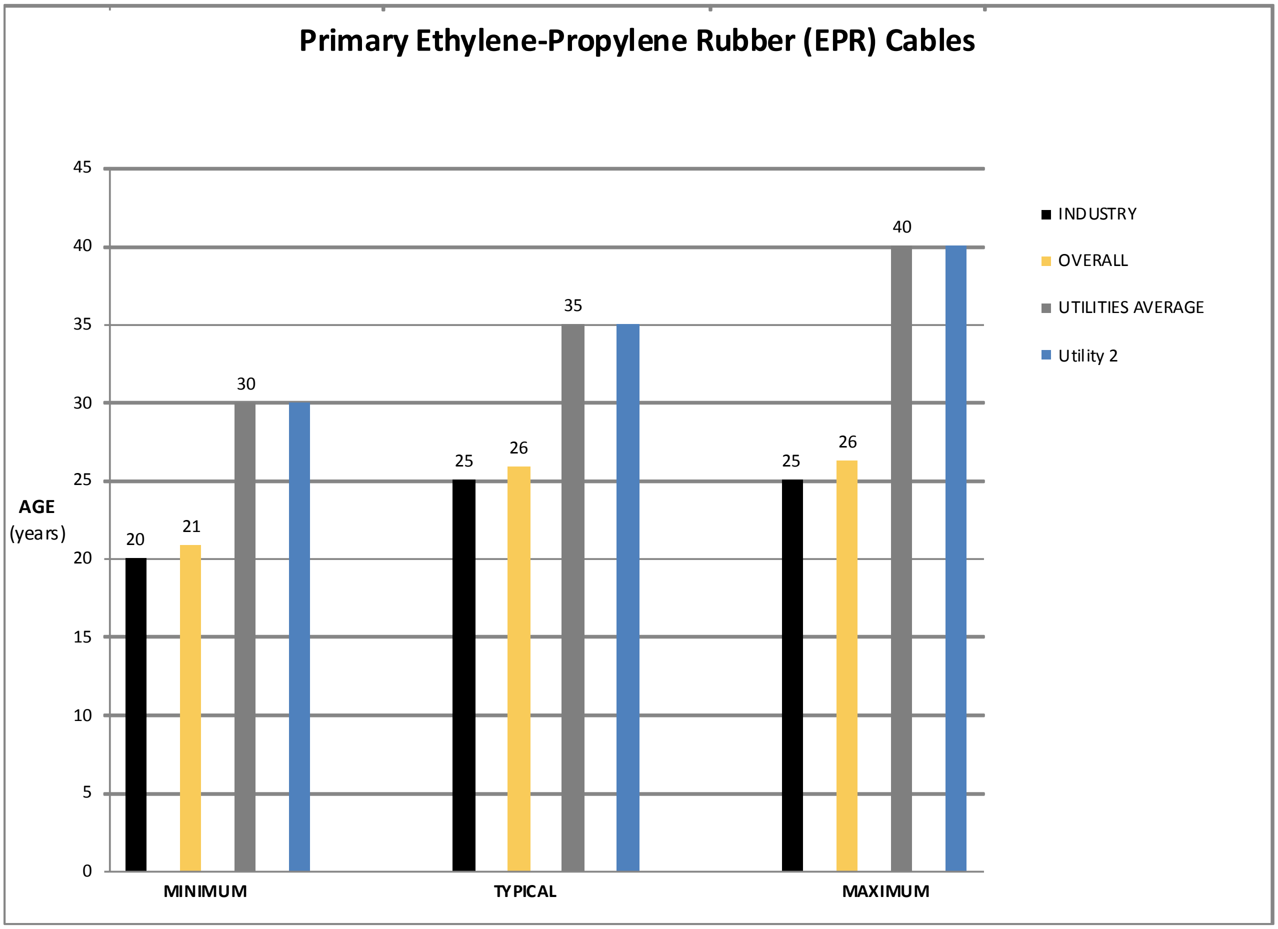


Figure 25-1 Useful Life Values for Primary Ethylene-Propylene Rubber Cables

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).

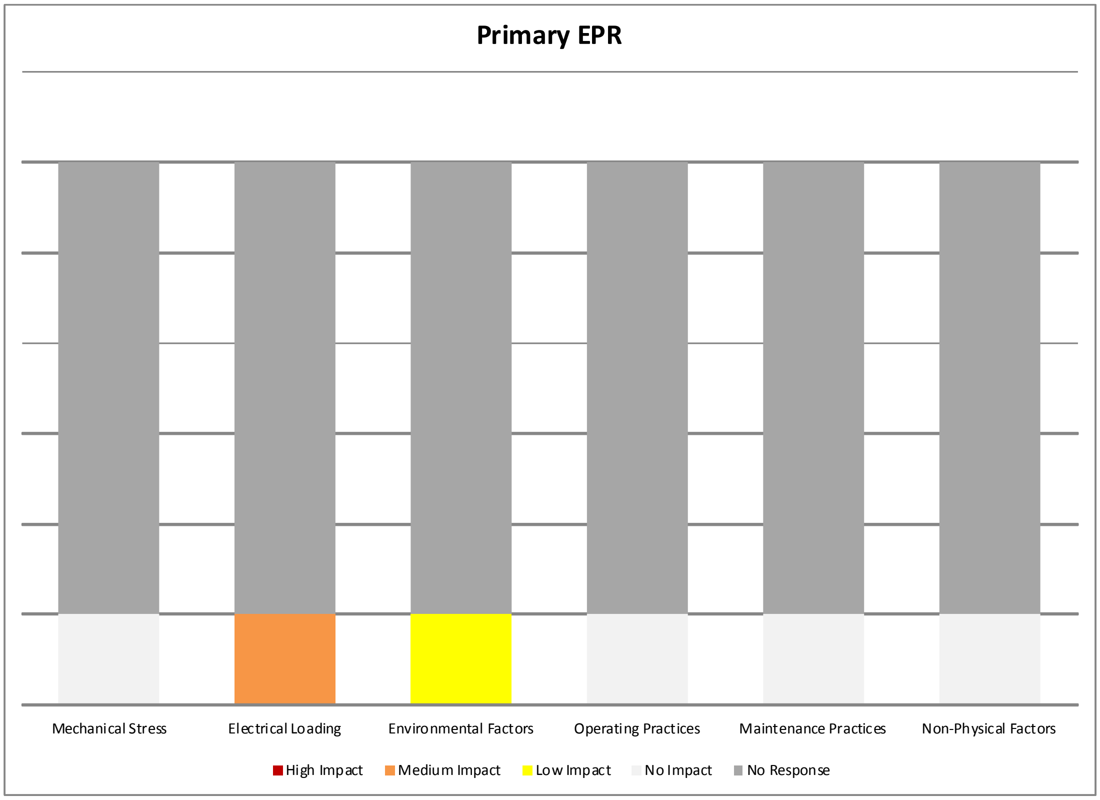


Figure 25-2 Impact of Utilization Factors on the Useful Life of Primary Ethylene-Propylene Rubber Cables

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).

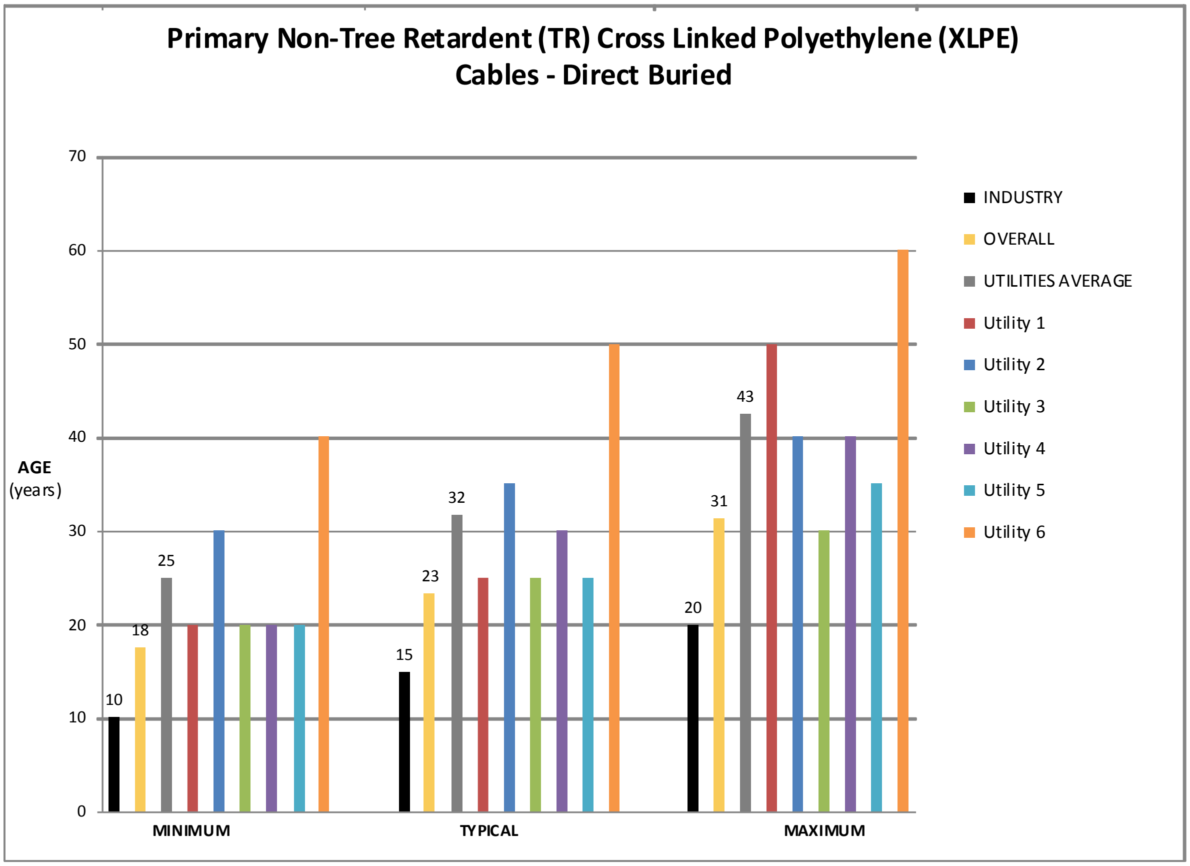


Figure 26-1 Useful Life Values for Primary Non-Tree Retardant Cross Linked Polyethylene Cables – Direct Buried

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).

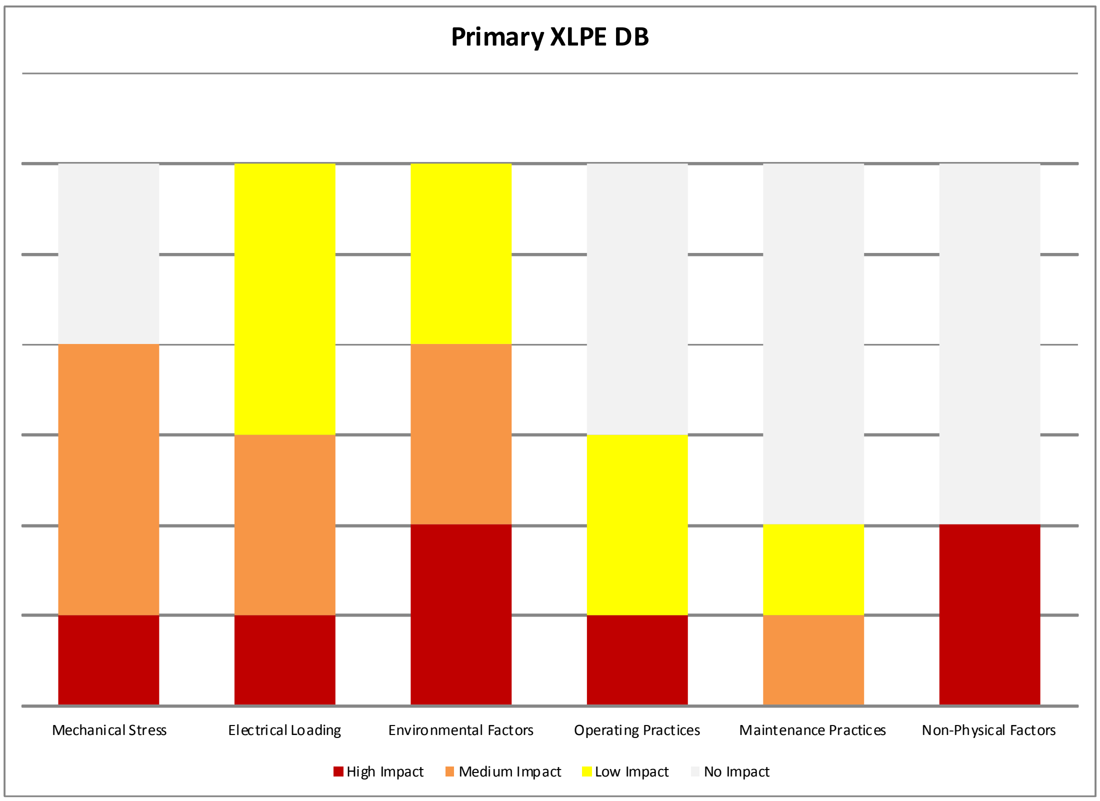


Figure 26-2 Impact of Utilization Factors on the Useful Life of Primary Non-Tree Retardant Cross Linked Polyethylene Cables – Direct Buried

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).

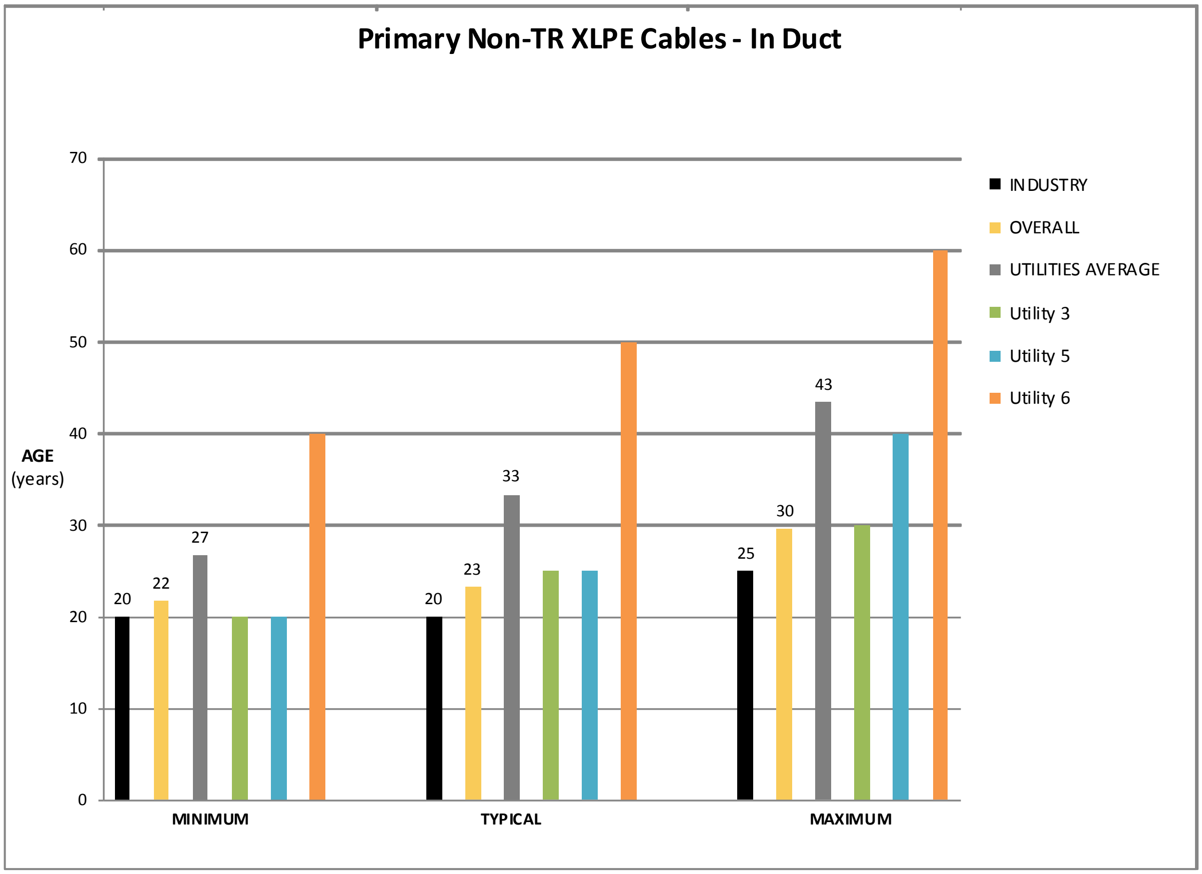


Figure 27-1 Useful Life Values for Primary Non-Tree Retardant Cross Linked Polyethylene Cables – In Duct

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).

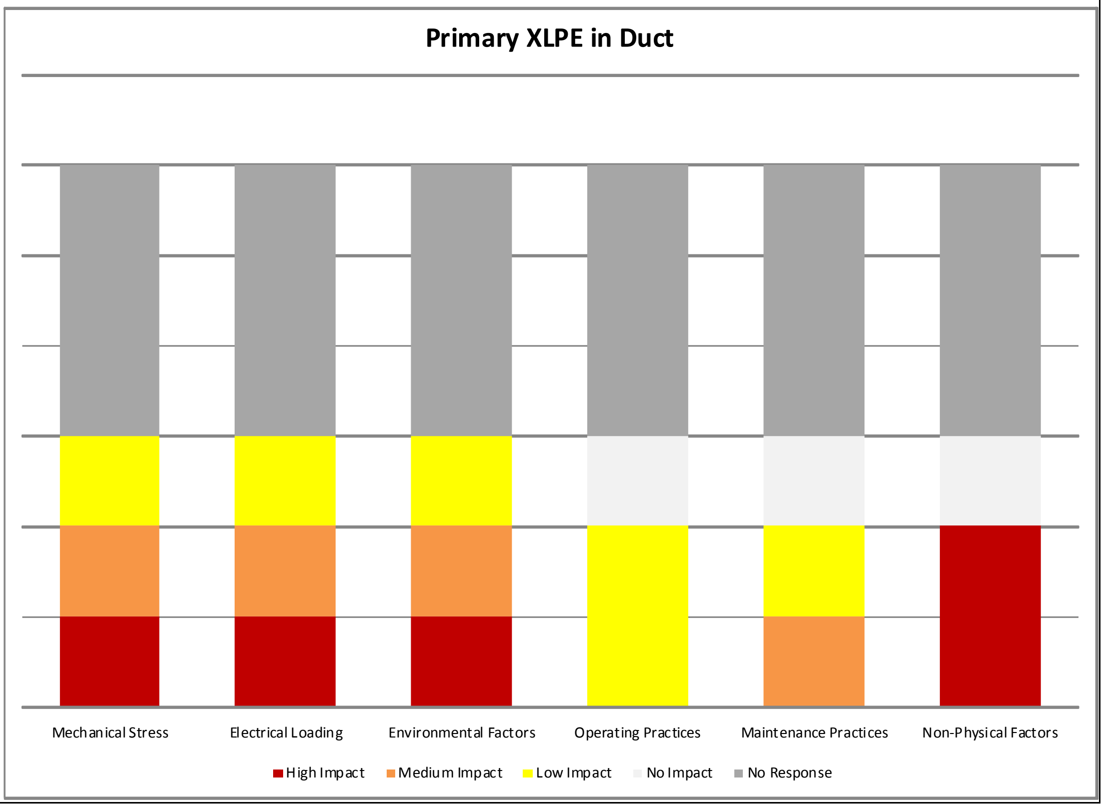


Figure 27-2 Impact of Utilization Factors on the Useful Life of Primary Non-Tree Retardant Cross Linked Polyethylene Cables – In Duct

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).

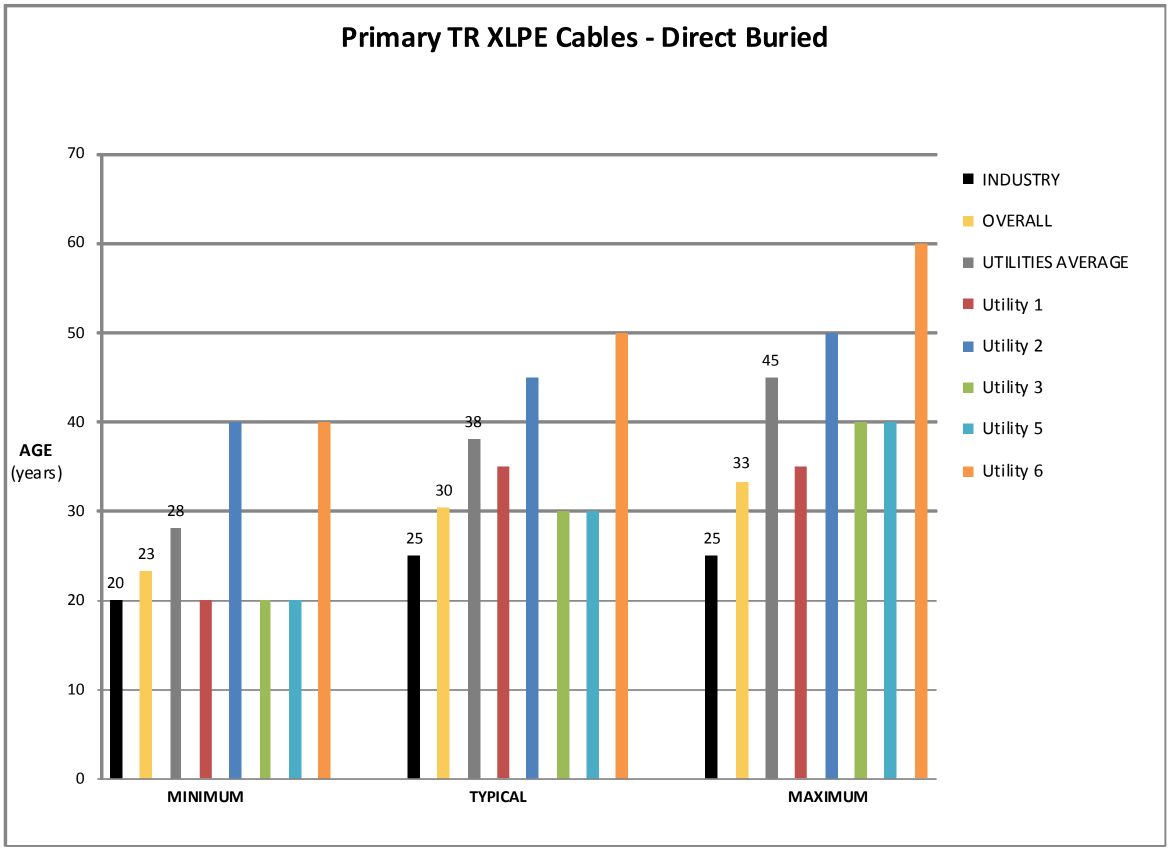


Figure 28-1 Useful Life Values for Primary Tree Retardant Cross Linked Polyethylene Cables – Direct Buried

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).

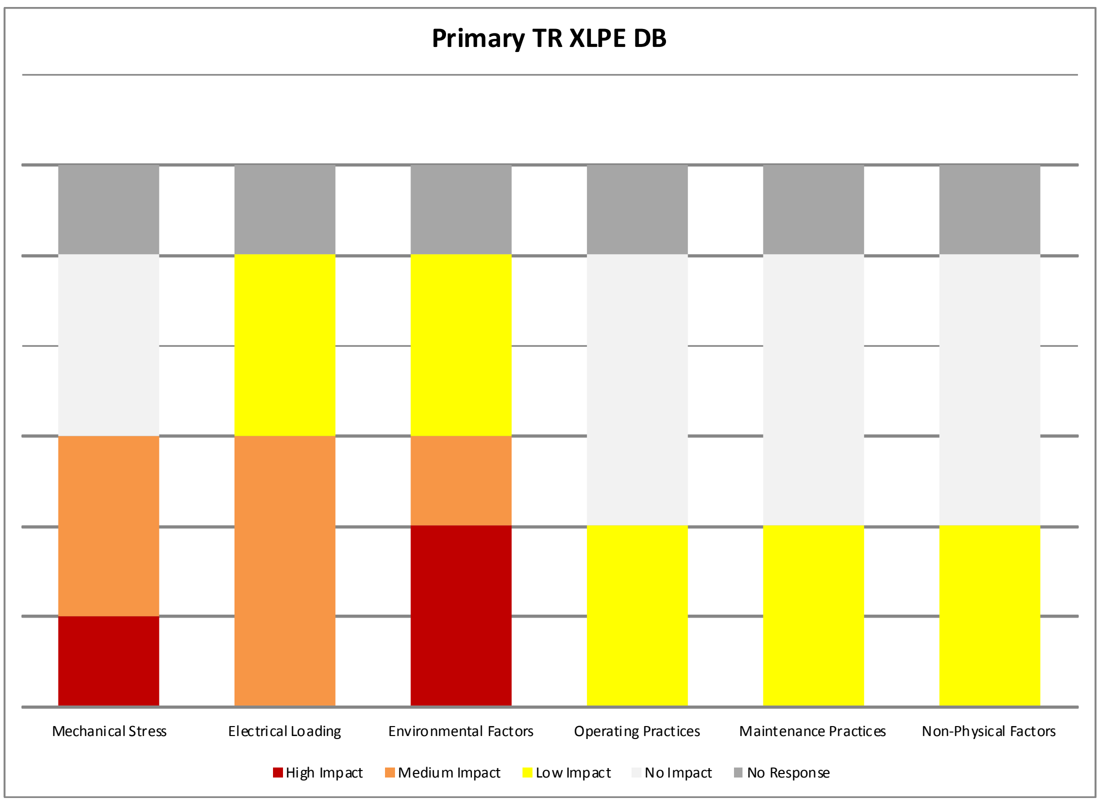


Figure 28-2 Impact of Utilization Factors on the Useful Life of Primary Tree Retardant Cross Linked Polyethylene Cables – Direct Buried

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).

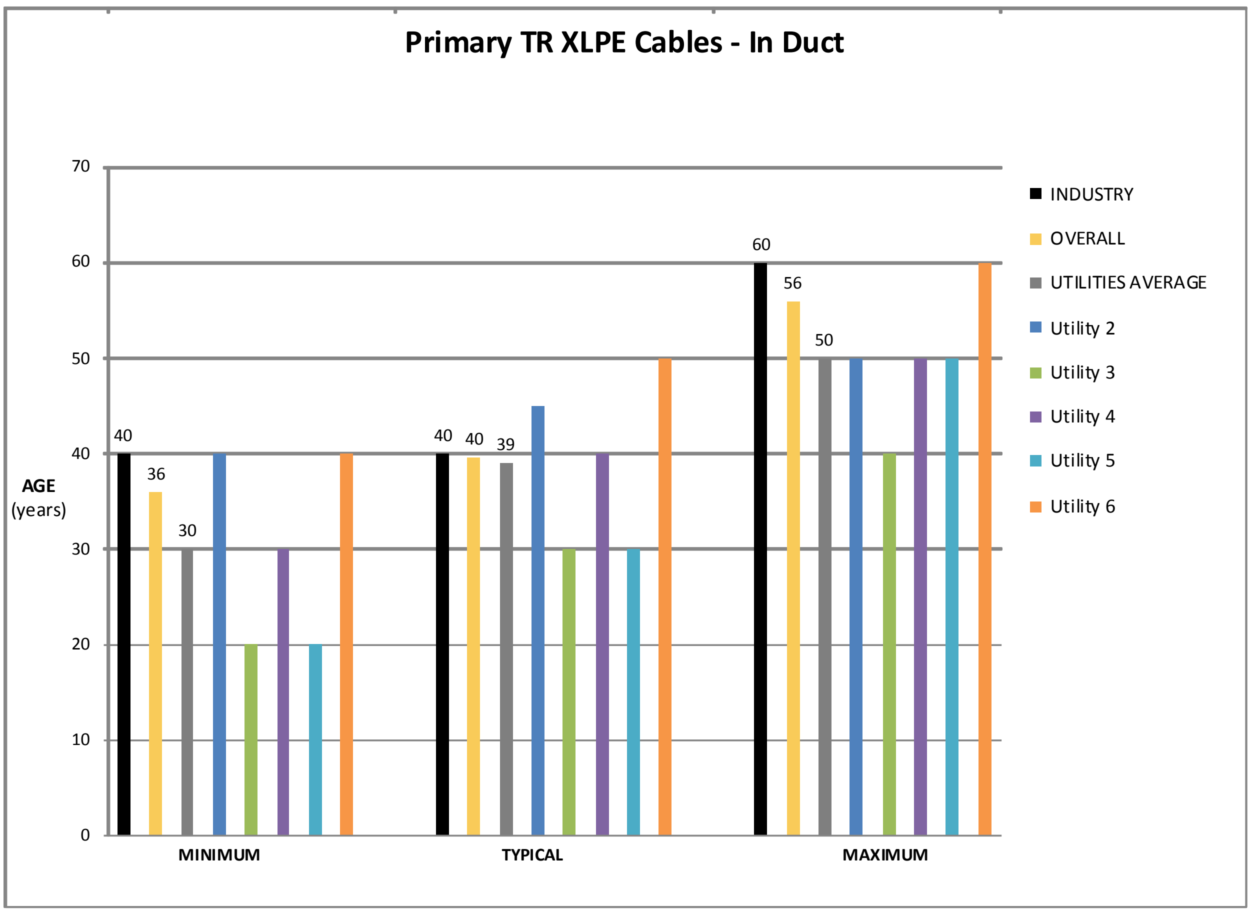


Figure 29-1 Useful Life Values for Primary Tree Retardant Cross Linked Polyethylene Cables – In Duct

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).

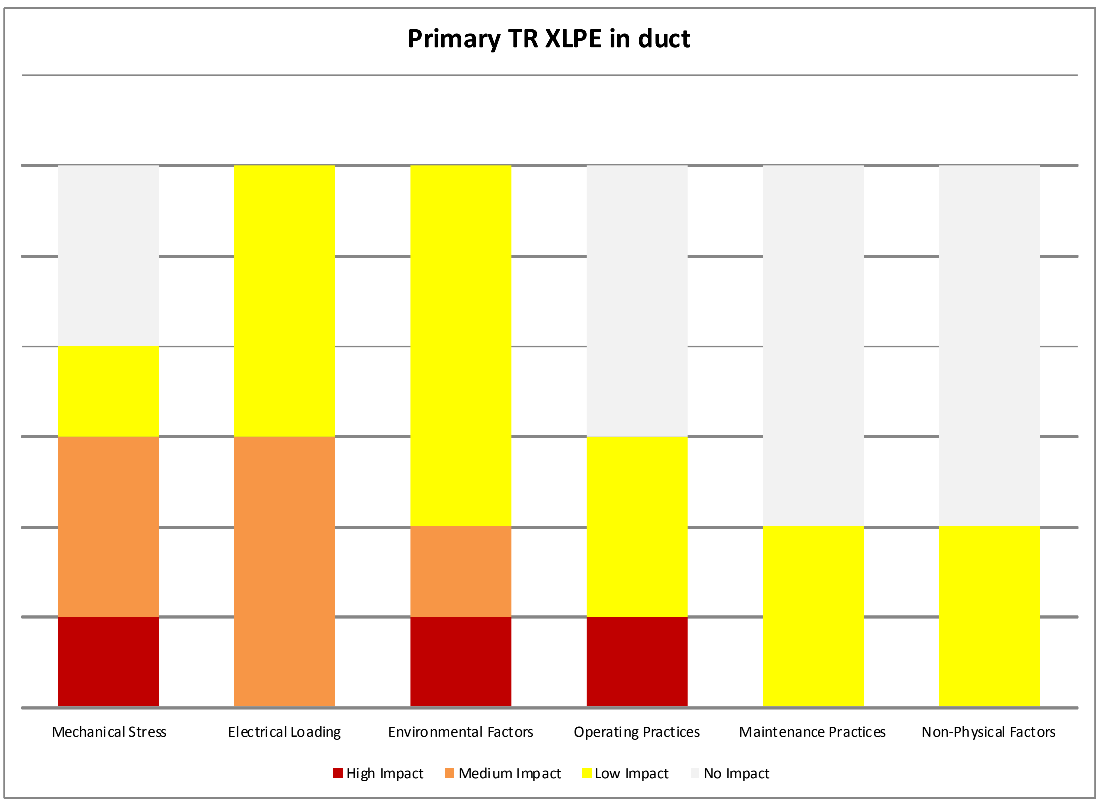


Figure 29-2 Impact of Utilization Factors on the Useful Life of Primary Tree Retardant Cross Linked Polyethylene Cables – In Duct

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).

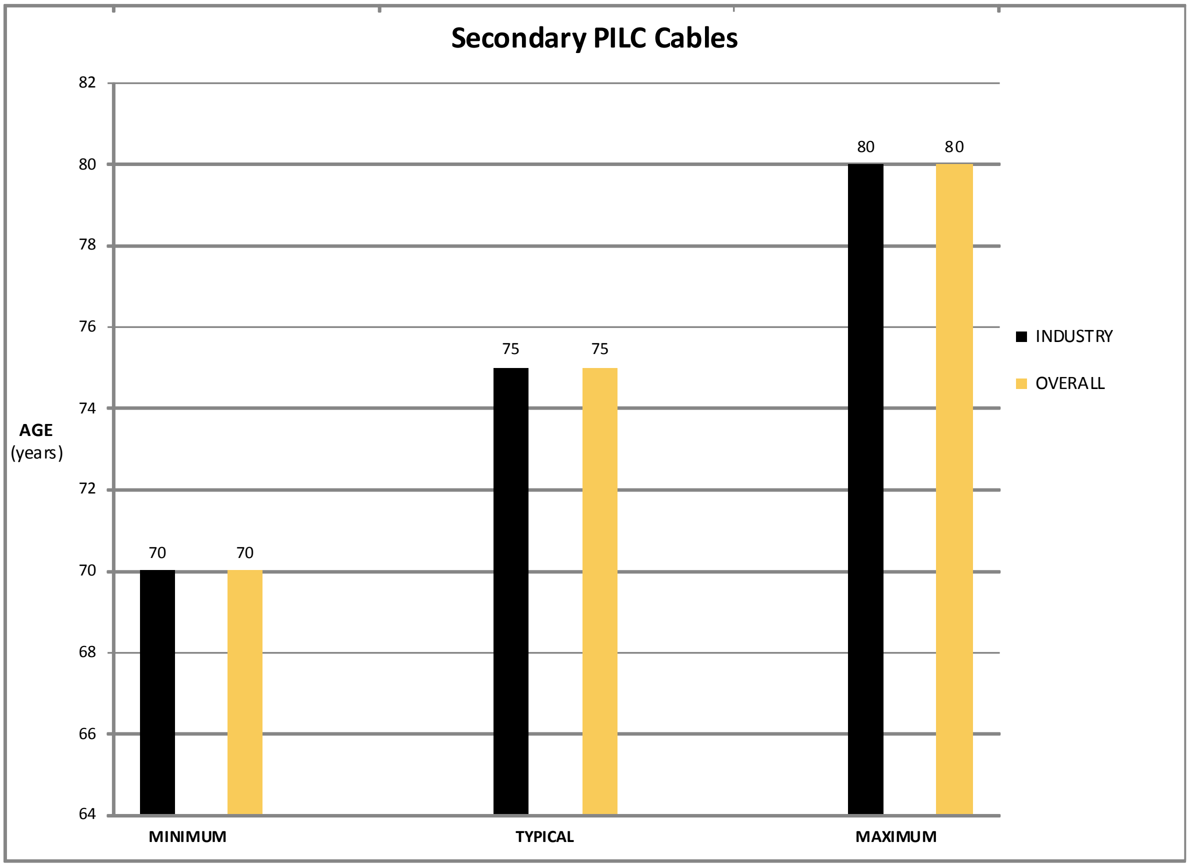


Figure 30-1 Useful Life Values for Secondary Paper Insulated Lead Covered Cables

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).

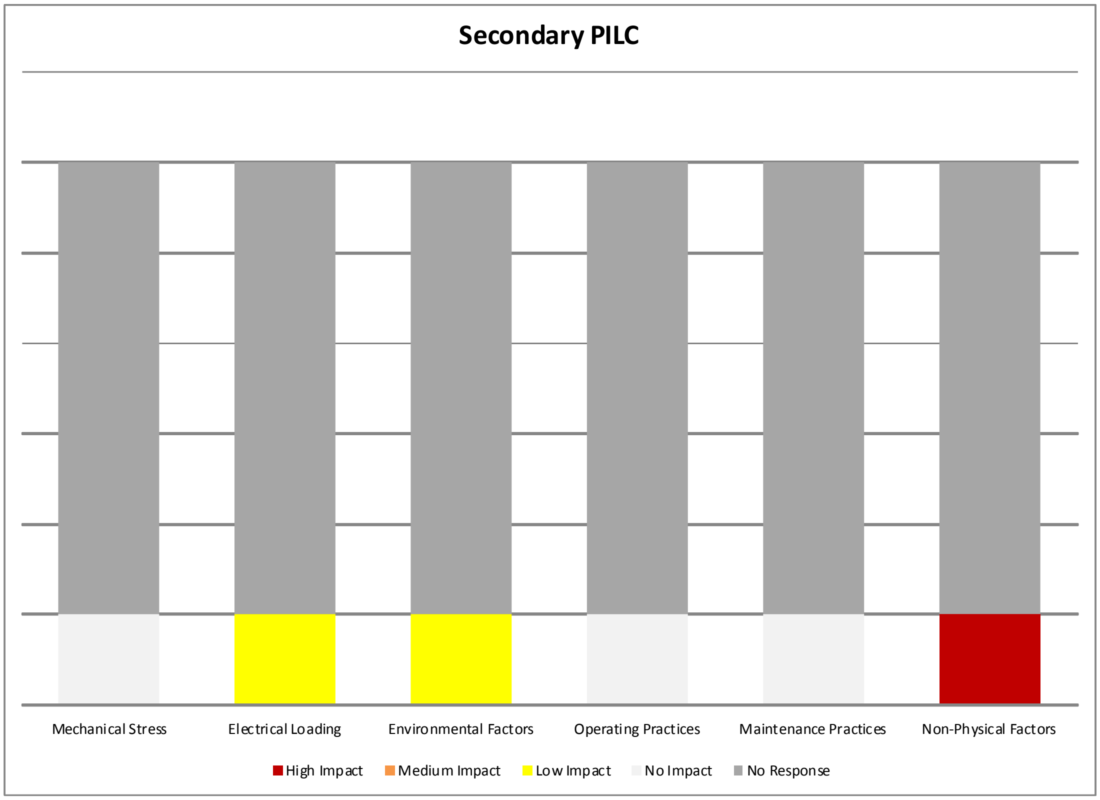


Figure 30-2 Impact of Utilization Factors on the Useful Life of Secondary Paper Insulated Lead Covered Cables

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).

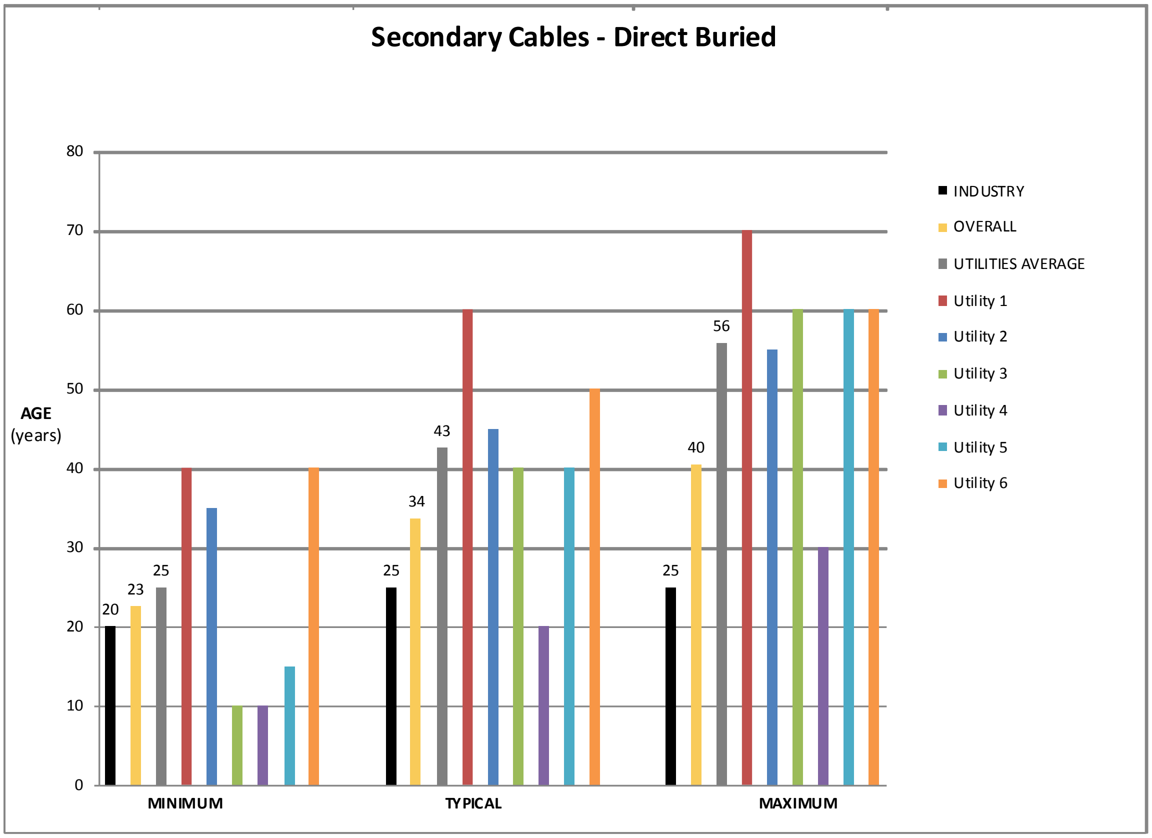


Figure 31-1 Useful Life Values for Secondary Cables – Direct Buried

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).

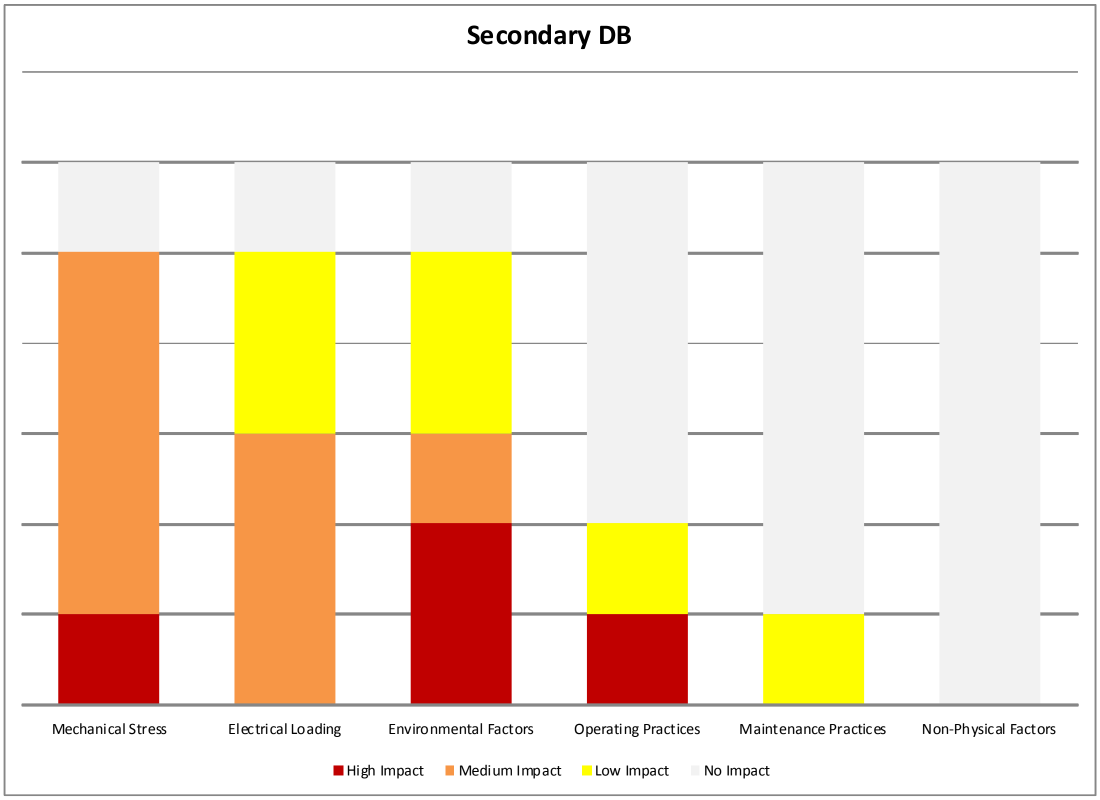


Figure 31-2 Impact of Utilization Factors on the Useful Life of Secondary Cables – Direct Buried

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).

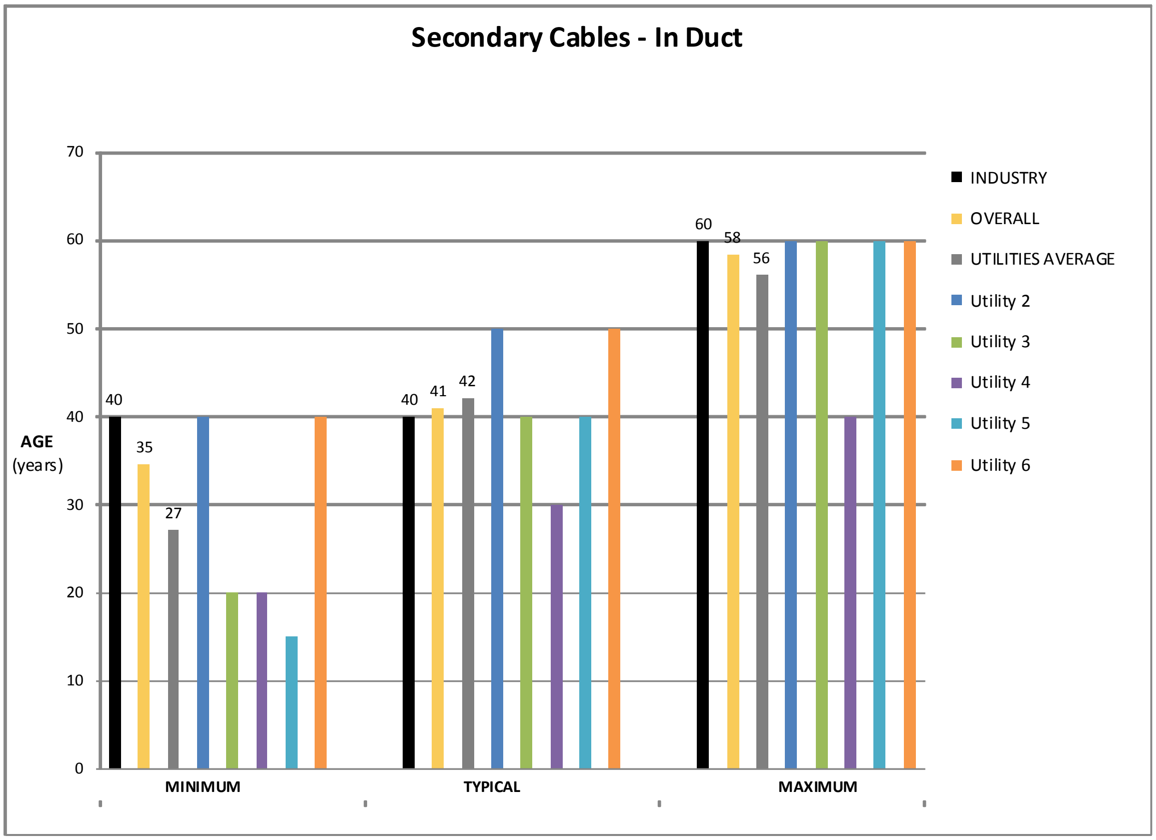


Figure 32-1 Useful Life Values for Secondary Cables – In Duct

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).

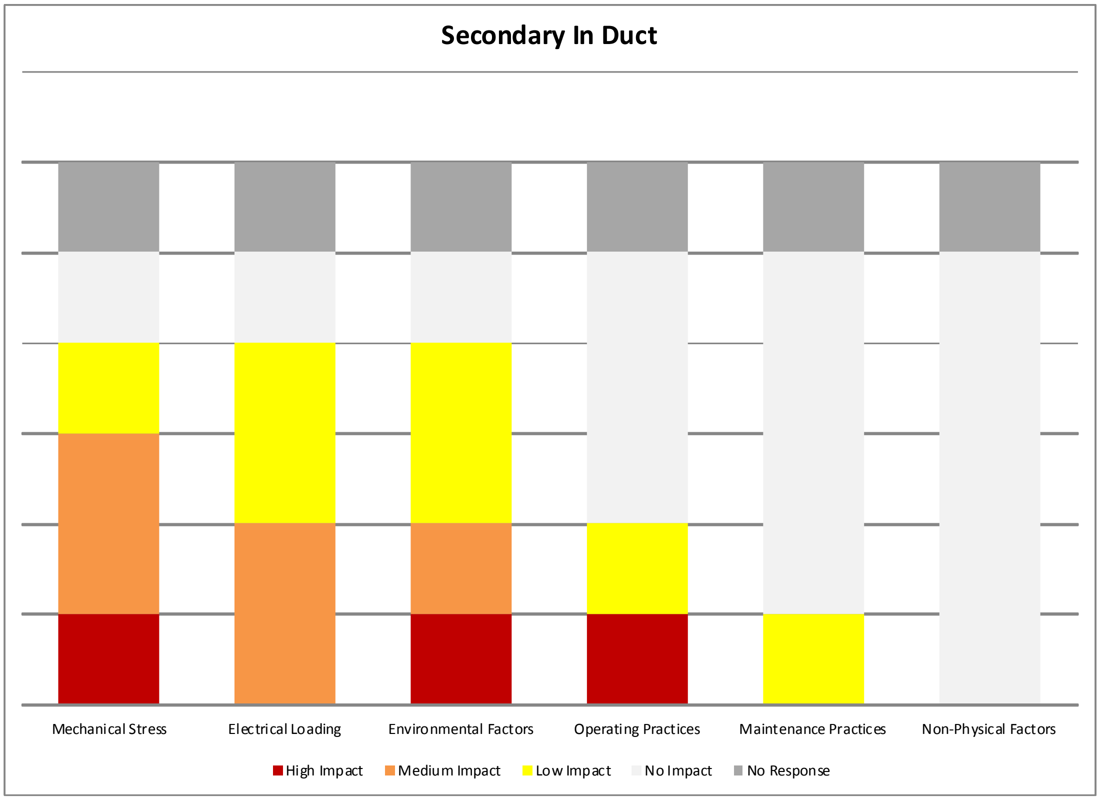


Figure 32-2 Impact of Utilization Factors on the Useful Life of Secondary Cables – In Duct

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).

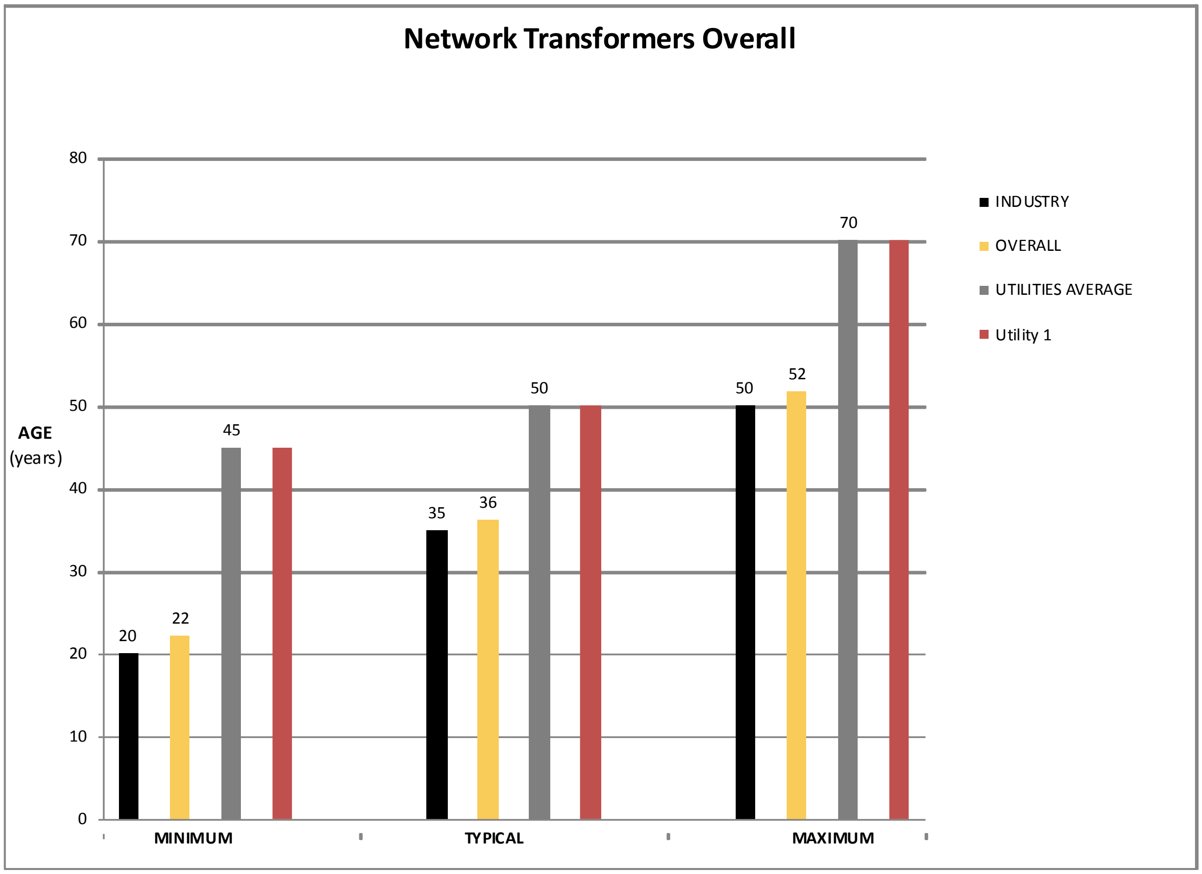


Figure 33-1 Useful Life Values for Network Transformers

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).

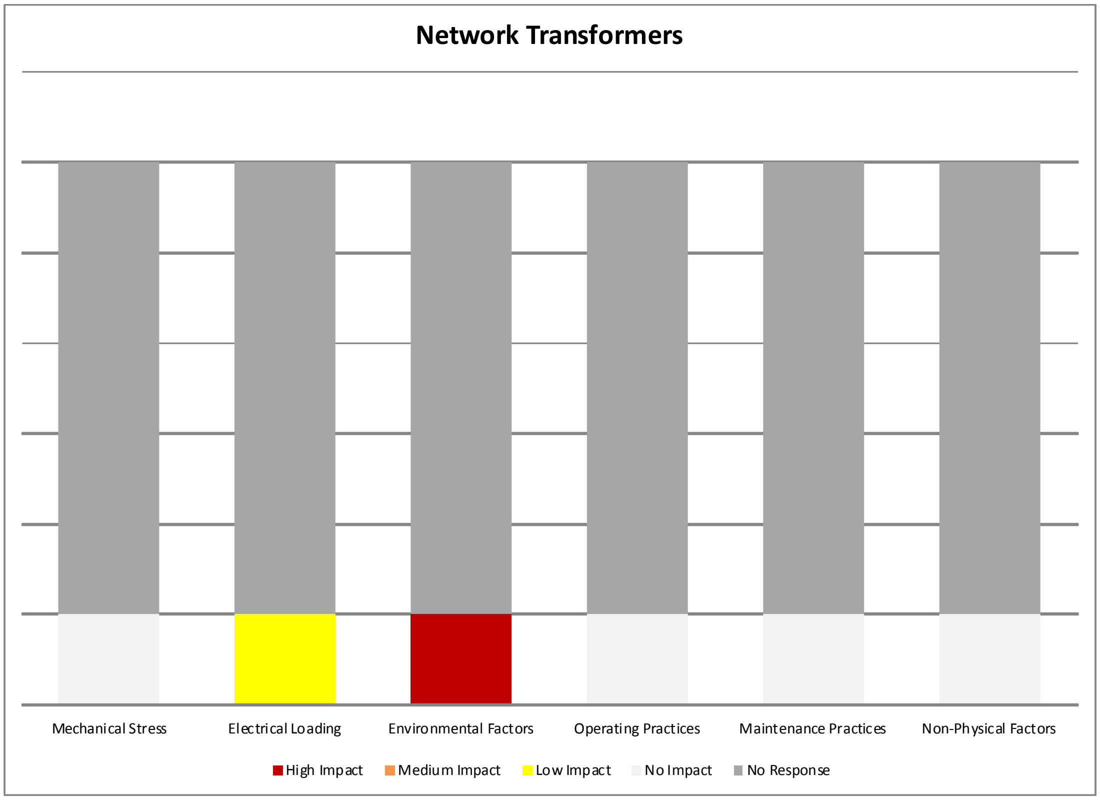


Figure 33-2 Impact of Utilization Factors on the Useful Life of Network Transformers

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).

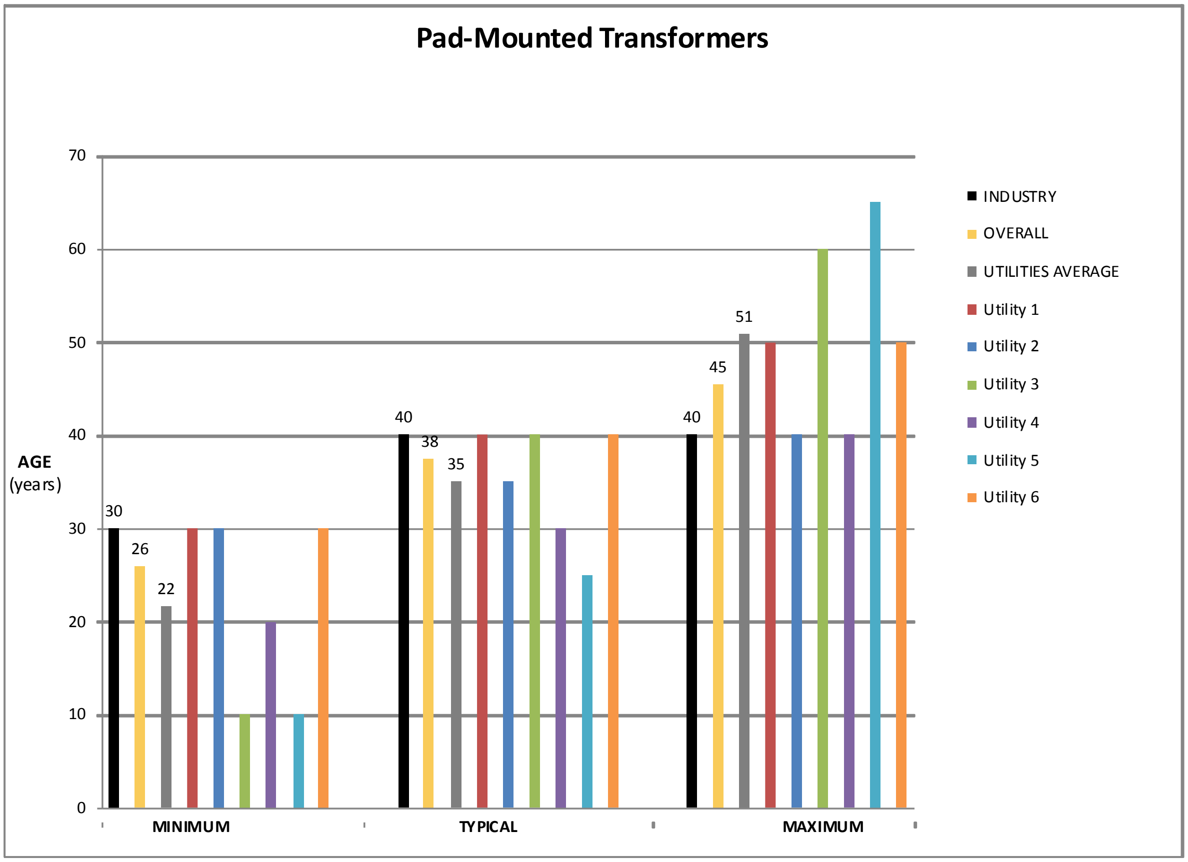


Figure 34-1 Useful Life Values for Pad-Mounted Transformers

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).

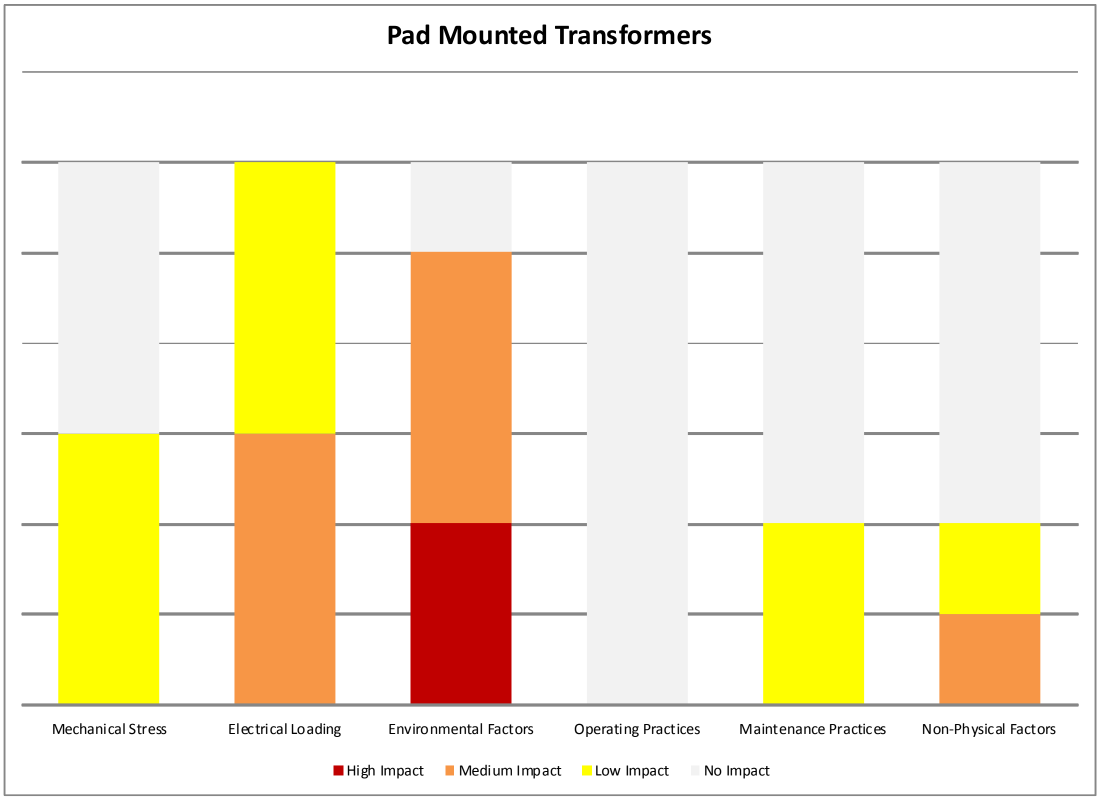


Figure 34-2 Impact of Utilization Factors on the Useful Life of Pad-Mounted Transformers

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).

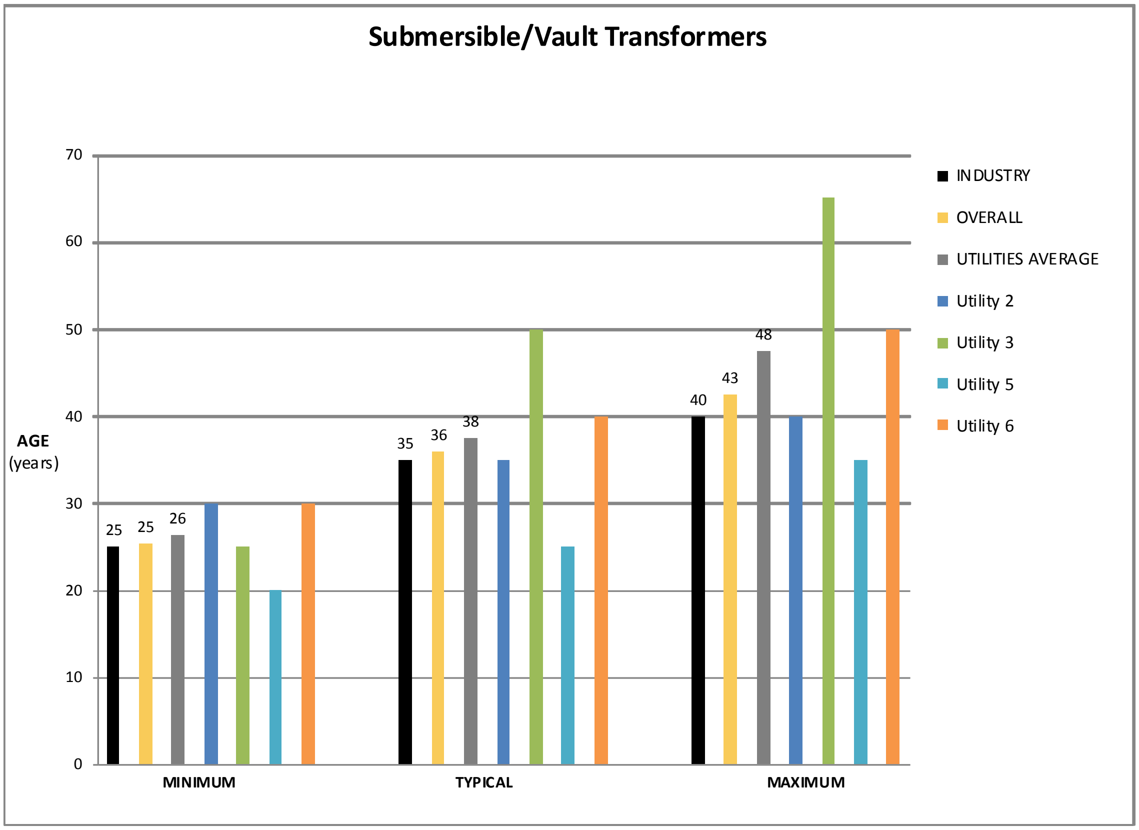


Figure 35-1 Useful Life Values for Submersible and Vault Transformers

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).

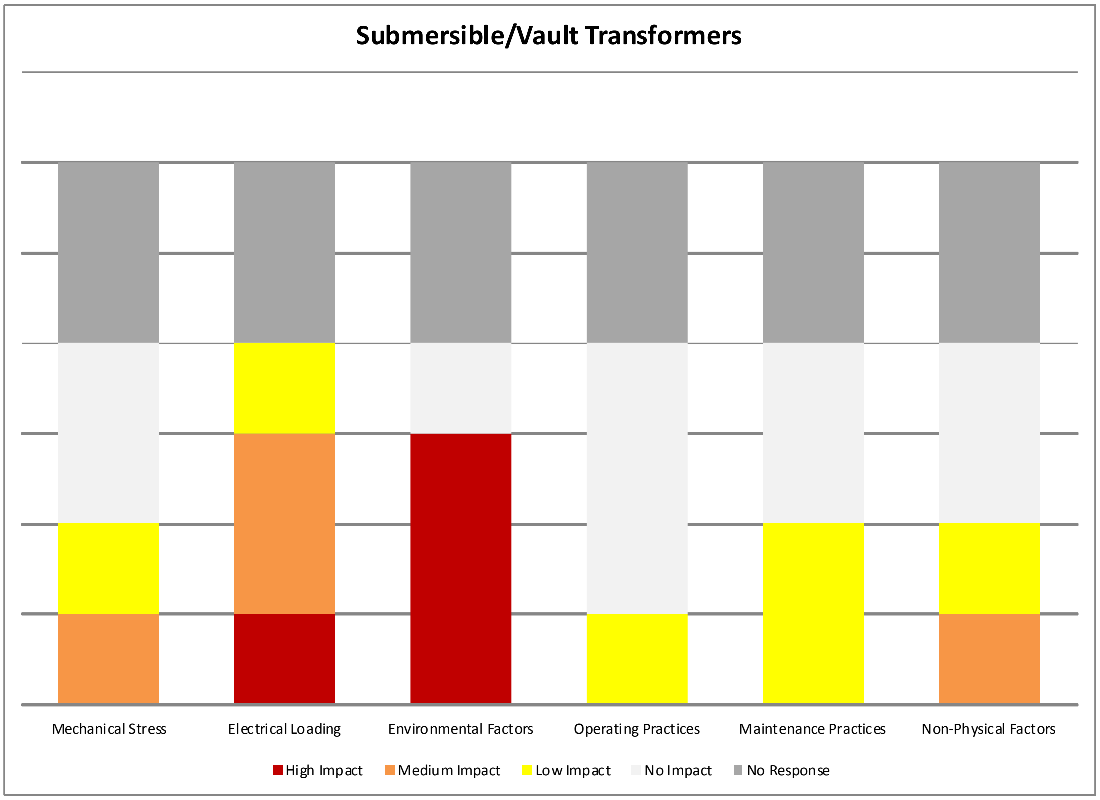


Figure 35-2 Impact of Utilization Factors on the Useful Life of Submersible and Vault Transformers

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).

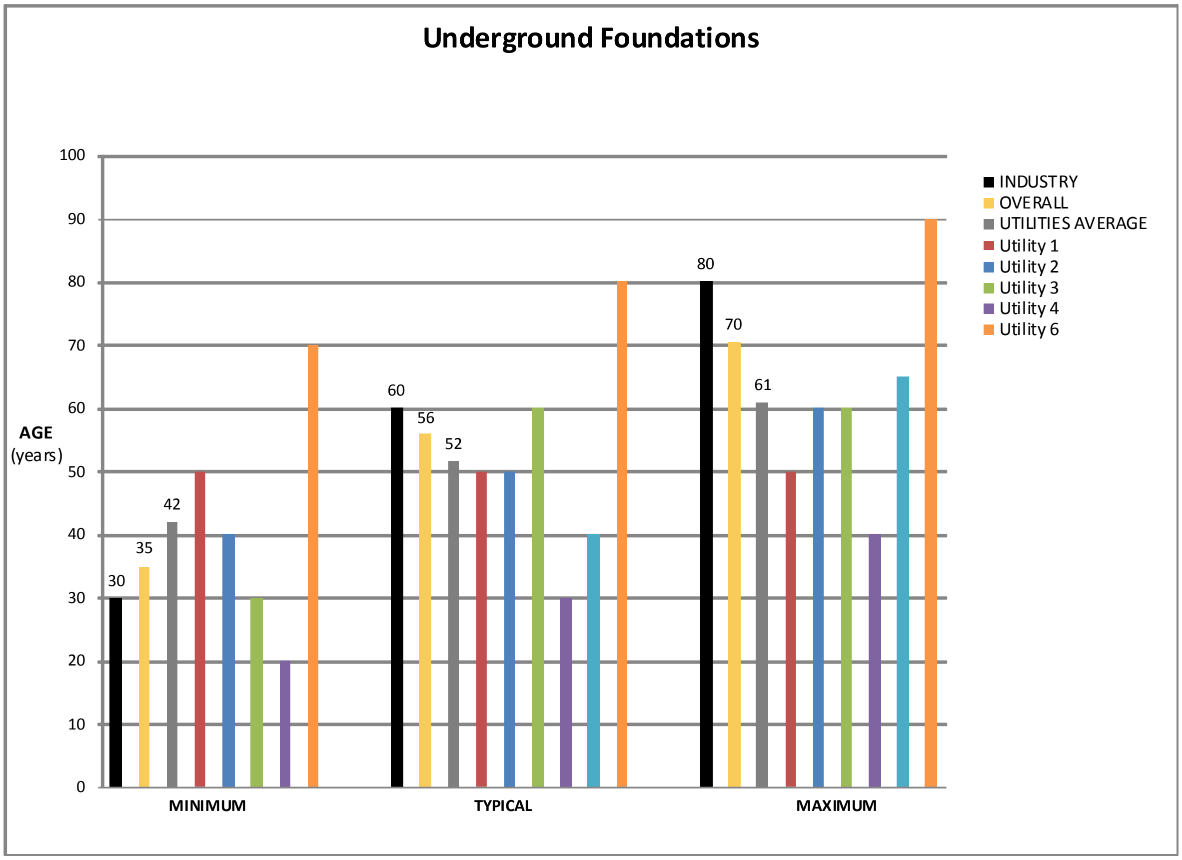


Figure 36-1 Useful Life Values for Underground Foundations

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).

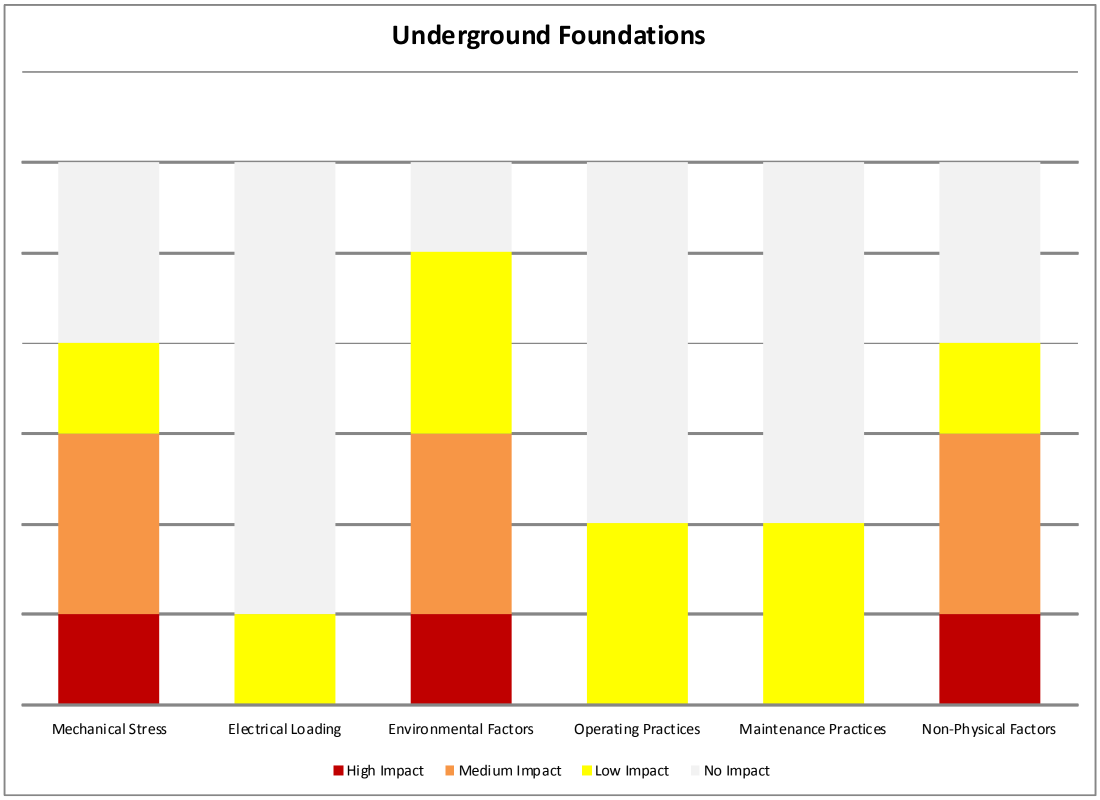


Figure 36-2 Impact of Utilization Factors on the Useful Life of Underground Foundations

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).

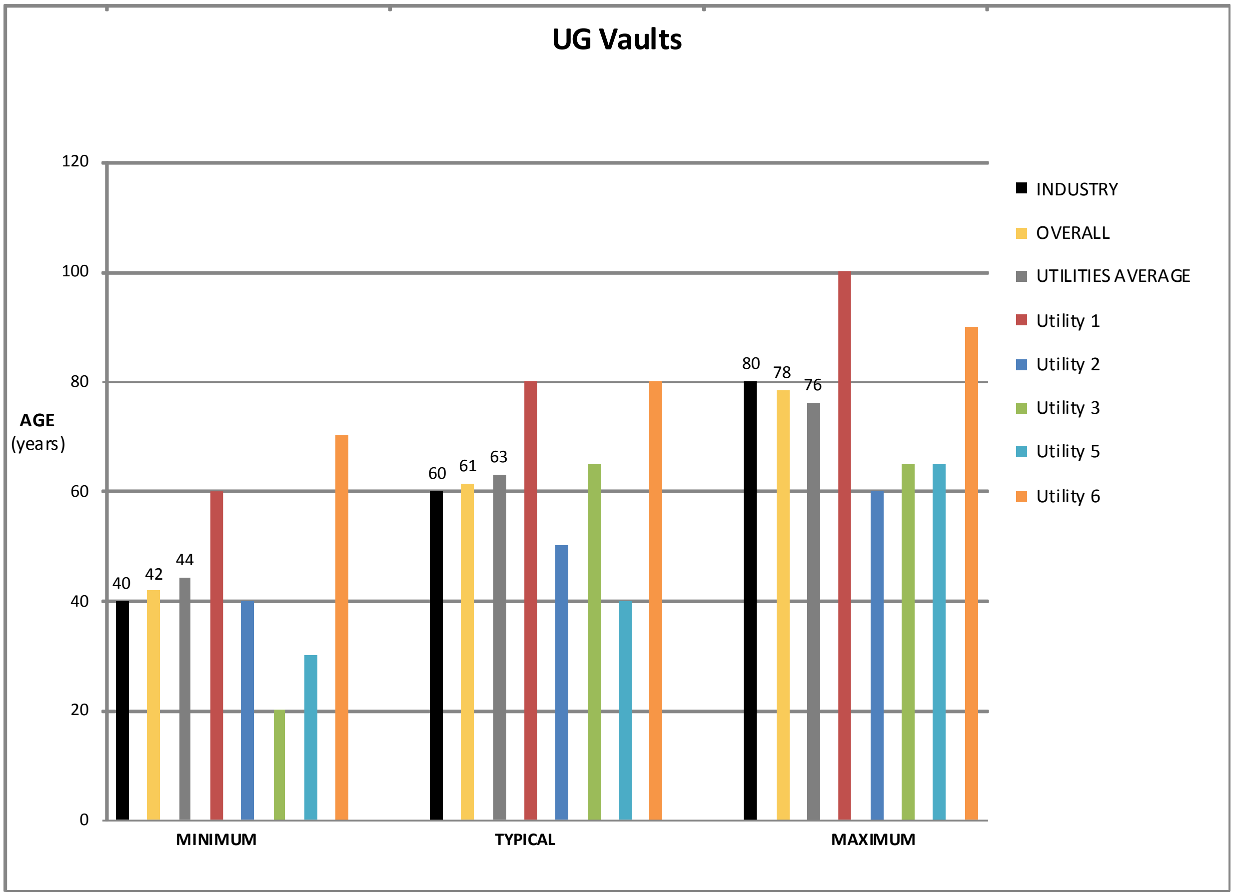


Figure 37-1 Useful Life Values for Underground Vaults

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).

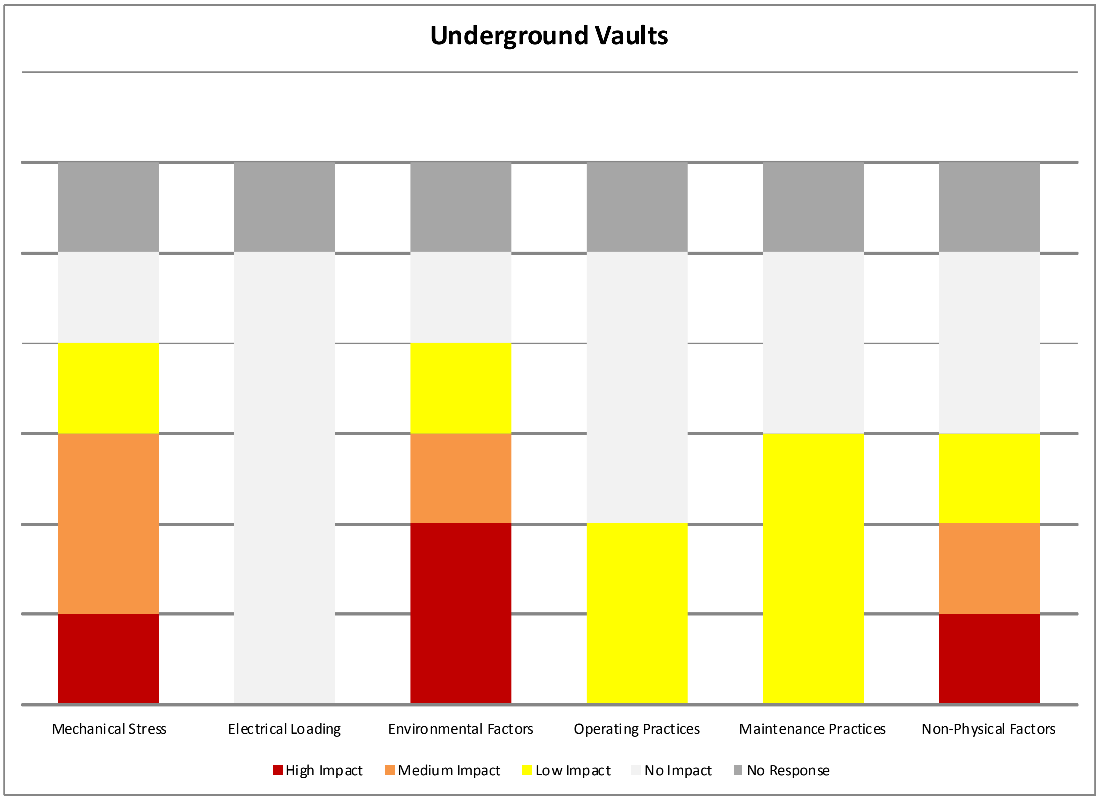


Figure 37-2 Impact of Utilization Factors on the Useful Life of Underground Vaults

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).

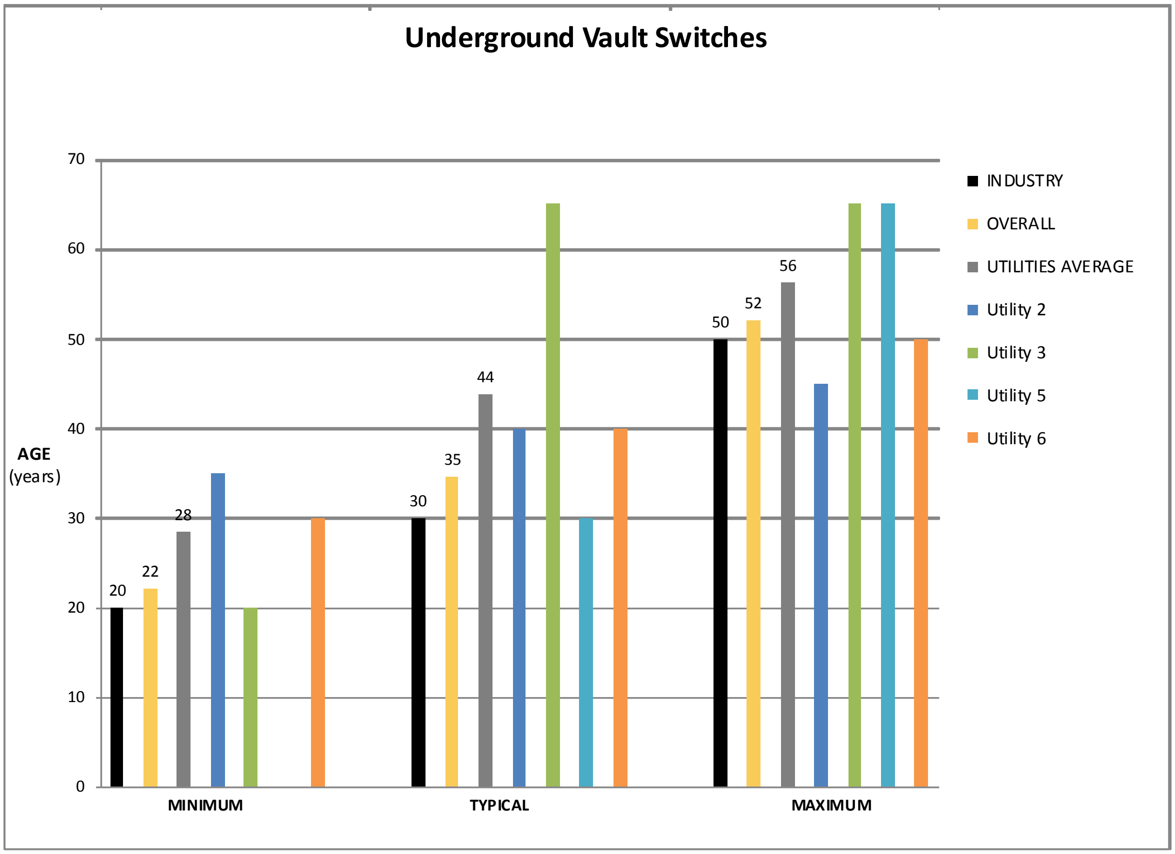


Figure 38-1 Useful Life Values for Underground Vault Switches

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).

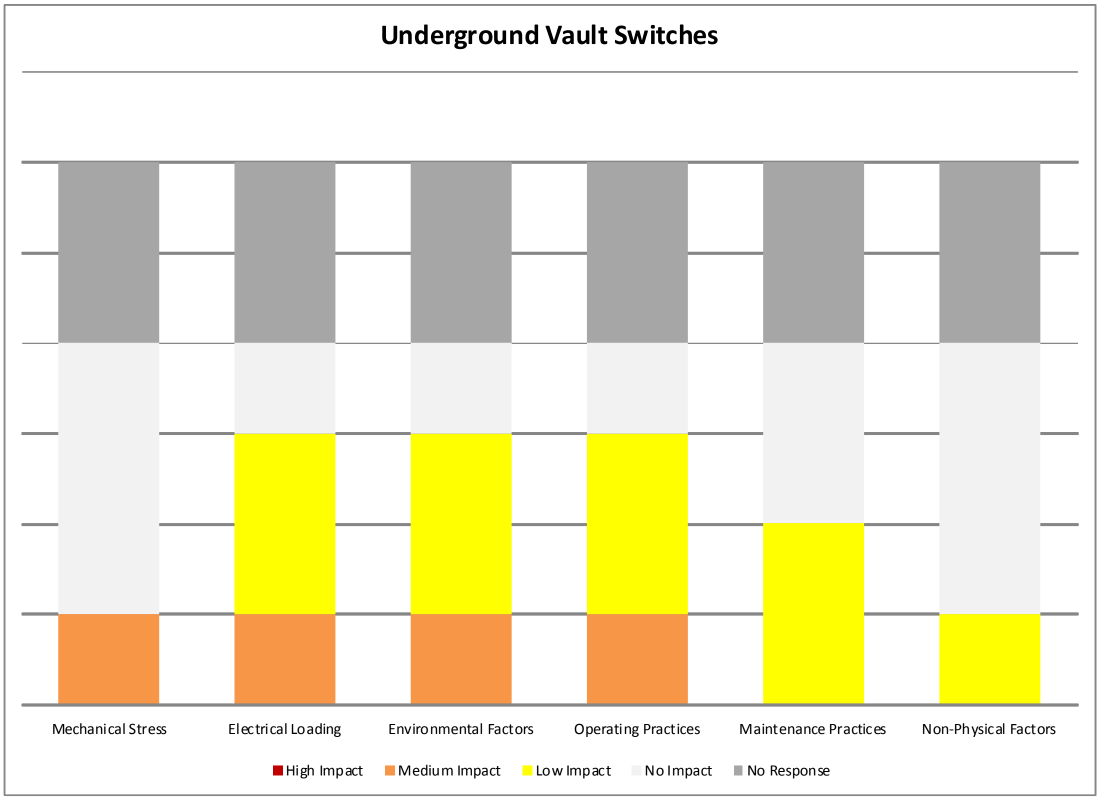


Figure 38-2 Impact of Utilization Factors on the Useful Life of Underground Vault Switches

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).

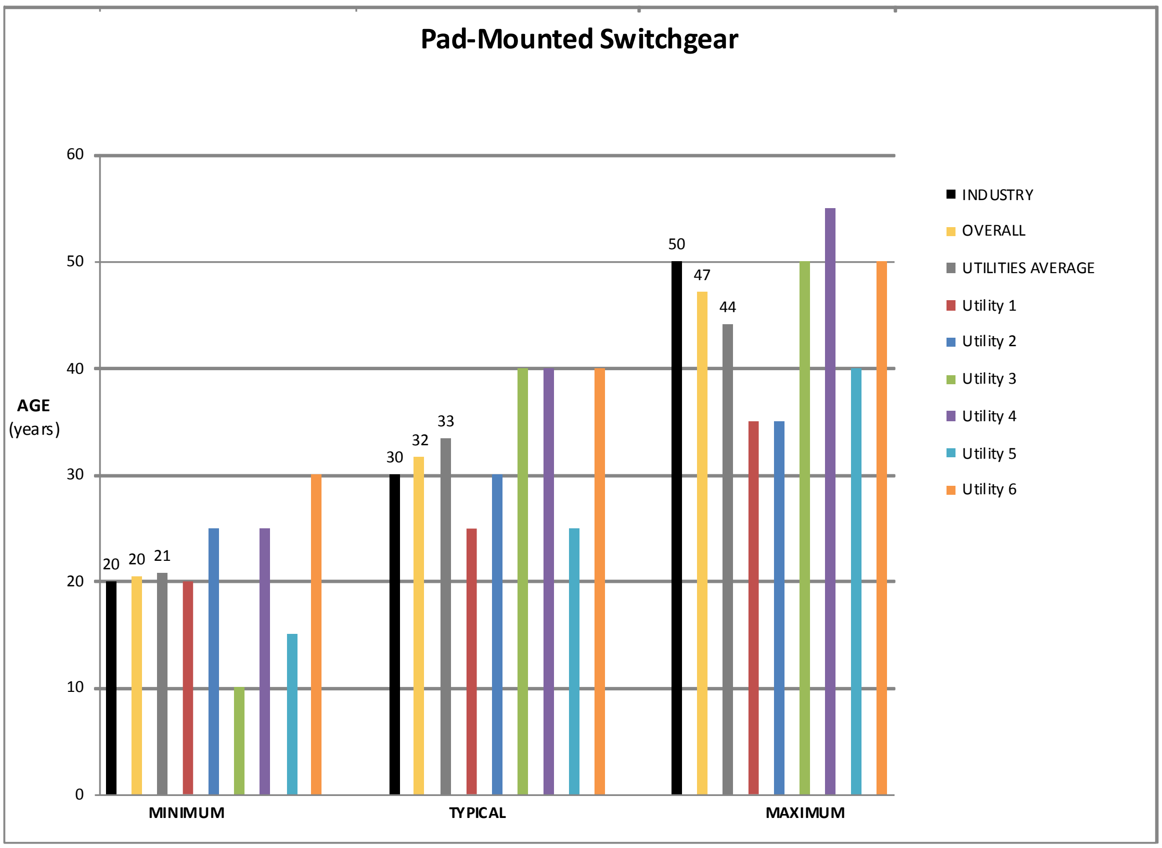


Figure 39-1 Useful Life Values for Pad-Mounted Switchgear

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).

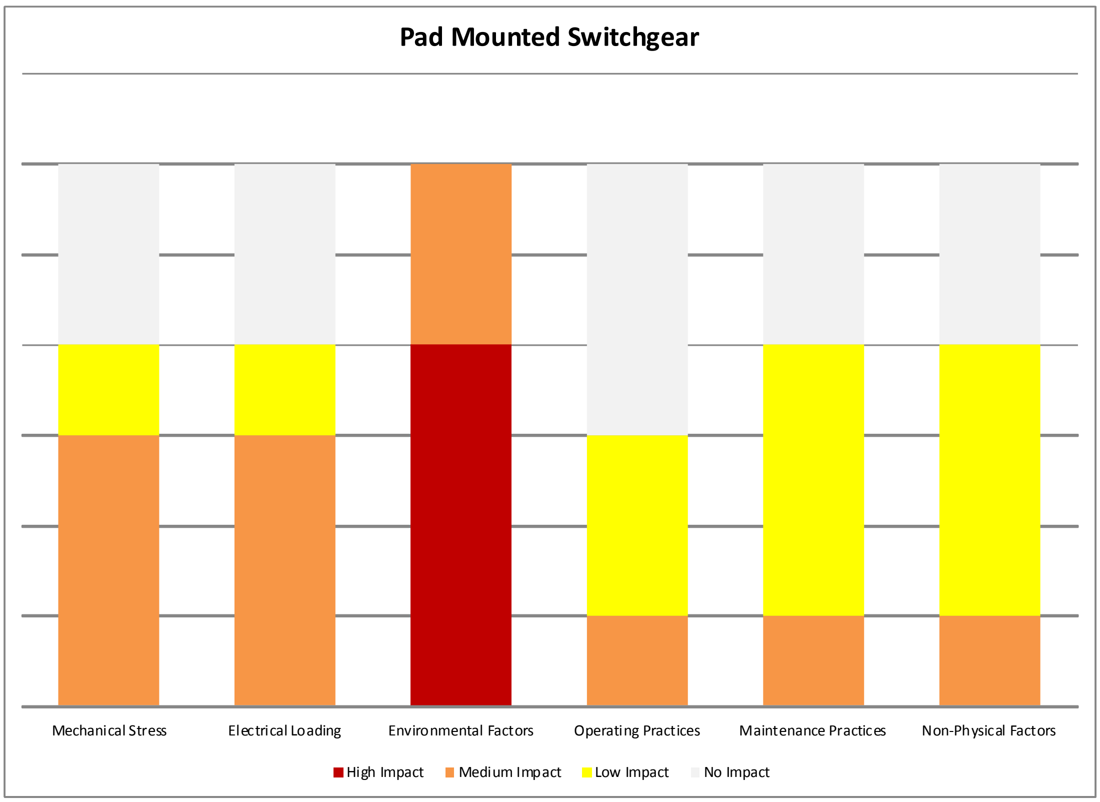


Figure 39-2 Impact of Utilization Factors on the Useful Life of Pad-Mounted Switchgear

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).

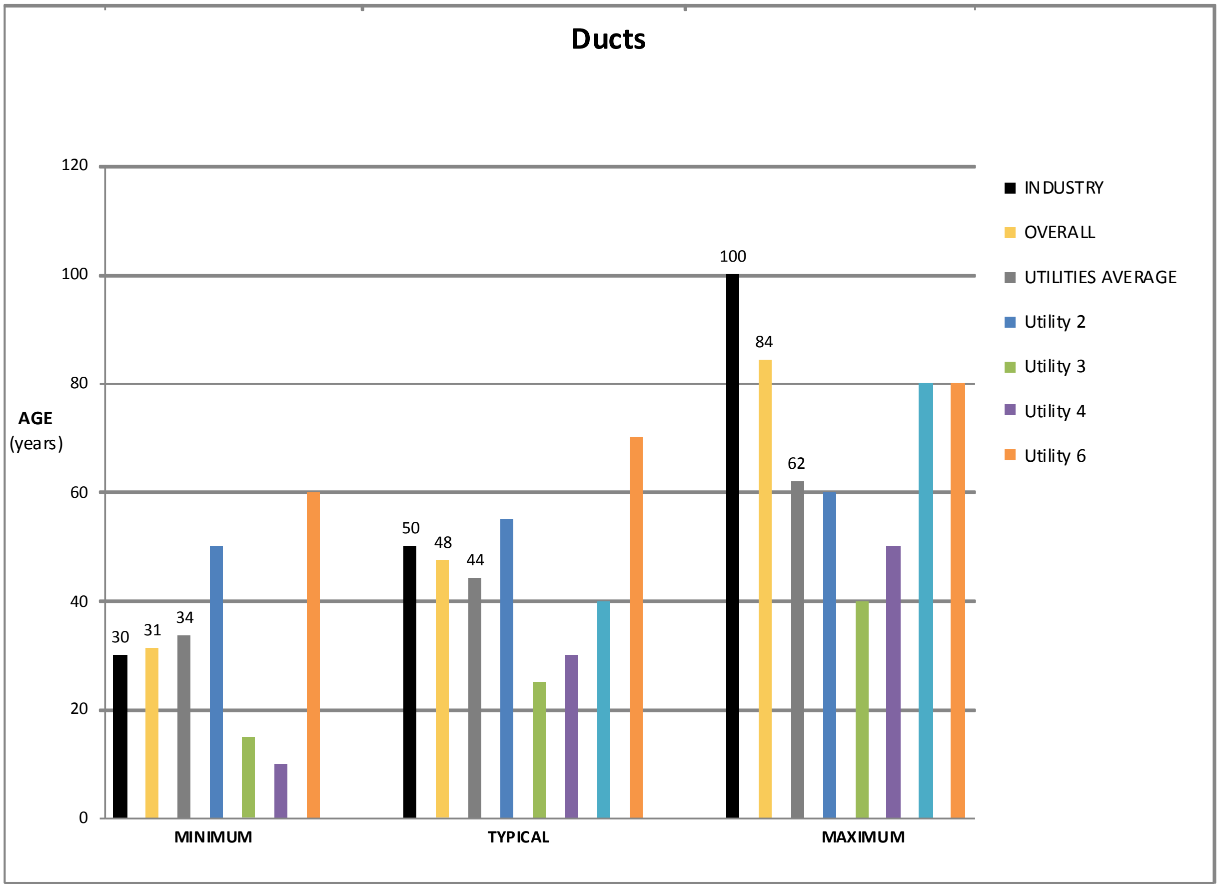


Figure 40-1 Useful Life Values for Ducts

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).

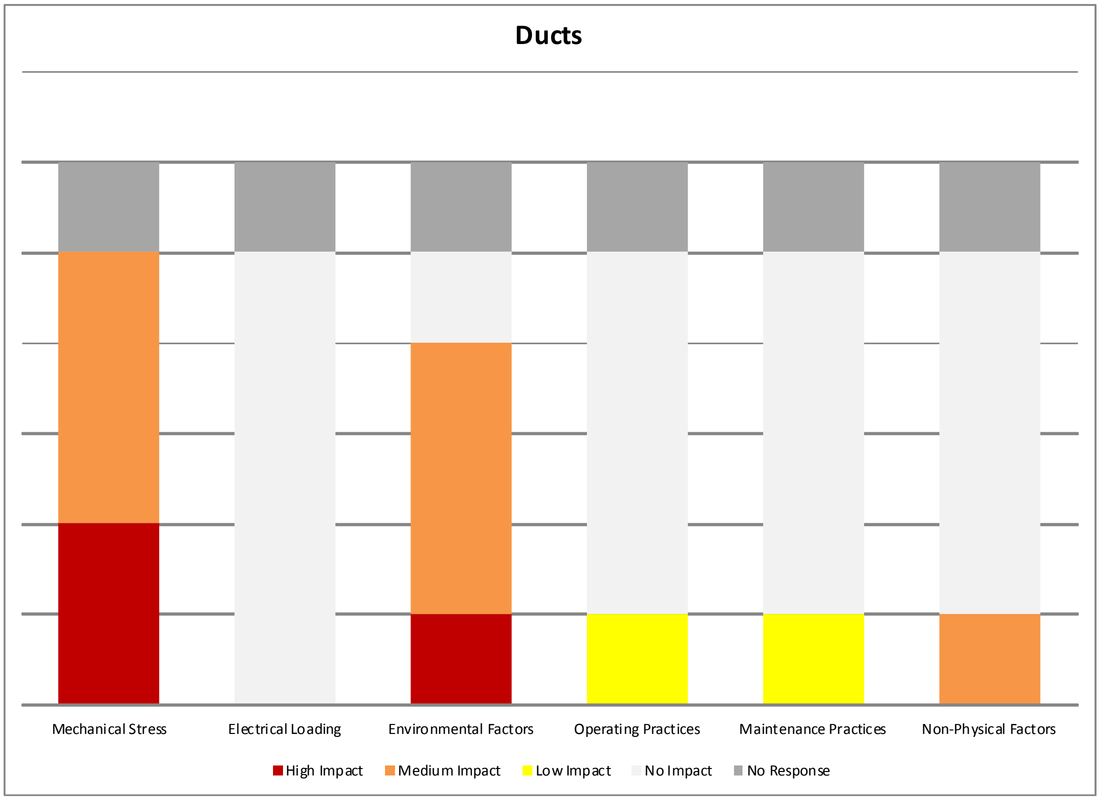


Figure 40-2 Impact of Utilization Factors on the Useful Life of Ducts

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).

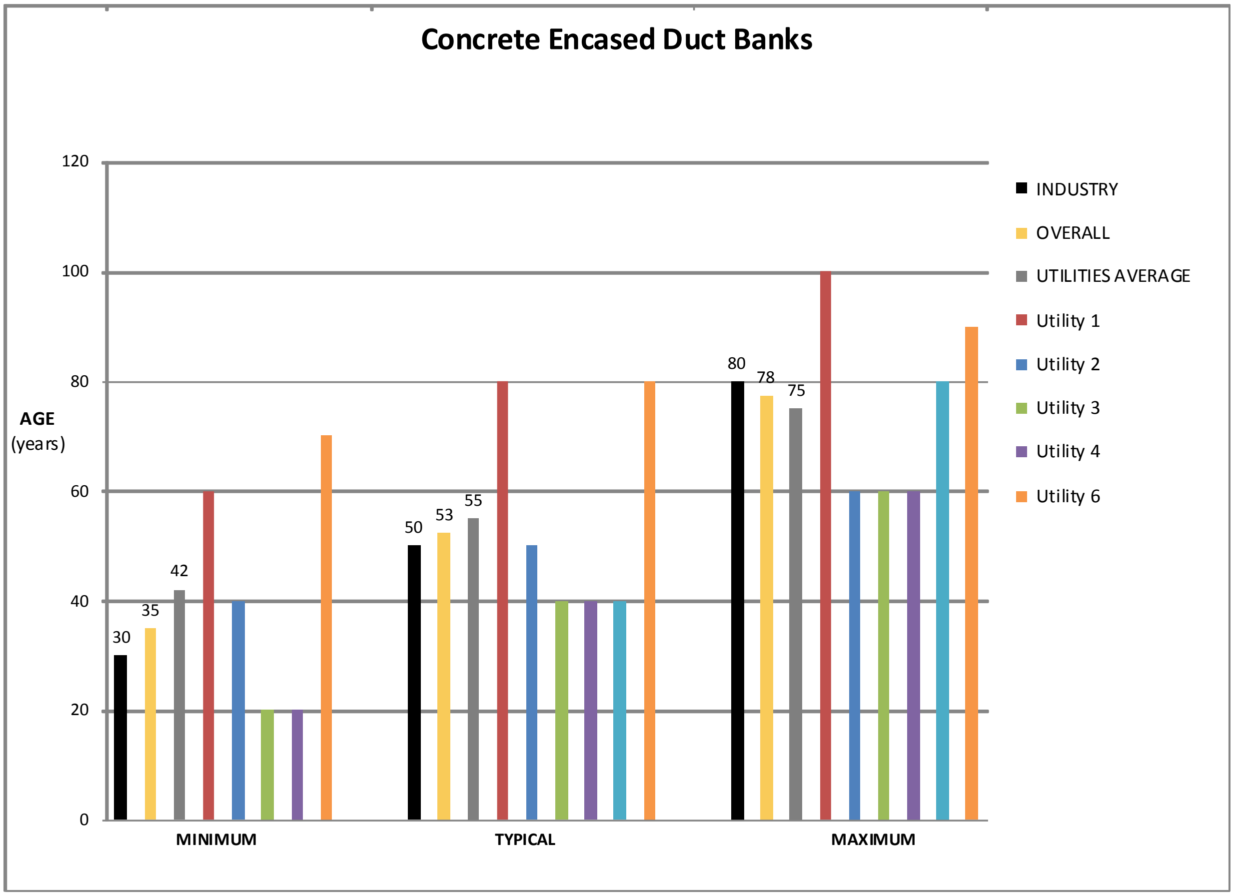


Figure 41-1 Useful Life Values for Concrete Encased Duct Banks

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).

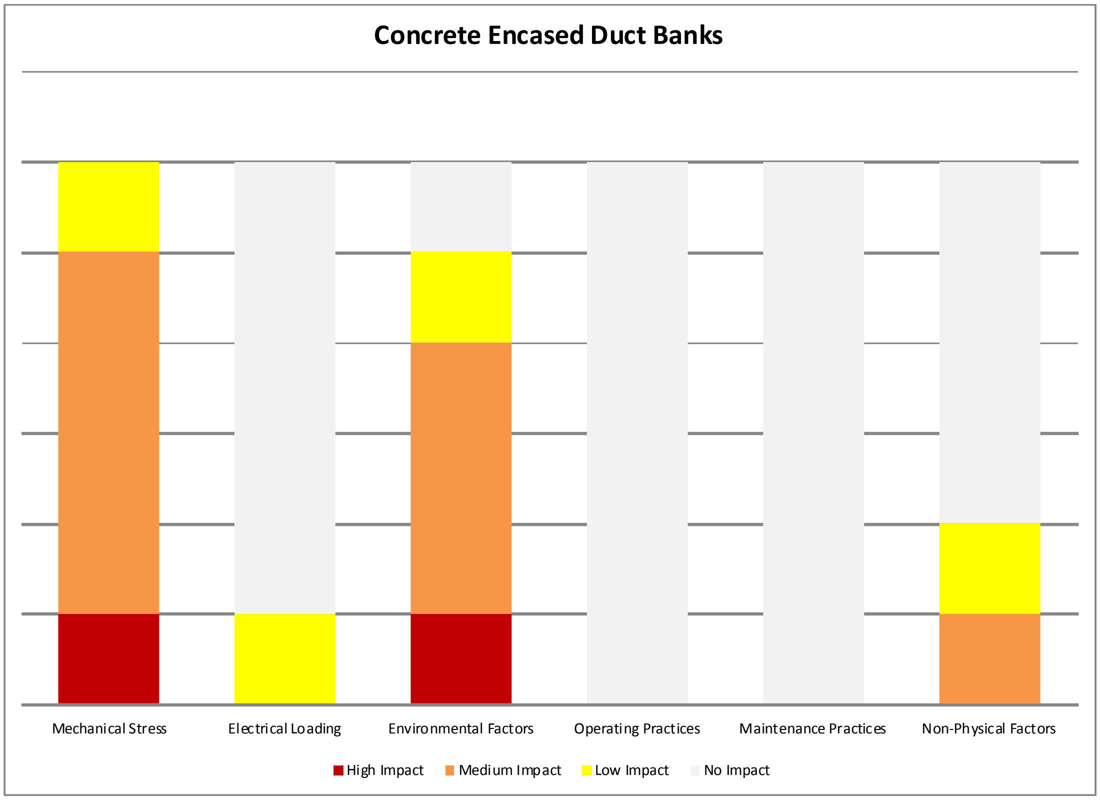


Figure 41-2 Impact of Utilization Factors on the Useful Life of Concrete Encased Duct Banks

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).

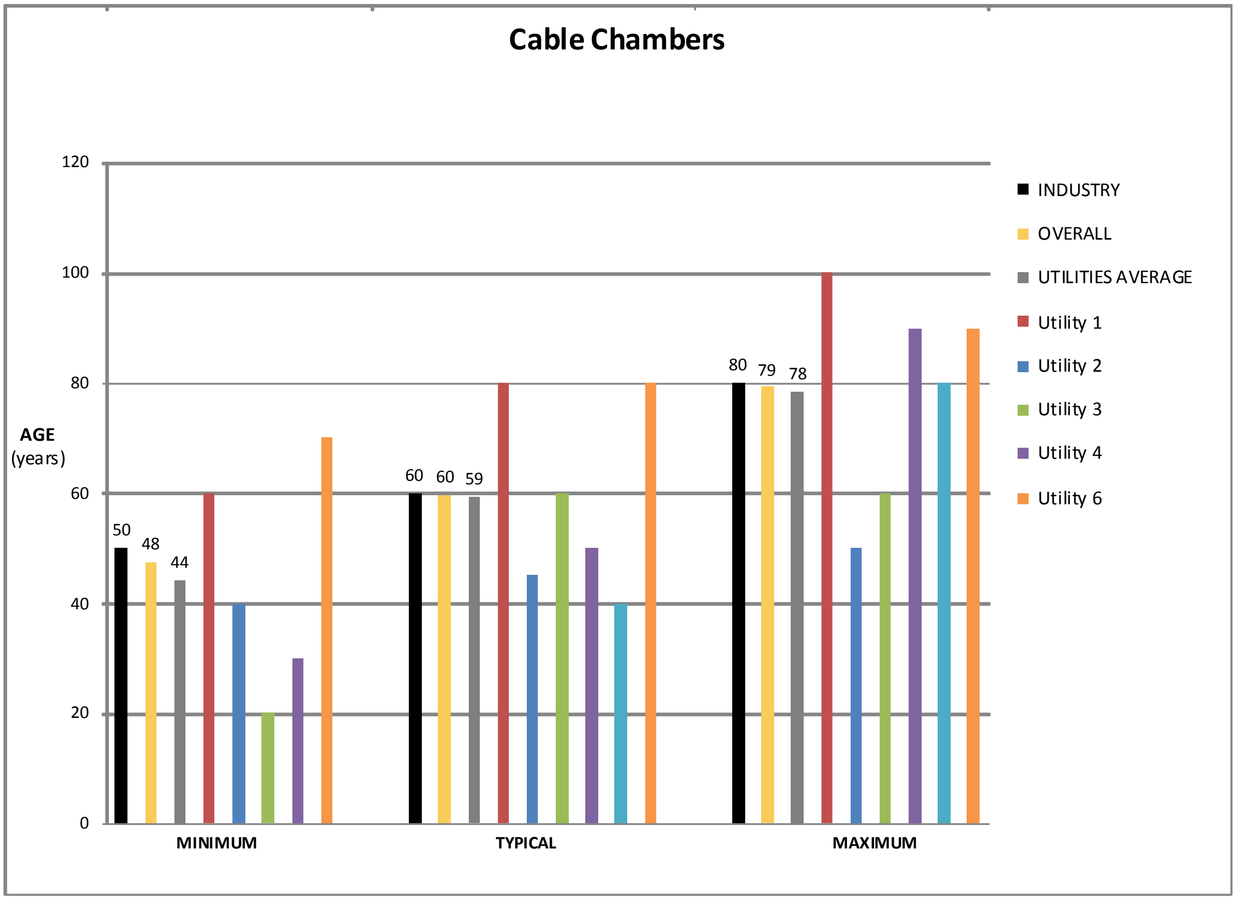


Figure 42-1 Useful Life Values for Cable Chambers

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).

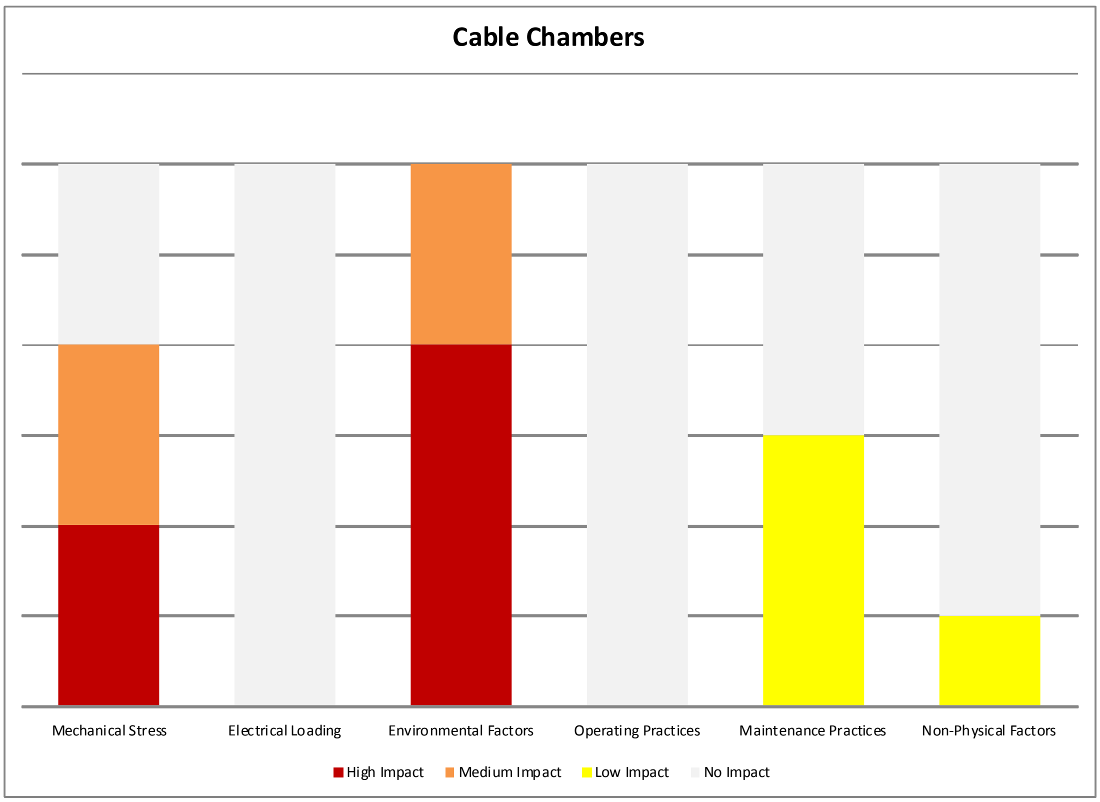


Figure 42-2 Impact of Utilization Factors on the Useful Life of Cable Chambers

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).

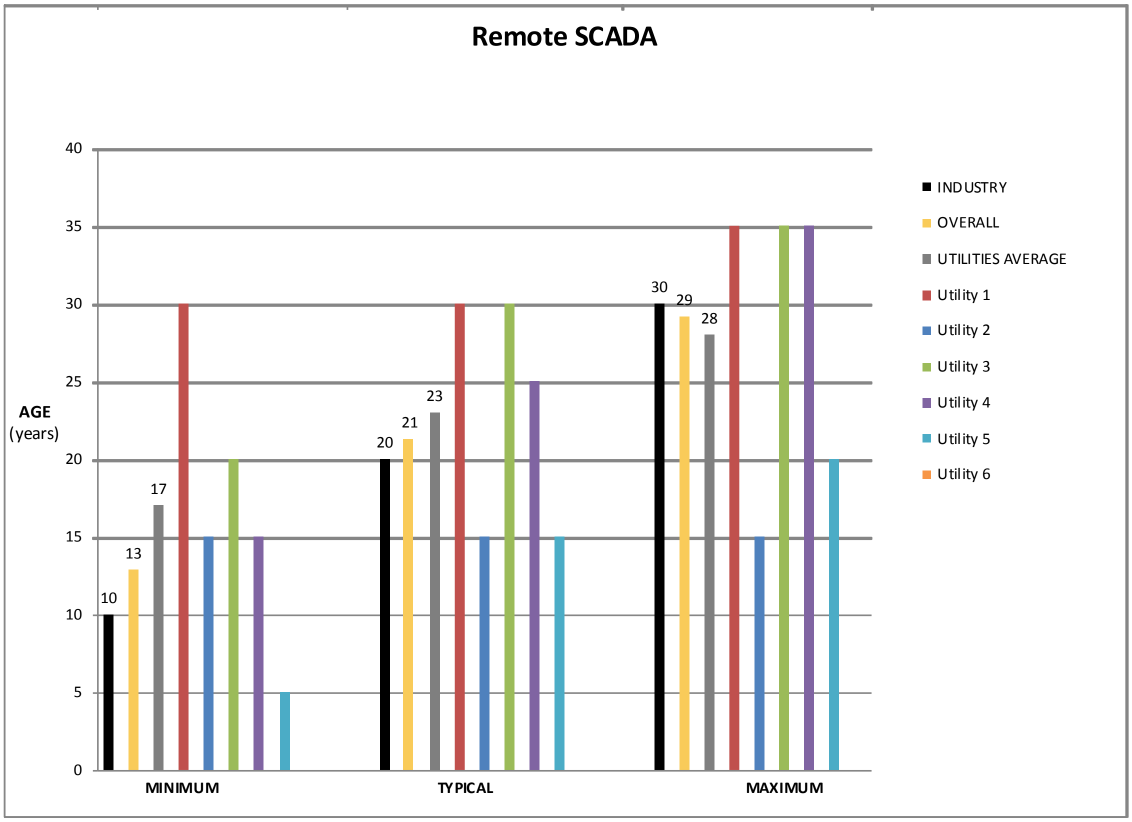


Figure 43-1 Useful Life Values for Remote Supervisory Control and Data Acquisition

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).

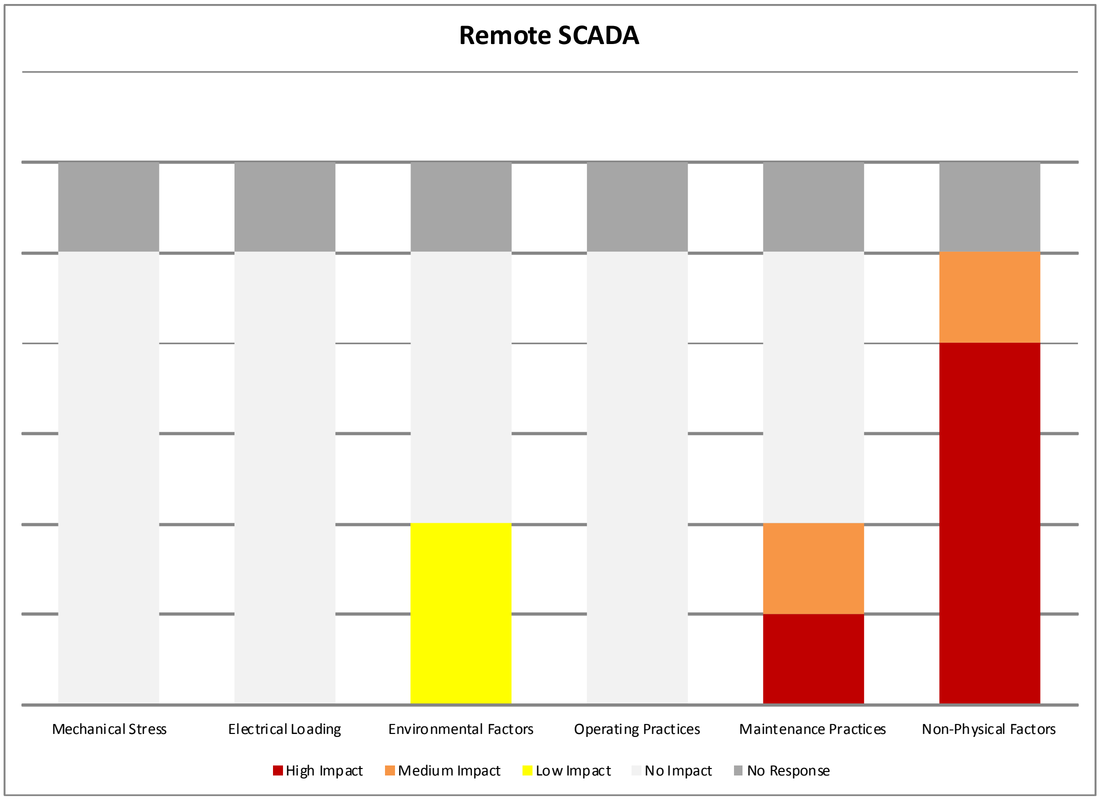


Figure 43-2 Impact of Utilization Factors on the Useful Life of Remote Supervisory Control and Data Acquisition

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

<u>Definitions used in Useful Life Analysis for Utility Asset Groups</u>

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

$$\text{MIN UL} = \mu - k\sigma \qquad \text{(Equation 1)}$$

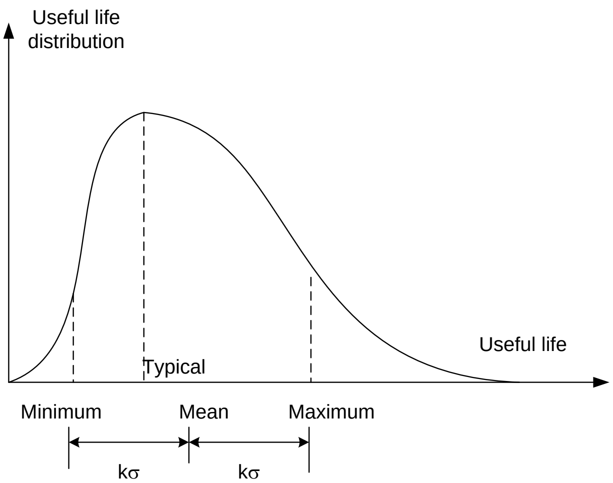
Where $k = \sqrt{3}$ (defined in later section)
σ standard deviation of useful life distribution

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



<u>Assumptions in Useful Life Analysis for Utility Asset Groups</u>

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

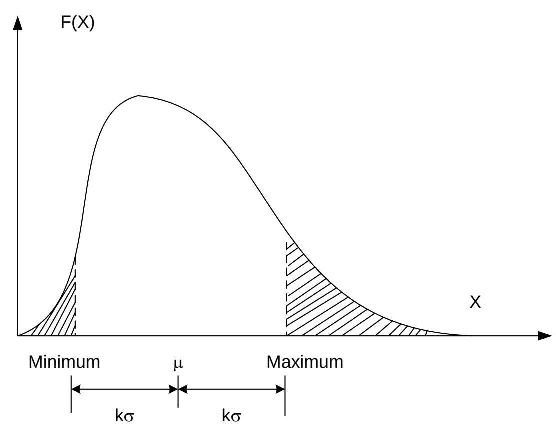
For any uni-modal useful life distribution, the coverage of a specific useful life range can be calculated using Chebyshev's inequality.

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:

$$\Pr(|X - \mu| \leq k\sigma) = \mathrm{erf}\left(\frac{k}{\sqrt{2}}\right)$$

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 $\mathrm{erf}\left(\frac{\sqrt{3}}{\sqrt{2}}\right) = 91.7\%$ 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 K

CIMA Report

Hardening the Distribution System against severe storms – Final Report

Alectra Utilities

Distribution System Plan (2020-2024)

PowerStream

Hardening the Distribution System against severe storms

Final Report

October 2014

T000320A

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HARDENING THE DISTRIBUTION SYSTEM AGAINST SEVERE STORMS

FINAL REPORT

Prepared by : Walter Lionel Franco, P. Tech.

Ted P. Wojcinski, P. Eng.

Verified by : Denis Chartrand, Eng.

T000320A

October 3rd, 2014

7880 Keele Street, Suite 201
Vaughan ON L4K 4G7
CANADA

Phone : 905-695-1005
Fax : 905-695-0525
www.cima.ca

Executive Summary

This report presents various options, for PowerStream's consideration, to effectively "harden" the distribution system against ice storms and severe weather in general. Options include enhancements to vegetation management practices, distribution design, standards, operations, third party interactions, a strategic undergrounding program, and the upgrade of existing systems to present day standards (i.e. rear yard services).

The report is structured in seven parts:

1. *A review of climate change impacts and the need to adapt to changing weather conditions in the PowerStream service territory*
2. *A review of the North American practices and papers to harden distribution systems against various forms of severe weather*
3. *A summary of the consultations with PowerStream staff on the impact of severe weather, their current experiences and their ideas to harden the distribution system*
4. *A review and analysis of PowerStream's current practices with respect to designing, constructing, maintaining and operating the distribution system in changing climate conditions. Practice enhancements for potential adoption are summarized*
5. *A summary of practice enhancements prioritized for adoption consideration with high level budgetary Capital and OM&A impacts where appropriate or available.*
6. *Appendices*
7. *Reference list of the various documents reviewed in the development of the report*

Going forward, PowerStream's distribution system is expected to be primarily impacted by severe changing weather conditions related to:

1. *Temperature*
2. *Heavy Rain/Flooding*
3. *High Wind velocity/Wind gusts*
4. *Tornadoes*
5. *Freezing Rain*

Climate change projections show primarily increased probabilities of occurrence (return times) in the categories listed above. Magnitude of events experienced may increase slightly. The distribution system can be adapted to the increased frequency of occurrence and variations in magnitude.

Many North American utilities have developed programs to “harden” their distribution systems against increasing effects of severe weather such as hurricanes, ice storms, etc. Most programs consist of enhanced vegetation management programs and construction standards. Resiliency measures are also developed, hand in hand with hardening, to bring the distribution system back on-line as soon as possible after a severe weather event.

PowerStream’s current practices are considered “good utility practices” as defined in the OEB Distribution System Code. Enhancements to practices are suggested and will demonstrate “best in class” performance.
Practice enhancements have been developed into specific recommendations where appropriate. Recommendations are grouped into 3 key categories:

1. *Vegetation Management*
2. *Strengthening the Distribution System*
3. *Securing Stations*

The recommendations are prioritized within each category and have been assessed for cost and impact to provide a high level perspective for program development options and tradeoffs. Some of the programs have suggested paces to provide for consistent spending while delivering results within a reasonable timeframe that demonstrates progressive hardening of the distribution system. Program selection to be determined by PowerStream through budgetary and rate recovery processes.

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APPENDIX

REFERENCES

1. CHANGING CLIMATE IMPACTS ON POWERSTREAM SERVICE TERRITORY

1.1 CURRENT WEATHER NORMS

The two areas PowerStream serves have distinct characteristics. PowerStream north (Barrie and satellite communities) is located for the most part in County of Simcoe, while PowerStream south (Vaughan, Richmond Hill, Markham and Aurora) is located in the southern part of York Region. The two service areas are not contiguous. The service areas are about 45 minutes' drive from each other along Highway 400.

The PowerStream South service area has a humid continental climate (Köppen climate classification Dfa[1]) with four distinct seasons featuring cold, somewhat snowy winters and hot, often humid summers. Precipitation is moderate and consistent in all seasons, although summers are a bit wetter than winter due to the moisture from the Gulf of Mexico and the Great Lakes.

The PowerStream North service area has warm and sometimes hot summers with cold, longer winters (Köppen climate classification Dfb[2]) with roughly equal annual precipitation as the PowerStream south service area. Along the eastern shores of Georgian Bay (Penetanguishene area), frequent heavy lake-effect snow squalls increase seasonal snowfall totals upwards of 3 m (120 in). Barrie is on the southern edge of this snowbelt region.

The Köppen climate classification is the most widely used climate classification system. See figure 1 for Canada map of the Köppen climate classification.

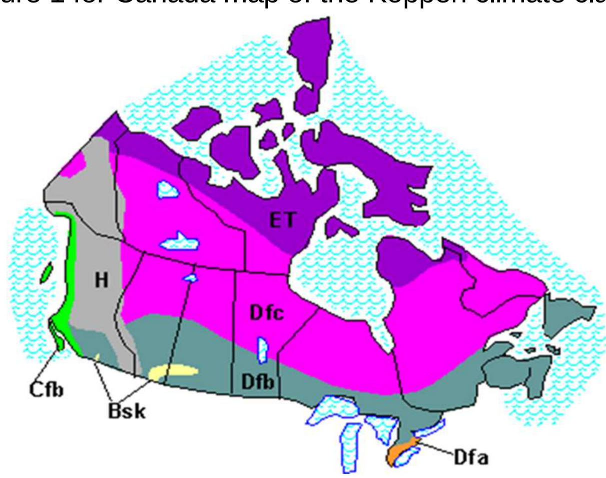

FIG 1. KÖPPEN CLIMATE CLASSIFICATION – CANADA[3]

1 http://en.wikipedia.org/wiki/Woodbridge,_Ontario
2 http://en.wikipedia.org/wiki/Barrie
3 http://www.rossway.net/Koppengeiger.htm

In both areas the proximity to the Great Lakes moderates winter temperatures but also results in significant snowfall in the general area. The Great Lakes moderation also results in higher autumn and winter precipitation. Autumn can also bring hurricane remnants and heavy precipitation.

Data from the Barrie Water Pollution Control Centre WPCC weather station (Environment Canada, 2010)[4] shows that the total annual precipitation (~925 mm) has decreased slightly (10 mm) over the 31 years of record (1978 – 2008). The total winter precipitation (~225 mm) has remained unchanged. The Total summer precipitation (~275 mm) has increased by 50 mm. Precipitation during the 2013-2014 winter was 9% below average nationally.

Severe weather in the summer manifests itself mostly in the form of thunderstorms that can damage overhead distribution plant. In the winter, severe weather may consist of snow squalls, high winds and the occasional episode of freezing rain. Major storms (high winds, ice storms) are 1 - 2 times per year. There have been 25 ice storms in southern Ontario since the mid-1800s. Ice storms last between 12 hours and 1-2 days. For example, Toronto experienced a total of 5 days (17 hours) of freezing rain in the period 1953 – 2001. Average freezing rain amount is 20-40 mm. It should also be noted that severe weather conditions can be the result of multiple contributors (i.e. high winds and freezing rain at the same time) which would compound the effects on the distribution system. For example, the 2013 ice storm could have been worse if high winds were also present.

Examples of severe events include Hurricane Hazel in 1954, the Barrie and Vaughan tornados in 1985 and 2009 respectively, the ice storm 1998, and the Toronto snowstorm of 1999.

With respect to summer temperatures, urban heat islands (i.e. central cores of Barrie, Markham, etc.) are generally 3°C higher than surrounding rural areas. In the summer, stagnant tropical air masses can result in heat waves and drought conditions. Average annual temperatures across Ontario have increased between 0°C and 1.40°C with the biggest increases in the spring. Winter temperature across Canada has increased by 3°C over the past 67 years while summer temperatures have increased 1.3°C over the same period.

4 Barrie in a Changing Climate : a Focus on Adaptation – Final Report – Ontario Center for climats impacts and adaptation ressources (OCCIAR) - 2010

Data from the Barrie WPCC weather station (Environment Canada, 2010) shows that the average annual mean temperature (~7.8°C) at this location has increased 1.7°C over 31 years of record (1978 – 2008). The average winter mean temperature (~-5°C) has increased 2.2°C and the average summer mean temperature (~20.5°C) has increased 1.8°C.

Spring and summer are tornado season in south Ontario and these can reach both PowerStream service areas and cause significant damage as evidenced by the Barrie tornado of 1985 and the Vaughan tornado of 2009.

Rapid snowmelt and flooding can occur in the spring. Most flooding is January to May due to rain on snow conditions. Flooding due to heavy rain has a return period (repeat interval) of about 25 years, although there have been seven major events in the Toronto area, adjacent to PowerStream south, in past 20 years, the most recent being flooding in Burlington in August 2014.

Current weather norms can result in a number of climate events that the distribution system may experience in any year. The following events and threshold triggers are reproduced from the Toronto Hydro Electric System PIEVC Pilot Case Study (2012):

High Temperature	–	Average annual # days with T=> 30°C
Low Temperature	–	Average annual # days <-20°C
Heat Wave	–	3 or more days with Tmax =>30°C
Severe Heat Wave	–	3 or more days with Humidex =>40°C
Extreme Humidity	–	# Days with Humidex => 40°C
Cold Wave	–	3 or more days with Tmin <=-20°C
Temperature Variability	–	Daily T ranges => 25°C
Freeze-thaw cycle	–	annual probability of at least 70 freeze-thaw cycles (Tmax >0 and Tmin <0)
Fog	–	~15 hours/year (average) with visibility <= 0km
Frost	–	no threshold
High wind/downburst	–	gusts > 70km/h (~21 days/year at Airport)
High wind/downburst	–	gusts > 90km/h (~2 days/year at Airport)
Tornados	–	Tornado vortex extending from surface to cloud base (near infrastructure)
Heavy Rain	–	Daily rainfall > 50mm/day
Heavy 5 days total rainfall	–	Days of cumulative rain > 70 mm of rain
Ice Storm	–	Average annual probability of at least 25 mm of freezing rain per event

Freezing Rain	–	Average annual probability of freezing rain events lasting 6h or more (i.e. typically more than 10mm of freezing rain)
Blowing snow/Blizzard	–	Average # days/year with blowing snow (7.8/year)
Heavy snowfall	–	Snowfall > 10cm (2-3 days/yr)
Snow accumulation	–	Snow on the ground with depths => 30 cm and persisting for 5 or more days (0.17 events/year)
Hail	–	Average # of hail days (~1.1/year)
Severe thunderstorms	–	Average # of Thunderstorm Days (~2.8/year)
Lightning	–	Average # days/year with cloud-ground lightning strikes (~25)
Drought/Dry periods	–	At least one month at Ontario low water response level II (i.e. with mandatory water conservation)

The thresholds are limits beyond which the weather can have an adverse impact on distribution system infrastructure. Overhead infrastructure is more vulnerable to weather conditions than underground infrastructure.

Of the above events, mainly high winds/downbursts, tornados, ice storms, freezing rain and heavy rainfall are historically considered to have widespread impacts on the distribution system infrastructure when they occur.

1.2 CLIMATE CHANGE PROJECTIONS

The Intergovernmental Panel on Climate Change (IPCC) and other scientific bodies conclude that climate change affecting the entire world has started and will continue into the future driven in part by thermal inertia of the oceans. The impact of climate change varies by region. The southern Ontario region will be affected by climate change. A review of climate change literature was conducted focusing on papers/reports that provided some level of climate modelling forecasts for both the PowerStream north and south areas or adjacent areas (i.e. Toronto). Key papers consulted were:

- Barrie in a Changing Climate: a Focus on Adaptation – Final Report – 2010
- Canada's Sixth National Report on Climate Change (2014) – Government of Canada
- Changing Weather Patterns, Uncertainty and Infrastructure Risks: Emerging Adaptation Requirements - Environment Canada – 2007

- City of Barrie Emergency Management
- Climate Change Scenario over Ontario Based on the Canadian Regional Climate Model (CRCM4.2) – Ouranos - 2010
- Detection of Tornado Frequency Trend Over Ontario, Canada - Zuohao Cao, and Huaqing Cai – 2011
- Estimation of Severe Ice Storm Risks for South-Central Canada - Office of Critical Infrastructure Protection and Emergency Preparedness – 2003
- From Impacts to Adaptation: Canada in a Changing Climate 2007 – Natural Resources Canada
- Historical Climate Trends for Barrie, Ontario - Ontario Centre for Climate Impacts and Adaptation Resources (OCCIAR) – 2010
- Insurance Bureau of Canada - Telling the Weather Story - The Institute for Catastrophic Loss Reduction - 2012
- National Engineering Vulnerability Assessment of Public Infrastructure To Climate Change - Toronto and Region Conservation Authority – 2010
- Possible impacts of climate change on freezing rain in south-central Canada using downscaled future climate scenarios – C. S. Cheng, H. Auld, G. Li, J. Klaassen, and Q. Li - 2007
- Severe Ice Storm Risks in Ontario - Meteorological Service of Canada Environment Canada-Ontario Region – 2004
- The Tornadoes in Ontario Project (TOP) - Meteorological Service of Canada – 2003
- Toronto's Future Weather and Climate Driver Study - SENES Consultants Limited - 2011
- Toronto Hydro-Electric System Public Infrastructure Engineering Vulnerability Assessment Pilot Case Study

The following opinions are offered with respect to climate change in Southern Ontario and potential impacts to PowerStream's distribution system.

1.2.1 Temperature

Temperature is expected to increase. This will mean shorter, warmer winters with more rain and less snow, especially in the Barrie area. In the Toronto area, there will be a significant reduction in the number of days that the maximum temperature will be below zero and a significant increase in the number of days that the minimum temperature will be above the freezing point.

The TRCA[5] study (PowerStream South area equivalent) predicts that:

- Temperature days >30°C to more than double by 2050 – occurrences per year moving from “moderate/possible” to “often”
- Temperature days <-30°C to decrease - occurrences per year moving from “occasional” to “remote”
- Heat waves (3 or more days >32°C) historical pattern is once every 2 years. In the future there will be an increase in heat wave frequency and dry soil. (Dry soil affects thermal resistivity and the ability of underground cables to shed heat) – occurrences per year moving from “moderate/possible” to “often”
- Cold wave (3 or more days between -20°C and -10°C) is decreasing in the future – occurrences per year moving from “occasional” to “remote”

The IBC report[6] states that:

- Temperature extremes will move from about 12 hot days in the 1961–1990 period to about 37 in the period 2041–2069.
- The number of frost-free days is expected to double in winter 40 years from now.
- The number of days below –15°C and –20°C both showed decreasing trends from 1970–2006 and are expected to decrease greatly in next 40 years.

The Toronto Future Weather report[7] (PowerStream south area equivalent) stated that for the period 2040 - 2049:

- There will be less snow and more rain during the winter
- There will be 26 fewer snow days per year (9 less in December)
- Average annual temperatures increase of 4.4°C
- Average winter temperatures increase by 5.7°C
- Average summer temperatures increase by 3.8°C
- Extreme daily minimum temperature "becomes less cold " by 13°C
- Extreme daily maximum temperature "becomes warmer " by 7.6°C

5 National Engineering Vulnerability Assessment of Public Infrastructure to Climate Change – Toronto and Region Conservation Authority - 2010
6 Insurance Bureau of Canada – Telling the Weather Story – The Institute for Catastrophic Loss Reduction - 2012
7 Toronto’s Future Weather and Climate Driver Study – SENES Consultants Limited - 2011

The City of Barrie Emergency Management states[8]:

- The city is at risk from extreme heat and cold waves

The From Impacts to Adaptation: Canada in a Changing Climate 2007 report states[9]:

- Temperature days >30°C to more than double by 2050

The Climate Change over Ontario report states[10]:

- Annual mean minimum temperature is projected to increase all over Ontario. The warming is projected to be between 3 and 4 degrees at the 2050s horizon. For the 2070-2099 period, the warming is projected to be between 4 and 6 degrees.
- Mean daily maximum temperature is expected to increase over Ontario, with warming from 2 to 4 degrees and from 4 to 6 degrees at the 2050s and 2080s horizons, respectively.
- Mean annual temperature is projected to increase all over Ontario, between 2°C and 4°C, and between 4°C and 6°C for the 2050s and 2080s horizons, respectively.
- The number of occurrences of heat waves per year is projected to increase all over Ontario, but not uniformly. This change would range on average from 0 to 2.5 and from 1 to 5 occurrences per year at the 2050s and 2080s horizons, respectively. The greatest changes would occur in Southern Ontario

All reports support similar temperature projections.

Of interest to note, the electricity demand pivot point is 18°C. Every 10°C increase in summer temp has 4-5x impact on demand compared to 10°C decrease in winter temperature, hence the higher importance of heat wave changes versus cold wave changes. This primarily has an impact on demand and little effect on distributions system components unless they are already fully or overloaded to begin with.[11]

8 http://www.barrie.ca/Living/Emergency%20Services/Emergency-Planning/Pages/PlanningFacts.aspx
9 From Impacts to Adaptation: Canada in a Changing Climate 2007 – Natural Resources Canada
10 Climate Change Scenario over Ontario Based on the Canadian Regional Climate Model (CRCM4.2) – Ouranos - 2010
11 From Impacts to Adaptation: Canada in a Changing Climate 2007 – Natural Resources Canada

Overall assessment is that temperature changes by themselves will not present a problem to the distribution system that warrants "hardening" efforts.

1.2.2 Precipitation/Flooding

Future precipitation in southern Ontario is not expected to increase significantly on an annual basis. What is expected is that the frequency of future precipitation is expected to decrease while the intensity of individual events is expected to increase.

The TRCA study[12] (PowerStream South area equivalent) predicts that:

- Heavy Rain days (rainfall greater than or equal to 50 mm within a 24-hour period) will increase – occurrences per year moving from "moderate/possible" to "often"
- Heavy 5 day rain (a period of 5 days with a total rainfall exceeding 100 mm) will increase – moving from "remote" to "occasional".
- Winter Rain days (rainfall greater than or equal to 25 mm of rain – January - March) will stay roughly the same at "moderate/possible".

The IBC report[13] states that:

- In PowerStream south area, precipitation will increase by about 10% in winter. In the summer the precipitation changes will be much smaller, about 5% increase in PowerStream north and a little smaller change in PowerStream south.
- Heavy rains have shown the greatest seasonal increase over southern Ontario in the spring. Projecting forward for Ontario, the annual maximum 24-hour precipitation rate that at present occurs once every 20 years, will occur more often and become a once every 12–14 year event. This can present an increased risk of flash floods

The Toronto Future Weather report[14] (PowerStream south area equivalent) stated that for the period 2040 - 2049:

- There will be slightly more precipitation (snow and rainfall) overall

12 National Engineering Vulnerability Assessment of Public Infrastructure to Climate Change – Toronto and Region Conservation Authority - 2010

13 Insurance Bureau of Canada – Telling the Weather Story – The Institute for Catastrophic Loss Reduction - 2012

14 Toronto's Future Weather and Climate Driver Study – SENES Consultants Limited – 2011

- Precipitation amounts will remain similar to present for about 8 months of the year
- Precipitation increases markedly in July and August (with 80% and 50% increases respectively over present values)
- The number of days of precipitation per month decrease (except in July and August)
- Extreme rainstorm events will be more intense. There will be fewer but more severe weather occurrences.
- Large increase in size of extreme (daily) rain events in July (almost threefold)

The City of Barrie Emergency Management[15] states:

- The City is at risk from severe winter storms: heavy snow, strong winds, freezing rain and from severe summer storms: heavy rain and flooding, strong winds, lightning, hail and tornadoes

The From Impacts to Adaptation: Canada in a Changing Climate 2007 report[16] states that:

- There will be a slight decrease(<2.5%) in precipitation for the entire province over the next 50 years
- Southern Ontario will see up to 10% in precipitation decrease during the summer and fall periods by 2050. Winter precipitation may increase by 10% during the same period

The Climate Change over Ontario report[17] states:

- Annual precipitation is projected to increase over all Ontario
- The wintertime precipitation is projected to increase all over Ontario.
- The summertime precipitation is projected to decrease in southern Ontario by as much as 25% (2050) and 40% (2080).
- Summertime soil moisture will decrease over most of Ontario

15 http://www.barrie.ca/Living/Emergency%20Services/Emergency-Planning/Pages/PlanningFacts.aspx
16 From Impacts to Adaptation: Canada in a Changing Climate 2007 – Natural Resources Canada
17 Climate Change Scenario over Ontario Based on the Canadian Regional Climate Model (CRCM4.2) – Ouranos - 2010

All reports indicate that precipitation projections have a high degree of variability with the majority projecting slight increases in annual precipitation. All tend to agree that extreme rainfall events will increase.

Increased heavy rainfall occurrences and intensity in the summer will lead to more flooding risk. The majority of floods recorded to date occurred during the January to May period and were the result of rain-on-snow conditions. Spring flooding events are expected to decrease due to increasing winter temperatures, earlier spring and more winter thaws. In general, streams in the Toronto area are characterized by steep slopes and little or no natural storage capacity. This leads to frequent inundation of the floodplains during intense storms and the spring snowmelt runoff.

In the PowerStream South area, three key watershed systems are the Humber, Don and Rouge river systems. For the Humber river system, the risk of flooding remains in portions of Woodbridge, and Oak Ridges (Richmond Hill)[18.] For the Don River system risk of flooding remains in areas of Vaughan (Steeles/Dufferin, Keele/Hwy7, Keele/Langstaff. North Rivermede Industrial area west of Hwy 407) and Richmond Hill (Yonge/Elgin mills)[19]. For the Rouge river system, risk of flooding remains in areas of Markham (Hwy7/ Kennedy to McCowan)[20]. Figures 2 and 3 indicate flood vulnerable parts of the Don and Rouge River watersheds.

In the PowerStream North area, the City of Barrie, three separate subwatersheds are the: Barrie Creeks, Lovers Creek and Hewitt's Creek. There is some risk of spring flooding along the three creek systems.

18 Humber River Watershed Report Card 2013
19 Don River Watershed Report Card 2013
20 Rouge River Watershed Report Card 2013

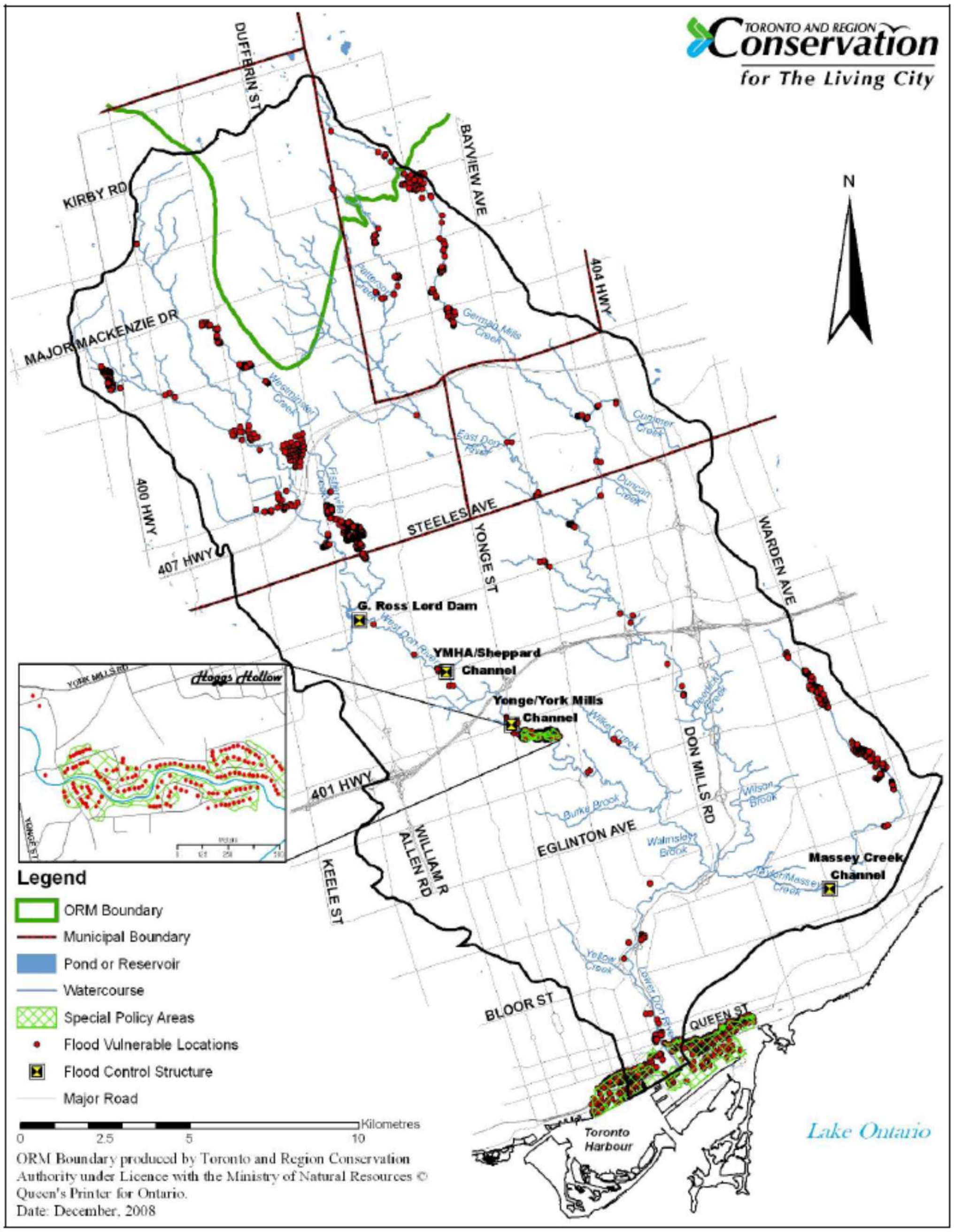

FIG 2. FLOOD VULNERABLE AREAS OF THE DON WATERSHED[21]

21 Rouge River Watershed Report Card 2013

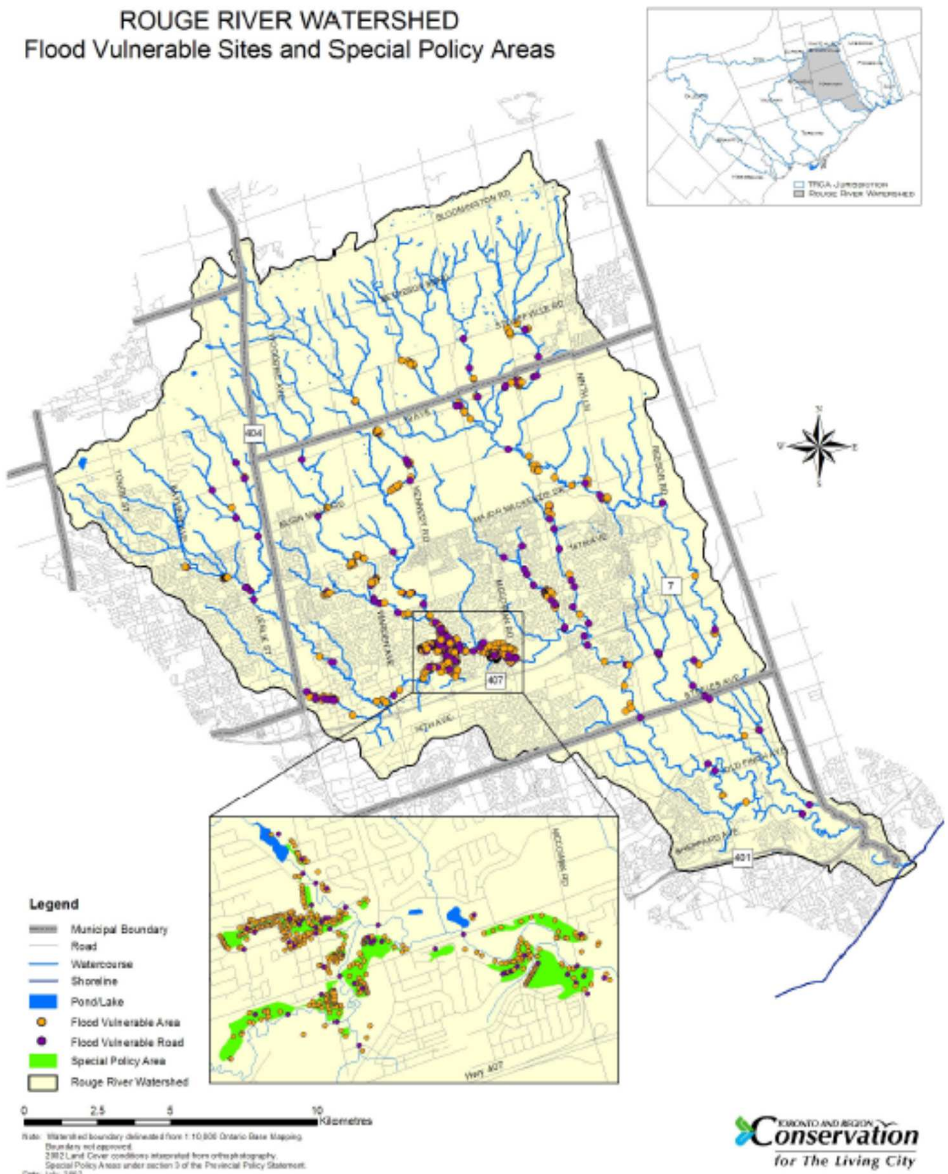

FIG 3. FLOOD VULNERABLE AREAS OF THE ROUGE WATERSHED[22]

In Toronto, there were 7 major heavy rainfall events in the last 20 years that resulted in flooding. Heavy rainfall is defined as rainfall that is greater or equal to 50 mm/hour or greater or equal to 75 mm in three hours. The return period (repeat interval) for these events was considered to be 25 years, so there has been a marked frequency increase in this type of event. In York Region there were 24 such events and in Simcoe area there were 13 to 43 such events. Regional return times are approaching annual events which are of importance to PowerStream as infrastructure is regionally located not just in one specific location.

22 Rouge River Watershed Report Card 2013

On the positive side, for the Humber, Rouge and Don River watersheds, Markham, Vaughan and Richmond Hill have comprehensive up to date storm water management systems in place that minimize the risk of future flooding compared to historical norms. Figure 4 provides a visual of heavy rainfall occurrences in the southern Ontario region.

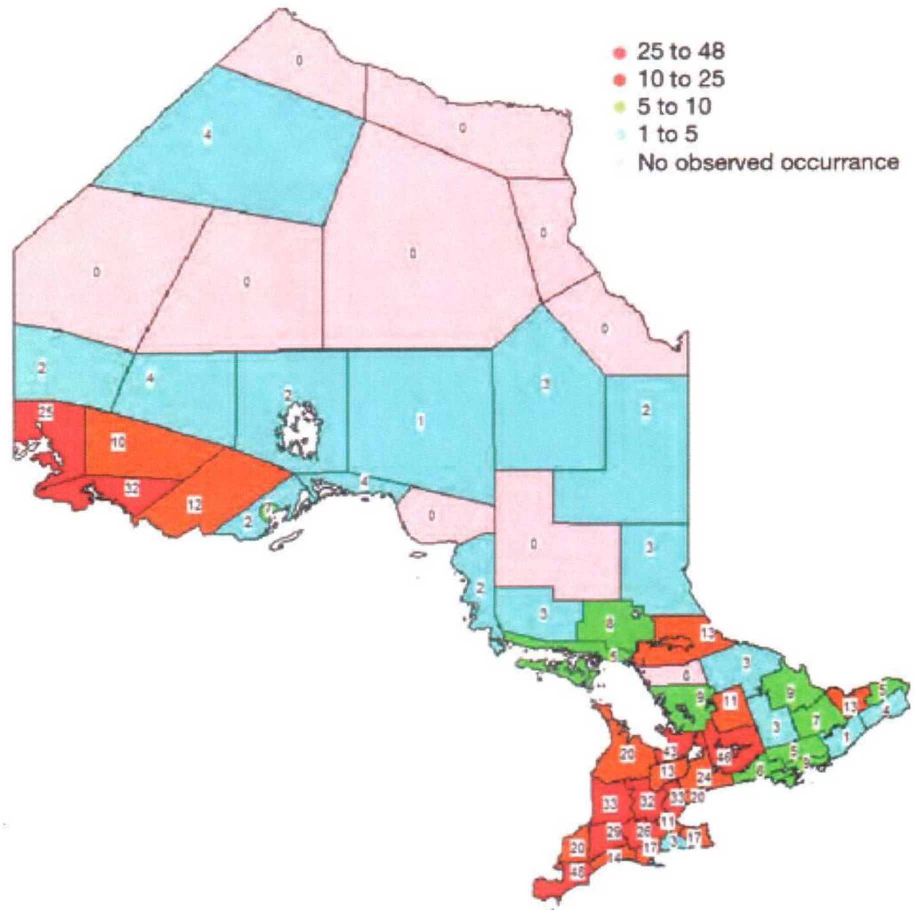

FIG 4. OCCURRENCES OF HEAVY RAINFALL 1979-2004[23]

Infrastructure that is located below grade (i.e. underground vaults, transformer station basements) is at risk of future flooding potential based on the changing return times experienced in the last 20 years. Events occurring every 1-2 years can be expected somewhere in PowerStream's service territory.

Station roof infrastructure can be subject to heavy rain events that can stress current roof condition.

23 From Impacts to Adaptation: Canada in a Changing Climate 2007 – Natural Resources Canada

Soil moisture decreases (and associated increases in thermal resistivity) require that cable ampacity values be reviewed for underground cables loaded to current maximum values. Station egress cables are of primary concern.

1.2.3 Severe weather/wind

Winds are expected to increase in frequency and velocity.

The TRCA study[24] (PowerStream South area equivalent) predicts that:

- the average number of days in a given year, with wind speeds recorded at greater than or equal to 63 km/hour will roughly remain the same at "moderate/possible"
- there will be a slight increase in hurricane/tropical storm sustained surface winds (speeds of 118km/hour or more) occurrences per year moving from "improbable/highly unlikely" to "remote"

The IBC report[25] states that:

- Severe weather frequency - an event that occurred on average once every 50 years will be likely to occur about once every 35 years by 2050. Weather events that used to happen once every 40 years are now happening once every six years in some regions in the country.
- Summer days with more than 50 km/hour winds have shown a significant increasing trend in Toronto, where the windy days increased on average by three times after 2000. This indicates an increased frequency of more severe damaging winds in the decades to come. The highest summer wind increases, also about 10%, will occur over the Great Lakes.
- There will be wintertime wind increases over northern Ontario and extending south over parts of the Great Lakes of nearly 10% by 2050.

The Toronto Future Weather report[26] (PowerStream South area equivalent) stated that for the period 2040 - 2049:

- There will be fewer but more severe weather occurrences including damaging winds.
- The average wind speed is expected to remain unchanged

24 National Engineering Vulnerability Assessment of Public Infrastructure To Climate Change - Toronto and Region Conservation Authority – 2010

25 Insurance Bureau of Canada - Telling the Weather Story - The Institute for Catastrophic Loss Reduction - 2012

26 Toronto's Future Weather and Climate Driver Study - SENES Consultants Limited - 2011

- maximum hourly winds reduced
- maximum wind gusts reduced

The From Impacts to Adaptation[27]: Canada in a Changing Climate 2007 report states that:

- the frequency and magnitude of future wind storms is likely to increase

The THES PIEVC report[28] states that:

- Future winds above threshold to increase
- Trees impacted when wind reach/exceed 50-70km/h
- HV power lines impacted when wind reach/exceed 80-100km/h based on current standards

All reports indicate that wind speeds related to severe weather events are expected to increase in the future. Lack of data has precluded any definitive value of what specific severe wind speeds are expected to see in the future. Just more probability of events occurring that exceeds the current frequency and magnitude. A 10% increase in historical average annual peak wind gusts at Pearson Airport is shown at figure 5.

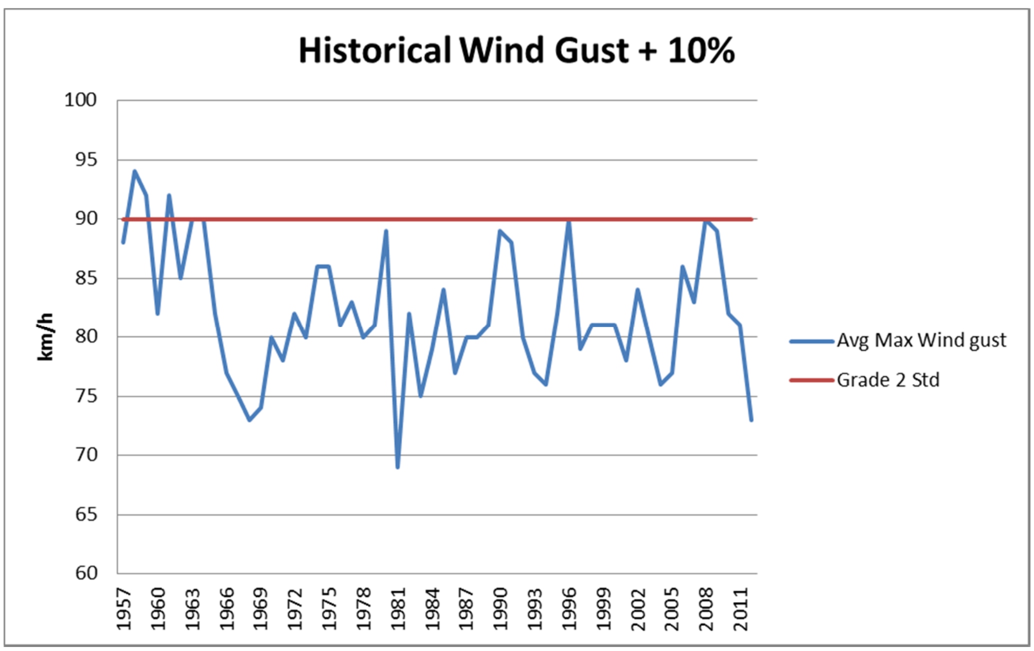

FIG 5. HISTORICAL + 10% WIND GUSTS AT PEARSON AIRPORT

27 Estimation of Severe Ice Storm Risks for South-Central Canada - Office of Critical Infrastructure Protection and Emergency Preparedness – Government of Canada – 2003
28 Toronto Hydro Electric System PIEVC Pilot Case Study (2012)

The graph shows that a 10% increase in yearly average wind gust is still within the expected performance of Grade 2 construction criteria (90 km/h withstand). A review of historical data shows that a 10% increase in peak gusts would result in ~4 gusts per year in excess of 90kmh versus the historical ~2 per year.

Of note with respect to wind speed increases, an Insurance Australia group report[29] stated that a 25% increase in peak gusts results in a 650% increase in building damage. Overhead infrastructure would be particularly vulnerable to significant increases in severe storms and wind speed.

While all poles would be at increased risk with wind speed increases, large 4 circuit poles with additional equipment (switches, transformers, etc.) would have the most load and equipment at risk. Station roof infrastructure can be subject to extreme wind events that can stress current roof condition.

1.2.4 Tornados

Tornados are rare but extremely destructive events. The historical frequency for Tornados in southern Ontario[30] has been in the order of 1×10^{-4}(< 1 in a 1000 probability) per $0.0001 km^2 yr^{-1}$. For PowerStream this works out to roughly 1 tornado somewhere in PS territory every 12.4 years

The TRCA study[31] (PowerStream South area equivalent) predicts that:

- The future probability of occurrence will remain the same at “remote”.

The IBC report[32] states that:

- There will be more frequent tornados in southwestern Ontario

The information gathered indicates that tornados will still be rare localized events that would be impossible to harden against for an overhead system. As figure 6 shows, even a robustly built municipal station is at the mercy of the power of a tornado.

29 Insurance Bureau of Canada - Telling the Weather Story - The Institute for Catastrophic Loss Reduction - 2012
30 Toronto Hydro Electric System PIEVC Pilot Case Study (2012)
31 National Engineering Vulnerability Assessment of Public Infrastructure To Climate Change - Toronto and Region Conservation Authority – 2010
32 Insurance Bureau of Canada - Telling the Weather Story - The Institute for Catastrophic Loss Reduction - 2012

FIG 6. SUBSTATION DESTROYED BY TORNADO[33]

1.2.5 Freezing Rain / Ice Storms

Freezing rain is a major hazard to infrastructure, especially overhead wires and poles. Freezing rain can cause tree branches and entire trees to bend and break and collapse on power distribution lines. Ice accumulation due to freezing rain can reach a point where even with no trees present, wires and poles can no longer sustain the weight and the structure collapses. The effect of freezing rain is cumulative. Small branches break at ~6-12 mm of ice accumulation. Large branches break at ~12-25 mm of ice accumulation. Add

33 http://www.wfec.com/media-center/photo-galleries/cana-substation

some wind and these thresholds are reduced. Literature studies on freezing rain and ice storms indicate that 30 mm of ice accumulation will likely result in major power outages lasting several days. 40 mm of ice accumulation will result in community disasters as a significant portion of the overhead distribution system will be destroyed. The 2013 storm event in southern Ontario was a moderate one with accumulations of ice significant enough to bring down branches and trees but not enough to bring down wires and poles themselves.

The TRCA study[34] (PowerStream South area equivalent) predicts that:

- The likelihood of freezing rain or drizzle, equal to or greater than 0.2 mm in diameter is expected to increase by 40% in the December to February period and decrease by 10% in November, March and April period - occurrences per year moving from “moderate/possible” to “probable”.
- Freezing rain amounts of less than 25mm is expected to increase - moving from “moderate/possible” (0.25 to 0.75 occurrences per year) to “probable” (1.25 to 2 occurrences per year).
- Ice Storms amounts of 25 mm or more is expected to increase – moving from “remote” (0.01 to 0.05 occurrences per year) to “occasional” (0.1 to 0.25 occurrences per year).

According to the Toronto Hydro Electric System PIEVC Pilot Case Study (2012)[35,] historical freezing rain frequency and severity in the Toronto area has been as follows:

- Freezing rain/drizzle – 8.8 days per year (0.1 mm – 0.3 mm/hr)
- Freezing rain at least 4 hours – 1.4 days per year (6 – 8 mm up to 15 mm)
- Freezing rain at least 6 hours – 0.65 days per year (once every 2 years) (9-12 mm up to 25 mm)
- Multi day ice storms => 25 mm – 0.06 days per year (once every 17 years) (>25 mm)

The THES PIECV[36] report also states that:

- Severe ice storms with 25 mm or more of freezing rain have occurred 3 times in the last 50 years. Two of the occurrences were only 8 years apart (1960 and 1968). See figure 7.

34 National Engineering Vulnerability Assessment of Public Infrastructure To Climate Change - Toronto and Region Conservation Authority – 2010
35 Toronto Hydro Electric System PIEVC Pilot Case Study (2012)
36 Toronto Hydro Electric System PIEVC Pilot Case Study (2012)

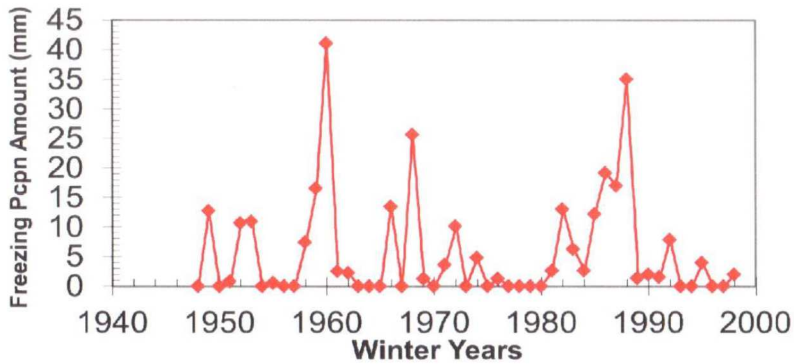

FIG 7. ESTIMATED 6 DAY DURATION ANNUAL MAXIMUM FREEZING PRECIPITATION FOR WOODBRIDGE WEATHER STATION

The IBC report[37] states that:

- The percentage increase for severe freezing rain events (lasting six hours per day or longer) is projected to be about 35% in southwestern Ontario and around the lower lakes.

The Estimation of Severe Ice Storm Risks for South-Central Canada[38] report states that:

- Frequency and intensity of ice storms to increase.
- There will be an increase in weather types for freezing rain >= 6 hours. The Great Lakes influence on freezing rain occurrence will show a decreased frequency on the west side shores of Lake Ontario, North shore of Lake Erie. In fall, early winter & early spring.
- In central Canada, the CSA/CEA freezing rain ice design criteria for high voltage power and transmission lines indicates a design limit for overhead structures of approximately 25 mm of radial ice accretion (not freezing rain totals) on a 1 inch conductor. Therefore, damage to the electrical transmission system normally occurs in the more severe ice storms. However, transmission lines may fail and towers may be damaged in less severe ice storms under the effects of "galloping," as the conductors and guy wires erratically oscillate and stretch under moderate but steady wind conditions.

37 Insurance Bureau of Canada - Telling the Weather Story - The Institute for Catastrophic Loss Reduction - 2012

38 Estimation of Severe Ice Storm Risks for South-Central Canada - Office of Critical Infrastructure Protection and Emergency Preparedness – Government of Canada – 2003

Changing Weather Patterns, Uncertainty and Infrastructure Risks: Emerging Adaptation Requirements report[39] states:

- Trees magnify the impact of ice storms. Tree management near distribution lines is an important adaptation action needed to reduce risks of power distribution system outages.
- Investigation included an assessment of the CSA/CEA freezing rain ice design criteria for high voltage power and transmission lines. The results indicated that the existing design ice loading specifications for overhead structures (not freezing rain totals) adequately cover existing ice storm return periods (repeat interval) for most regions, but would need to be upgraded if ice storm frequencies or amounts increase.
- the potential for long power outages and for community disasters becomes likely when freezing rain totals exceeded approximately 40 mm.

The Canadian Regional Climate Model (CRCM4.2) report[40] indicates an increase in longer duration freezing rain episodes as indicated in figure 8.

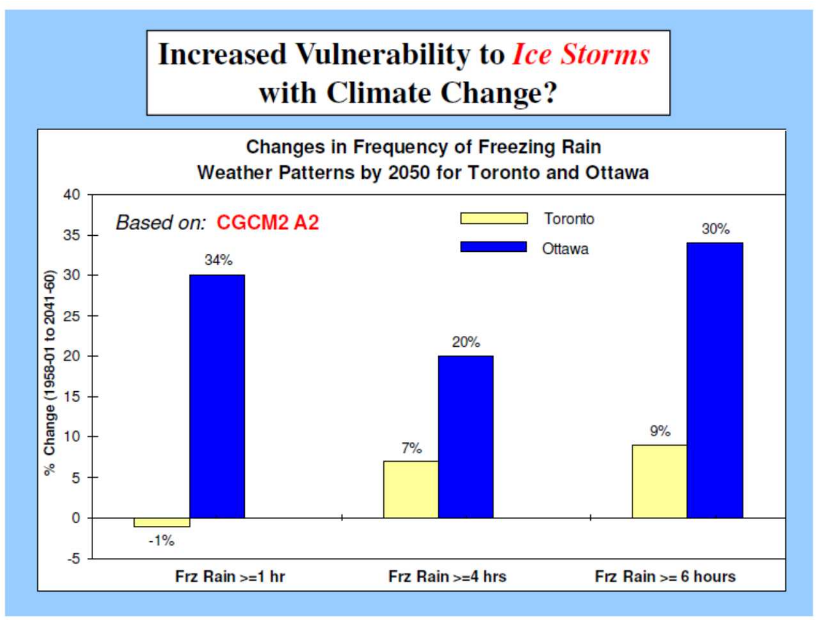

FIG 8. ICE STORMS AND CLIMATE CHANGE

39 Changing Weather Patterns, Uncertainty and Infrastructure Risks: Emerging Adaptation Requirements – Environment Canada – 2007

40 Climate Change Scenario over Ontario Based on the Canadian Regional Climate Model (CRCM4.2) – Ouranos - 2010

Most reports indicate that increases in freezing rain duration and intensity will be highest in northern and eastern Ontario. Moderate increases will be felt in southern Ontario with the Toronto area seeing a 10% increase in freezing rain frequency by 2050. A similar impact would be felt in the PowerStream service areas. For severe ice storms (>25 mm ice accumulation) this would change the historical probability from 0.06 per year (once every 17 years) to 0.07 per year (once every 14 years).

1.2.6 Impact Summary

The key findings of current and forecast climate norms and damage potential to PowerStream's distribution system are summarized in the table below:

Weather Event	Current norms	Climate Change Norms	Damage potential
Temperature	~12 days > 30^0C per year	Temp days >30^0C to double by 2050	Overload potential to equipment already heavily loaded
Heavy Rain/Flooding	Historical return of 25 years	Increased risk of flash floods	Station flooding
High Wind velocity/wind gusts	Severe high winds once every 50 years	Severe high winds once every 35 years	Aged overhead assets and multiple circuit poles at greatest risk
Tornados	Once every 12.4 years	Once every 12.4 years	Massive localized destruction of infrastructure
Freezing Rain >25mm	Once every 17 years	Once every 14 years	Major power outages

In summary, over the next 35 years, the number of days of 30 °C or more will double. The frequency and severity of heavy rain/flooding, high winds and freezing rain will increase.

It should be noted that climate change impacts can affect more than one type of infrastructure (i.e. transportation, communication, etc.). This needs to be taken into consideration in not just the initial design but in the response efforts to mitigate the effects of climate change. Hardening and resiliency efforts are warranted to ensure continued reliability of supply with the impacts of climate change.

2. DISTRIBUTION SYSTEM HARDENING - REVIEW OF NORTH AMERICAN UTILITY PRACTICES

There are two key concepts related to improving the performance of electrical distribution systems in severe storm situations: hardening and resiliency.

- Hardening - physical changes to make particular pieces of infrastructure less susceptible to storm-related damage
- Resiliency - increasing the ability to recover quickly from damage to facilities' components or to any of the external systems on which they depend

The following represents a summary of what some North American utilities are doing, or have done, to "harden" their distribution system.

2.1 HYDRO-QUEBEC[41]

The 1998 ice storm resulted in an accumulation of 40 to 90 mm of freezing rain between the 4th and the 11th of January in the southern regions of Quebec. As a result, Hydro-Quebec lost about 3,000 km of the network including 1,000 transmission pylons, 4,500 transformers and more than 16 000 wood distribution poles. At the peak of the crisis 1.5 million customers were left without electricity. The cost of the 1998 ice storm was evaluated to be $2 billion; the immediate cost to restore electrical service was $1 billion. After the crisis an additional $1 billion dollars was invested to reinforce the transmission and distribution networks. Major work began in 2000 to reinforcing the networks, it continued until 2006 for the distribution network and is ongoing for the transmission network and expected to be completed in 2015.

Hydro-Quebec transmission division (TransÉnergie) has developed and is implementing a program in order to secure electrical supply to the distribution network. A third of a billion dollars has been invested so far for the construction of four transmission electrical ties:

- Monteregie tie
- Montreal downtown tie
- Quebec City downtown tie
- Quebec-Mauricie tie.

An additional $400 million dollars is invested to reinforce the original transmission networks.

41 Renforcement du réseau de distribution d'Hydro-Québec - Rapport sur les orientations de fin de programme November 9th 2004

The Distribution network is composed of 100,000 km of lines which about 90% are overhead lines. One of the major elements of the hardening strategy is reinforcing these lines, Hydro-Quebec invested $200 million dollars to minimize the impacts and consequences of future storms by selecting concepts and technologies that exceed current standards and would be able to withstand major storms. The reinforcement program has two major objectives:

1. An increase in design criteria
2. Introduce the controlled failure concept to minimize damage

To achieve this, equipment has been modified and major changes have been made to distribution network construction criteria to be able to sustain up to 45 mm of ice. This value was chosen as Hydro-Quebec decided to manage the risk on a 50 year probability of occurrence. HQ revised its standards and created two sets of standards they call “regular” and “robust”. The regular standard applies to most of the grid and aims to withstand 1.41 inches of ice (36 millimeters). The robust standard has the objective of ensuring that critical portions of the system can withstand 1.77 inches (45 millimeters) of ice. Between 1999 and 2006, HQ hardened the critical portions of the system to the new Standard Criteria’s.

5,300 km of network was enhanced with the new controlled failure construction criteria. This makes Hydro-Quebec standards one the highest in the electrical distribution industry.

Poles and anchors have also been modified to better withstand the range of climates they are being exposed to. Hydro-Quebec has developed a polymer-based additive (PA) that is injected into poles treated with chromated copper arsenate (CCA) to make them as easy to climb as poles treated with pentachlorophenol (PCP) or other preservatives. This additive reduces the hardness usually found in other CCA treated poles without affecting the service life of the pole and allows the line teams to easily climb on them with their climbing equipment. This is very useful for inaccessible poles. With respect to anchors, Hydro-Quebec has stopped the installation of 10’’ screw anchors and replaced them with 14’’ anchors. Hydro-Quebec has also added the triple helix (10’’-12’’-14’’) screw anchor and the 900 sq.in. anchor plate to their inventory.

The new controlled failure system, which includes controlled sequential failures of crossarms and conductor ties, will ensure that if the lines are exposed to an extreme ice load they will fall without dragging the poles with them. Anti-cascade systems have been perfected to avoid the domino’s effect that created the damages experienced in the 1998 ice storm event. Every tenth distribution pole has anti-cascading to limit damage from pole collapse. Hydro-Quebec’s post storm analysis showed that 80% of the time spent in repairing the network was spent in replacing poles (see Figure 9); this time will be considerably reduced with the implementation of these concepts.

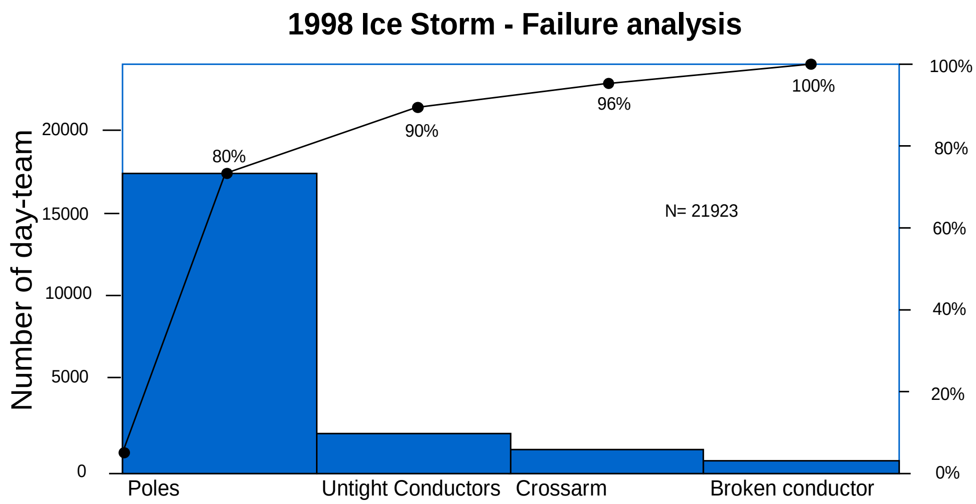

FIG 9. 1998 ICE STORM – FAILURE ANALYSIS [42]

Post-ice storm vegetation management was undertaken in order to increase the reliability of the distribution networks. Trees represent a major problem in most of Quebec's regions so a special pruning program was created and a substantial budget increase was enacted in order to eliminate overhangs and prune trees deemed dangerous to the lines in all areas at risk of receiving 25 mm or more of freezing rain. Work started with lines connecting priority customers such as hospitals, pumping stations, police and fire stations and shelters. The work was then completed on parts of the network that service dense populated cities. Of the 100,000 km of network, 37,500 km have undergone intense pruning at the cost of $20 million dollars (part of the overall $200M budget). Education of the public on the vegetation management program is very important in order to obtain the populations' support. Therefore, Hydro-Quebec has created different tools to facilitate this work.

The total vegetation management cycle varies from 3 - 6 years. For the priority distribution back bone, mainly 3 phase circuits, a 3 years cycle is normal. The remainder, mainly single phase conductors, is on a 6 year cycle. Planning is done every year and identifying dangerous trees is a priority. Worst performing feeders are identified and worst performing feeders at year N are treated at year N+1. Hydro Quebec does not trim services lines but forestry planners do advise the customer about what needs to be done.

42 Renforcement du réseau de distribution d'Hydro-Québec - Rapport sur les orientations de fin de programme November 9th 2004

In collaboration with the transmission division, Hydro-Quebec distribution has created reinforced links between satellite transmission substations. This allows bigger flexibility in case a satellite substation is damaged then the reinforced distribution link from another satellite substation will assure the supply in backup energy to priority customers. In case of a major event, Hydro-Quebec will repair these links first and then resume work on other parts of the network.

Finally, the typical number of circuits per pole is 1 (15MVA circuit). The exception is 2 and needs special approval. There are never more than 2 circuits per pole. Undergrounding from the substation to pockets of load is standard in urban and semi-urban areas. In rural areas, normally all the circuits can be aerial. Undergrounding in rural would be an exception.

2.2 MANITOBA HYDRO[43]

The Manitoba-Hydro distribution systems consist of 4 kV to 25 kV lines and the sub-transmission has voltages of 33 and 66 kV. It owns about 150 stations in the western part of Manitoba with 78,000 km of lines and over 500 feeders that can be up to 20 miles long in rural locations. See figure 10.

43 Manitoba Hydro Mitigates Ice Issue on Power Lines - Nov 1, 2012 Robert Lapka, Manitoba Hydro | T&D World Magazine

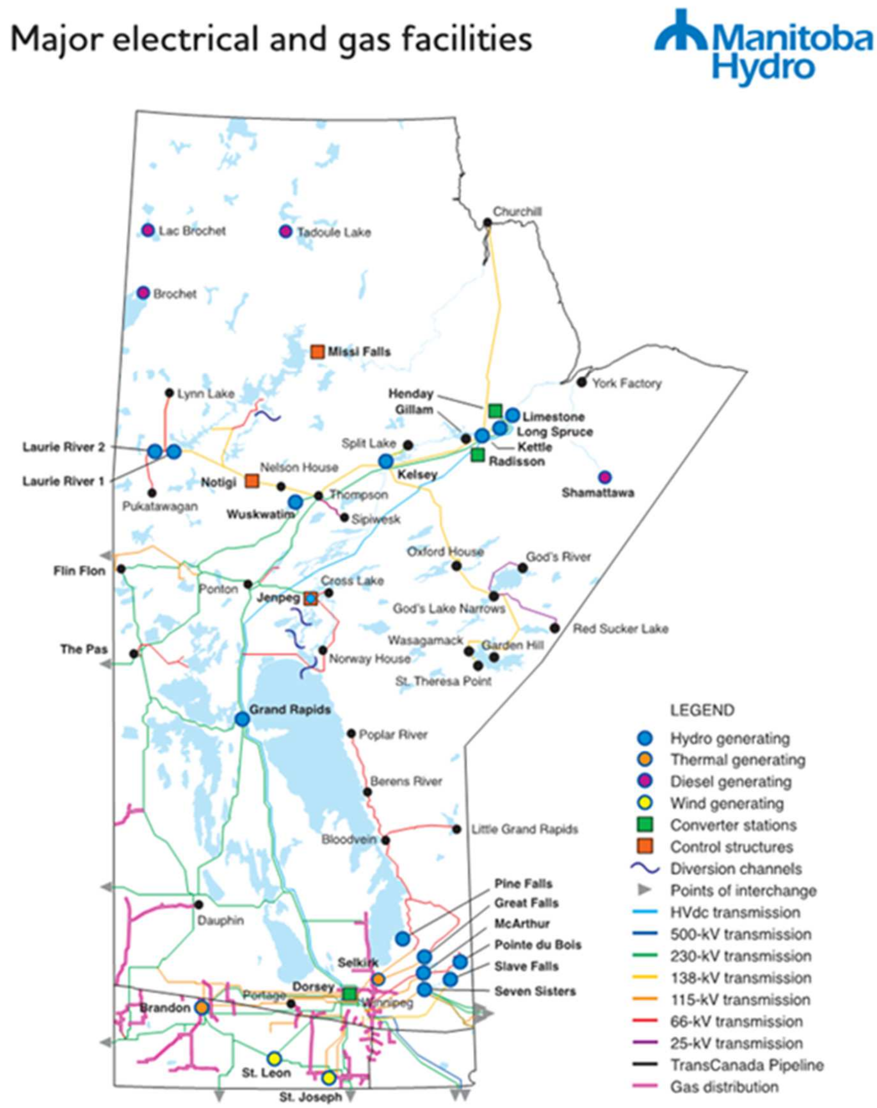

FIG 10. MANITOBA HYDRO FACILITIES[44]

About 96 per cent of the electricity Manitoba Hydro produces each year, 30 billion kilowatt-hours on average, is generated at 15 hydroelectric generating stations on the Nelson, Winnipeg., Saskatchewan, Burntwood and Laurie Rivers.

44 Manitoba Hydro Mitigates Ice Issue on Power Lines - Nov 1, 2012 Robert Lapka, Manitoba Hydro | T&D World Magazine

The province's remaining electricity needs are fulfilled by:

- 2 thermal generating stations;
- 4 remote diesel generating stations;
- Wind power purchases from independent wind farms in Manitoba.

Manitoba Hydro has an extensive infrastructure to support the production and delivery of power in the province. In 2011–12 they've invested $479 million toward maintaining a secure and dependable delivery system.

Weather conditions in the region are very extreme and fluctuating. High humidity, below-freezing temperatures and ice storms are favorable to ice forming on power lines. In windy conditions icy lines can whip violently and gallop causing tie wires to break, poles to snap and steel towers to snap. Quick removal of that ice helps prevent equipment breakage and loss of power.

Two methods have been approved by the Manitoba Hydro to remove ice from its lines[45]:

1. Ice melting
2. Ice rolling

Ice Melting

A short-circuit is placed at one end of a sub-transmission line, this creates a current flow and a gradual temperature increase in the line and melts the ice. Ice melting can be used only between -15°C and 0°C and it takes about 10 minutes to melt ice off the line. Ice melting is used on sub-transmission and distribution lines. Through the use of spare transformer banks, line configuration and portable substations mounted on a semi-trailers, the utility is able to perform this work while maintaining power to customers.

Ice Rolling

Field crew use an upside-down pulley attached to a wooden stick with a fiberglass insert and rope to remove ice on conductors. Line crew pull the rope/stick assembly and the ice roller applies pressure to crack the ice off the line (see figure 11). The line can be rolled in an energized state depending on the weather. In windy or wet weather, the line is rolled de-energized. This method is effective but depends on the amount of ice on the line and cannot be used if temperatures are hovering around 0°C as the ice becomes soft and flexible. A 10-person crew can de-ice roughly 1.6 kilometres of line per hour.

45 Manitoba Hydro Mitigates Ice Issue on Power Lines - Nov 1, 2012 Robert Lapka, Manitoba Hydro | T&D World Magazine

FIG 11. ICE ROLLING[46]

Manitoba Hydro has developed a new vision ice system, which incorporates live camera images. Connected to a communication system, the cameras give a real- time view of ice accumulation. The cameras are protected in a weatherproof housing and pointed directly to the power lines. Even with all this technology, field crew observations and reports are still a big part of the prevention plan.

46 Manitoba Hydro Mitigates Ice Issue on Power Lines - Nov 1, 2012 Robert Lapka, Manitoba Hydro | T&D World Magazine

2.3 CON ED - POST SANDY ENHANCEMENT PLAN[47]

Consolidated Edison services New York City. In the wake of Superstorm Sandy, ConEd embarked on a long-term storm plan (Post Sandy Enhancement Plan - PSEP) to make sure that their system is less susceptible to similar storms and more responsive to customer needs. The PSEP focuses on three key efforts:

- Fortifying the electric, gas, and steam systems against future storms;
- Improving estimated times of restoration, and enhancing storm planning and restoration processes;
- Improving the flow of information to customers and other stakeholders.

$1 billion will be invested over a 4 year period to achieve this. Some of the key hardening projects being undertaken are:

- Reconfiguring the most vulnerable underground networks to form separate flood areas – segmentation strategy.
- Flood-proofing energy equipment including requiring commercial customers, in those areas prone to flooding, to install submersible or elevated equipment in their facilities.
- Installing additional distribution automation such as sectionalizing switches to allow system operators to identify and isolate problem areas and rapidly bring power back to the surrounding areas.
- Upgrading of overhead distribution equipment, with the aim of making the system more resilient against damage from high winds and downed trees and limbs.
    - Separating feeders into sections and installing remotely operated sectionalizing switches to isolate problems, so that damage does not cause outages for all customers on the feeder.
    - Redesigning feeders so that they can be supplied power from both ends, or potentially from customer generation sources (e.g., combined heat and power/distributed generation) giving operators more options for restoring service.
    - Installing stronger poles able to withstand wind gusts of up to 110 miles per hour in strategic locations.
    - Redesigning wires to provide better protection from falling tree limbs, and to detach more easily when force on the wire is more extreme to reduce the likelihood of damage to poles and other pole-top equipment.

47 Post Sandy Enhancement Plan – Consolidated Edison - 2013

  - Expanding use of overhead cables for greater resistance to damage from high winds and tree branches.
  - Creating greater tree clearances around distribution facilities near substations and critical infrastructure.
- Selectively undergrounding portions of the overhead system based on analysis of outage data and field surveys of tree density – focusing on areas where tree trimming alone may not be sufficient, and where the added costs can provide significant added value in terms of reducing future restoration costs.
- Evaluating ways to shore up information systems to withstand flooding - focusing on expanding the use of water-resistant fiber-optic communications and control systems, rather than copper wires.
- Developing plans to create strategically placed sub-networks that can be isolated from the rest of the grid and incorporating customer-side distributed generation resources into restoration plans.

ConEd's key focus on hardening was to reduce the impact of flooding and minimizing loss of their underground network system, as a whole, due to localized flooding. Summary of hardening efforts are in Table 1.

ELEMENT	HARDENING STRATEGY	COMMENTS
Substations	Each station that flooded during Sandy will be hardened to a new flood-level design – determine new minimum elevation for critical equipment	Install new expansive RTV foam seals at any trench and conduit penetrations into the critical areas of the station to minimize the infiltration of water.
UG Distribution	Move to submersible standard; install sectionalizing equipment to isolate flood areas (sub-network design)	Avoids taking an entire network out of service
	Watertight shrink-wrap cover that will enclose and protect RTU boxes in submersible locations.	
OH Distribution	Lower the number of customers served by each segment of primary supply to fewer than 500 using reclosers and SCADA switches	Will reduce OH outages by 15 – 20%
	Stronger equipment poles(+15% strength) – capable of withstanding wind gusts of 110 miles per hour – to be used on main runs and/or heavy tree cover areas, as well as for feeders supplying critical customers	
	Add isolation devices on runoffs that are more than two spans in length	Fusing laterals – trip saving

ELEMENT	HARDENING STRATEGY	COMMENTS
	Sectionalize overhead loops into smaller loops; add supply feeders; DG supply;	
	Use Hendrix Aerial Cable vs open wire design	More robust
	Implement so-called "sacrificial components," such as breakaway hardware and detachable service cable and equipment, to prevent pole and customer equipment damage during storms	
Proactive design/mtce	Incorporating hardening solutions for future storms into the repair process, or deferring permanent repairs until a stronger solution is available	
Customer infrastructure	Customers in flood-prone areas either install submersible electrical equipment, or raise critical equipment above the ground floor	Reduce the probability that the system would be impacted by a fault current on the customers' side of the meter
Selective undergrounding	Replace portions of the overhead system with underground equipment – focus on (1) feeders supplying areas that have experienced the highest storm-damage impact and (2) feeders supplying facilities that are vital to maintain community support following severe storms, such as hospitals, police and fire stations, schools, and stores that sell basic necessities, such as food, medicine, gasoline, and building supplies. Also select existing overhead double circuit distribution lines that have shown a history of higher exposure to incidents, and replace them with underground distribution mainline systems	$6.2 million per mile (2007)
Vegetation Management	"Hazard Tree" program – identify trees that are tall enough to contact the overhead distribution system and are also dead, declining, diseased, or otherwise structurally unsound.	Work with landowners to find agreeable solutions. All tree removals require written landowner authorization
	New clearance standard for Orange & Rockland territory of 15 feet to the side, 15 feet below and 20 feet above certain conductors	All 34.5 kV distribution wires, and the portions of 13.2 kV circuits that run between the transformer and the first protective device, such as a recloser.
	Branch Reduction program - view limbs as levers that can be pulled down by snow, ice, or wind stresses. By proactively shortening the length, can reduce the likelihood that a branch will break under weather stresses.	Training required for contractors and employees

ELEMENT	HARDENING STRATEGY	COMMENTS
Communication	New Con Ed owned fiber loops to reduce reliance on external telecomm carriers	Higher reliability level than carrier circuits; offers highest level of cyber and physical security; improve recovery time in the event of communications failures
	Reinforce antenna systems and implement backup generators at several critical fibre network and radio sites.	

TABLE 1 – CON ED HARDENING EFFORTS

2.4 LIPA STORM HARDENING PLAN (PSEG)[48]

LIPA was the Long Island Power Authority that serves Long Island, New York (excluding New York City). Since 2014 LIPA has become PSEG Long Island, but LIPA will be used in terms of reviewing their storm hardening plans. See Figure 12 for their territory

Serves approximately 1,110,853 customers
1,230 square miles of service territory
8,950 miles of overhead wire
4,661 miles of underground cable
535,050 utility poles

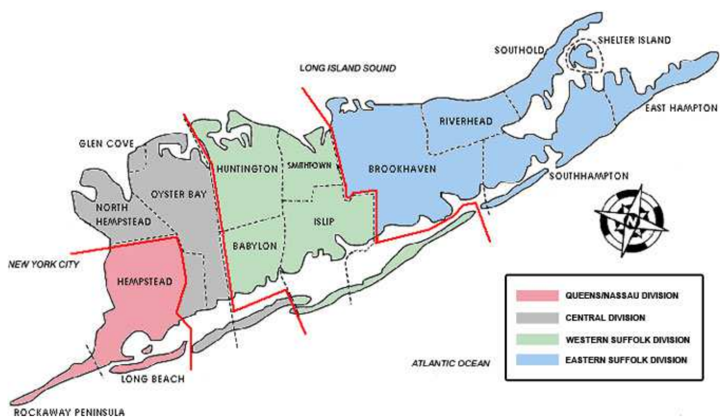

FIG 12. PSEG (LIPA) SERVICE TERRITORY

LIPA adopted a $500M-20 year proactive storm hardening plan in 2006. See Table 2 for the annual expenditure hardening plan. The purpose of the plan was to improve the capability of the electric system on Long Island to withstand the impacts of hurricanes and other severe storms, and to shorten the time required to restore service to customers when outages occur due to storms.

48 LIPA Storm Hardening Talking Points - 2012

The plan had 3 areas of focus:

- Durability - “minimize damage caused by severe storms”
- Resilience - “minimize impact of storm damage”
- Restoration - “minimize outage times”

PLAN KEY COMPONENTS	ANNUAL EXPENDITURE
Storm Hardening + Reinforced foundations to support critical equipment and structures + Higher strength steel infrastructure + Higher strength poles + Equipment repositioning to mitigate flooding issues + Selective undergrounding	$20M
Vegetation Management + Removal of dangerous trees adjacent to lines + Accelerated tree trim cycles in areas + Increase annual tree trimming mileage targets + Expand transmission right of ways to provide additional clearance	$5M

TABLE 2 – LIPA STORM HARDENING PLAN

Durability and Resilience initiatives

- Installation of new underground circuits
- Replace deteriorated poles
- Protect substations from flooding and storm surges
- Reinforce substation foundations and structures to withstand higher wind speeds
- Increase strength of selected pole lines to withstand higher wind speeds and storm related flooding along rail corridors and at major road crossings. LIPA moved from a Class 2 pole to a Class H1 pole, ensured no more than two attachments per pole, and does not allow junction boxes on these poles
- Prioritize Transmission Lines for hardening

- Increase strength of selected distribution pole lines to withstand higher wind speeds at distribution circuit supply points (e.g.. riser poles exiting substations, highway crossings), key automated circuit sectionalizing points and major equipment poles
- Increase tree trimming clearance and removal of hazardous trees/limbs outside clearance zones
- Fusing review

Restoration Initiatives

- Continue to expand distribution automation across the system
- Improve Damage Assessment process - field damage reports to be analyzed and entered into the OMS; job level information and estimated restoration times to be been to given to customers much sooner following a major storm
- Upgrade the Outage Management System (OMS)
- Implement a comprehensive resource control system to manage field personnel during restoration (Resources on Demand)
- Expand mobile substation capabilities - purchase of new emergency replacement equipment; mobility for use across the system
- Expand mobile generator capabilities - in-house capability up to 300 kVA; contracts in place for unique circumstances

LIPA made efforts to harden its transmission and stations to withstand a Category III Hurricane. The impact of their storm hardening efforts were noticeable in the impacts of Hurricane Irene (2011) compared to Hurricane Gloria (2005). See Table 3.

	Hurricane Gloria(2005) – Category 4	**Hurricane Irene(2011) – Category 3**
Landfall	Category 1-2	Category 1
Substation outages	30%	12%
Feeder lockouts	74%	19%
Damaged poles	n/a	½ of Gloria

TABLE 3 – POST HARDENING HURRICANE IMPACTS

Hurricane Sandy landfall by comparison was a Category 1 level.

2.5 PSEG – NEW JERSEY[49]

PSEG serves the New Jersey area.

PSEG's Energy Strong program calls for $3.9 billion in investments over 10 years to harden utility infrastructure and guard against increasingly extreme weather. The utility proposes spending $2.6 billion in the first five years, with a potential investment of another $1.3 billion in the following five years. In May of 2014, PSEG reached an agreement with its Regulator that resulted in a $1.22 billion settlement in its Energy Strong proposal to proactively protect and strengthen its electric and gas systems against severe weather conditions.

Key elements of the approved plan, to be enacted over 3 years, are:

- $620 million to raise, relocate or protect 29 switching and substations that were damaged by water in recent storms.
- $350 million to replace and modernize 250 miles of low-pressure cast iron gas mains in or near flood areas.
- $100 million to create redundancy in the system (distribution automation), reducing outages when damage occurs.
- $100 million to deploy smart grid technologies to better monitor system operations to increase the ability to more swiftly deploy repair teams.
- $50 million to protect five natural gas metering stations and a liquefied natural gas station affected by Sandy or located in flood zones.

Most elements of the hardening plan deal with issue related to flooding. The final settlement was considerably pared down from the original proposal that included additional items such as relocation of rear lot supplies, etc.

2.6 CONNECTICUT LIGHT AND POWER[50]

The Connecticut Light and Power (CL&P) electric distribution system serves approximately 1.2 million customers and covers approximately 4,400 square miles. CL&P's distribution system consists of approximately 16,976 circuit miles of overhead primary construction, and 6,352 circuit miles of underground primary construction, including both direct-buried and underground duct and manhole primary construction.

49 PSEG Settlement Fact Sheet 2014
50 Connecticut Light and Power Company System Resiliency Plan – CLP - 2012

The service territory includes heavily-treed areas, shoreline areas, and hilly terrain. Weather conditions are often severe and include ice and snow storms, heavy winds, thunderstorms, and occasional hurricanes and tornadoes. In the absence of trees, the distribution system infrastructure itself is generally able to withstand wind up to approximately 70 miles per hour and ¾" of radial ice before extensive damage begins to occur.

In 2012, (CL&P) produced a $300M 5-year System Resiliency Plan. CL&P expects that upon completion of the System Resiliency Plan fewer customers will be without service during both normal, day-to-day activities and especially in the wake of major and catastrophic storms and those customers that are without service will be restored more quickly.

CL&P's key goals in the development of the System Resiliency Plan include the following:

i. Achieve significant, sustainable improvement in infrastructure performance during weather events.
ii. Focus the System Resiliency Plan initially on the most impactful activities, with special emphasis on the CL&P's worst-performing circuits.
iii. Provide preference in the System Resiliency Plan to initiatives that also provide important improvement in day-to-day operations and system reliability.
iv. Utilize infrastructure retrofit initiatives (those targeted at achieving an immediate impact by directly seeking out and changing out a portion of the distribution system infrastructure) to achieve both near term and lasting impact.
v. Utilize infrastructure evolution initiatives (those targeted at achieving impact over a much longer period of time, such as modifying the criteria for selection of pole size/class) to continuously improve infrastructure resiliency gradually over the next 40 to 50 years mainly through revisions to construction standards and material selection/usage.
vi. Ensure expected improvement results occur and are sustained.

The CL&P's System Resiliency Plan includes three areas; vegetation management, structural hardening, and electrical hardening.

Vegetation management - enhanced tree trimming ("ETT") (clearing a wider envelope around primary wires, removal of overhanging limbs as well as weak, diseased or leaning risk trees in proximity to wires) and trimming on a shorter cycle. See Figure 13.

FIG 13. OVERHANG BRANCH FAILURE

Structural Hardening - strengthen structures incrementally over a long period of time through design standard and material changes, as well as which field structures may need to be retrofit in the near term to meet new design expectations.

Electrical Hardening - making electrical distribution conductors more resilient to failure during weather events and also utilizes protective device upgrades on overhead circuits to minimize the number of customers impacted when interruptions do occur. CL&P is evaluating the costs, benefits and prioritization of upgrading its older “bare wire” primary conductors with stronger, more tree-resistant covered “tree wire”. Circuit segment sectionalizing will be examined to determine if opportunities exist to minimize customers impacted by adding intermediate protective devices.

The electric supply to critical facilities can be “selectively hardened” to provide much higher levels of power supply security so that they can meet important societal needs. CL&P has identified the following general methods of “selectively hardening” electricity supplies to critical regional/town facilities:

1. Undergrounding distribution lines from the nearest bulk substation to critical facilities.
2. Supplying such facilities with reliable back-up generation that can provide alternative supply for extended periods of time.
3. Developing an electrical micro-grid (to these facilities) with local generation that can “island” and continue to supply the facilities during catastrophic weather events.

CL&P is evaluating the resiliency of its substation facilities relative to extreme weather. This evaluation predominately involves:

1. Identifying substations that may be in areas prone to flooding from either ocean or river initiated events.
2. Determining the extent of flooding that might be expected to occur and its potential impact on substation equipment.
3. Evaluating options for mitigating the impact of flooding on substation equipment.

Tree trimming in the Plan consists largely of two general initiatives, (i) working towards achieving a four-year cycle trim rate(8' (side), 10' (under) and 15' (top) clearance) and, (ii) working towards clearing the most critical circuitry to enhanced trimming specifications in order to reduce exposure of these lines to tree-related interruptions during major storms. Enhanced clearances involve removal of overhanging branches as well as removal of trees, from backbone circuitry and laterals that supply a larger number of customers that because of their condition and/or orientation to distribution lines pose an elevated risk, particularly during major weather events. CL&P expects a reduction of tree-related outages of at least 35% during major storms, and 50% at other times, as a result of fewer interruptions on circuitry that is trimmed to enhanced specifications.

Structural and electrical upgrades are planned for (i) certain critical line crossings (major, limited-access highways and major railroads) and (ii) on circuits with a history of poor reliability performance. These critical line crossings will be structurally upgraded to withstand category 3 hurricane force winds.

CL&P has incorporated both a structural design strength assessment and an inspection-based conditional assessment on backbone and major lateral structures to identify legacy plant that is vulnerable to wind and ice loading.

Electrical hardening upgrades will have three focus areas:

1. Segments of line on the worst performing circuits that are heavily treed and perform substantially poorer than average segments in terms of failures per mile will be considered for electrical rehabilitation or reconductoring (if bare) with either spacer cable or 175 mil tree-resistant, covered wire to reduce the amount of tree-related failures.

2. Segments of line where the bare conductor consists of aged very small gauge copper, will be considered for reconductoring with spacer cable or 175 mil tree resistant, covered wire. Very small gauge copper wire is mechanically frail and has a high propensity to break with relatively small limb contact or on longer span lengths for ice accretion of ¾" or greater.
3. Circuitry will be evaluated for other upgrades including the addition of intermediate protective devices to limit impact of line failure in terms of numbers of customers impacted.

Modifying/increasing the strength of the standard pole class used for distribution construction, composite (as opposed to wooden) cross arms, and modification of pole top configuration are options that are being considered as potential changes to standards.

Implement cost-effective system automation techniques to improve system resiliency through deployment of substation breaker automation, deployment of remotely-indicating right-of-way Smart Grid Sensors, deployment of additional recloser batteries to ensure longer life during major storms.

2.7 FLORIDA POWER & LIGHT[51]

FPL's storm hardening initiative has three key elements:

1. **Application of extreme wind loading ("EWL") criteria to critical infrastructure facilities** - FPL implemented EWL into three wind regions corresponding to expected extreme winds speeds of 105, 130 and 145 miles per hour. FPL began applying EWL to the top critical infrastructure feeders and any associated laterals serving critical customers. Critical feeders include those that serve facilities such as hospitals, 911 Centers, Emergency Operation Centers ("EOCs"), water treatment plants, police and fire stations. EWL is also being applied to poles included in FPL's targeted critical pole program. This program focuses on poles that can impact restoration efforts and includes poles on key highway crossings.
2. **Incremental hardening to certain feeders supplying critical community needs** - The objective of the incremental hardening program has been to increase the overall wind profile of a feeder to a higher wind rating, up to and including EWL. Some of the options that FPL has been using include pole guying, relocation, adding intermediate poles, upgrading of poles. FPL has targeted poles that are critical to restoration efforts and have additional electric equipment such

51 Hurricane Wilma and FPL - 2006

as automated feeder switches/reclosers capacitor banks and multiple circuits.

3. **Construction design guidelines that require EWL for the design and construction of all new overhead facilities, major planned work, relocation projects and daily work activities** - The guidelines are primarily associated with changes in pole class, pole type and desired span lengths to be utilized. For example, prior to this initiative, FPL used class 3 wood poles in critical pole locations however their new design standards call for Class III-H concrete poles in these cases.

After the storms, all Florida utilities implemented ten storm hardening initiatives including:

1. Three-year vegetation management cycle for distribution circuits
2. An audit of joint-use attachment agreements
3. A six-year transmission structure inspection program
4. Hardening of existing transmission structures
5. A transmission and distribution geographic information system
6. Post-storm data collection and forensic analysis
7. Collection of detailed outage data
8. Increased utility coordination with local governments
9. Collaborative research on effects of hurricane winds and storm surge
10. A natural disaster preparedness and recovery program

2.8 CITY OF OCALA UTILITY SERVICES[52]

The City of Ocala Utility Services is a small utility in Florida with 48,456 customers.

The key effort at storm hardening involved the City passing an ordinance in 2007 requiring all electrical facilities for new developments to be designed and installed using underground construction methods. This would lessen exposure to wind damage and speed restoration efforts after future storm events.

The utility standards, policies, guidelines, practices and procedures comply with the extreme wind loading standards of the NESC for:

1. New Construction
2. Expansion, rebuild or relocation of existing facilities

52 Ocala Electric Utility Storm 2013 Hardening Report

The utility has a Remove and Replace tree voucher program that addresses problem and hazard trees on property adjacent to utility easements by providing removal services and rewarding customers who cooperate with replacement vouchers and educational materials as an incentive.

2.9 OKLAHOMA GAS AND ELECTRIC (OGE)[53]

In 2009, OGE instituted a 3 year system hardening program that included:

1) Aggressive vegetation management. OGE concluded that managing vegetation around power lines is one of the most effective strategies for hardening a distribution system. OGE's program consists of several elements:
    a. Removal of risk trees
    b. Using herbicide more aggressively in rural areas
    c. Removing all voluntary trees with diameters of eight inches or less within easements
    d. Establishing four additional feet of clearance over standard 8 feet or 12 feet
    e. Removal of overhangs
    f. Implementation of the "right tree, right place" program

2) Circuit hardening. OGE's program has focused on upgrading circuits to current design standards, strengthening support structures, replacing certain wire conductors, upgrading the grade of construction for certain distribution facilities and targeting undergrounding of certain lateral sections of distribution lines.

2.10 ENTERGY[54]

ETI is located in southeast Texas and serves approximately 413,000 retail customers in 27 counties. ETI's transmission and distribution systems serves customers spread out over approximately 15,000 square miles ranging from the coastline of the Gulf of Mexico (between Port Bolivar and the Texas-Louisiana state line) to the northern boundaries located between 100 to 180 miles inland. ETI's entire service territory is susceptible to damage during severe weather. The most extensive damage has occurred during ice storms and hurricanes.

CIMA

53 Oklahoma System Hardening Plan – 2009 Commission Order
54 Entergy Texas Inc. Infrastructure Improvement and Maintenance Report - 2011

To harden infrastructure for ice storms, ETI's standards follow the NESC combined ice and wind loading requirements. To harden distribution infrastructure for hurricanes, the following strategies were employed:

- Install minimum class 3 poles on trunk feeders for new construction or replacement in coastal areas
- Expand installation of storm guys, and
- Convert existing wood pole interstate crossings with steel poles.

ETI's distribution vegetation management program uses a multi-tiered approach to total ROW management. These subprograms include:

- Proactive (planned) Maintenance Program - ETI assigns a tailored cycle time (time between trims) to each feeder based on such factors as growth rates, type and density of side and floor vegetation, vegetation-related outage information, time from last maintenance trim, and other reliability metrics.
- Reactive (unplanned) Maintenance Program – this addresses customer requests for trimming, emergency situations, and other maintenance needs outside the annual trim plan.
- Hazard Tree ID & Removal Program - In 2002 Entergy developed the system-standard Danger Tree Patrol Process. This process identifies the timeline for hazard tree patrols and the physical attributes OC's will look for while conducting patrols. Hazard tree criteria includes, but is not limited to:
    - Dead trees with overhang
    - Dead trees straight up or leaning toward the line
    - Trees with a lean toward the line
    - Trees uprooting toward the line
    - Trees in decline, diseased or decaying (e.g.: lighting, base rotting, or weakened)
    - Broken limbs overhanging the line
    - Bad crotch/codominent stems that have branches overhanging the line or angle towards the line
    - Dead branches on a live tree that overhang the line
    - Vines 3/4 or more up the pole
    - Trees that are imminent (e.g.: within 1 or 2 days of falling) danger to the conductor, use the reactive process

- "Skyline" Overhang Removal Program - the removal of any limb capable of falling or hinging down upon energized conductors. ETI employs skylining on a limited basis, primarily on the main trunk of feeders, to decrease the potential for outages on these high customer count areas of line.
- Herbicide Application Program – targets vine problems for herbicide treatment in fast-growth areas and to destroy all tall growing woody tree species from under the line, promoting grasses and other non-woody plant species, and creating more easily accessible ROW's.
- Tree Growth Regulator (TGR) Program - the application of tree growth regulators that will allow for the increase in cycle time clearing

2.11 SUMMARY OF LARGE UTILITY HARDENING EXPENDITURES

The Table 4 summarizes the program cost and duration for a number of the larger utilities identified in this report. It must be understood that the programs reflect different investment focuses (i.e. some are gas and electric vs just electric) and locational needs whereby investments are geared to specific customer segments and not the overall customer base (i.e. urban focus vs rural focus). Hardening programs are costly and depending on scope, can take many years to implement.

Utility	Customers	Hardening program cost	Hardening program duration
Hydro-Québec	4.1 million	$200 million	6 years
Consolidated Edison	3.3 million	$1,000 million	4 years
LIPA	1.1 million	$500 million	20 years
PSEG New Jersey	2.5 million	$1,200 million	3 years
CL&P	1.2 million	$300 million	5 years

TABLE 4 – HARDENING PROGRAMS EXPENDITURE SUMMARY

2.12 DISTRIBUTION SYSTEM HARDENING - PAPER REVIEW

2.12.1 Best Practices in Storm Response (DistribuTech 2010)[55]

A paper on Best Practices in Storm Response was presented at DistribuTech 2010. The paper covers all utility activities to prepare for, combat and recover from a storm event. A brief mention was made of storm-hardening activities typically undertaken by utilities during normal operation is described below.

55 Best Practices for Storm Response on U.S. Distribution Systems – Lavelle A. Freeman, Gregory J. Stano, Martin E. Gordon DistribuTech

- Florida PSC issued Order No. PSC-06-0351-PAA-E1, requiring the investor-owned electric utilities to file plans and estimated implementation costs for ten ongoing storm preparedness initiatives including a three-year vegetation management cycle for distribution circuits; an audit of joint-use attachment agreements; a six-year transmission structure inspection program; and hardening of existing transmission structures. Some of the more common storm hardening activities include: tree trimming/vegetation management, system design changes, and maintenance activities such as pole inspection/replacement programs

2.12.2 Best Practices in Vegetation Management (Texas)[56]

A paper on Best Practices in Vegetation Management in Texas focused on vegetation management practices for distribution systems at all common distribution voltages. Vegetation caused outages is due to two mechanisms:

1. Mechanical tear-down of electric lines and/or apparatus, causing outages.
2. Electrical short circuits or arcs causing overcurrent faults, most often resulting in operation of system protection devices to clear the fault, thereby causing an outage.

The majority of tear-down conditions are due to trees outside the utility ROW and trim zone. Wind, ice and snow accumulations are the contributing factors to mechanical tear-down situations. Key learning points with respect to vegetation management are:

1. Trees and other vegetation represent less than 20% of all fault causation for non-storm conditions.
2. Mechanical tear-down is the primary (e.g. 80%) cause of vegetation outages. This is exacerbated during storms and/or high winds which cause trees to fall.
3. Electrical contact between a single conductor and live branches is rarely the root cause of a vegetation-caused outage.
4. Single-phase vegetation faults for 15 kV class or lower distribution voltages are rare due to the relatively low voltage gradient from line to ground.
5. Arcing vegetation faults on 15 kV class single-phase feeders are rare absent mechanical forces causing direct phase to neutral (metal to metal) contact.

56 Best Practices in Vegetation Management For Enhancing Electric Service in Texas - Texas Engineering Experiment Station – 2011

6. Higher voltage distribution feeders (e.g. 25 kV, 35 kV) have an increased probability of electrical faults due to vegetation because of the higher voltage gradient.
7. Phase-to-phase vegetation faults occur on 15 kV feeders if two conditions are met.
   (a) The vegetation (e.g. branch) must bridge phases in a mechanically stable way over a sufficient time period to create an arc path by charring and burning the branch (generally requires solid contact on the order of minutes).
   (b) The vegetation must not burn or fall free before a permanent outage occurs (e.g. arcing fault initiating protective device operation).
8. Downed energized electrical conductors represent a fire hazard and an electrical hazard to the public.

The report recommends a move from simple cycle based re-growth clearing to a program that focuses on elimination of overhanging branches and hazard trees in the vicinity of lines, especially heavily loaded three phase circuits. They also recommend using condition based scheduling of vegetation management to optimize the value of funds expended (Reliability Centered Vegetation Management). This would include documented inspection criteria for vegetation specialists.

Mandating a continual minimum clearance distance of vegetation from conductors will not achieve reliability objectives. Vegetation intrusion within a few feet of conductors has little effect on overall reliability (due to high impact of tear-down events).

Finally, ensuring that tree planting on municipal streets under powerlines is coordinated with the local utility will ensure that inappropriate trees are not being planted.
The best practice with respect to vegetation management budgets must include long term, sustainable, and consistent funding that is not subject to wild swings or instability.

2.12.3 Ice Resistant Tree Populations - (Trees and Ice Storms – Second Edition)[57]

The University of Wisconsin has issued a publication “Trees and Ice Storms” that classifieds tree species by their susceptibility to ice storms as shown in the Table 5.

57 Trees and Ice Storms – University of Illinois - 2006

Susceptible	Intermediate	Resistant
American basswood	American beech	Armur maple
American elm	Boxelder	Baldcypress
Bigtooth aspen	Chestnut oak	Balsam fir
Black ash	Choke cherry	Bitternut hickory
Black cherry	Douglas-fir	Black walnut
Black locust	Eastern white pine	Blackgum
Black oak	Gray birch	Blue beech
Bradford pear	Green ash	Bur oak
Butternut	Japanese larch	Catalpa
Common hackberry	Loblolly pine	Colorado blue spruce
Eastern cottonwood	Northern red oak	Crabapple
Honey locust	Paper birch	Eastern hemlock
Jack pine	Pin oak	Eastern redcedar
Pin cherry	Red maple	European larch
Pitch pine	Red pine	Ginkgo
Quaking aspen	Scarlet oak	Hophornbeam
Red elm	Scotch pine	Horsechestnut
River birch	Slash pine	Kentucky coffeetree
Siberian elm	Sourwood	Littleleaf Linden
Silver maple	Sugar maple	Mountain ash
Virginia pine	Sycamore	Northern white cedar
Willow	Tamarack	Norway maple
	Tulip poplar	Norway spruce
	White ash	Ohio buckeye
	Yellow birch	Pignut hickory
		Shagbark hickory
		Swamp white oak
		Sweetgum
		White oak
		White spruce
		Witch-hazel
		Yellow Buckeye

Adapted from Hauer et al. (1993) and published reports from 42 primary publications. Species ratings are consistent with the first edition of this publication except for green ash, pin oak (both previously rated as susceptible) and bur oak (previously rated as intermediate).

TABLE 5 – ICE STORM SUSCEPTIBILITY OF TREE POPULATIONS[58]

58 Trees and Ice Storms – University of Illinois - 2006

Tree species that have "included" bark (bark that is sandwiched in the narrow junction between two dominant tree stems) are particularly susceptible to ice storm damage and breakage. The publication notes that storm damage can be placed into five categories:

1. broken branches,
2. trunk bending,
3. splitting of main or co-dominant stems,
4. complete trunk failure,
5. tipping or up-rooting.

A proactive program that examines and assesses trees for any of the above potential hazards is important to mitigate future effects of severe weather.

2.12.4 MEA Report – Design and Component Failure Analysis from the 1998 Ice Storm (2000)[59]

This report is in the PowerStream library. The report is a survey of distribution utility responses (13) to the damage caused by the ice storm.

The key cause of outages was broken or downed lines caused by tree branches falling on lines. Secondary cause was broken or downed lines caused by ice loading alone. Damaged poles and insulators were the least frequent causes of outages.

The respondents indicated that armless construction (no cross arms), short spans, aggressive tree trimming, use of polymer insulators and adequate guying would go a long way to mitigate future outages. A number of services were lost by the service entrance rack being pulled away from the home. It was recommended that bolts, rather than screws, be used to secure the service entrance rack to the building.

The report identified seven different approaches to improving the reliability of the distribution system:

1. Re-building the system to a higher factor of safety (2.0 instead of 1.6)
2. Reducing span length
3. Installing periodic ground anchors in the direction of the line in long straight sections to act as dead-end structures
4. Avoid using high aspect ratio ground anchors

59 MEA Report – Design and Component Failure Analysis from the 1998 Ice Storm (2000)

5. Increasing the mechanical strength of components covered in CSA Standards
6. More aggressive vegetation control
7. Separation of communication and distribution systems from service poles

The top two approaches were judged to be vegetation control and reducing span length. Also higher loads on lines stressed guy wires and anchors beyond the mechanical limits of high aspect ratio guying systems causing guying failures and pole displacements.

2.12.5 MEA Report – Effectiveness of Maintenance Practices and Retrofit Designs in Improving Distribution System Reliability[60]

This report is in the PowerStream library. The report is a survey of distribution utility responses (19) to identify initiatives to decrease outages on the Distribution System.

Overhead plant improvement recommendations included replacing open wire with "tree proof" cable in highly treed areas; reducing pole fires through mitigation measures; and implementing cyclic vegetation management.

2.12.6 TD World storm hardening article (Quanta Technologies)[61]

This article compiled a list of the 12 best practices for distribution system hardening including:

1. Pole test and treat- ensure no pole has lost more than one-third of its original strength and no pole is likely to have lost more than one-third of its original strength before its next scheduled inspection.
2. Feeder inspections - have a formal feeder inspection program that periodically examines feeders for problems that will likely lead to an outage during normal and/or storm conditions.
3. Attachment audits - Third-party attachment audits should occur, at a minimum, every five years for all three-phase main feeder trunks
4. Foreign owned poles - ensure foreign-owned poles are in as good of shape as their own poles in terms of remaining strength and loading.
5. Setting depths - develop standards and processes to ensure the foundation of distribution poles will not fail before the pole(s).

60 MEA Report – Effectiveness of Maintenance Practices and Retrofit Designs in Improving Distribution System Reliability

61 Storm Hardening the Distribution System – TDWorld Magazine - Richard E. Brown – 2010

6. Loading calculations - have systems and processes in place to ensure poles do not become overloaded after they are initially installed.
7. Grade B construction - have an explicit process to review new construction and rebuilds to decide whether the system should be built to Grade B (NESC standard), or equivalent, rather than a weaker standard.
8. Non-wood poles - have standards for at least one type of non-wood distribution pole as a viable alternative should this be necessary for hardening
9. Post-storm data collection - have a plan that has trained staff collect data on distribution damage sites immediately after a storm subsides.
10. Hardening tool kit - develop a hardening tool kit that consists of a set of approved approaches to hardening and an application guide for their use.
11. Like-for-unlike replacement - enact systems and processes that allow the system to be gradually hardened through normal work processes.
12. Strengthen critical poles - identify critical poles that are highly undesirable to fail during a major storm. Take targeted actions to strengthen these poles.

2.12.7 Edison Electric Institute – Before and after the storm (2014)[62]

This report by the Edison Electric Institute is a compilation of recent studies, programs, and policies related to storm hardening and resiliency.

System hardening - physical changes to the utility's infrastructure to make it less susceptible to storm damage, such as high winds, flooding, or flying debris.

Resiliency - the ability of utilities to recover quickly from damage to any of its facilities' components or to any of the external systems on which they depend.

Hardening measures include:

- Undergrounding – eliminate poles and bury distribution lines to avoid the impact of severe weather. Has aesthetic benefits but tends to be cost prohibitive. Selective undergrounding is a compromise solution.

62 Before And After The Storm – EEI – 2014

- Vegetation Management – maintaining clearances is not sufficient. Targeted vegetation management of hazard branches and trees is more effective. Need to coordinate with municipalities to control tree planting beneath power lines.
- Higher Design Construction Standards – a targeted approach is recommended. Focus on the local conditions of the distribution facilities. Identify critical, poor performing, weak elements and replace them with improved system designs (e.g.. composite poles, guying, stronger pole classes, etc.). Have a robust inspection and maintenance plans to identify and mitigate potential structural problems.
- Smart Grid – utilize a looping system with distribution automation to detect outages and reroute power. This may not be effective in large tear-down situations – nowhere for the power to go.
- Microgrids – like the Smart Grid, it is vulnerable to large tear-down events.
- Advanced Technologies – hydrophobic nano-particle coatings on distribution lines may inhibit the formation of ice.

2.12.8 Hardening and Resiliency- U.S. Energy Industry Response to Recent Hurricane Seasons (2010)[63]

This report considered storm hardening measures in the energy sector. Electricity hardening measures noted were:

- Wind Protection
    - Upgrading damaged poles and structures
    - Strengthening poles with guy wires
    - Burying power lines underground
- Flood Protection
    - Elevating substations/control rooms
    - Relocating/constructing new lines and facilities
- Modernization
    - Installing asset tools and databases
    - Deploying sensors and control technology

Wind impacts on trees and powerlines are noted in the Table 6.

63 Hardening and Resiliency U.S. Energy Industry Response to Recent Hurricane Seasons – DOE – 2010

Category	Winds	Impact to Trees	Impacts to Power Lines
1	74-95 mph	Large branches of trees will snap and shallow rooted trees can be toppled.	Extensive damage to power lines and poles will likely result in power outages that could last a few to several days.
2	96-110 mph	Many shallowly rooted trees will be snapped or uprooted and block numerous roads.	Near-total power loss is expected with outages that could last from several days to weeks
3	111-130 mph	Many trees will be snapped or uprooted, blocking numerous roads.	Electricity will be unavailable for several days to a few weeks after the storm passes.
4	131-155 mph	Most trees will be snapped or uprooted and power poles downed.	Power outages will last for weeks to possibly months.
5	> 155 mph	Nearly all trees will be snapped or uprooted and power poles downed.	Power outages will last for weeks to possibly months.

TABLE 6 – SAFFIR-SIMPSON HURRICANE WINDS AND SELECTED IMPACTS[64]

Hardening for wind, for distribution systems, usually involves upgrading wooden poles to concrete, steel, or a composite material, and installing guys and other structural supports. Proper placement of guy wires can increase the ability of a pole to withstand higher winds. A pole truss system may also achieve similar results by increasing the pole bending capacity by one or more classes.

Elevating substations is effective hardening against flooding.

Distribution automation and sensors can lead to self-healing grids as part of a modernization hardening strategy.

3. FORECAST WEATHER DISTRIBUTION INFRASTRUCTURE IMPACTS SUMMARY

A review of climate change projections and distribution system hardening practices by the utilities examined in the previous section provides a number of potential key climate change impacts and responses. Some of these can be considered by PowerStream to address forecasted climatic change related impacts to the distribution system.

64 NOAA, National Weather Service, National Hurricane Center, http://www.nbcnoaa.gov/pdf/sshws_table.pdf accessed May 22, 2010

3.1 TEMPERATURE IMPACTS

Overall assessment is that temperature changes by themselves will not present a problem to the distribution system that warrants "hardening" efforts. Equipment loading will have to be monitored to ensure that sufficient capacity exists to handle the increasing frequency of heat waves. Drought conditions would warrant the review of soil thermal resistivity at station cable egress to ensure cable ampacity is not compromised – avoid thermal runaway effects.

3.2 HEAVY RAIN/FLOODING IMPACTS

The impact of heavy rains and localized flooding is of concern to ground level and below grade infrastructure vulnerable to water damage. For PowerStream this vulnerability may exist in certain transformer and municipal stations that have below grade equipment or ground level equipment and is in a flood prone area. Equipment examples include batteries and charging units in transformer station basements, relay cabinets, etc.

Hardening options would be to consider moving vulnerable equipment out of station basements to ground level locations and to ensure that vulnerable ground level equipment is above any known localized historical flood levels.

3.3 HIGH WIND VELOCITY/WIND GUSTS IMPACTS

Increasing average wind velocity and peak wind gusts will impact pole structures. Moving to higher grade construction or loading safety margin at critical poles or locations can mitigate against this. Selective undergrounding of portions of the distribution system will also work but is a much more expensive alternative.

3.4 TORNADO IMPACTS

Tornados are infrequent events and almost impossible to protect against with an overhead system as funnel wind speeds will exceed even the most robust construction standard.

3.5 FREEZING RAIN IMPACTS

As with the high winds scenario, higher construction standards and selective undergrounding can mitigate against ice storm impacts. In addition, the installation of breakaway connectors, enhanced tree clearances and third party interactions will reduce the overall damage impact.

4. POWERSTREAM STAFF CONSULTATIONS

A number of key PowerStream staff were consulted on their experiences and thoughts on the key issues of the 2013 ice storm and what hardening ideas/actions could be investigated for adaptation to mitigate the effect of future storms.

Some key observations were:

- Most of the 2013 ice storm problems were due to limbs on lines even in recently cleared areas; ice did not bring down infrastructure
- Most trees and limbs causing the problems were outside normal trim zones; hazard trees/limbs outside the trim zone need to be addressed
- Overhead secondaries are not part of the tree trimming program; this is where a number of the problems were
- Backyard construction was the most problematical to deal with from access and restoration perspective; left for last because most labour intensive and time consuming to restore
- Few failures on arterial streets; ice accumulation flashovers resulted in a few pole fires
- Most failures were in heavily treed side streets and rural areas
- Some pole locations are relatively inaccessible once installed (i.e. 407 ramps)
- A number of customer standpipes were damaged as a result of tree/tree limbs taking down the overhead service cable. In a few cases customers had to wait days, even after power was available, to get their services repaired by electricians
- Current overhead and underground standards are good but legacy construction is less robust (pole class and guying)

Some of the key ideas were:

- Remove, at a minimum, the primary from rear lots; this will make it easier for restoration purposes; mitigates weather and animal issues with respect to primary conductors
- In short term, focus on addressing rear lot tree trimming
- Consider expanded uses of insulated tree cable in heavily treed areas
- Coordinate with municipalities to ensure future tree planting along boulevards is compatible with existing overhead powerlines
- Incorporate secondary tree trimming into the vegetation management program

- Investigate more robust alternatives to wood poles (i.e. composite); may be more resistant to pole fires in high contamination areas
- Investigate the use of breakaway clamps for conductors
- Use electronic type reclosers for radial and backlot feeds instead of fuses
- Eliminate radial feeds; ensure loop configuration is in place so all have alternative supply points; diversify supply routes to large commercial customers
- If possible, put highway crossings underground – coordinate with bridge construction to get ducts installed in bridge structure
- Focus on hardening deadend and crossing poles; more storm guying in general
- Increase sectionalizing of feeder segments and distribution automation, especially in high treed area
- Underground major intersections and other strategic sections of line; diversify feeder routing
- Enforce underground supply as policy in undeveloped areas
- Review lifecycle cost of overhead versus underground with the cost of outages to customers included

These consultations were taken into consideration and incorporated into the practice review and hardening recommendations as deemed appropriate.

5. POWERSTREAM PRACTICES AND PHILOSOPHIES - HARDENING REVIEW

5.1 VEGETATION MANAGEMENT

5.1.1 Background

PowerStream's vegetation management practice is documented in its internal procedure ENG-P-018 Vegetation Management Procedure.

A three year tree trimming cycle has been adopted for the entire service area. It consists of annual cycle clearing (1/3 of PowerStream's service territory) and an annual program to address vegetation impacting worst performing feeders. To date the actual cycle clearing time for the whole service area is in the 4-5 year range however this is expected to improve in the near term as resources are allocated to achieve the 3 year cycle target.

Clearing is based on tree species and results in line clearances, between cycles, of 0.1 m – 3.5 m.

The program is limited to PowerStream plant on road rights of way and easements (including dedicated resources to address rear lot easements). It addresses PowerStream owned secondary service conductors crossing private property on an exception basis. If a customer calls with concerns about vegetation around the service conductor, PowerStream will respond and trim the vegetation. Otherwise the secondary lines are not dealt with. There are typically 15-20 calls a week related to service line trimming, quite a number of them related to back lot feeds. Since the ice storm, calls have increased to 20-30 a week. The program also does not address customer owned conductors, typically long span rural primary runoffs. The customer is considered responsible for vegetation clearing around lines that they own.

The line clearing activities are performed as per procedures outlined by PowerStream, the Occupational Health and Safety Act and its Regulations, the IHSA Rule Book and the IHSA Safe Practice Guide - Safety in Line Clearing Operations.

Line clearing performed in a given cycle is recorded on a Vegetation layer in the GIS.

On the strategic side, PowerStream has instituted tree planting coordination meetings with municipalities and the Region to ensure that incompatible tree species are not planted under or adjacent to powerlines.

5.1.2 Analysis

PowerStream's vegetation management program is typical of most utilities and as such can be said to follow good utility practice. The fixed cycle approach tends to result in all areas of the distribution system receiving equal attention which by itself can lead to over/under attention to vegetation growth in different areas. Discussions with staff have indicated that the fixed cycle approach is somewhat augmented by identification of vegetation "hot spots" (specific calls received from customers). This results in "out-of-cycle" pruning for select high vegetation growth areas. In addition to annual line clearing, vegetation congestion around worst performing feeders is targeted (worst peforming feeders identified by reliability deterioration from all causes). By incorporating a focus on "hot spots" and worst performing feeders, PowerStream has adopted aspects of reliability centered maintenance for vegetation which is considered a best practice in vegetation management. It will help ensure that funds are focused on where they will achieve the greatest impact on improving tree contact related reliability. This will have little impact on mechanical teardown (trees/limbs breaking wires and other distribution components) related reliability.

As seen in the 2013 ice storm, a number of outages were due to mechanical line teardown or contact due to branches and falling trees outside the trim zone (generally trees located on private property). Some damage was done to customer service standpipes and secondary lines as a result of teardowns. Severe storm teardowns and contacts from trees outside the trim are not mitigated through standard line clearances for trees. Severe winds and ice storms can result in limbs and trees outside the trim zone coming into contact with lines causing outages and at times, bringing them down. Mechanical teardown and severe storm contact can be mitigated through vegetation management programs that combines enhanced clearances and a proactive hazard tree program to remove potential teardown/contact sources.

PowerStream website information on vegetation management provides information to customers regarding planting and maintaining vegetation near powerlines and electrical equipment. As noted above, branches and trees outside the trim zone account for most mechanical teardowns. PowerStream website information does not address the need for proactive assessment of hazard trees on customer property outside the trim zone.

Tall 4-circuit poles present trim issues for vegetation at or over the top of the pole structure. Forestry vehicles currently have an 80 feet working height on road allowance and less to deal with field side issues. Overhang issues on 4-circuit polelines are difficult to deal with due to limited reach of forestry equipment.

A gap that exists at present is the treatment of overhead secondary services. Service line issues are dealt with on a reactive, not proactive basis. Secondary services, either front lot or rear lot, are addressed by exception in the existing line clearing program.

5.1.3 Summary of good utility practice in vegetation management

- PowerStream has adopted a 3 years tree trimming cycle to standard trim clearances including rear lot easements;
- PowerStream has adopted an annual vegetation management focus on worst performing feeders;
- Out of cycle “hot spot” issues addressed;
- Line clearing records are maintained in the GIS;
- PowerStream liaises with municipalities to coordinate tree planting below/adjacent to distribution lines

5.1.4 Potential practice adaptations

In reviewing best practices for vegetation management, there are a number of initiatives that PowerStream should consider adopting to improve its vegetation maintenance program:

1. Consider enhancing the trim zone - increase tree trimming clearances. Minimum clearance at 27.6 kV is currently 1.0 m with a maximum clearance of 1.5 m – 3.5 m depending on tree species. Approaches by other utilities have resulted in enhanced clearance with some adopting a "blue sky" approach to overhanging limbs. Complete overhead clearance is preferred to eliminate limb collapse on the circuits below. In absence of complete above wire clearance, consider the use of "tree cable" (i.e. Hendrix) to minimize contact issues. This would be especially beneficial in rear lot overhead where the single phase primary supply would be retained. View limbs as levers that can be pulled down by snow, ice, or wind stresses. By proactively shortening the limb length, the likelihood that a branch will break under weather stresses can be reduced. A target of 25 mm radial ice carry will cover most ice storms encountered. Limb pruning radius will be species and condition dependent. It should be noted that in all papers and practices reviewed, line clearing by itself is deemed insufficient to address vegetation related outages as a result of severe storm situations.

2. Consider incorporating aspects of reliability centered maintenance in the fixed pruning cycle program. A reliability centered program relies on rate-of-change tree-related outages, increase in hot spot frequency and expert assessment to determine where tree trimming is required. This will enhance the fixed cycle program in allocating resources. Fixed cycles tend to spend too much attention on areas that have good reliability history but perform better when augmented by "out-of-cycle" pruning. The vegetation management program could be documented in detail (scope, responsibilities, contractor requirements, planning, strategy, records, etc.).

3. Consider instituting a "Hazard Tree" program that identifies trees outside the trim zone that are tall enough (adopt ESA criteria) to contact the overhead distribution system and are also dead, declining, diseased, or otherwise structurally unsound. This can be incorporated as part of the 3 years trim cycle. Work with municipalities and home owners to expedite removal of hazardous trees/limbs outside clearance zone. A tree voucher program, that

addresses problem and hazard trees on property adjacent to utility easements, has been put in place by other utilities. It works by providing removal services and rewarding customers who cooperate with replacement tree vouchers and educational materials as an incentive.

4. Consider including proactive service line (when owned by PowerStream) clearing on private property as part of the 3 years trim cycle. These lines are owned by PowerStream and in general the responsibility for maintaining plant is a function of ownership. This means that line clearing responsibility, and ensuring plant is in a safe condition, extends beyond the plant on road allowance and also encompasses PowerStream plant private property. PowerStream, like other Ontario LDCs, has the authority under the Electricty Act to "enter and maintain any land for the purpose of cutting down or removing trees, branches or obstructions". This should be explicitly mentioned in the Conditions of Service.

   Most utilities in Ontario do not trim secondary lines on private property or do so on an exception basis. There are a few (i.e. Sault Ste. Marie. PUC) that do and explicitly state so:

   "It is the responsibility of PUC Distribution to maintain safe minimum clearances between trees and power lines as well as service lines that feed homes and businesses. PUC will only remove trees outside this safe limit when the tree poses a direct danger of falling into the line causing a hazard…..PUC Distribution is responsible to trim trees both within the municipal roadway and on private lands to the prescribed safe clearances from power lines."

   These set the bar for a forward looking standard of duty of care for the residential service class as a whole.

5. Consider continuing to educate and inform the municipalities, property developers and clients on vegetation near powerlines and how they can help to keep the network safe (i.e. add to PowerStream website – "Homeowners Guide to Maintaining Your Trees after Ice Storms and Preventing Further Damage"). Proactive education will mitigate future vegetation related issues in severe storm situations.

6. Consider training design staff and construction in basic vegetation management to help identify potential problems. A ½ day or 1 day course by a trained arborist can identify vegetation conditions that should be brought to the attention of the Line Clearing coordinator.

5.2 BACKYARD CONSTRUCTION

5.2.1 Background

PowerStream's position on residential backyard construction is documented in the Rear Lot Remediation Plan (December 2013). The report recommends a long-term remediation program which starts in 2015, and continues for 15 years to 2029, until all residential rear lot locations have been addressed. A total of 4,058 residential customers (1.1% of PS total) are currently fed from rear lot services. Some rear lot remediation work is currently underway and so for an expected 2015 program start there will be 3589 customers fed from rear lots to be scheduled for remediation. The average age of the rear lot fed areas is 45 years. PowerStream four remediation options:

- **Option 1** – Replace existing rear lot with new rear lot overhead
- **Option 2** – Replace existing rear lot with new front lot overhead
- **Option 3** – Hybrid – Install primary cable & transformer at front lot underground; replace/keep pole & secondary at rear lot
- **Option 4** – Replace existing rear lot with new front lot underground

Option 1 is the least expensive capital option and has been chosen as recently as 2005 when the Kleinburg rear lot supply was rebuilt and converted from 8 kV to 16 kV primary supply. It maintains the status quo of both the primary and secondary supply in the rear lots along easements.

Option 2 while feasible, is not considered achievable due to expected public and political backlash against new overhead plant in an "underground" area. An Option 1 program would cost approximately $27M (~$7.5k/customer).

Option 3 eliminates primary supply vulnerability but maintains secondary supply vulnerability to extreme weather conditions. The total cost of the program, based on Option 3, is approximately $59.5M (~$16.6k/customer).

Option 4 eliminates both the primary and secondary vulnerability to extreme weather conditions and potential political repercussions due to misplaced future reliability expectations. The total cost of the program based on Option 4 is approximately $87.4M, (~24.3k/customer).

Stakeholders interviewed were in general agreement that the rear lot supplies are problematical in both normal and severe weather conditions. There is anecdotal consensus that overall reliability will improve with the removal of rear lot primary in that primary related outages due to vegetation contact would be eliminated leading to less trouble calls and reduced trimming needs. It would be also somewhat safer with the primary removed for both workers and the homeowners. The retention of rear secondaries will continue to pose operational and customer service challenges. The key issue is the high cost and limited value to completely convert these areas to a more robust form of supply that can withstand severe weather impacts.

5.2.2 Analysis

PowerStream has developed a comprehensive strategy to remediate existing residential rear lot construction by 2029. The 15 year plan does not eliminate rear lot construction. In a number of cases, primary supply will be moved to the front yard and undergrounded. This will effectively mitigate the effects of extreme weather on the primary supply in the local area. In most, if not all cases, the secondary supply will remain in the rear and remain vulnerable to extreme weather conditions. Upstream overhead primary will also remain vulnerable to the extremes of severe weather.

The 2013 ice storm demonstrated the vulnerability of front and rear lot overhead secondary services to extreme weather events. Most of the problems were with the secondary services being pulled down due to vegetation issues. The rear lot primary and secondary bus was not as impacted in this particular set of circumstances, other than fuses operating on the overhead rear primary supply. This may not be the case under future scenarios if extreme weather events exceed the conditions experienced in 2013.

Environment Canada indicated that between 20 and 30mm of freezing rain fell in the area between Niagara and Trenton as a result of the 2013 ice storm[65]. Toronto Pearson Airport experienced 43 hours of freezing rain. The City of Markham reported that they had 20 – 25mm of ice accumulation[66], the City of Vaughan had 25mm and the City of Barrie had 20mm[67].

According to the Toronto Hydro Electric System PIEVC Pilot Case Study (2012) freezing rain storms lasting at least 6 hours have a probability of occurring every other year (0.65 annual probability) and can bring ice accumulation levels of up to 25mm. Multiday ice-storms with $\geq$ 25 mm of ice accumulation occur less frequently (0.06 annual probability). **With between 20**

65 Environment Canada – Canada's Top Ten Weather Stories for 2013
66 Ice Storm – December 2013 / Presentation to General Committee January 8, 2014
67 Ontariostorms.com

and 25mm of ice accumulation being reported in the PowerStream service territory, the 2013 ice storm can be considered a moderate one in line with the criteria for the 0.65 annual probability category. Very little if any PowerStream plant was brought down by ice accumulation that one would expect from an ice storm with > 25mm ice accumulation that would fall in the 0.06 annual probability category. This is also supported by the TRCA study that indicated that daily freezing rain amounts of less than 25 mm are expected to occur 1.25 to 2 times per year.

Climate change forecasts indicate that ice storms such as that experienced in 2013 are increasing in frequency (moving from once every two years to more of an annual occurrence). More severe ice storms with greater accumulation (>25 mm) that can take down wires and poles by weight alone, are expected once every 14 years according to the Toronto Hydro Electric System PIEVC Pilot Case Study (2012). The TRCA study was even more conservative with a range of 4 to 10 years repeat time for such storms.

This Option 3 remediation proposal will leave the rear lot secondaries exposed to extreme weather (mitigated by the vegetation management program) and it is likely that the customers will be impacted by service teardowns in future ice storms similar to what they experienced in 2013. It is expected that the underground primary supply will not be as impacted as in the past so outages may be limited to more individual homes versus all rear lot homes unless the secondary bus is torn down. Some secondary mitigation measures, such as breakaway connectors, may limit future damage to the customer service entrance equipment, but operational difficulties in accessing rear lots will lengthen repair and restoration times as in 2013. There would be less need for electricians to rebuild customer service stacks and get ESA permits for restoration.

The overall reliability of rear lot secondary overhead is similar to front lot overhead secondary. Both are impacted by weather and vegetation events. It is only in extreme weather conditions, as in the 2013 ice storm, that the differences in accessibility and restoration times between back and front are magnified. This needs to be taken into account in determining the “value” gained from the rear lot remediation options.

If Option 3 is chosen, it needs to be considered together with a program (material & labour) to install secondary breakaway connectors. This effectively raises the cost of Option 3 to $60.6M.

The 2013 ice storm also demonstrated the need to accelerate the mitigation program. The current program pace results in poles and hardware being replaced at points well past the Typical Useful Life standard (45 years) that have been reported to the OEB. With expected increases in return times in December through to February, it is quite feasible to have multiple freezing rain events, of varying ice accumulation and wind strength, over a 15 year period. Customer outcomes, expressed through direct feedback and municipal representative feedback to PowerStream staff, expect that appropriate actions will be taken to prevent reoccurrence of backlot problems that occurred as a result of the 2013 ice storm.

Of related interest is Toronto Hydro's rear lot conversion program. Since 2007, Toronto Hydro has embarked on a 20+ year program to convert rear lot overhead supply to front lot underground supply. The program is a full conversion program where the primary and secondary lines are removed from the rear lots and placed underground in the front lots. The poles have been left in the rear lot for the telecommunication provider needs (pole ownership transferred over). The cost to do this has been around $30k per customer with the biggest cost being the work to trench/bore secondary cables to the meter bases in the back of each customer's house. Annual program expenditures have been around $15 - $20M and represent a positive NPV expenditure for rate case financial analysis. Future annual expenditures are in the $10M range. All conversion costs have been borne by Toronto Hydro and are rate base funded. Customer communication is key in the successful implementation of the conversion program (i.e. equipment location, property disruption, etc.).

5.2.3 Summary of good utility practice in Backyard Construction

- PowerStream has a documented asset management program for rear lot residential plant. The long term plan is to move most of overhead rear lot primary supply to front yard underground supply. The Program has been smoothed ($3.2M/year + 3% inflation) to mitigate rate impacts. Prioritization is based on area end-of-life status.

5.2.4 Potential Practice Adaptations

In reviewing PowerStream's practices for backyard construction, there are a number of initiatives that PowerStream should consider adopting:

1. Consider accelerating the mitigation program to expeditiously deal with plant installed in the 1950s through to the 1970s that are already past the Typical Use for Lies (TUL) pole point (45 years). Consider a 6 year-$41M program to expedite replacement of pre-1980 vintage plant. This will partially address expected customer outcomes and mitigate risk of backyard plant subject to a future freezing rain event similar to the 2013 ice storm. Post 1980 plant ($18.6M program) can be scheduled for the 2024 – 2030 period.

2. For Option 3, consider installing breakaway connectors on overhead secondary services. Expedite installation, as a separate program, if current 15 year backyard remediation program is to be maintained. A three year install program is recommended. This will mitigate the problem of customer standpipe damage due to teardowns.
3. Consider Option 4 to completely eliminate residential rear lot supply. This will address expected customer outcomes and mitigate risk of backyard plant subject to a future freezing rain event similar to the 2013 ice storm. A 10 year - $60M program could expedite replacement of pre-1980 vintage plant. Post 1980 plant ($27.4M program) can be scheduled for the 2025 – 2030 period.

5.3 UNDERGROUNDING PRACTICES

5.3.1 Background

PowerStream's undergrounding practice/philosophy is documented in its Conditions of Service and Underground relocation policy. Overhead construction has been PowerStream's standard method of distribution on arterial streets as it is a lower cost of installation, it provides a high degree of flexibility in dealing with changing infrastructure requirements due to new commercial customers coming on stream, is not impacted by the space issues for required switching units that an underground system would need and has less technical barriers. For example, in the PowerStream north service area, the 44 kV distribution system is overhead as there are technical barriers related to very limited product availability for undergrounding 44 kV, particularly in regards to compact switching units. 44 kV undergrounding is not technically practical except for limited straight runs. In summary, the general practice is to consider undergrounding where overhead supply facilities are not possible for various reasons (i.e. limited building clearances). Note that this is not applicable to residential and commercial subdivisions where municipal by-laws and subdivision agreements require the developer to install underground plant for aesthetic reasons.

Section 3 of the Conditions of Service indicates that residential and general service customers are eligible to obtain overhead or underground service connections. This would be determined by the nature of the infrastructure in the area for single site plan applications. For example, an applicant in overhead area would likely get an overhead service connecting (depending on service size and voltage). Residential and commercial/industrial subdivisions are generally supplied via an underground distribution system as a result of municipal planning requirements that require undergrounding of power lines and other infrastructure (phone, cable, etc.).

On arterial streets, PowerStreams standard practice to install overhead facilities has resulted in 2 and 4 circuit pole lines to accommodate growth. This has been a flexible installation practice with a lower impact on rates compared to an underground equivalent installation. There is a high cost premium to install an underground system along arterial streets.

Recent efforts by municipal and transit authorities to build transit corridors along key arterial streets have reinforced the principle that the premium for constructing underground versus overhead should be paid by the requesting party and not the ratepayer.

5.3.2 Analysis

PowerStream's underground policy on arterial streets is typical for a number of major urban utilities. Where overhead construction can be used, it is and when space/clearances for overhead construction are not available, then underground construction is used. This has resulted in increasing density of circuitry on poles (moving from 2 to 4 circuits) as the municipalities have grown. 4 circuit construction on poles places a considerable amount of load (~ 60 MVA @ 27.6kV) at risk of disruption due to extreme weather events or other causes. Most non-weather disruptive events (i.e. foreign interference) affect a single pole location and are dealt with in a timely manner. Weather disruptive events can impact multiple poles/areas and require considerable time to restore to normal conditions (i.e. June 17, 2014 wind burst that resulted in loss of a 12 pole section along Warden Avenue in Markham and 46 hour outage to directly affected customers).

Most residential and commercial/industrial subdivisions are at low local weather related risk since they are designed as underground supply areas. They are impacted by damage to upstream plant that is vulnerable to severe weather events. Some subdivisions are supplied by overhead distribution lines.

Due to cost concerns, industry undergrounding hardening measures have ranged from a "going forward" approach to undergrounding new construction and only undergrounding existing construction when plant is to be replaced or relocated to selectively undergrounding portions of the overhead system (strategic undergrounding). Others have taken positions on the maximum number of circuits that will be allowed on overhead facilities (e.g. 2 circuits) and as such adopted a fixed "line-in-the-sand" beyond which underground facilities are utilized. Positions such as requiring all new service connections to be underground, would mitigate the impacts (i.e. downed service conductors, standpipes ripped off buildings, etc.) that were seen during the 2013 ice storm.

Fixing a limit to the amount of overhead circuits on a poleline has merit from a risk perspective, aesthetic perspective and restoration perspective. An underground 2 circuit system has the potential to backup a parallel 2 circuit overhead supplied area in the event of catastrophic damage to the overhead system. Appropriate interconnections with the supply area would be required. There are approximately 1200 poles of 27.6 kV 4-circuit in the system which equates to approximately 49 km of 27.6 kV 4-circuit poleline. Converting the top 2 circuits to a parallel underground supply would be in the order of $157M. A side benefit of this would be that the remaining two overhead circuits would likely be retroactively “hardened” as a result of the original design. This should be considered as adding “value” to offset the undergrounding cost. For example, an analysis of the 4-circuit pole line on Warden that collapsed in the wind burst indicated that it had been designed to withstand a 104kmh wind. By removing the top two circuits and leaving everything else in place, the 2-circuit poleline could have withstood a 152km/h wind (a 46% improvement in relative strength). The rebuild cost for the Warden poleline was approximately $520,000 – approximately $43.3k per pole.

Undergrounding the entire distribution system is an option but it is very expensive. A previous high-level analysis by PowerStream estimated a cost of $4.5 billion to underground the entire system.

Strategic undergrounding (converting existing high value overhead lines to underground) is generally targeted to improve the security of supply of critical facilities (i.e. hospitals, water pumping station, etc.). Generally these facilities tend to be prioritized for restoration in most utility emergency response plans. It also can be directed to specific sections of overhead line that are vulnerable to severe weather situations (i.e. north/south lines in open areas). Strategic undergrounding can also take advantages of opportunistic synergies, such as road widenings, bridge building/rebuilding, etc. to incorporate new underground facilities in a cost effective manner.

5.3.3 PowerStream area assessment

PowerStream North in Barrie - The 44 kV distribution system egresses from HONI owned Barrie TS and Midhurst TS. The normal limit is 2 x 44kV circuits on a pole line. The exception is in the vicinity of Midhurst TS where egress congestion has resulted in 3 x 44kV circuits on poles for some distance (Anne St. North). At times this circuitry congestion can be even more pronounced with additional underbuild circuits as well (i.e. 13.8 kV underbuild with 44 kV circuits above). Double circuit 44 kV polelines can be found on around a dozen other roads mostly in short sections. The 44 kV system supplies the 13.8 kV MSs and approximately 80 customer substations.

PowerStream North in Barrie - The 13.8kV distribution system is a mix of overhead and underground. In most cases the overhead 13.8 kV is limited to single circuits, sometimes as underbuild to overhead 44 kV circuits, with 2 circuit exceptions on portions of Essa Rd., Big Bay Point Rd., Bayview Avenue, Yonge St. and Mapleview Ave.

PowerStream North in Barrie - The 4 kV distribution system is a mostly overhead system, with some underground, primarily serving Barrie's inner core, including the downtown area. The number of customers and load served by 4kV infrastructure is relatively low compared to 13.8 kV and 44 kV facilities.

PowerStream South in Aurora – The 44 kV and 13.8 kV overhead system share most main arterial polelines with mainly a single 44 kV feeder with one or two 13.8 kV feeders as underbuild. Bathurst St., Bayview Avenue and Leslie St., all north-south roads, have the highest circuit density on the poles.

PowerStream South – The 27.6 kV system services in Vaughan, Richmond Hill and Markham. There are some minor residual MS 8 kV facilities in Vaughan and Markham but these lines service less than 5% of total load so are somewhat inconsequential with respect to the benefits of strategic undergrounding. Most of the 27.6 kV overhead system interconnects at various points except for some radial spurs in the rural areas of the three municipalities. There is approximately 49 km of 27.6 kV four circuit poleline present along major arterial streets and near station feeder egress points. Most newer residential and commercial subdivisions are underground. In general, underground lines have a better reliability record with respect to weather events, vegetation and animal contact and vehicular related damage. Underground faults tend to be permanent, unlike most overhead momentary faults, and can take more time to repair after identification of the fault location. Underground assets also present a significant cost liability when end of life is reached such as the cost to replace an entire underground subdivision. If equipment is located underground (i.e. transformers in vaults) then flooding becomes a new hazard that needs to be considered in planning, design and operations.

There are a number of approaches to "strategically" underground portions of the distribution system. One utility plans to underground areas prone to vegetation outages, another will focus on undergrounding from the station to "critical" facilities (as it defines them) while another will underground multi-circuit poles with high weather exposure.

For PowerStream, the best approach is seen to “strategically” underground portions of overhead lines to reduce 4 circuit poleline exposure to severe weather. Reducing 4 circuit pole lines to 2 circuit polelines would reduce the load and infrastructure at risk of severe weather. The undergrounded circuits would be able, in most cases, to backup the remaining overhead circuits in the event of severe weather problems. This has implications for past and future plant as going forward, approximately 52 km of new 4 circuit poleline is planned to be added over the next 10 year period.

5.3.4 Summary of good utility practice in Undergrounding

- Undergrounding is chosen where overhead supply options are not possible, or where funded by a third party, demonstrating good financial consideration of undergrounding impacts on ratepayers.
- Where implemented, direct buried cable in duct, emphasizing low relative installation cost and high values of reliability, has been the method of choice.

5.3.5 Potential Practice Adaptations

In reviewing PowerStream’s practices for undergrounding, there are a number of initiatives that PowerStream should consider adopting:

1. Consider adopting a proactive strategy for new or upgraded service connections that require them to be underground.
2. Consider adopting a limit of 2 circuits (13.8 kV / 27.6 kV / 44 kV) per pole line. Utilize parallel underground construction for excess circuitry with appropriate interconnection nodes that back up overhead supplied areas.
3. Consider undergrounding the entire distribution system.
4. Consider undergrounding station egress cables to distribution points that result in connections to 2 circuit overhead lines (as opposed to 3 or 4 circuit lines immediately outside stations).
5. Consider taking advantage of opportunities to underground critical points/areas on the distribution system in conjunction with road relocation work and new/rebuilt bridge crossings over major highways.

5.4 STANDARDS

5.4.1 Background

PowerStream has developed its own underground and overhead construction standards. Overhead construction standards cover framing and associated material for infrastructure on poles at all voltage levels. Underground construction standards cover installations of underground and grade level plant. Standards provide for common material and construction assemblies according to the design of the pole line.

5.4.2 Analysis

PowerStream overhead standards have undergone recent review and consolidation as a result of the Barrie merger. All internal staff interviewed consider the overhead standards to be in excellent condition. The standards have been set up to accommodate pole construction utilizing anywhere from Class 2 to Class H3 western red cedar wood poles. There is no standard for composite or concrete poles. PowerStream's Standards Committee is currently looking into pros/cons for the use of composite, concrete, ductile iron, steel and wood poles.

Use of alternatives to wood poles constitutes a "one-time" custom designed installation and material specified for a particular job.

Composite poles have been piloted in the past (Bayview Avenue) with satisfactory results. Compared to wood poles, composite poles are lighter, stronger and have lower conductive properties and are more fire resistant. They are not as vulnerable to rot and insect damage as wood poles are. They also do not lose strength as they age, so require minimal maintenance and inspection needs. This could be an operating savings worth exploring. Composite poles are designed to withstand heavy winds loads and impacts. Guying needs are reduced or eliminated through design and pole selection. Being hollow, composite poles also have a strategic advantage of being able to house the pole ground wire (theft mitigation) and large diameter poles may even be able to house communication related infrastructure. Modular nature of some composite pole products allows for a range of pole lengths and strengths to be made from discrete individual pole sections. The key drawback to use of composite poles at the distribution level has been the initial upfront cost which can be up to double the cost of a traditional wood pole. Overall lifecycle cost (no testing, longer life) mitigates this impact.

PowerStream utilizes 15 kV insulators for 13.8 kV circuits and 46 kV insulators for 27.6 kV circuits and 44 kV circuits. Overinsulation is considered a key mitigation strategy to reducing pole fires. PowerStream has adopted this strategy at the 27.6 kV level. The 13.8 kV and 44 kV construction does not mitigate pole fires in this area, however the incidences of pole fires at these voltage levels has been historically low so mitigation pressures are low as well.

Other strategies to mitigate pole fires include the elimination of wood crossarms and installation of high-resistance ground wire. PowerStream has not eliminated the use of crossarms but has standardized on fiberglass crossarms. Fiberglass crossarms are superior to wood crossarms in life, mechanical strength, insulation resistance and resistance to contamination. They are considered to provide superior protection against pole fires versus wooden crossarms.

PowerStream overhead standards are based on CSA Overhead Standard “heavy” weather loading on conductors which equates to a 12.5mm radial thickness of ice. Severe ice accumulation beyond the loading limit can cause significant loss to conductors and poles. Pole loss is more problematical and time-consuming to replace. In the 1998 Ice Storm, 80% of Hydro Quebec’s time to repair the distribution system was spent on pole replacement. Strategies to mitigate the loss of poles due to ice accumulation include controlled failure strategies where under certain conditions, crossarms, holding brackets and conductor detaches from the pole minimizing pole failure. The application of this strategy has to be reviewed to determine if it will work with multiple circuit pole structures and with public safety considerations in mind.

Overhead secondary service standards cover the basic material and connection arrangement from the utility pole to the customer’s overhead service stack. Standards incorporating breakaway connectors would serve to harden this part of the distribution system and mitigate vegetation damage to customer’s equipment.

Underground standards are focused on infrastructure associated with grade level installations (padmount and vault infrastructure). Trenching and conduit is well detailed. There is little detail on subsurface infrastructure for below grade equipment limited to cable chamber racking. Precast cable chambers have been used on a customized basis. With increasing interest in moving to subsurface installations (aesthetic reasons, space, weather, etc.) detailed standards and material for constructing cable chambers and underground vaults is warranted. Standards should incorporate operational and drainage requirements (clearances to operate/work, connections to sewers, backwater valves, sumps, etc.).

5.4.3 Summary of good utility practice in Standards

- PowerStream has a complete and comprehensive set of overhead construction standards that adhere to CSA and ESA Regulation 22/04 requirements.

- PowerStream's underground construction standards meet their current needs and adhere to CSA and ESA Regulation 22/04 requirements.
- PowerStream is actively studying alternatives to wood poles that will meet design, assembly and operational needs.

5.4.4 Potential Practice Adaptations

In reviewing PowerStream's practices for Standards, there are a number of initiatives that PowerStream should consider adopting:

1. Consider developing standards for the use of composite poles as an alternative to wood poles.
2. Consider using breakaway overhead connectors at the utility pole to mitigate limb damage to customer overhead service entrance equipment.
3. Consider using controlled failure mechanisms, similar to those developed by Hydro-Quebec, for new and existing infrastructure. The controlled failure mechanisms on the Hydro-Quebec overhead distribution network prevent cascade failure of overhead pole lines in case of excessive ice loads. For crossarm pole strucutres, the sequence of controlled failure begins with the rupture of the crossarms on designated dead-end structures, followed by the controlled failure of all tie wires holding the conductors on the inline crossarm structures, and finally by the failure of the crossarms themselves on the inline poles, with the objective of preventing cascading failure of poles and anchors. To implement the same controlled failure mechanism on the PowerStream network, PowerStream would need to review their current standards, material and design practices. For designated dead-end crossarms to fail, PowerStream would have to determine the crossarm stress limits that would result in breakage under a certain ice load. For the inline poles structures, PowerStream's current arrangement of armless stand-off brackets with clamp line post insulators would need to be reviewed. For the controlled failure mechanisms to work here, PowerStream would have to research and review current design practices and material mechanical failure limits to ensure creating weak points of failure so that the conductor could detach itself from the insulators or that the insulator could break or detach itself from the standoff bracket should the ice loads exceed design criteria. With the new controlled failure system, the conductor will fall to ground without bringing down associated poles and anchors.
4. Consider the creation of standards covering cable chamber and vault construction to deal with drainage and operational needs.

5.5 DESIGN

5.5.1 Background

PowerStream's design practices have been developed in consideration of maintaining "good utility practice" as described in the OEB's Distribution System Code (DSC). The DSC defines "good utility practice" means any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry in North America during the relevant time period, as applied to electricity distribution facilities of similar design, size and capacity to the facilities of PowerStream or any of the practices, methods and acts which, in the exercise of reasonable judgement in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good practices, reliability, safety and expedition. Good utility practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in North America.

Design practices are documented in PowerStream's comprehensive Distribution Design Manual. The Distribution Design Manual is issued to assist Distribution Design Technicians and Service Layout Technicians in the technical matters of design, construction and maintenance. There manual covers four principle design areas:

1. Capital Design
2. Residential and Industrial & Commercial Subdivision Design
3. Industrial & Commercial Service Design
4. Service Layout Design

OH construction conforms to the standards detailed in C.S.A. – C22.3 OH Systems (2010).

UG construction conforms to the standards detailed in C.S.A. – C22.3 No. 7-10 (2010).

Station design conforms to relevant CSA, IEEE and ANSI standards.

Other documents that guide the design practices in terms of construction, system configuration and operation are:

- PowerStream Overhead and Underground Standards
- PowerStream Planning Philosophy
- PowerStream Distribution Automation Strategy

- PowerStream Asset Condition Assessment information
- PowerStream Policies and Procedures
- Engineering Planning 5 Year Capital Plan

5.5.2 Analysis

PowerStream relies on overhead construction design for most of its distribution system that is located on arterial roads. This has resulted in overhead pole assemblies consisting of up to 4 circuits in certain areas. New residential and commercial/industrial subdivisions tend to be supplied via underground facilities as a result of the design requirements put upon the developer by the local municipality. Single unit site plan installations can be supplied underground or overhead depending on the local infrastructure that is in place at the time. There are approximately 3500 legacy residential rear-lot fed services and 32,300 front lot fed overhead services.

From a weather sensitivity perspective, the underground supplied subdivisions are “weather hardened” but as they are fed from the overhead supply system on arterial roads, their “reliability of supply” is linked to the performance of overhead plant that can be subject to adverse weather conditions.

PowerStream relies almost exclusively on the use of Western Red Cedar poles for typical overhead pole line design. Other pole types have been used in the past by predecessor utilities (i.e. concrete in Richmond Hill) or through pilot projects (i.e. composite poles on Bayview Avenue). Composite poles offer advantages over wood poles in terms of consistency of production (known strength), non-biodegradable, and resistance to pole fires. Installations of non-wood poles is done on a case by case basis and requires close coordination with the Standards group.

In general, PowerStream’s overhead poleline designs meet the CSA Grade 2 construction requirements except where Grade 1 construction is required per CSA Standard (i.e. rail crossing). In designing the poleline the minimum class of pole required to achieve minimum pole height is used as a starting point. In some cases this can vary from a Class 2 to class H3 pole (e.g. 75’ pole). Pole loading calculations are performed and can be satisfied through pole size modification and/or guying. Storm guying is focused on north-south lines in “unsheltered” areas. There are no storm guying consideration for east-west lines. Poles with expensive equipment (i.e. LIS) are also storm guyed. Storm guying helps strengthen the pole against wind related failure but once failure occurs, it will not protect against cascading failure (i.e. Warden Avenue pole line failure). Periodic in-line guying (i.e. periodic dead-end guying) is not normally considered in pole line design. Grade 1 construction utilizes higher loading factors in calculating assumed loads thereby providing a higher safety factor taking into account uncertainties in loading conditions and strength of materials. Under non-linear analysis, minimum load factors are based on the coefficient of variation (COV), for the given pole material as verified by the manufacturer.

Weather loading of structures is based on the CSA – C22.3 “Heavy” designation. This is deemed appropriate for PowerStream’s service area. The key defining criteria for “Heavy” weather are:

- Radial thickness of ice, mm = 12.5 mm (25mm overall)
- Horizontal wind loading, N/m2 = 400
- Temperature = –20°C

It should be noted that the only difference between “Heavy” and “Severe”, the highest CSA weather loading category is a radial ice thickness of 19 mm (38 mm overall). Climate change projections for the PowerStream area while indicating slightly higher probabilities of freezing rain in certain months, increased storm intensity in summer months, potential 10% increase in wind intensity, do not direct a move to the “severe” weather loading criteria. Figure 14 from CSA Standard Overhead Systems C22.3 No. 1-10, maps the current weather loading classifications for the various regions of Canada. Southern Ontario is considered a “Heavy” loading area based on past historical records.

FIG 14. WEATHER LOADING MAP

PowerStream is in the process of reinforcing all pole crossings of restricted access highways. Existing wood pole structures, that age and lose strength over time, will be replaced by concrete or steel or composite poles to ensure Grade 1 construction standards continue to be met. Going to large and stronger pole classes will also increase the “footprint “of the installed pole which may have some aesthetic impact.

PowerStream is moving from linear design methods for wood pole structures to geometric non-linear design. It is expected that geometric non-linear design will become the sole method for design of wood pole structures in the next release of the CSA – C22.3 OH Systems standard that is expected sometime in 2015. PowerStream is piloting use of the Schneider Overhead Design Analysis (OHDA) software for pole structure design. This product allows for the importation of data from ESRI Designer GIS thereby acting as an extension of the Designer tool with access to the additional functionality present in the Designer tool. Discussions with PowerStream staff have indicated that the OHDA's finite element calculations are currently linear which means that changes would be required to continue to use this product for non-linear analysis. PowerStream staff is working with the vendor to adapt the product for non-linear analysis.

Existing pole structures are managed through PowerStream’s Asset Management practices. Poles are periodically inspected and any that test for < 60% of initial design strength (per C22.3 No. 1-10 section 8.3.1.3) are scheduled for replacement to bring the pole structure back up to original design strength.

Network configuration, capacity utilization, switching/sectionalizing and distribution automation criteria are specified in the various planning documents.

PowerStream station design tends to be customizable based on location, lot shape/composition and feeder egress capability. Stations are designed to relevant CSA, IEEE and ANSI standards/specifications.

Past transformer station designs have allowed for some electronic components (i.e. battery chargers) to be placed in locations (basements) that could be at risk due to localized severe weather flooding. (Greenwood TS#1 and #2 are just east of a flood risk area) There is an opportunity to harden the existing transformer station facilities to flooding by relocating sub-grade components to a higher level. Future designs will take this risk into consideration and insure that sub-grade station components are not “water” sensitive. Barrie municipal station facilities are generally above grade so operational risk due to flooding is low.

5.5.3 Summary of good utility practice in Design

- PowerStream constructs overhead facilities by default to Grade 2 Construction requirements and to Grade 1 requirements where specified by CSA – C22.3.
- PowerStream calculates weather loading as per the "heavy" criteria in CSA – C22.3.
- PowerStream is adopting non-linear analysis techniques for analysis of its pole structures.
- PowerStream has created a comprehensive Design Manual to guide technicians in the technical matters of design, construction and maintenance of the distribution system.
- Poles are periodically inspected and replaced when strength reduces to 60% initial design
- Station designs to ensure flood impactive equipment is above grade.

5.5.4 Potential Practice Adaptations

In reviewing PowerStream's practices for Design, there are a number of initiatives that PowerStream should consider adopting:

1. Consider installing periodic ground anchors in the direction of the line in long straight sections to act as dead-end structures (i.e. HQ uses every 10 poles)
2. Consider adapting designs to be able to withstand wind gusts of up to 120 km/h in strategic locations (rail and highway crossings, station egress riser poles, 4 circuit poles at corners of major intersections, corner poles, dead end poles, 407 ramp poles, other locations deemed critical by PowerStream) and that require a minimum of guying.
3. Consider having poles containing 2 or more primary circuits to be designed to Grade 1 construction standards (Safety factor = 2.0). This is the standard practice in major utilities such as Hydro Quebec, BC Hydro and ATCO.
4. Consider using non-wood poles for 3 or more primary circuits based on the advantages previously mentioned and the increased load at risk
5. Consider a 70% strength replacement target for Grade 1 construction.
6. Consider moving existing flood sensitive equipment above grade in existing stations.

5.6 SYSTEM CONFIGURATION AND PROTECTION PRACTICES

5.6.1 Background

PowerStream currently owns and operates eleven DESN Transformer Stations in the south service area. These Stations are supplied from 230 kV Hydro One transmission circuits. They step the voltage down to the 28kV distribution level. Each station typically consists of 8 to 12 feeders, supplying a combination of three phase and single-phase loads. In the Aurora and Barrie areas, power is supplied from Hydro One transformer stations that step the voltage down to the 44 kV distribution level. The 44 kV feeders in turn supply PowerStream owned Municipal Stations that step the voltage down to 27.6 kV, 13.8 kV, 8.32 kV and 4.16 kV voltage levels that comprises most of the distribution system infrastructure.

5.6.2 Analysis

(i) Configuration

PowerStream's network configuration and planning criteria have a major impact on reliability of supply to customer load. PowerStream's distribution grid is configured in an open grid arrangement. This method of supply has multiple primary feeders (13.8 kV, 27.6 kV, 44 kV) traversing the distribution area with multiple interconnections between the feeders at various points. In the event of a fault on a feeder or loss of supply to a particular feeder, adjacent feeders could pick up supply to customers, except for those customers in the faulted area. The ability of adjacent feeders to pick up load is limited by the preloaded state, the quantity of feeder ties and spare capacity available. In a sense, on the primary side of the distribution system, most customers are implicitly connected to a "loop" type supply where they can be fed from an alternate feeder source if the primary feeder source is affected. Some customers have only one point of primary feeder supply and as such they are considered to have a "radial" supply. If elements of this supply are affected there is no contingency backup and they have to wait for repairs to be made to have power restored. Closing the "loop" in these situations would mitigate this.

There is also increasing amounts of Distributed Generation being connected to the distribution system. This could represent future potential alternate supplies subject to standards related to DG islanding.

The standard overhead conductors installed at PowerStream are 556 kcmil Aluminum. The ampacity of this overhead conductor at 30˚C is about 777 Amps or approximately 37 MVA (27.6 kV) / 60 MVA (44 kV). Normal maximum load for this size of conductor is 600 Amps and Normal planning loading is 400 Amps or 20MVA (27.6 kV) / 30 MVA (44kV) to allow for contingency switching.

Four circuit pole lines are common throughout PowerStream's South service area (27.6 kV). Loss of a pole (weather, vehicle hit etc.) would result in the loss of four circuits and possibly 60 to 80 MW of load. Depending on the site specific location of the affected pole(s), certain customers could expect an outage of 8 to 12 hours while the repairs are taking place. The recent June 17, 2014 pole line collapse on Warden Avenue, due to a microburst, resulted in a 46 hour interruption to the customers in the affected area.

In the Barrie area, the normal limit is 2 x 44 kV circuits on a pole line. The exception is in the vicinity of Midhurst TS where egress congestion has resulted in 3 x 44 kV circuits on poles for some distance (Anne St. North). At times this circuitry congestion can be even more pronounced with additional underbuild circuits as well (i.e. 13.8 kV underbuild with 44 kV circuits above).

Underground residential subdivisions are fed via a "loop" supply with a normally open point at one of the transformers in the middle of the underground feeder. Commercial/Industrial underground subdivisions are also fed via a "loop" supply.

The current feeder configuration will be improved by increased feeder segmentation and load transferability between feeders based on guidelines in PowerStream's recently published Distribution Automation strategy. Feeders will be divided into 3 segments (2.5 switching points per feeder, including a tie switch between feeders) that, together with installation of reclosers and motorized switches, will improve flexibility for operators and line crews to deal with contingency situations. PowerStream has piloted Automated Feeder Restoration (AFR) and Fault Detection Isolation and Recovery (FDIR) schemes for enhanced outage management capabilities.

(ii) Protection

PowerStream's Protection standards are ably described the Feeder Protection Standard - PS-STD-PF-01. The information below is based on a review of this document.

Most of the protection settings at the stations and along the distribution feeders have been set up for an overhead supply system. The general overhead protection philosophy basics are:

1. Treat all faults initially as temporary.

2. Circuit breaker/recloser lockouts should only occur when it has been determined that a fault is permanent. All PowerStream feeders are permitted to perform a single shot reclose attempt. Feeders that are predominately underground (80% or more) will not attempt a reclose.
3. The smallest possible portion of line should be removed from service in the case of a fault.
4. The fault should be cleared as quickly as possible to minimize hazard to the public, damage to equipment and to minimize the impact on power quality

PowerStream has implemented two feeder protection philosophies: “trip saving” and “fuse saving” depending on location.

A “trip saving” protection scheme allows the feeder breaker to clear transient and permanent faults on the feeder. Faults on the load side of lateral fuses are cleared by the associated lateral fuse. Trip saving is typically applied on Urban feeders in PowerStream South where:

- Service response times are much shorter for replacing fuses.
- The majority of the distribution conductors on the load side of the lateral fuses are underground.
- Faults on underground conductors tend to be permanent, not transient.
- Typically protections of underground feeders do not incorporate a reclosing scheme because underground faults are nearly always permanent. It is recommended that feeders which are 80% or more underground not be permitted to reclose.
- It is preferable to clear the lateral fuses in order to avoid momentary interruptions to all the customers on the feeder.

A “fuse saving” protection scheme allows the feeder breaker to clear non-permanent faults on the entire feeder without blowing sectionalizing fuses. Fuse saving is typically applied on rural feeders in PowerStream North where the majority of service lines are overhead and the service response times are much greater for replacing fuses.

Both schemes are designed to maximize the efficient coordination of protective devices to minimize overall outage time and reliability impacts to customers. Fuses need to be coordinated downstream from the first protective device (i.e. station circuit breaker or recloser) to ensure proper operation and alignment with the protection scheme for the specific feeder. In this sense each feeder needs to be analysed from beginning to end to ensure all protective devices coordinate properly.

Typical source of faults on the distribution system are:

- Tree contact (vegetation growth or falling limbs)
- Animal contacts (squirrels, racoons, etc.)
- Failed equipment (transformers, switchgear, etc.)
- Foreign interference (cars hitting poles or padmounted equipment)
- Weather and environmental sources (storms, ice, salt contamination, etc.)

From a storm hardening perspective, the protection standards are adequate and sufficient as long as the actual field installations of fuses and settings follow the protection philosophy. Misapplication of protective devices can result in nuisance operations and increased outage and restoration times (i.e. two 65k fuses in series will not coordinate).

In a storm situation there would be a heightened concern for multiple downed conductors and public safety, especially due to teardown effects of tree/tree limbs on poles and circuits. High-impedence faults due to downed conductors can be in the very low range (i.e. 10 – 100 amps) and may not be seen by low-set overcurrent protection. PowerStream's SEL 451 feeder protection relays have high-impedence fault protection built in. Enabling the SEL 451 relay High-Impedence fault protection mitigates the problems caused by downed conductors. This feature has been enabled in stations equipped with the SEL 451 relay.

This feature should also be enabled in the SEL 651R field relays paired with reclosers as part of the AFR scheme where deemed appropriate.

This feature is not present in the SEL 351 relays used with MS protection mostly in the Barrie service area. Protection is limited to Low Set overcurrent settings on the SEL 351 relays. Low set protection operates if there is sufficient current and is designed for equipment protection versus high impedence protection designed for safety and fire issues.

5.6.3 Summary of good utility practice in System Configuration and Protection

- Feeder grid arrangement provides for alternate methods to route supply in event of a contingency
- Fault sensing, sectionalizing switches and distribution automation allows for rapid isolation of impacted area and rapid restoration of customers outside of affected area

- Stations equipped with SEL 451 relays have had high impedence fault protection enabled. PowerStream has a program to replace existing TS feeder protection relays with new SEL 451 relays with high impedence fault protection enabled.

5.6.4 Potential Practice Adaptations

In reviewing PowerStream's practices for System Configuration and Protection, there are a number of initiatives that PowerStream should consider adopting:

1. Consider identifying and implementing opportunities for closing the "loop" on "radials" based on loading criteria in the Urban Design Issues report.
2. Consider reviewing all PowerStream feeders for protection coordination. Redundant, inexistent or misapplied protective devices should be identified and dealt with to suit the protection scheme applicable for the respective feeder.
3. Consider enabling high impedence fault detection in existing devices (i.e. SEL 651 relays) where appropriate
4. Consider incorporating high impedence fault detection at the MS level when and where appropriate.

5.7 THIRD PARTY AND CUSTOMER PRACTICES

5.7.1 Background

PowerStream interacts with a number of third parties in its day to day operations. A listing of third partys and perceived areas of interaction and interest with respect to weather related plant issues are shown in Table 7.

Third Party	Third Party Interactions	Third Party Interests	Third Party Perception of Weather related risks
PowerStream non-operations staff	Provide operations support as required	Assist with restoration activities	Limited ability to assist; loss of normal functionality
Residential Customer	Vegetation on private property; access issues	Reliable supply; aesthetics; get power on as soon as possible	Supply/reliability shortfalls; multiday outages
Small Commercial	Vegetation on private property; access issues	Reliable supply; get power on as soon as possible	Supply/reliability shortfalls; multiday outages
Large Commercial/Industrial	Vegetation on private property; access issues	Reliable supply; get power on as soon as possible	Supply/reliability shortfalls; multiday outages

Third Party	Third Party Interactions	Third Party Interests	Third Party Perception of Weather related risks
MEARIE	Provide PS with claim insurance	Reliable supply and diligent design of system	Excessive claims or class actions due to perceptions of inadequate design, configuration and maintenance
Cable/Telephone companies	Share facilities on PS poles: PS facilities on some Bell poles	Infrastructure able to withstand severe weather events	PS Infrastructure collapse results in service loss and damage to their plant
External support groups (i.e. forestry, other utilities, etc.)	Assist PS in restoration activities	PS coordination of activities and logistical support	working conditions need to be safe
Suppliers (material, food, lodging)	Provide PS with required logistical needs	PS logistical coordination and timely communication	Loss of logistical capability due to weather
Environment Canada	Provide forecast and real time appraisal of weather conditions; damage predictions	Accurate and timely information to stakeholders	Inaccurate information
Media	Disseminate information on restoration activities to public	Timely and accurate information updates	Inaccurate and/or non-timely information
HONI	Transmission affected by severe weather; distribution feeders and facilities that feed PS affected by severe weather; some PS plant on HONI poles and vice versa	Restoration of infrastructure as soon as possible	Crew/material availability; PS Infrastructure collapse results in service loss and damage to their plant
Municipalities(non-shareholders)	Municipal approvals for lines on road allowance; vegetation planting in vicinity of lines; vegetation control;	General visual aesthetics; healthy and growing tree canopy; reliable supply to customers	Supply/reliability shortfalls affecting their constituents
Municipal services (police, fire, parks, etc.)	Help to maintain public safety; assist with making area safe for PS crews to perform work	Make roads and sidewalks safe as soon as possible; provide emergency facilities for displaced public	Long term damage to infrastructure and public accessibility
Generators	Disconnection from grid upon loss of grid supply	Stable market and ability to connect to distribution system; islanding capability	Long term disruption to generation capability
OEB	Regulatory approval of storm costs to be passed on through rates; approval of storm mitigation plans	Efficient, low cost and reliable market; regulatory compliance	Increasing storm costs to be passed on through rates; political impact

Third Party	Third Party Interactions	Third Party Interests	Third Party Perception of Weather related risks
Provincial Government	Can provide emergency assistance in a major catastrophe; policy with respect to climate change and infrastructure standards	Efficient, low cost and reliable market to stimulate growth and political goodwill	Localized negative political impact
CSA	Overhead and underground utility infrastructure standards	Ensure that standards allow for appropriate grade of construction for local climate conditions	Standards do not ensure that extreme weather events can be withstood
ESA	Permits for customer equipment damaged by weather related event	Public safety is maintained through a weather related situation	Some customer facilities may be energized and in an unsafe condition
OPA	Transmission and regional reliability of supply	Regional planning incorporates climate change planning	System reliability decrease due to changing climate conditions
IESO	**Transmission affected by severe weather;**	**Grid adheres to IESO reliability guidelines; restoration of infrastructure as soon as possible**	Loss of major portions of grid; grid collapse

TABLE 7 – THIRD PARTY INTERACTIONS

Third party activities impact the storm performance of the distribution system before and during storm events. It is important to ensure that third party activities impact positively on the storm performance of the distribution system.

5.7.2 Analysis

Analysis of third party interactions is limited those that deal with hardening the distribution system as opposed to resiliency and other impacts.

Residential, commercial and industrial customers are serviced from PowerStream plant. In some cases, vegetation on customer property can interfere with PowerStream or customer owned plant as a result of a severe weather situation. Access to PowerStream plant on customer property can also be a problem in a severe weather situation. Implementing a “Hazard” tree program as mentioned in the Vegetation section may be able to mitigate some of the issues related to trees on private property. PowerStream like all other Ontario LDCS has the right under the Electricity Act to enter private property to maintain their plant and this would also apply to PowerStream owned service conductor and any related line clearing. Eliminating the need to access

PowerStream plant on private property (i.e. rear-lot feeds) can also mitigate customer impacts on storm response.

Cable and telephone companies often share space on PowerStream poles to run their communication lines. Communication infrastructure is installed in accordance to CSA standards and ESA regulation 22/04. The location and quantity of foreign plant on PowerStream poles is coordinated and controlled by PowerStream. In a severe weather situation, there will be occurrences where lines and poles are brought down due to wind, ice loading or vegetation related mechanical teardown. In this case PowerStream and telecommunication plant is down and in the same vicinity. In general the telecommunication companies wait for PowerStream to rebuild the pole before they come in and re-attach their plant. PowerStream builds and maintains its overhead infrastructure to the "Heavy" grade of construction. It is important for PowerStream to ensure by contract and by inspection that third party poles, on which it has its infrastructure, are also built and maintained to this standard.

Impacts to HONI transmission plant would adversely impact the ability of PowerStream to provide power to its customers. It is important that the transmission infrastructure meets the IESO reliability guidelines for supplying stations that supply PowerStream customers and expected weather conditions in South-Central Ontario. Recent planning studies with HONI, the OPA and IESO have identified actions to be taken by HONI to meet the IESO reliability guidelines. Weather withstand capability should be discussed as part of the planning exercise. Like other third parties, it is important for PowerStream to ensure that HONI plant supplying embedded PowerStream customers is built and maintained to the same standard as PowerStream plant. Redundancy of supply paths to embedded customers should also be pursued.

Municipalities coordinate the placement and type of plant of road allowance (i.e. sewer, water, poles, sidewalks, etc.). They approve PowerStream's plans for plant on road allowance. It is important that other works in the vicinity of PowerStream overhead plant do not negatively impact on the distribution system. A key municipal controlled activity that affects PowerStream overhead plant is the planting of trees on directly under or adjacent to the distribution lines on road allowance. Planting the wrong species of tree can result in future vegetation encroachment problems with the distribution lines. Municipalities are often restrictive in permitting the pruning of the tree canopy. This can also result in future problems due to the teardown impact of limbs in a severe weather situation. PowerStream has started consultations with municipalities with respect to tree planting coordination. This discussion should also extend to tree canopy pruning and "hazard" tree removal on private property that can be assisted through judicious use of municipal by-laws.

The OEB is aware of severe weather impacts on the distribution system. Proactive regulatory engagement with the OEB will help promote the case for spending on storm hardening programs in the future.

The Provincial government sets energy policy. Policy directives could be put in place to provide direction to the OEB and utilities in determining cost recovery for undergrounding existing overhead systems to mitigate climate change impacts.

PowerStream presence on CSA Standards committees and ESA Regulation 22/04 committees will ensure that PowerStream is kept up to date on evolving standards and regulations and that PowerStream strategic interests and represented.

5.7.3 Summary of good utility practice in Third Party interactions

- Vegetation control issues are communicated to PowerStream's customers through its website and other publications.
- PowerStream controls and coordinates third party access to its pole structures.
- Planning studies initiated by PowerStream have identified actions required by HONI to strengthen the transmission system to current IESO reliability guidelines.
- PowerStream has begun discussions with municipalities to coordinate tree planting under or near overhead lines.
- PowerStream maintains strong ties and relationships with OEB staff.

5.7.4 Potential Practice Adaptations

In reviewing PowerStream's practices for Third Party interactions, there are a number of initiatives that PowerStream should consider adopting:

1. Consider ensuring that the conditions of Service are clear on PS ability to enter property to trim overhead secondary lines - see Vegetation Management section.
2. Consider developing a Hazard tree identification and mitigation program for trees on private property – see Vegetation Management section.
3. Consider ensuring joint use agreements with third parties incorporate expected grade of construction and maintenance assurances to withstand severe weather conditions.

6. DISTRIBUTION SYSTEM HARDENING – RECOMMENDATIONS SUMMARY

PowerStream's post-storm review identified 38 areas for review to improve the performance of the system during severe weather events. This report is one of the 38 areas of review.

There are two key concepts related to improving the performance of electrical distribution systems in severe storm situations: hardening and resiliency.

Hardening - physical changes to make particular pieces of infrastructure less susceptible to storm-related damage

Resiliency - increasing the ability to recover quickly from damage to facilities' components or to any of the external systems on which they depend

In order to maintain acceptable levels of safety and reliability of its distribution system, a strategy composed of short, medium and long-term hardening related actions should be implemented as shown in Figure 15.

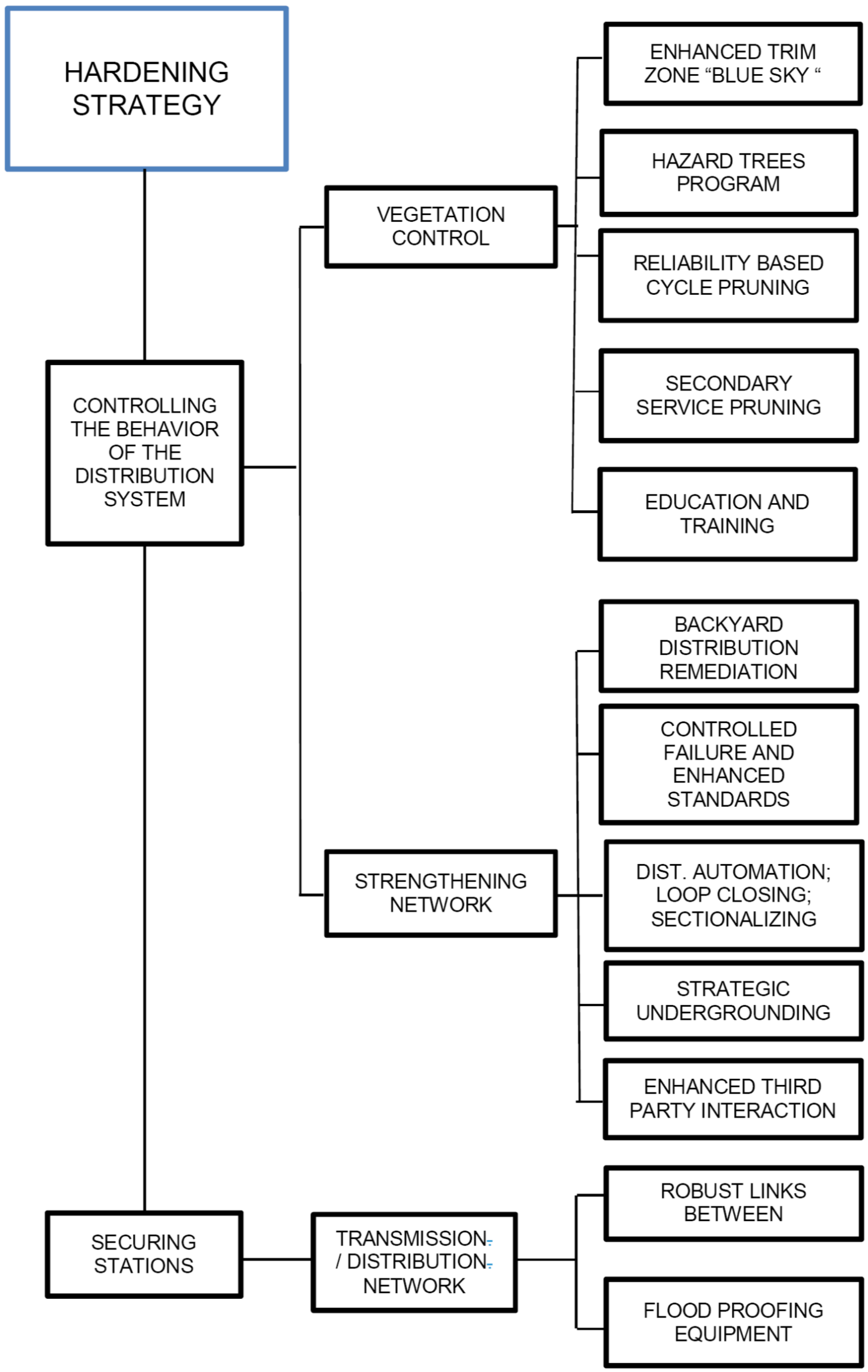

FIG 15. HARDENING STRATEGY

6.1 RECOMMENDATIONS

The report recommendations, for the most part, focus on hardening related matters as defined in Figure 15. These hardening options are discussed in the Controlling the Behaviour of the Distribution System, and Securing Stations sections.

It is understood that a number of the other 37 areas for review focus on resiliency and communication related matters such as emergency plans, mutual aid agreements, emergency generators, customer communications, etc. and as such resiliency related matters are not noted here.

The following recommendations have been derived based on previous information presented in this report related to climate change, best practices in physical hardening and PowerStream's existing practices in the design, configuration and operation of its distribution system. They augment PowerStream's existing good utility practices in distribution design, construction and operation.

Recommendations have been prioritized for implementation, in each of the three hardening categories, based on importance, cost and effectiveness in advancing hardening of the distribution system. Some recommendations involve expenditures that will be capital and others operating. Relative cost and hardening impact assessments (high, medium or low) are also provided. In some cases, a number of recommendations can be acted on concurrently. Some recommendations are presented in multiple options generally dealing with a "going forward" approach or a "legacy remediation" approach.

Where available, unit costs were based on PowerStream information, CIMA+ information, utility equipment supplier information and finally general estimates on perceived effort.

6.1.1 Vegetation control

There are 6 Vegetation control recommendations presented in Table 8. They are listed in order of priority with respect to a combination of cost and impact towards distribution system hardening. They are Operating in nature and would be funded as such.

Item	Option	Hardening Recommendation Description	Units	Program	Cost	Cost level	Impact level
V1		Create enhanced trim zone	total clearance to be 3.5m side;3.5m below; all above	Operating	$5.1M	Medium	High
V2		Incorporate aspects of reliability centered maintenance into the line clearing cycle	N/A	Operating	<$20k	Low	Medium
V3		Hazard tree program	Trees off road allowance	Operating	$100k	Medium	High
V4		Overhead service line clearing	32 300	Operating	$300k	Medium	Medium
V5		Educate stakeholders	N/A	Operating	<$20k	Low	Low
V6		Train design and construction staff	N/A	Operating	<$20k	Low	Low

TABLE 8 – VEGETATION CONTROL RECOMMENDATIONS

6.1.2 Strengthening the Distribution System

There are 18 Strengthening the Distribution System recommendations presented in Table 9. They are listed in order of priority with respect to a combination of cost and impact towards distribution system hardening. A number of recommendations address a common specific hardening action but have alternatives (a or b) that can be selected. In some cases the alternatives are strictly choose “a or b” but not both (i.e. backyard conversion). Other alternatives represent a split in program effort to address past infrastructure, future infrastructure or even both if so desired. This represents an understanding that funding for hardening programs is not unlimited and careful selection of programs and scope is required.

Item	Option	Hardening Recommendation Description	Units	Program	Cost	Cost level	Impact level
S1	a	Hybrid conversion - 5-6 years for pre 1980; address post-1980 in 2024 thru 2029	3589	Capital	$59.5M	High	Medium
		Breakaway connectors	3589	Capital	$1.1M	Medium	Medium
	b	Full conversion - 8 years for pre 1980; address post-1980 in 2024 thru 2029	3589	Capital	$87.4M	High	High
S2		All new or upgraded services underground	+ 400 annually	Capital	<$20k	Low	High
S3		Joint use standards	N/A	Capital	<$20k	Low	Medium
S4		Critical poles designed to handle 120kmh winds	459	Capital	$1.84M	Medium	High
S5		Breakaway connectors	36 100	Capital	$5.4M	Medium	Medium
S6		Periodic in-line anchoring (ie. storm dead end)	every 6 - 10 poles	Capital	$8M	Medium	Medium
S7		Poles with 2 or more primary circuits to Grade 1 construction -consider non-wood material	1200+	Capital	$24M	High	High
S8		70% strength replacement target for Grade 1 construction	As identified per pole testing	Capital	<$50k annually	Low	Medium
S9		Develop composite pole standards	stds book	Capital	<$50k	Low	Medium
S10	a	Controlled failure mechanism	See cost	Capital	+6%	Medium	Medium
	b	Controlled failure mechanism	See cost	Capital	$45k/km	Medium	Medium
S11		Opportunities for closing the "loop" on "radials" should be identified and implemented.	potential locations	Capital	TBD	Medium	Medium
S12	a	Underground station egress cables to 2 circuit riser points - going forward only	800m	Capital	$4M	Medium	Medium
	b	Underground station egress cables to 2 circuit riser points - existing infrastructure	TBD	Capital	$5000/m	Medium	Medium
S13	a	Strategic undergrounding - Limit overhead circuits to maximum of 2 for the key supply voltage in the area	51.7 km future	Capital	$155M	High	Medium
	b	Strategic undergrounding - convert existing 4 circuit poles to 2 circuit poles and 2 circuit underground	49km exist	Capital	$157M	High	High
S14		Strategic Undergrounding - Incorporate ducts in new/refurbished bridge structures or similar critical points	404/400 crossings	Capital	$300/m	Low	High
S15	a	Underground the distribution system – going forward only	120km	Capital	$360M	High	Medium
	b	Underground the distribution system – existing infrastructure	All	Capital	$4,500M	Very High	High
S16		Review and update feeder protection coordination	TS and MS feeders	Capital	$150k	Low	Low
S17		Install and enable High Impedence fault detection where appropriate	5 TS	Capital	$1.5M+	Medium	Low
S18		Cable chamber and vault drainage standards	as required	Capital	$10k/unit	Low	Low

TABLE 9 – STRENGTHENING THE DISTRIBUTION SYSTEM RECOMMENDATIONS

6.1.3 Securing stations – Transmission / Distribution Network

This area covers practices that tend to deal with securing transformer stations with respect to severe storm events. There are 3 Securing stations recommendations presented in Table 10. They are listed in order of priority with respect to a combination of cost and impact towards distribution system hardening. The After-storm management plan requires station inspection after service has been restored to ensure that all station assets are in good operating condition and standards have not been compromised.

Item	Option	Hardening Recommendation Description	Units	Program	Cost	Cost level	Impact level
SS1		Move existing flood sensitive equipment above grade in existing stations.	As per list	Capital	$1.1M	Medium	Medium
SS2		Updates on transmission system capability to withstand severe weather events.	annually	Operating	<$20k	Low	Medium
SS3		After storm management plan	as required	Operating	<$20k	Low	Low

TABLE 10 – SECURING STATIONS RECOMMENDATIONS

A summary graphic of respective option cost and impact assessment is shown in Table 11.

OPTION COST / IMPACT ASSESSMENT				
IMPACT	HIGH	S2; S14	V1; V3 S4;	S1b; ; S7; S13b; S15b*
	MEDIUM	V2; S3; S8; S9; S10 SS2	V4 S5; S6; S10a; S10b; S11; S12a; S12b SS1	S1a; S13a; S15a
	LOW	V5; V6 S16; S18 SS3	S17	
		LOW	MEDIUM	HIGH
		COST		

TABLE 11 – OPTION COST / IMPACT ASSESSMENT

** Very High cost*

In general, programs have been prioritized in the three recommendation sections by their impact on weather hardening the distribution system and relative cost to implement along with information from interviews with PowerStream Executive and staff. Interviews provided useful information on customer feedback received related to severe weather and service reliability expectations; existing asset management programs; and practical experiences in designing, constructing, operating and maintaining distribution infrastructure in PowerStream's service territory.

PowerStream's future pace in hardening the distribution system will be determined by the amount of capital and operating funds available to be allocated to the various programs that PowerStream chooses to pursue. A sample mix of capital program options based on varying levels of fixed annual funding and Table 9 priority position is illustrated in Tables 12 and 13.

Annual Capital funds	Program	Program Cost	Notes
$5M	S1b - full backyard conversion	$87.4M	12 year program ($5M/year) for pre- 1980 plant
	S2 – all new services UG	<$20k	Forward looking policy change to mitigate severe weather impacts on new service connections
	S3 – Joint use standards	<$20k	Ensure third party plant build to common grade of construction (i.e. "Heavy")
$10M	S1b - full backyard conversion	$87.4M	6 year program($10M/year) for pre- 1980 plant
	S2 – all new services UG	<$20k	Forward looking policy change to mitigate severe weather impacts on new service connections
	S3 – Joint use standards	<$20k	Ensure third party plant build to common grade of construction (i.e. "Heavy")
$15M	S1b - full backyard conversion	$87.4M	6 year program($10M/year) for pre- 1980 plant
	S2 – all new services UG	<$20k	Forward looking policy change to mitigate severe weather impacts on new service connections
	S3 – Joint use standards	<$20k	Ensure third party plant build to common grade of construction (i.e. "Heavy")
	S4 – Critical poles to handle 120kmh winds	$1.84M	5 year program($400k/year) for critical poles
	S5 – Breakaway connectors	$5.4M	5 year program - $1.1M/year to install breakaway connectors on overhead service conductors
	S6 – inline storm guying	$8M	5 year program($1.6M/year) focused on N-S critical lines (1000 poles)
	S7 – poles with 2+ circuits to Grade 1	$24M	12 year program ($2M/year)

TABLE 12 – CAPITAL FUNDING AND HARDENING PROGRAM VARIANTS

$5M Program	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12
S1	$5M	$5M	$5M	$5M	$5M	$5M	$5M	$5M	$5M	$5M	$5M	$5M
S2	<$20k	c	c	c	c	c	c	c	c	c	c	c
S3	<$20k	<$20k	<$20k	<$20k	<$20k	<$20k	<$20k	<$20k	<$20k	<$20k	<$20k	<$20k
S4	-	-	-	-	-	-	-	-	-	-	-	-
S5	-	-	-	-	-	-	-	-	-	-	-	-
S6	-	-	-	-	-	-	-	-	-	-	-	-
S7	-	-	-	-	-	-	-	-	-	-	-	-
S8	-	-	-	-	-	-	-	-	-	-	-	-
S9	-	-	-	-	-	-	-	-	-	-	-	-
S10	-	-	-	-	-	-	-	-	-	-	-	-
S11	-	-	-	-	-	-	-	-	-	-	-	-
S12	-	-	-	-	-	-	-	-	-	-	-	-
S13	-	-	-	-	-	-	-	-	-	-	-	-
S14	-	-	-	-	-	-	-	-	-	-	-	-
S15	-	-	-	-	-	-	-	-	-	-	-	-
S16	-	-	-	-	-	-	-	-	-	-	-	-
S17	-	-	-	-	-	-	-	-	-	-	-	-
S18	-	-	-	-	-	-	-	-	-	-	-	-

$10M Program	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12
S1	$10M	$10M	$10M	$10M	$10M	$10M	c	c	c	c	c	c
S2	<$20k	c	c	c	c	c	c	c	c	c	c	c
S3	<$20k	<$20k	<$20k	<$20k	<$20k	<$20k	<$20k	<$20k	<$20k	<$20k	<$20k	<$20k
S4	-	-	-	-	-	-	$400k	$400k	$400k	$400k	$400k	c
S5	-	-	-	-	-	-	$1.1M	$1.1M	$1.1M	$1.1M	$1.1M	c
S6	-	-	-	-	-	-	$1.6M	$1.6M	$1.6M	$1.6M	$1.6M	c
S7	-	-	-	-	-	-	$2M	$2M	$2M	$2M	$2M	$2M
S8	-	-	-	-	-	-	-	-	-	-	-	-
S9	-	-	-	-	-	-	-	-	-	-	-	-
S10	-	-	-	-	-	-	-	-	-	-	-	-
S11	-	-	-	-	-	-	-	-	-	-	-	-
S12	-	-	-	-	-	-	-	-	-	-	-	-
S13	-	-	-	-	-	-	-	-	-	-	-	-
S14	-	-	-	-	-	-	-	-	-	-	-	-
S15	-	-	-	-	-	-	-	-	-	-	-	-
S16	-	-	-	-	-	-	-	-	-	-	-	-
S17	-	-	-	-	-	-	-	-	-	-	-	-
S18	-	-	-	-	-	-	-	-	-	-	-	-

$15M Program	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12
S1	$10M	$10M	$10M	$10M	$10M	$10M	c	c	c	c	c	c
S2	<$20k	c	c	c	c	c	c	c	c	c	c	c
S3	<$20k	<$20k	<$20k	<$20k	<$20k	<$20k	<$20k	<$20k	<$20k	<$20k	<$20k	<$20k
S4	$400k	$400k	$400k	$400k	$400k	c	c	c	c	c	c	c
S5	$1.1M	$1.1M	$1.1M	$1.1M	$1.1M	c	c	c	c	c	c	c
S6	$1.6M	$1.6M	$1.6M	$1.6M	$1.6M	c	c	c	c	c	c	c
S7	$2M	$2M	$2M	$2M	$2M	$2M	$2M	$2M	$2M	$2M	$2M	$2M
S8	-	-	-	-	-	-	-	-	-	-	-	-
S9	-	-	-	-	-	-	-	-	-	-	-	-
S10	-	-	-	-	-	-	-	-	-	-	-	-
S11	-	-	-	-	-	-	-	-	-	-	-	-
S12	-	-	-	-	-	-	-	-	-	-	-	-
S13	-	-	-	-	-	-	-	-	-	-	-	-
S14	-	-	-	-	-	-	-	-	-	-	-	-
S15	-	-	-	-	-	-	-	-	-	-	-	-
S16	-	-	-	-	-	-	-	-	-	-	-	-
S17	-	-	-	-	-	-	-	-	-	-	-	-
S18	-	-	-	-	-	-	-	-	-	-	-	-

Notes: "-" = no funding
"c" = program complete

TABLE 13 – CAPITAL FUNDING AND HARDENING PROGRAM YEARLY PROGRESS

Conclusions

In this report, a number of potential distribution system hardening options have been presented for PowerStream's consideration. It is understood that creating a hardening program requires careful consideration of costs to balance rate impact and hardening program progress. By adopting a balanced rate fundable program of a number of these options, PowerStream will position itself as a company that has understood the impact of climate change on distribution infrastructure and has diligently moved forward to adapting its infrastructure to continue to deliver safe and reliable power.

CIMA+ have confidence that the information provided will enable PowerStream to develop a multi-year portfolio of distribution hardening measures that is rate base fundable and provides value to the customer.

A P P E N D I X A

Questions

Power Stream staff interview questions

1. What does “distribution system hardening” mean to you?
2. What was the role of your area (i.e. design, lines, system control, etc.) in the ice storm preplan and restoration efforts?
3. What were the specific infrastructure impacts caused by the ice storm that stand out to you?
4. Which were the most problematical?
5. Do you feel you had the resources and tools to respond effectively?
6. Do you have any thoughts on current tree trimming practices and what changes would minimize damage and outage response times in a future severe storm situation?
7. Do you have any thoughts on existing backyard construction and what changes would minimize damage and outage response times in a future severe storm situation?
8. Do you have any thoughts on current underground distribution practices and what changes would minimize damage and outage response times in a future severe storm situation?
9. Do you have any thoughts on the current design practices and what changes would minimize damage and outage response times in a future severe storm situation?
10. Do you have any thoughts on the current set of standards and what changes would minimize damage and outage response times in a future severe storm situation?
11. Do you have any thoughts on system configuration, protection and related operating practices and what changes would minimize damage and outage response times in a future severe storm situation?
12. Are there any other suggestions that you think could minimize damage and outage response times in a future severe storm situation?
13. Do you have any thoughts on how external agencies (i.e. ESA) could have aided assisted in the restoration efforts?
14. Do you have any thoughts on how third parties (i.e. cable) helped/hindered restoration efforts?
15. Are there any specific areas of the distribution system that stand out to you as in need of storm hardening efforts?

A P P E N D I X B

Future 4 circuit pole lines – Next 10 years

Future 4 circuit pole lines - next 10 years:

Vaughan	**km**	
4 Ccts on Kirby Sdrd from Kipling to Jane St	6	
4 Ccts on Weston Rd from Kirby to Rutherford	6	
4 Ccts on Teston Rd Ave from Kipling to Jane St	6	
4 Ccts on Kipling Ave from Kirby to Teston Rd	2	
4 Ccts on Jane St from Teston Rd to KVTL	4	
4 Ccts on Jane St from Steeles to Hwy 7	2	
4 Ccts on Jane St from Rutherford to Langstaff Rd	2	
4 Ccts on Steeles from Jane to Keele St	2	
4 Ccts on Hwy 7 from Weston Rd to Jane St	2	
4 Ccts on Major Mack from Pine Valley to Weston Rd	2	
	34	
Markham		
4 ccts on Warden from Hwy 7 to Major Mack Dr	4	
4 Ccts on 14th Ave from Hwy 48 to 9th Line	2	
	6	
Richmond Hill (due to road widening work)		
4 Ccts on Carrville Rd from Bathurst St to Yonge St	2	
4 Ccts on Yonge St from 16th Ave to Major Mack	2	
	4	
Barrie		
4 ccts on Sunnidale from Anne to Ferndale	1.6	
4 ccts on Ferndale from Edgehill to Tiffin	1.5	
4 ccts on Essa from Ferndale to Mapleview	2.2	
4 ccts on Mapleview Drive from Essa to Veterans	1.3	
4 ccts on Big Bay Point Road from Fairview to Bayview	0.5	
4 ccts on Big Bay Point Road from Huronia to Leggott Ave	0.6	
	7.7	
		51.7

APPENDIX C

Strategic Undergrounding

Strategic Undergrounding

4 Circuit pole to 2 circuit pole/2 circuit UG conversion schedule

Cost to convert: $3.2M/km

Priority	Municipality	Street	From/To	Line Orientation	Circuits	Avg. Pole Strength	KM	Project Cost($M)	Notes
1	Vaughan	Centre St.	Bathurst to Dufferin St.	East-West	4 x 27.6kV	83%	2.1	$6.72	Commercial/Residential - aesthetics - high rise
2	Vaughan	ROW	Greenwood TS to Centre St	North-South	8 x 27.6kV (2)	N/A	0.5	$1.60	VTS1/1EStation egress - no public exposure
3	Vaughan	Weston Rd.	Hwy #7 to Langstaff Rd	North-South	4 x 27.6kV	94%	3.2	$10.24	High density commercial
4	Richmond Hill	Hwy#7	Silver Linden to 404	East-West	4 x 27.6kV	82%	2.5	$8.00	High density commercial - VIVA
5	Vaughan	Major Mackenzie Drive	Weston Rd to Jane St	East-West	4 x 27.6kV	N/A	2.1	$6.72	400 crossing/Wonderland - hospital(?)
6	Vaughan	Hwy#7	Jane St. To Keele St	East-West	4 x 27.6kV	N/A	2	$6.40	Vaughan City Centre area
7	Vaughan	Dufferin St.	Greenwood TS to Langstaff Rd.	North-South	4 x 27.6kV	96%	1.75	$5.60	407/7 Highway crossing
8	Vaughan	Islington Avenue	Langstaff Rd to Rutherford Rd.	North-South	4 x 27.6kV	N/A	2	$6.40	Residential - aesthetics
9	Vaughan	Bathurst St.	Rutherford Rd. to Hwy#7	North-South	4 x 27.6kV	80%	2.2	$7.04	Residential - aesthetics
10	Markham	Riviera	Roddick to Woodbine	East-West	4 x 27.6kV	N/A	0.7	$2.24	Industrial area
11	Vaughan	Langstaff	Dufferin to Keele	East-West	4 x 27.6kV	N/A	2.2	$7.04	Industrial area
12	Vaughan	Keele	Langstaff Rd to Rutherford Rd.	North-South	4 x 27.6kV	N/A	2.2	$7.04	Commercial/Industrial
13	Vaughan	Jane St.	Hwy #7 to Courtland	North-South	4 x 27.6kV	N/A	2.4	$7.68	Commercial/Industrial
14	Vaughan	Hwy#7	Keele St. to Centre St.	East-West	4 x 27.6kV	N/A	1.8	$5.76	Commercial area
15	Vaughan	Huntington Rd.	Langstaff Rd to Rutherford Rd.	North-South	4 x 27.6kV	88%	2.1	$6.72	Low density residential - exposed
16	Vaughan	Hwy#7	Centre St to Langstaff Rd	East-West	4 x 27.6kv	N/A	1.8	$5.76	Highway parallel
17	Vaughan	Rutherford Rd	Weston Rd to Jane St	East-West	4 x 27.6kV	N/A	2	$6.40	400 crossing/Commercial
18	Vaughan	Rutherford Rd	Huntington Rd to Hwy 27	East-West	4 x 27.6kV	N/A	2	$6.40	Low density residential - VTS3 egress
19	Vaughan	Rutherford Rd	Hwy 27 to Islington Ave.	East-West	4 x 27.6kV	N/A	2.5	$8.00	Winding road/hill - residential
20	Vaughan	Rutherford Rd	Islington Ave. to Weston Rd	East-West	4 x 27.6kV	N/A	3.5	$11.20	low density residential
21	Markham	Woodbine Ave.	16th to Major Mackenzie Dr	North-South	4 x 27.6kV	90%	2.2	$7.04	Residential - aesthetics
22	Markham	Roddick Rd.	14th to Riviera	North-South	4 x 27.6kV	N/A	0.2	$0.64	MTS1 egress - H1/H2
23	Markham	Warden Ave	14th to HONI ROW	North-South	4 x 27.6kV	N/A	0.4	$1.28	Rail crossing/commercial
24	Markham	Warden Ave	14th to N. of Gibson Dr	North-South	4 x 27.6kV	N/A	1.4	$4.48	Commercial area (2013 rebuilt)
25	Markham	Kennedy Rd.	Helen to Hwy 407	North-South	4 x 27.6kV	N/A	0.3	$0.96	MTS3/3E egress - highway
26	Markham	Hwy #7	Cochrane to 404	East-West	4 x 27.6kV	83%	1.8	$5.76	Commercial area - VIVA - H2/H3
27	Markham	Hwy #7	Frontenac to town Centre	East-West	4 x 27.6kV	83%	1.3	$4.16	Commercial area - VIVA - H2/H3
							49.2	$157.28	
			Other						
	Vaughan	Hwy #27	MMD to Langstaff	North-South	2 x 27.6kV; 2 x 8kV	84%	4	$12.80	low density residential
	Vaughan	Keele	Hwy #7 to Administration Rd	North-South	2 x 27.6kV; 2 x 8.32kV	86%	0.3	$0.96	Commercial
	Markham	Woodbine Ave.	Riviera to Denison	North-South	2 x 27.6kV; 2 x 13.8kV	72%	1.8	$5.76	Commercial
	Markham	Bayview Avenue	John to Romfield	North-South	2 x 27.6kV; 1 x 13.8kV; 1 x 8.32kV	78%	2.2	$7.04	Commercial/residential
	Aurora	Leslie St	Wellington to Vandorf	North-South	2 x 44kV; 2 x 13.8kV	N/A	3	$9.60	low density commercial
	Aurora	Bayview Avenue	Ballymore to Stone Rd	North-South	2 x 44kV; 2 x 13.8kV	97%	4.3	$13.76	Commercial/residential
	Aurora	Vandorf	Leslie St. to Engelhard	East-West	2 x 44kV; 2 x 13.8kV	N/A	2.8	$8.96	Residential
	Aurora	St. John Sideroad	Bathurst St. to Bayview Avenue	East-West	2 x 44kV; 2 x 13.8kV	N/A	4.3	$13.76	Commercial/residential
	Barrie	Bayview Avenue	Mapleview Dr. to Big Bay Point Road	North-South	2 x 44kV; 2 x 1	N/A	1.5	$4.80	Commercial/residential - H1
	Barrie	Anne St.	Neelands to Cundles	North-South	3 x 44kV + 1 x	88%	1.2	$3.84	low density rural
	Vaughan	Albion-Vaughan	KVTL to Kirby	North-South	2 x 44kV; 1 x 27.6kV, 1 Unk	N/A	2.5	$8.00	concrete - low density rural
	Vaughan	Kirby	Albion-Vaughan to CPR	East-West	2 x 44kV; 1 x 27.6kV, 1 Unk	N/A	1	$3.20	concrete - low density rural
							78.1	$249.76	
								$252.96	

A P P E N D I X D

Rear Lot Priority List (2015-2029)

Rear Lot Priority List 2015-2029

Year	Location Reference #	Municipality	Year	2014 Age	Project	# of Customers	Project Cost	Option 3 Annual Cost	Option 4 Annual cost
2015	1	Barrie	1958	56	Shirley/ Vine	20	$1,065,718	$6,461,116	$9,492,672
	2	Barrie	1955	59	Blake/ Kempenfelt	21			
	4	Barrie	1968	46	North Park/ Park Dale	40			
	18	Penetanguishene	1975	39	Shannon Rd. at Main St.	11	$178,710		
	15	Penetanguishene	1975	39	Burke/ Country Club	10	$162,464		
	16	Penetanguishene	1968	46	Maria/ Edward	12	$194,957		
	42	Aurora	1968	46	Yonge & Wellington (NW) - Phase 1	69	$2,728,207		
	49	Markham	1962	52	Bayview & Steeles (NE) - Phase 1	191	$2,131,060		
2016	22	Tottenham	1965	49	Queen to Eastern and top of Eastern and Wilson - Phase 1	68	$883,687	$7,259,730	$10,665,996
	3	Barrie	1956	58	Wellington/ Oak	68	$1,392,391		
	42	Aurora	1968	46	Yonge & Wellington (NW) - Phase 2	185	$2,800,809		
	49	Markham	1962	52	Bayview & Steeles (NE) - Phase 2	191	$2,182,843		
2017	22	Tottenham	1965	49	Queen to Eastern and top of Eastern and Wilson - Phase 2	67	$1,117,968	$7,079,690	$10,401,481
	21	Tottenham	1960	54	Frazer Ave. 3 Phase line & Perdue Pl/ Alphonsus Crt.	22			
	27	Tottenham	1968	46	West side of Queen from #146 to Lionel Stone	58	$847,605		
	42	Aurora	1968	46	Younge & Wellington (NW) - Phase 3	185	$2,878,574		
	49	Markham	1962	52	Bayview & Steeles (NE) - Phase 3	191	$2,235,543		
2018	24	Tottenham	1980	34	Queen St. to Adeline Ave. and Rogers to Brown St. North Side - Phase 1	85	$1,144,795	$6,792,096	$9,978,947
	23	Tottenham	1965	49	Queen St. to Keogh St. and Wilson to Dilane St. E - Phase 2	30	$438,416		
	12	Alliston	1955	59	Victoria W. of Downey	8	$1,595,091		
	25	Tottenham	1971	43	North side of Adeline from Rogers to Brown St.	33			
	30	Tottenham	1974	40	Eastern Ave. backing onto railway from Wilson to Park	n/a			
	8	Barrie	1955	59	Marian/ Pratt/ Shannon - Phase 1	93	$1,324,602		
	45	Markham	1964	50	Main St. Unionville & Carlton(SW) - {NW side of Hwy 7/Kennedy} - Phase 1	156	$2,289,192		
2019	24	Tottenham	1980	34	Queen St. to Adeline Ave. and Rogers to Brown St. North Side - Phase 2	46	$1,212,199	$6,647,977	$9,767,207
	29	Tottenham	1968	46	East of Queen from George to Ryan Ln.	27			
	8	Barrie	1955	59	Marian/ Pratt/ Shannon - Phase 2	29	$1,364,340		
	5	Barrie	1957	57	Johnathan/ Bathwell	73			
	9	Barrie	1960	54	Alexander/ Oliver	40	$1,439,536		
	11	Alliston	1950	64	Queen/ Victoria E.	21			
	20	Penetanguishene	1973	41	Tessier at west of Main St.	18			
	19	Penetanguishene	1968	46	Robert St. at Main north side	16			
	28	Tottenham	1973	41	North of Mill St. and South of George and West of Queen	16	$207,926		
	45	Markham	1964	50	Main St. Unionville & Carlton(SW) - {NW side of Hwy 7/Kennedy} - Phase 2	155	$2,423,976		
2020	23	Tottenham	1965	49	Queen St. to Keogh St. and Wilson to Dilane St. E - Phase 1	89	$1,248,565	$6,663,221	$9,789,604
	7	Barrie	1955	59	Gunn/ Oakley Park Sq./ St. Vincent	92	$1,517,313		
	6	Barrie	1968	46	Ottoway Ave.	91	$1,400,647		
	45	Markham	1964	50	Main St. Unionville & Carlton(SW) - {NW side of Hwy 7/Kennedy} - Phase 3	155	$2,496,696		
2021								$0	$0
2022								$0	$0
2023									
2024	47	Markham	1982	32	Hwy 7 & McCowan (SE) - Phase 1	148	$2,956,339	$2,956,339	$4,343,454
2025	47	Markham	1982	32	Hwy 7 & McCowan (SE) - Phase 2	147	$3,034,104	$3,391,525	$4,982,829
	17	Penetanguishene	1988	26	Maria St. near robert St. E	9	$146,218		
	14	Beeton	1989	25	Main W./ Centre N.	13	$211,203		
2026	48	Markham	1994	20	Steeles & Henerson (NE & NW) - {NW Side of Steeles/Bayview} - Phase 1	190	$2,571,596	$2,571,596	$3,778,189
2027	48	Markham	1994	20	Steeles & Henerson (NE & NW) - {NW Side of Steeles/Bayview} - Phase 2	115	$2,648,744	$2,648,744	$3,891,535
2028	13	Alliston	2006	8	Sir Frederick Banting/ Victoria E.	8	$163,810	$3,275,679	$4,812,628
	44	Markham	2006	8	Major Mackenzie & Warden (SW)	63	$3,111,869		
	43	Vaughan	2005	9	Islington & Seville (NE & SE) - {NE Side of Major Mackenzie/ Islington}-Phase 1	114			
2029	26	Tottenham	2010	4	Brown St. from Railway to Queen St.	36	$584,871	$3,774,505	$5,545,503
	43	Vaughan	2005	9	Islington & Seville (NE & SE) - {NE Side of Major Mackenzie/ Islington}-Phase 2	64	$3,189,634		
Program Total:						3589		$59,522,219	$87,450,044

= North Locations
= South Locations

1.4692 Option 4 multiplier

APPENDIX E

Summary of the recommendations

Item	Option	Hardening Recommendation Description	Notes
V1		Create enhanced trim zone	PS existing is 1.0-3.5m side/bottom/top - Con Ed std 5.0m side; 5.0m below; 6.6m above; CLP 2.2 m side; 3.1m below; 5m above. UIC 3.0m side, "blue sky" above. Arborist expertise required. 3x current cost ($1.2M south; $0.5M north)
V2		Incorporate aspects of reliability centered maintenance into the line clearing cycle	SAIFI considerations, expert assessment, etc.
V3		Hazard tree program	Arborist expertise requried; baseline assessment of $100k; periodic review of hazard trees incorporatede as part of 3 year cycle; Remove and replace voucher system
V4		Overhead service line clearing	Limb pruning with customer consultation; 3rd man on truck required; can be done as part of regular 3 year cycle
V5		Educate stakeholders	Hazard tree/storm impact focus
V6		Train design and construction staff	1 or 1/2 day VM training
Item	Option	Hardening Recommendation Description	Notes
S1	a	Hybrid conversion - 5-6 years for pre 1980; address post-1980 in 2024 thru 2029	**See Appendix D**
		Breakaway connectors	install within 3 years; mat = $50/service, labour = $250/service
	b	Full conversion - 8 years for pre 1980; address post-1980 in 2024 thru 2029	**See Appendix D**
S2		All new or upgraded services underground	amend Conditions of Service; increased cost to the customer; regulatory approval
S3		Joint use standards	common grade of construction and maintenance assurances to withstand severe weather conditions
S4		Critical poles designed to handle 120kmh winds	41 highway,239 railway crossings and 179 major intersection (4 circuit poles) - assume 20% to be replaced at $20k/pole
S5		Breakaway connectors	Front and rear overhead; mat = $50/service, labour=$250/service; assume 50% have vegetation issues
S6		Periodic in-line anchoring (ie. storm dead end)	Install periodic ground anchors in the direction of the line in long straight sections to act as storm dead-end structures; assume 1000 poles to retrofit at $8k/pole
S7		Poles with 2 or more primary circuits to Grade 1 construction -consider non-wood material	4 circuit pole count - $20k/pole
S8		70% strength replacement target for Grade 1 construction	Accelerates replacement rate through pole replacement program
S9		Develop composite pole standards	develop composite pole stds from wood pole stds.
S10	a	Controlled failure mechanism	new infrastructure - +6% increase in project cost
	b	Controlled failure mechanism	existing infrastructure - $45k/km to retrofit
S11		Opportunities for closing the "loop" on "radials" should be identified and implemented.	1. Weston - Kirby to KVTL 2. Leslie - N. of Elgin to Stouffville 3. MMD 9th line to Reesor Rd 4. Elgin Rd - Markham locations
S12	a	Underground station egress cables to 2 circuit riser points - going forward only	Vaughan TS4 opportunity; assume $5000/m based on MTS4 figures
	b	Underground station egress cables to 2 circuit riser points - existing infrastructure	Existing TS; assume $5000/m based on MT4 figures
S13	a	Strategic undergrounding - Limit overhead circuits to maximum of 2 for the key supply voltage in the area	10 year forecast - UG 2 circuits @ $3.0M/km (no removal considerations); **See Appendix B**
	b	Strategic undergrounding - convert existing 4 circuit poles to 2 circuit poles and 2 circuit underground	1200 existing 4 circuit poles; 49km of 4 circuit poleline - UG 2 circuits @ $3.2M/km; **See Appendix C**
S14		Strategic Undergrounding - Incorporate ducts in new/refurbished bridge structures or similar critical points	4W2H(8 ducts) - $300/m
S15	a	Underground the distribution system – going forward only	10 year forecast - approx. 40km in the north; approx. 80km in the south.(52km = 4 circuit poleline) - assume $3.0M/km
	b	Underground the distribution system – existing infrastructure	Entire existing distribution system
S16		Review and update feeder protection coordination	3 year program - $50k annually
S17		Install and enable High Impedence fault detection where appropriate	5 TS feeder relays; at MS level where appropriate
S18		Cable chamber and vault drainage standards	permit, storm sewer connection, backwater valve
Item	Option	Hardening Recommendation Description	Notes
SS1		Move existing flood sensitive equipment above grade in existing stations.	battery chargers, battery banks, etc.
SS2		Updates on transmission system capability to withstand severe weather events.	HONI, OPA and IESO consultation
SS3		After storm management plan	Ensure TS and MS facilities are secure

Note: The "a" and "b" designations in the Options column represent alternatives within a specific hardening recommendation(ie. convert just backyard primary to front underground or convert all backyard primary and secondary to front undergound).

Note: Low costs generally assessed as <$1M; Medium cost generally assessed as >$1M and < $10M; High costs generally assessed as > $10M; Very high reserved for complete UG conversion

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REFERENCES

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ENG-P-P013 - Short Circuit Levels Calculations
ENG-P-P014 - Installation of Load Interrupter Switches at Major Intersections
ENG-P-P015 - Process for Designation of Annual Worst Performing Feeders
ENG-P-P016 - Reliability Committee Terms of Reference
ENG-P-P017 - Equipment Failure, Analysis, Reporting and Corrective Action System
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ENG-P-P019 - Pole Inspection and Testing
ENG-P-P020 - Vault Inspection and Maintenance
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Other related

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7880 Keele Street
Suite 201
Vaughan ON L4K 4G7

T. 905 695-1005
F. 905 696-0525

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