Burlington hydro inc.

Appendix C

Needs Assessment Report

Hydro One Networks Inc.
483 Bay Street
Toronto, Ontario
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NEEDS ASSESSMENT REPORT

Region: Burlington to Nanticoke

Date: September 06, 2022

Prepared by: Burlington to Nanticoke Technical Working Group

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Disclaimer

This Needs Assessment Report was prepared for the purpose of identifying potential needs in the Burlington to Nanticoke Region and to recommend which need may be a) directly addressed by developing a preferred plan as part of NA phase and b) identify needs requiring further assessment and/or regional coordination. The results reported in this Needs Assessment are based on the input and information provided by the Technical Working Group (TWG) for this region.

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Executive Summary

REGION Burlington to Nanticoke Region (the "Region")

LEAD Hydro One Networks Inc. ("HONI")

START DATE: MAY 11, 2022 **END DATE:** September 06, 2022

1. INTRODUCTION

The second Regional Planning cycle for the Burlington to Nanticoke Region was completed in October 2019 with the publication of the Regional Infrastructure Plan ("RIP") report. This is the third cycle of Regional Planning for the region.

The purpose of this Needs Assessment ("NA") is to: a) identify any new needs and/or to reaffirm needs identified in the previous Regional Planning cycle; and, b) recommend which needs may be i) addressed by developing a preferred plan as part of the NA phase which do not require further regional coordination and ii) identify needs requiring further assessment and/or regional coordination.

2. REGIONAL ISSUE/TRIGGER

In accordance with the Regional Planning process, the Regional Planning cycle should be triggered at least every five years. Considering these timelines, the 3rd Regional Planning cycle was triggered in May 2022 for the Burlington to Nanticoke Region.

3. SCOPE OF NEEDS ASSESSMENT

The scope of this NA covers the Burlington to Nanticoke Region and includes:

- Review and reaffirm needs/plans identified in the RIP;
- Identify any new needs resulting from this assessment;
- Develop options and recommend a preferred plan for need(s) that do not require further regional coordination; and
- Recommend which need(s) require further assessment/regional coordination in the next phases of the Regional Planning cycle.

The Technical Working Group ("TWG") may also identify additional needs during the next phases of the planning process, namely Scoping Assessment ("SA"), Integrated Regional Resource Plan ("IRRP") and RIP, based on updated information available at that time.

The planning horizon for this NA assessment is 10 years.

4. INPUTS/DATA

The TWG representatives from Local Distribution Companies ("LDC"), the Independent Electricity System Operator ("IESO"), and Hydro One provided input and relevant information for this Region regarding capacity needs, reliability needs, operational issues, and major high-voltage (HV) transmission assets requiring replacement over the planning horizon. The community energy plans will be further evaluated during the next phases of this Regional Planning cycle.

5. ASSESSMENT METHODOLOGY

The assessment's primary objective is to identify the electrical infrastructure needs in the Region over the study period. The assessment methodology includes review of planning information such as load forecast, conservation and demand management ("CDM") forecast, available distributed generation ("DG") forecast information, any system reliability and operation issues, and major HV equipment requiring replacement.

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 HV equipment requiring replacement with consideration to "right-sizing".

6. NEEDS

I. Update of identified needs from previous cycle

The following near- term needs identified in the Burlington to Nanticoke 2nd Cycle RIP report have been addressed/ completed:

1. Cumberland TS: Power factor correction
2. 115 kV B3/B4: Line section from Horning Mountain Jct. to Glanford Jct. requiring refurbishment
3. Elgin TS: Transformers & switchgears requiring replacement (Replacing two DESNs with a single unit)
4. Newton TS: Transformers (T1/T2) requiring replacement
5. Kenilworth TS: Transformer & switchgear requiring replacement (Replacing two DESNs with a single unit)

The status of remaining near-term needs is as follows:

1. 115 kV B7/B8: Line section from Burlington TS to Nelson Jct. requiring refurbishment
   Planned for in-service in 2024
2. Dundas TS (Load transfers/Balancing)
   Planned for in-service in 2023
3. Gage TS: Transformers & switchgear (T3/T4 and T5/T6 DESNs) requiring replacement
   In Execution: Planned in-service in Q4 2023
4. Kenilworth TS: Power factor correction
   Planned for in-service in Q4 2023

5. Norfolk area supply capacity

Near Term:

- Load transfers from Norfolk area to Jarvis TS is planned to be completed by the end of 2022.
- Additional reactive support at Norfolk TS is planned for 2023-24 timeframe.

Mid-Term:

- Upgrade Jarvis TS and build feeders to pick up Norfolk area loads – is planned for 2027-32 timeframe

II. Newly identified needs in the region

a. Line / Station Capacity

The following station capacity needs were identified in the Region:

1. Norfolk TS and Bloomsburg DS (Norfolk Area)

The loads at Norfolk TS and Bloomsburg DS are forecasted to exceed their supply capacities in 2030 and 2025 respectively. The supply capacity needs for these stations will be addressed through load transfers to Jarvis TS by building new feeders to pick Norfolk area loads. The Jarvis TS upgrade and required feeders to pickup Norfolk area loads are currently planned for 2027-2032 timeframe as described above. This need will be further reviewed during the next phases of this Regional Planning cycle.

2. Brant Area Supply

The 115 kV Brant area is supplied by two stations, i.e. Brant TS and Powerline MTS supplied by three 115 kV. Two (2) of the three (3) 115 kV circuits are supplied from Burlington TS and the third from Karn TS. The supply capacity of 115 kV system to Brant area to 165MW.

The coincident load in the 115 kV Brant area system may exceed the LMC of 165 MW before the end of the study period (2022-32). TWG recommends that this potential need be reviewed during the next phases of this Regional Planning cycle.

3. Caledonia TS

The load at Caledonia TS is forecasted to exceed its supply in 2030. The TWG recommended monitoring on the loading at Caledonia TS and to be further reviewed during the next phases of this Regional Planning cycle.

4. Nebo TS

The load at T3/T4 230/ 13.8 kV DESN at Nebo TS had been historically around its supply capacity and is currently forecasted to grow above its supply capacity. The TWG recommended monitoring the loading at this station and take remedial measures, if required. This DESN is planned to be refurbished in the 2027-2032 timeframe replacing existing 75 MVA nonstandard transformers with Hydro One standard 100 MVA units. This will also address the supply capacity need at this station. This need will be further reviewed during the next phases of this Regional Planning cycle.

5. Mohawk TS

The load at Mohawk TS had been historically around its current loading levels however is forecasted to grow and exceed station supply capacity by 2024. The TWG recommended Hydro One and Alectra to monitor loading levels at this station and take necessary actions, if required e.g. load transfers to the neighboring stations. This need will be further reviewed during the next phases of this Regional Planning cycle.

b. Aging Infrastructure Transformer Station and Transmission Circuit Replacements

Based on asset condition assessment, Newton TS 115 kV breakers have been identified for replacement.

7. RECOMMENDATIONS

The TWG recommends to continue with:

- Refurbishment of section of 115 kV B7/B8 line;
- Refurbishment of Gage TS (T3/T4 and T5/T6 DESNs);
- Load transfer from Dundas TS to Dundas TS #2 to address overloading;
- Supply capacity in Norfolk area;
- Power factor correction at Kenilworth TS; and
- Refurbishment need for 115 kV breakers at Newton TS.

The TWG also recommended that the concerned LDC and Hydro One to monitor the loading levels in Norfolk and Brant areas as well at Caledonia TS, Nebo TS and Mohawk TS and take necessary action to address overloading, if required. These needs will be further reviewed during the Scoping Assessment phase of this Regional Planning cycle.

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List of Tables and Figures

1 INTRODUCTION

The second cycle of the Regional Planning process for the Burlington to Nanticoke Region was completed in October 2019 with the publication of the Regional Infrastructure Plan ("RIP") Report.

The purpose of this Needs Assessment ("NA") is to identify new needs and to reconfirm and update any needs identified in the previous Burlington to Nanticoke Regional Planning cycle.

This report was prepared by the Burlington to Nanticoke Region Technical Working Group("TWG"), led by Hydro One Networks Inc. Participants of the TWG 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: Burlington to Nanticoke Region TWG Participants

1	Burlington Hydro Inc.
2	GrandBridge Energy Inc. (Formerly Energy+ and Brantford Power)
3	Alectra Utilities Corporation (former Horizon Utilities Inc.)
4	Hydro One Networks Inc. (Distribution)
5	Oakville Hydro Electricity Distribution Inc.
6	Independent Electricity System Operator
7	Hydro One Networks Inc. (Lead Transmitter)

2 REGIONAL ISSUE/TRIGGER

In accordance with the Regional Planning process, the Regional Planning cycle should be triggered at least every five years. As such, the 3rd Regional Planning cycle was triggered for the Burlington to Nanticoke region

3 SCOPE OF NEEDS ASSESSMENT

The scope of this NA covers the Burlington to Nanticoke region and includes:

- Review and reaffirm needs/plans identified in the RIP;
- Identify any new needs resulting from this assessment;

- Develop options and recommend a preferred plan for need(s) that do not require further regional coordination; and
- Recommend which need(s) require further assessment/regional coordination in the next phases of the Regional Planning cycle.

The TWG 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 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 230 kV and 115 kV step-down transformer stations. The sum of 2021 non-coincident summer station peak load of the Region was about 2341 MW. The boundaries of the Region are shown in Figure 1 below.

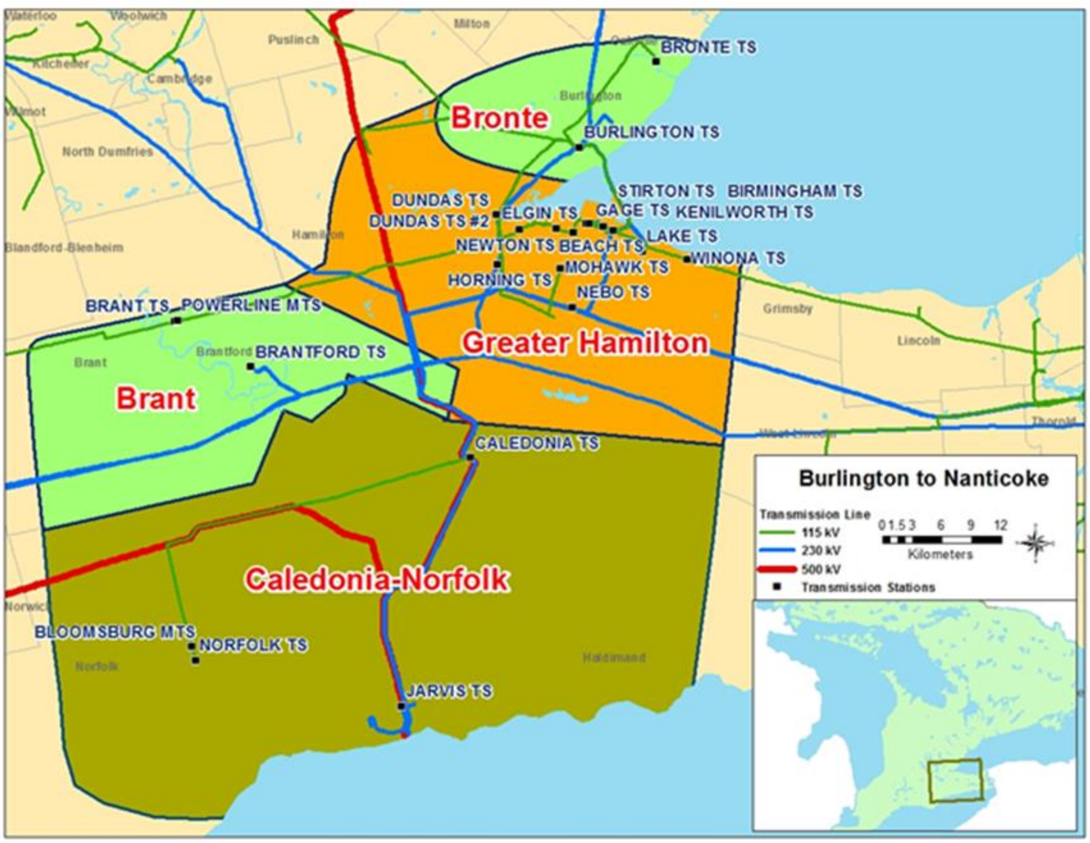


Figure 1: Map of Burlington to Nanticoke Regional Planning Area

Bulk electrical supply to the Burlington to Nanticoke Region is provided through the 500/230 kV autotransformers at 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 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 B12BL/B13BL line and B2 single circuit line.
  - Brantford TS supplied by the 230 kV double circuit transmission line M32W/M33W.

  The Brant Sub-region transmission facilities are shown in Figure 2.

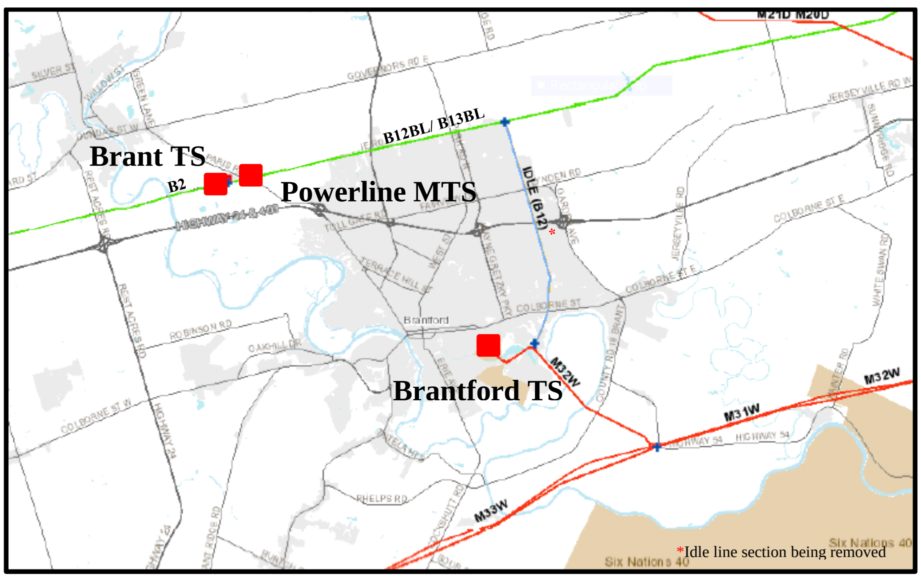


Figure 2: Map of Brant sub-region

The total 2021 non-coincident peak demand of the three stations was 280 MW. GrandBridge Energy (Merger of Brantford Power Inc. and Energy+ Inc.) is 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.

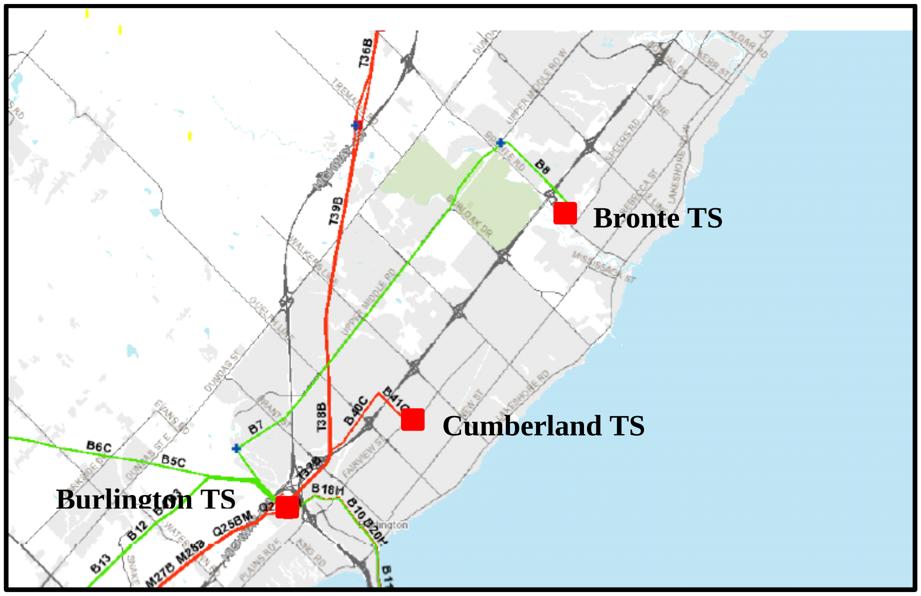


Figure 3: Map of Bronte sub-region

The area is served by Burlington Hydro and Oakville Hydro. The electricity demand is comprised of residential, commercial, and industrial customers. The total 2021 non-coincident peak station demand of the three stations was 358 MW.

- 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 four 115 kV step down stations Birmingham TS, Kenilworth TS, Stirton TS and Winona TS 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 (T3/T4 & T5/T6 DESNs), Horning TS, Nebo TS, Lake TS and two customer owned stations supplied from 230 kV circuits connecting into Beach TS and Burlington TS.
  - A large industrial customer currently supplied through 230 kV system is planning to connect a large additional load within his facilities.

The Greater Hamilton sub-region transmission facilities are shown in Figure 4.

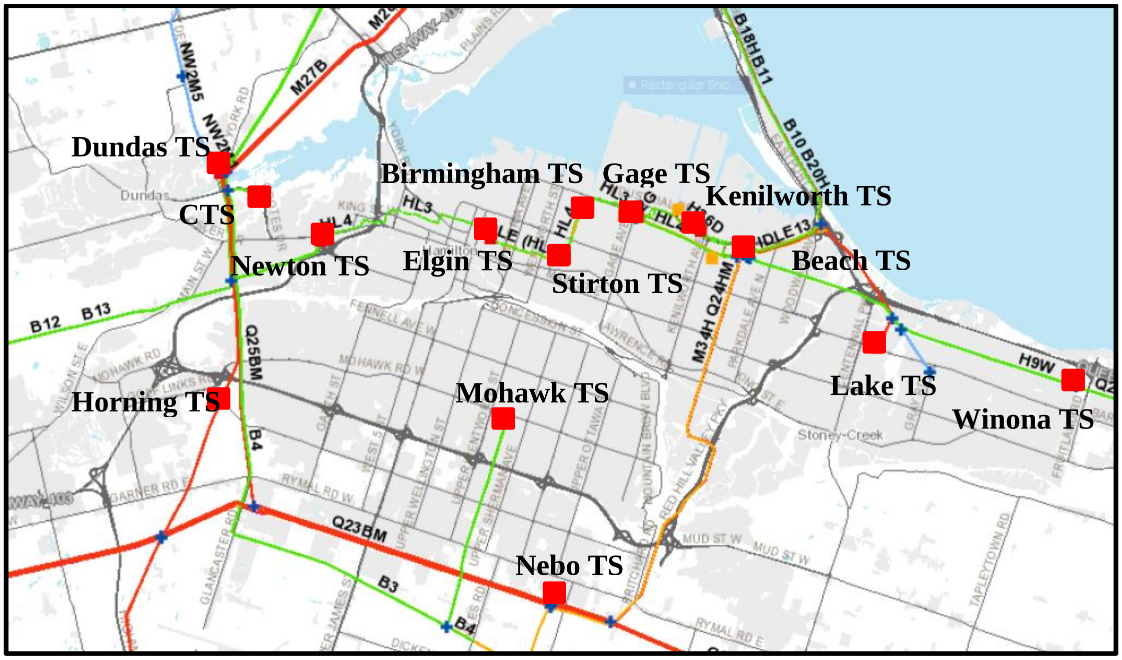


Figure 4: Map of Greater Hamilton sub-region

The total 2021 non-coincident peak demand of the Greater Hamilton sub-region was 1365 MW. The area is served by Alectra Utilities, Hydro One Distribution and Customer Transformer Stations (CTS) 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 and two (2) CTSs supplied from the 230 kV double circuit line N21J/N22J.
  - One of the CTSs is supplied from the 230 kV single circuit N20K. This is a new station where a large industrial customer previously supplied through Jarvis TS will be supplied by a new CTS.
  - 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 5.

  The area is served by Hydro One Distribution. The electricity demand mix is comprised of residential, commercial, and industrial uses. The 2021 non-coincident peak demand of this sub-region was 381 MW.

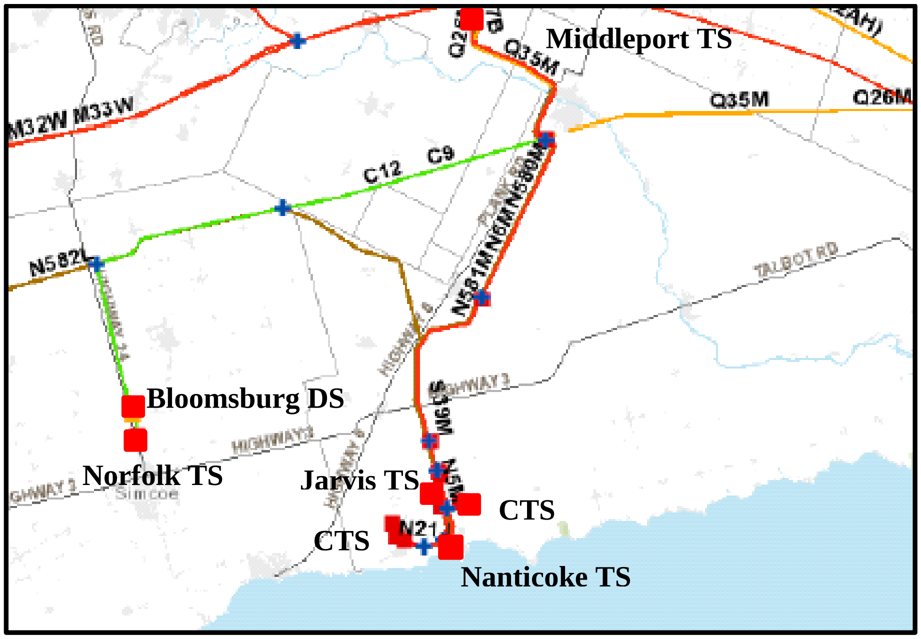


Figure 5: Map of Caledonia Norfolk sub-region

- Electrical single line diagrams for the Burlington to Nanticoke region's 500 kV/ 230 kV facilities and 115 kV facilities are shown below in Figure 6 and Figure 7.

The circuits and stations of the area are summarized in the Table 2 below:

Table 2: Transmission Station and Circuits in the Burlington to Nanticoke Region

115kV circuits	230kV circuits	Hydro One Transformer Stations
B3, B4, B5G, B6G, B7, B8, B10, B11, B12BL, B13BL, C9, C12, HL3, HL4, H5K, H6K, H9W, K1G, K2G, Q2AH	B18H, B20H, B40C, B41C, M34H, H35D, H36D, K40M, M20D, M21D, M27B, M28B, M31W, M32W, M33W, N5M, N6M, N21J, N22J, N37S, N20K Q24HM, Q23BM, Q25BM, Q30M, Q29HM, S39M,	Beach TS*, Birmingham TS, Bloomsburg DS, Brant TS, Brantford TS, Bronte TS, Burlington TS* DESN, Caledonia TS*, Cumberland TS, Dundas TS, Dundas TS #2, Elgin TS, Gage TS, Horning TS, Jarvis TS, Kenilworth TS, Lake TS, Mohawk TS, Nebo TS, Newton TS, Norfolk TS, Powerline MTS, Stirton TS, Winona TS and six (6) customer owned transformer station

*Stations with Autotransformers installed

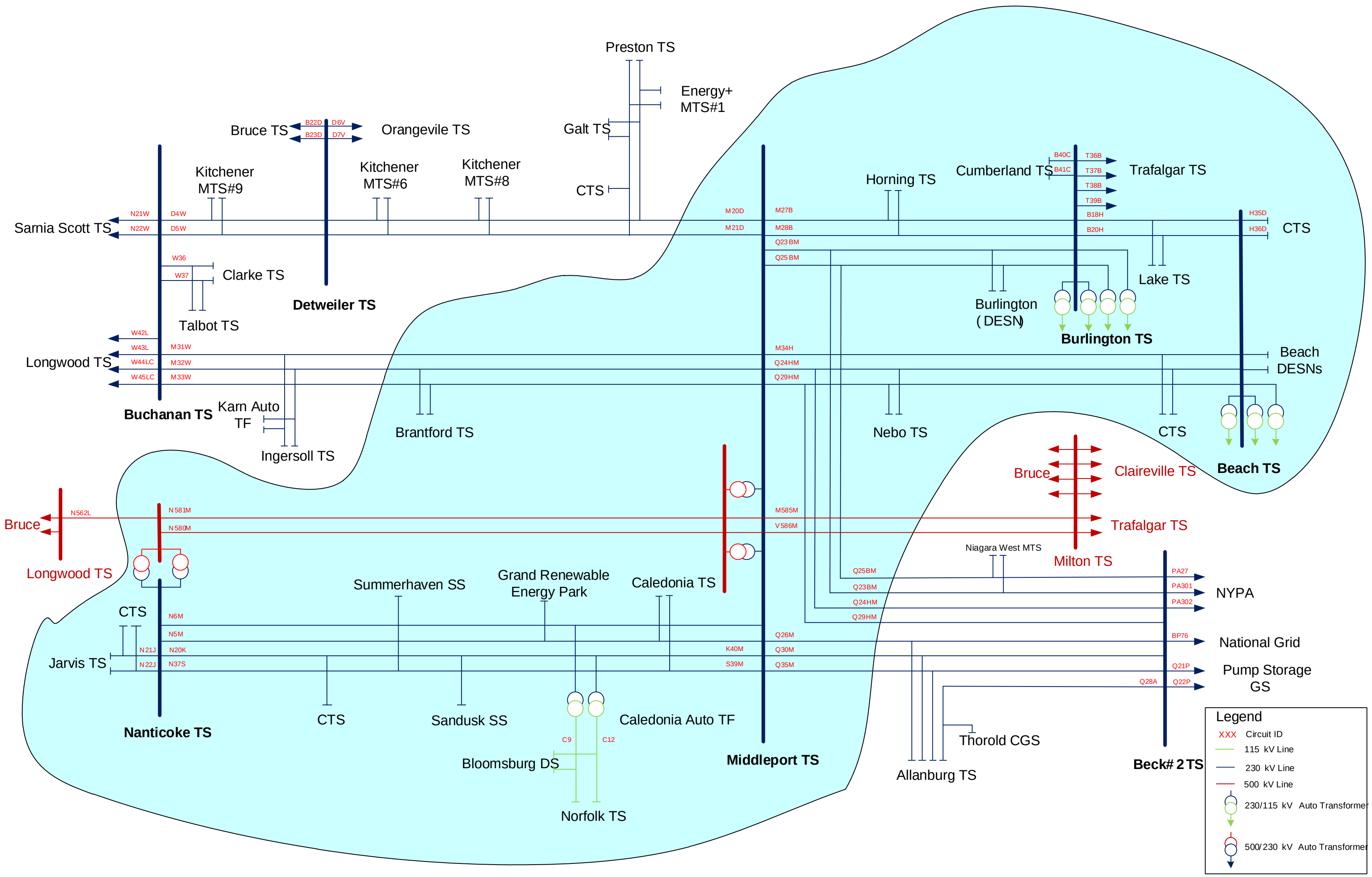


Figure 6: Burlington to Nanticoke Region 500 & 230 kV and Caledonia-Norfolk 115 kV Network

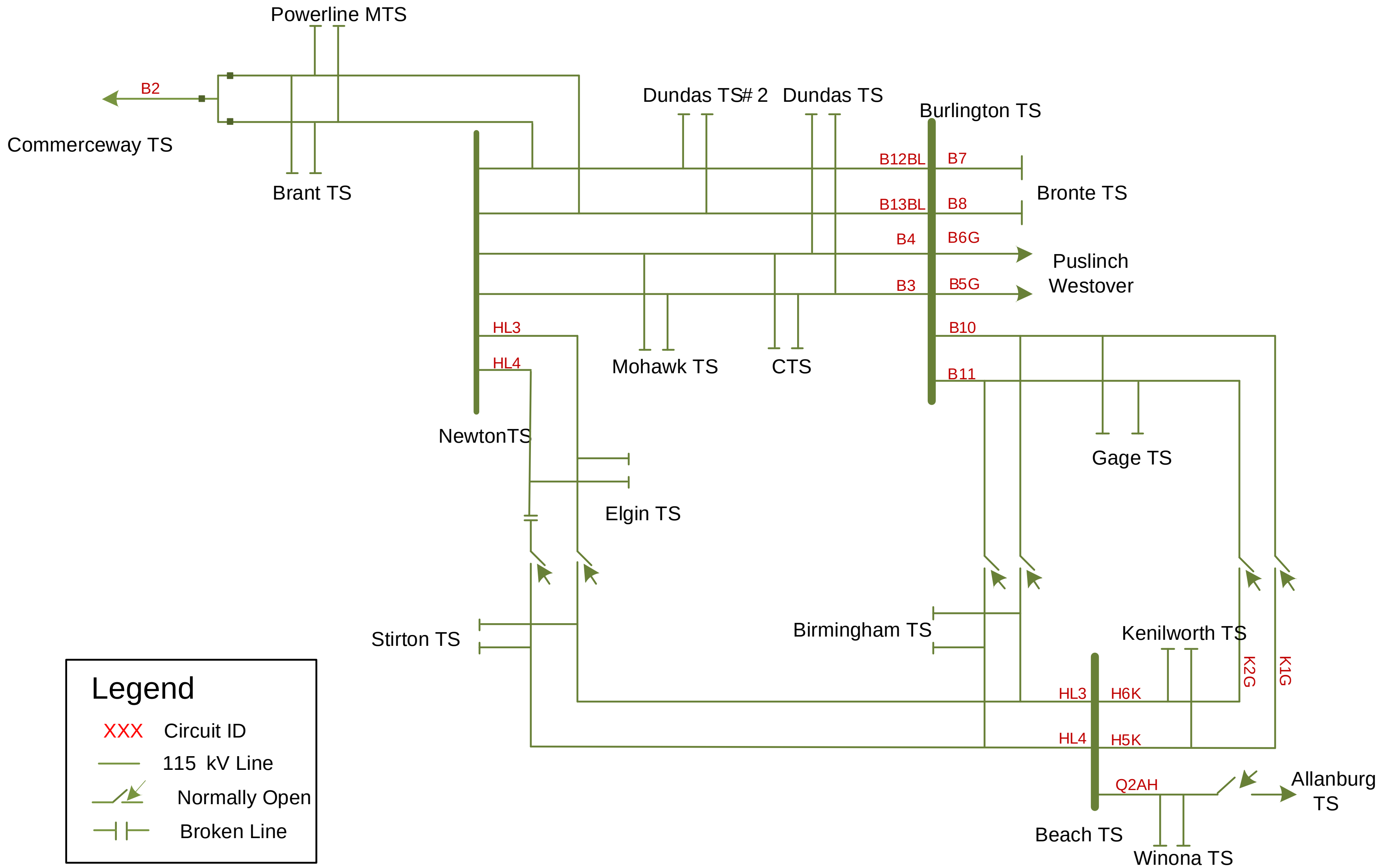


Figure 7: 115 kV Network Supplied by Burlington TS and Beach TS

5 INPUTS AND DATA

TWG participants, including representatives from LDCs, IESO, and Hydro One provided information and input for the Burlington to Nanticoke Region NA. The information provided includes the following:

- Burlington to Nanticoke Load Forecast for all supply stations;
- Known capacity and reliability needs, operating issues, and/or major assets requiring replacement/ refurbishment; and
- Planned/foreseen transmission and distribution investments that are relevant to Regional Planning for the Burlington to Nanticoke Region.

The community energy plans will be further evaluated during the next phases of this regional planning cycle.

6 ASSESSMENT METHODOLOGY

The following methodology and assumptions are made in this Needs Assessment:

Information gathering included:

i. Load forecast: The LDCs provided their load forecast for all the stations supplying their loads in the Burlington to Nanticoke region for the 10-year study period. The IESO provided a Conservation and Demand Management ("CDM") and Distributed Generation ("DG") forecast for the Burlington to Nanticoke region. The region's extreme summer non-coincident peak gross load forecasts for each station were prepared by applying the LDC load forecast growth rates to the actual 2021 summer peak extreme weather corrected loads. The extreme summer weather correction factors were provided by Hydro One. The net extreme summer weather load forecasts were produced by reducing the gross load forecasts for each station by the percentage CDM and then by the amount of effective DG capacity provided by the IESO for that station. It is to be noted that as contracts for existing DG resources in the region begin to expire, at which point the load forecast has a decreasing contribution from local DG resources, and an increase in net demand. This extreme summer weather corrected net load forecast for the individual stations in the Burlington to Nanticoke 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 based on asset condition assessment, 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;

- Any major high voltage equipment requiring replacement;
- Load forecast data was requested from industrial customers in the region; and
- The Region is summer peaking so is this assessment based on summer peak loads. Two load forecasts were developed i.e. Normal Growth scenario and High Growth scenario. The High Growth scenario load forecast was developed to conduct a sensitivity analysis to cover unforeseen developments like higher than expected EV charging trend during peak load conditions.

The following other assumptions are made in this report.

- The study period for this Needs Assessment is 2022-2032.
- Line capacity adequacy is assessed by using coincident peak loads in the area.
- 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 is determined by the Hydro One summer 10-Day Limited Time Rating (LTR) of a single transformer at that station.
- Adequacy assessment is conducted as per Ontario Resource Transmission Assessment Criteria (ORTAC).

7 NEEDS

This section describes emerging needs identified in the Burlington to Nanticoke Region, and reviews the near, mid, and long-term needs already identified in the previous Regional Planning cycle. A contingency analysis was performed for the region using the load forecast developed and no new system needs were identified.

The following near- term needs identified in the Burlington to Nanticoke 2^{nd} Cycle RIP report have been addressed/completed:

1. Cumberland TS: Power factor correction
2. 115 kV B3/B4: Line section from Horning Mountain Jct. to Glanford Jct. requiring replacement
3. Elgin TS: Transformers & switchgears requiring replacement
4. Newton TS: Transformers requiring replacement
5. Kenilworth TS: Transformer & switchgear requiring replacement

The status of the remaining near-term needs identified in the Burlington to Nanticoke 2^{nd} Cycle RIP report is summarized in Table 3 below.

Table 3: Near-Term Needs in Burlington to Nanticoke Region

No.	Needs	Status
1	115 kV B7/B8: Line section from Burlington TS to Nelson Jct. requiring refurbishment	Planned for in-service of 2024
2	Dundas TS: Load transfers	Hydro One Distribution is currently planning to build feeders required for load transfers from Dundas TS to Dundas TS #2. No new additional work inside Dundas TS #2 is required for these load transfers. The combined supply capacity of both Dundas stations is sufficient over and beyond the study period
3	Gage TS: Transformers & switchgear requiring replacement	Project in execution for the refurbishment of T3/ T4 and T5/ T6 DESNs to be replace with a new single DESN having larger transformers with a planned in-service in the Q4 2023
4	Kenilworth TS: Power factor correction	At Kenilworth TS the historical loading data indicated that under peak load the power factor is lagging below the ORTAC requirement of 0.9. To address this issue The TWG recommended Alectra Utilities to install capacitor bank and/or work with load customers supplied by Kenilworth TS to meet ORTAC power factor requirement of 0.9. The installation of capacitor bank at Kenilworth TS will be initiated after completion of refurbishment of this supply station in Q4 2023
5	Norfolk area supply capacity	Electrical supply to the Norfolk Area is provided through two (2) 115 kV C9/C12 transmission circuits supplied by 230/115 kV autotransformers at the Caledonia TS. These two 115 kV circuits have a load meeting capability (LMC) of approximately 88 MW and supply Norfolk area loads through two step down transformer stations, i.e. Bloomsburg DS and Norfolk TS. The load in Norfolk Area has held constant over the years below the LMC. The load however, has peaked at 94 MW during the summer of 2018. The 2nd cycle Burlington to Nanticoke RIP made recommendations to address immediate supply capacity needs in the Norfolk Area. This recommendation included distribution load transfers of approximately 6.5 MW from Norfolk area to Jarvis TS using existing feeders and additional reactive support at Norfolk TS to improve the voltage profile, resulting in an increase of the Norfolk Area LMC by approximately 10 MW. These two recommendations will increase the LMC of the pocket to approximately 105MW.

No.	Needs	Status
		The load transfers from Norfolk area to Jarvis TS are planned to be completed by end of 2022 and the additional reactive support at Norfolk TS is planned for 2023-24 timeframe. The RIP also recommended a further assessment to be carried out by the IESO and Hydro One to review the near to mid-term capacity needs. The IESO carried out this assessment and identified preferred options based on the load forecast at that time. No study report was published. These options should be reexamined with the updated forecast and an appropriate planning approach determined in the scoping assessment phase.

The current timing for the mid- and long-term electrical infrastructure needs identified in the Burlington to Nanticoke Region 2nd cycle RIP report are summarized below in Table 4.

Table 4: Status Update of Mid- and Long-Term Needs in Burlington to Nanticoke Region

No.	Needs	Planned Timeframe**
1	Birmingham TS: Transformer and metalclad switchgears requiring replacement	2027-32
2	Mid-Term Transformers at Nebo TS (T3/T4), Caledonia TS (T1) and Jarvis TS (T3/T4) requiring replacement	2027-32
3	Mid-Term replacement requirement of switchgears at Norfolk TS and Burlington TS	2027-32
4	Cables in Hamilton sub-region: H5K/H6K, K1G/K2G, HL3/HL4 requiring replacement	2033*
5	Norfolk area supply capacity: Install new 230 kV double circuit lines and a new DESN	2027-32
6	Beach TS: 230 kV autotransformers and DESN transformers requiring replacement	2027-32
7	Lake TS: Transformers and switchgear requiring replacement	2026-27
8	Burlington TS: 230 kV autotransformer requiring replacement	2027-32
9	Gage TS (T8/T9 DESN): Transformer and switchgears requiring replacement	2027-32

*- To be finalized through Hamilton IRRP Addendum by the IESO

**- Subject to change depending on multiple factors

7.1 Asset Replacement Needs for Major HV Transmission Equipment

The major HV transmission equipment considered in this assessment is shown in Table 5.

Table 5: Major High-Voltage Transmission Equipment Assessed for Replacement

No.	HV Equipment Included
1.	230/115kV Autotransformers
2.	230kV and 115kV load serving step-down transformers
3.	115kV Breakers
4.	230kV and 115kV transmission lines*
5.	230kV and 115kV underground cables*

*Requirement for a Leave to Construct (Section 92) for any alternative to like-for-like would be an appropriate threshold for which segments to include

Hydro One has identified 115 kV breakers at Newton TS with a planned in-service of 2025 as new additional asset replacement need for its major HV equipment over the next 10 years in the Burlington to Nanticoke Region. These needs are determined by asset condition assessment, which is based on a range of considerations such as equipment deterioration due to aging infrastructure or other factors; technical obsolescence due to outdated design; lack of spare parts availability or manufacturer support; and/or potential health and safety hazards, etc.

The TWG recommended continuation of addressing the new identified asset replacement need of 115 kV breakers at Newton TS as well as needs identified in the 2^{nd} cycle RIP report for the Burlington to Nanticoke Region.

7.2 Station and Transmission Capacity Needs in the Burlington to Nanticoke Region

The Station and Transmission supply capacities have been reviewed and the following needs have been identified in the Burlington to Nanticoke region during the study period of 2022 to 2032.

7.2.1 230/115 kV Autotransformers

The 230/115 kV autotransformers in the Burlington to Nanticoke TS supplying 115 kV stations in the Region are within their ratings for the loss of a single unit and are adequate to supply the forecasted load over the study period.

7.2.2 115kV Transmission Lines

The new area supply needs identified the following which may require regional coordination:

a) Bronte Area Supply

The Bronte Sub-region is within the Burlington-Nanticoke planning region. It roughly encompasses the cities of Burlington and Oakville. An IRRP was completed in 2016 to address the supply capacity issues for the loads supplied by Bronte TS. Bronte TS is radially supplied from the double-circuit 115 kV transmission line B7/B8 originating from Burlington TS. This IRRP recommended that the peak demand at Bronte TS be limited to 135 MW through incremental load transfers (as required) from Bronte TS to other neighboring stations. For the loads in excess of 135 MW the thermal loading of B7/B8 exceeds capacity following the loss of the companion circuit and the post contingency voltage drop exceeds 10% at Bronte TS. The loads at Bronte TS are forecasted to remain around the current supply capacity of 135 MW over the study period and beyond.

TWG recommend that the loading at Bronte TS has reached its capacity and any future loads in excess of 135 MW in this area be supplied from neighboring stations.

b) Brant Area Supply

The 115 kV Brant area is supplied by two stations i.e. Brant TS and Powerline MTS. An IRRP was completed by the IESO in 2015 to addresses the electricity needs of the area over the next 20 years up to 2033. The report recommended installation of a capacitor bank at Power line MTS and building of a new switching station integrating B12 and B13 115 kV circuits from Burlington TS with a single 115 kV circuit B8W supplied from Karn TS. These two measures increased the Load Meeting Capability (LMC) of 115 kV supply system to Brant area to 165MW.

The coincident load in the 115 kV Brant area system may exceed the LMC of 165 MW before the end of the study period (2032). Additional analysis is required to better assess the need timeframe is required.

TWG recommends Hydro One to monitor the loading on the Brant 115 kV supply system and take remedial measures, if required. This need will be reviewed during the Scoping Assessment phase of this Regional Planning cycle.

c) Norfolk Area Supply

The Norfolk area loads are supplied through Norfolk TS and Bloomsburg DS supplied through two 115 kV circuits from Caledonia autotransformers. In 2020, the IESO carried out an assessment of the supply capability in the Norfolk area when additional load growth was identified by the LDCs. As a result of this assessment, load transfers out of the Norfolk area and additional reactive support at Norfolk TS was recommended. These measures will increase the LMC of supply to Norfolk area from 88MW to 105 MW. In the mid-term the preferred option based on the load forecast at that time was to upgrade Jarvis TS and build four (4) 27.6 kV feeders from this station to Norfolk area to pick up loads limiting the loads supplied from the existing Norfolk area system to within its supply capacity.

Based on the current Normal Growth load forecast the loads are growing at a higher rate than anticipated before. TWG recommends Hydro One monitor the loading levels of Norfolk area supply system and take remedial measures, if required. This need will be reviewed during the Scoping Assessment phase of this Regional Planning cycle.

The remaining115kV circuits supplying the Region are adequate over the study period for the loss of a single 115kV circuit in the Region under the study assumptions of the Needs Assessment.

7.2.3 230 kV and 115 kV Facilities

A station capacity assessment was performed over the study period for the 230 kV and 115 kV supply stations in the Region using the summer station peak load forecasts. The results are as follows:

a) Transformer stations

i. Norfolk TS and Bloomsburg DS (Norfolk Area)

Norfolk TS and Bloomsburg DS are currently supplying loads of 66 MW and 38 MW Norfolk area loads respectively. The supply capacities of these two stations are 97 MW and 49 MW respectively.

The loads at Norfolk TS and Bloomsburg DS are forecasted to exceed their supply capacities in 2030 and 2025 under the Normal Growth scenario.

The current supply capacity of Norfolk area is limited by the capacity two (2) 115kV circuits supplying this area which is about 88 MW much lower than the combined supply capacity of Norfolk TS and Bloomsburg DS.

As described above in Table 3 and in Section 7.2.2, the supply capacity of Norfolk area is currently planned to be addressed mainly through load transfers reducing the loads on Norfolk TS and Bloomsburg DS bringing loading well below their supply capacities. This need will be reviewed during the Scoping Assessment phase of this Regional Planning cycle.

ii. Caledonia TS

Caledonia TS is currently supplying loads of 44 MW having a supply capacity of 99 MW. The load at Caledonia TS is forecasted to exceed its supply in 2030 under Normal growth load forecast scenario.

The TWG recommended Hydro One to monitor the loading at Caledonia TS and this need will be reviewed again during the Scoping Assessment phase of this Regional Planning cycle.

iii. Nebo TS

Nebo TS has two DESNs inside the station supplying loads in the city of Hamilton and surrounding areas. T1/T2 is a 27.6 kV DESN with current load of 122 MW having a supply capacity of 178 MW sufficient over the study period. The loads at T3/T4 13.8 kV DESN at Nebo TS had been historically around its supply capacity and is currently marginally overloaded supplying loads of 55 MW against its supply capacity of 51 MW.

The loads at this DESN are currently forecasted to grow above and beyond its supply capacity.

The TWG recommended that Hydro One and Alectra monitor the loading at Nebo TS T3/T4 DESN and take remedial measures, if required until refurbishment of this DESN is completed. This refurbishment is currently planned to be completed in the 2027-2032 timeframe replacing existing 75 MVA nonstandard transformers with Hydro One standard 100 MVA units. This need will be reviewed during the Scoping Assessment phaseof this Regional Planning cycle.

iv. Mohawk TS

Mohawk TS is a single DESN station supplying loads in the city of Hamilton. This station is currently supplying 81 MW of load having a supply capacity of 90 MW.

The peak load at Mohawk TS had been historically around its current loading levels, however the load at this station is forecasted to exceed its supply in 2024 under Normal growth scenario.

The TWG recommended that Hydro One and Alectra to monitor the loading Mohawk TS and take necessary actions, if required e.g. load transfers to the neighboring stations. This need will be reviewed during the Scoping Assessment phaseof this Regional Planning cycle.

All other transformer stations in the region are forecasted to remain within their normal supply capacity during the study period. Capacity needs for these stations will be reviewed in the next planning cycle.

Depending on the load growth and the future decisions on contracts for distributed energy resources connected to the station, the capacity of some stations could be reached in the long term (10+ years). The TWG will continue to monitor the load growth at the stations and will re-evaluate the capacity at the next planning cycle.

7.3 System Reliability, Operation and Restoration Review

No new significant system reliability and operating issues have been identified for this Region. Based on the net load forecast, the loss of one element will not result in load interruption greater than 150MW. The maximum load interrupted by configuration due to the loss of two elements is below the load loss limit of 600MW by the end of the 10-year study period.

8 SENSITIVITY ANALYSIS

The objective of a sensitivity analysis is to capture uncertainty in the load forecast as well as variability of electric demand drivers to identify any emerging needs and/or advancement or deferment of recommended investments. The TWG determined that the key electric demand driver in the Burlington to Nanticoke region to be considered in this sensitivity analysis is electric vehicle (EV) penetration and unforeseen electrification.
The TWG reviewed EV scenarios and any unforeseen electrification needs to develop high demand growth forecasts by applying + 50% additional growth to the growth rate on the extreme summer corrected Normal Growth net load forecasts. The normal and high growth forecasts are shown in Tables A.1, A.2, A.3 and A.4.

The impact of sensitivity analysis for the high growth scenario identified the following updates or new station capacity needs:

No.	Need	Normal Growth Scenario	High Growth Scenario
1	Brant Area Supply**	-*	-*
2	Norfolk Area Supply***	-*	-*
3	Norfolk TS***	2030	2028
4	Bloomsburg DS***	2025	2025
5	Caledonia TS	2030	2027
6	Nebo TS	2022	2022
7	Mohawk TS	2024	2023
8	Brant TS**	-	2031
9	Elgin TS	-	2027
10	Newton TS	-	2030

*- To be further assessed during the next phases of this Regional Planning cycle.

**- Supply capacity at Brant TS will be addressed along with Brant Area Supply capacity need

***- Supply capacity at Norfolk TS and Bloomsburg DS will be addressed along with Norfolk Area Supply capacity need

The sensitivity analysis identified the additional capacity needs at Brant TS, Elgin TS and Newton TS towards the end of the study period. These needs will be assessed again during the next phases of this Regional Planning cycle.

There are two (2) new CTSs one each in Caledonia-Norfolk and Hamilton sub-regions supplied through 230 kV systems. None of these CTS are expected to impact the supply capacity or reliability in the Burlington to Nanticoke Region.

9 CONCLUSION AND RECOMMENDATIONS

The TWG recommends to continue with the refurbishment of section of 115 kV B7/B8 line and Gage TS (T3/T4 and T5/T6 DESNs), load transfer from Dundas TS to Dundas TS #2 to address overloading at this station, supply capacity in Norfolk area, power factor correction at Kenilworth TS as well continue with new identified refurbishment need for 115 kV breakers at Newton TS.

The TWG also recommended that the concerned LDC and Hydro One to monitor the loading levels in Norfolk and Brant areas as well at Caledonia TS, Nebo TS and Mohawk TS and take necessary action to address overloading, if required. These needs will be further reviewed during the Scoping Assessment phase of this Regional Planning cycle.

10 REFERENCES

1. Regional Infrastructure Plan Report – Burlington to Nanticoke – October 2019
2. IESO Ontario Resource and Transmission Assessment Criteria (ORTAC) – Issue 5.0
3. Bronte IRRP (2016)
4. Brant IRRP (2015)

Appendix A: Extreme Summer Weather Adjusted Net Load Forecast

Table A.1: Burlington to Nanticoke Region – Non-Coincident- Normal Growth Net Load Forecast

Area	Station	LTR	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Brant 115 kV	Brant TS (T1 / T2)	101	74	81	86	87	88	88	89	89	90	94	95	96	97	98	100	101	102	103	105	106	108
	Powerline MTS (T1 / T2)	114	85	76	77	84	98	99	99	100	101	102	103	104	105	107	109	110	112	113	115	117	118
Brant 230 kV	Brantford TS (T3 / T4)	188	159	159	163	166	151	159	160	161	163	164	165	167	168	170	172	174	176	178	180	182	184
Burlington and Oakville 115 kV	Bronte TS (T2 / T5 / T6)	198	138	135	132	132	133	133	134	135	135	137	136	135	135	135	134	134	134	134	134	134	134
Burlington and Oakville 230 kV	Burlington TS (T15 / T16)	185	141	149	157	156	155	154	153	152	152	151	150	149	149	149	148	148	148	148	148	148	148
	Cumberland TS (T3 / T4)	174	113	125	137	137	138	138	138	139	140	142	142	141	141	140	140	140	140	140	140	140	140
Greater Hamilton 115 kV	Birmingham TS (T1 / T2)	76	14	15	15	16	16	16	17	17	17	18	18	18	19	19	19	20	20	21	21	21	21
	Birmingham TS (T3 / T4)	91	65	66	68	70	72	73	74	75	76	77	79	80	81	83	85	87	89	90	92	92	92
	Dundas TS (T1 / T2)	99	104	104	105	106	107	107	108	108	109	110	111	112	113	123	124	125	126	128	129	130	130
	Dundas TS #2 (T5 / T6)	89	52	52	52	52	53	53	53	53	54	55	56	56	57	59	60	61	62	64	65	65	65
	Elgin TS (T1 / T2)	134	90	97	101	110	116	120	122	124	126	128	130	132	137	140	142	146	149	152	155	155	155
	Gage TS (T3 / T4)	57	21	21	21	29	37	37	37	37	37	37	38	38	39	40	41	42	43	43	44	44	44
	Gage TS (T5 / T6)	57	12	12	12	14	16	16	16	16	16	16	16	17	17	17	18	18	18	19	19	19	19
	Gage TS (T8 / T9)	123	16	15	15	18	20	20	20	20	20	20	20	21	21	22	22	23	23	24	24	24	24
	Kenilworth TS (T2 / T3)	124	67	69	71	73	75	77	79	80	82	83	85	86	88	89	91	93	95	97	99	99	99
	Mohawk TS (T1 / T2)	90	86	89	92	95	97	100	102	105	107	109	111	112	114	117	119	122	124	127	129	129	129
	Newton TS (T1 / T2)	75	48	48	52	61	62	63	64	65	66	67	69	70	71	72	74	76	77	79	81	81	81
	Stirton TS (T3 / T4)	112	55	55	55	56	57	59	60	62	63	64	65	66	67	69	70	71	73	75	76	76	76
	Winona TS (T1 / T2)	89	61	64	66	68	70	71	72	73	74	75	76	77	79	80	82	84	85	87	89	89	89
	CTS		1	1	23	23	24	22	21	19	15	13	11	9	9	9	9	9	9	9	9	9	9
Greater Hamilton 230 kV	Beach TS (T3/T4)	135	33	34	36	37	38	39	40	41	42	42	43	44	44	45	46	47	48	49	50	50	50
	Beach TS (T5 / T6)	96	62	64	68	70	72	74	75	77	79	80	81	83	84	86	88	90	91	93	95	95	95
	Horning TS (T3 / T4)	113	71	73	76	78	81	83	85	87	89	90	92	93	95	97	99	101	103	105	107	107	107
	Lake TS (T1 / T2)	75	50	50	50	50	50	50	50	50	50	50	50	50	50	50	51	51	51	51	52	52	52
	Lake TS (T3 / T4)	113	54	56	58	59	59	59	60	62	63	64	65	66	67	69	70	71	73	75	76	76	76
	Nebo TS (T1/T2)	178	129	131	132	133	135	136	141	143	144	146	147	149	150	152	154	156	158	160	162	165	167
	Nebo TS (T3 / T4)	51	56	57	59	61	63	64	66	68	69	70	72	73	74	76	77	79	80	82	84	84	84
	CTS		262	259	257	255	254	252	250	249	247	246	245	244	242	242	241	241	241	241	241	241	241
Caledonia Norfolk 115 kV	Norfolk TS (T1/T2)	97	71	74	77	82	87	86	93	96	99	103	105	108	110	113	115	118	121	123	126	129	132
	Bloomsburg DS (T1/T2)	49	35	37	40	50	57	55	57	59	64	66	68	70	72	75	77	79	81	83	85	87	89
Caledonia Norfolk 230 kV	Caledonia TS (T1/T2)	99	57	63	68	79	84	85	95	98	100	103	105	108	110	113	115	118	121	124	127	129	132
	Jarvis TS (T3/T4)	105	51	55	58	62	69	72	74	76	79	82	84	86	90	92	94	97	100	102	105	107	110
	CTS		195	195	194	193	192	190	189	188	187	187	186	185	184	184	184	184	184	184	184	184	184

Table A.2: Burlington to Nanticoke Region – Coincident – Normal Growth Net Load Forecast

Area	Station	LTR	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Brant 115 kV	Brant TS (T1 / T2)	101	57	62	66	66	67	67	68	68	69	73	73	74	75	76	77	78	79	80	81	82	83
	Powerline MTS (T1 / T2)	114	72	65	65	72	83	84	85	85	86	87	88	89	90	92	93	94	95	97	98	100	101
Brant 230 kV	Brantford TS (T3 / T4)	188	139	139	142	145	132	140	140	141	143	144	145	147	148	149	151	153	154	156	158	160	161
Burlington and Oakville 115 kV	Bronte TS (T2 / T5 / T6)	198	114	111	109	109	109	110	110	111	111	112	112	111	111	111	111	111	111	111	111	111	111
Burlington and Oakville 230 kV	Burlington TS (T15 / T16)	185	123	131	138	137	136	135	134	133	133	132	131	131	130	130	130	130	130	130	130	130	130
	Cumberland TS (T3 / T4)	174	98	109	119	119	120	120	121	121	122	123	123	123	123	122	122	122	122	122	122	122	122
Greater Hamilton 115 kV	Birmingham TS (T1 / T2)	76	4	4	4	5	5	5	5	5	5	5	5	5	5	6	6	6	6	6	6	6	6
	Birmingham TS (T3 / T4)	91	48	49	50	51	53	54	54	55	56	57	58	59	60	61	62	64	65	67	68	68	68
	Dundas TS (T1 / T2)	99	93	94	94	95	96	96	97	97	98	99	100	100	101	111	112	113	114	116	117	117	118
	Dundas TS #2 (T5 / T6)	89	46	46	46	46	47	47	47	47	47	48	49	50	51	52	53	54	55	56	58	58	58
	Elgin TS (T1 / T2)	134	72	77	80	87	92	95	97	99	100	102	103	105	109	111	114	116	119	121	124	124	124
	Gage TS (T3 / T4)	57	7	7	7	10	13	13	13	13	13	13	13	13	14	14	14	14	15	15	15	15	15
	Gage TS (T5 / T6)	57	8	8	8	10	11	11	11	11	11	11	11	12	12	12	12	13	13	13	13	13	13
	Gage TS (T8 / T9)	123	11	11	11	13	15	15	15	15	15	15	15	15	16	16	16	17	17	17	18	18	18
	Kenilworth TS (T2 / T3)	124	41	42	43	45	46	47	48	49	50	51	51	52	53	54	55	56	58	59	60	60	60
	Mohawk TS (T1 / T2)	90	69	71	73	76	78	80	82	84	86	87	88	90	91	93	95	97	99	101	103	103	103
	Newton TS (T1 / T2)	75	43	43	47	54	56	57	58	58	60	61	62	63	64	65	66	68	69	71	73	73	73
	Stirton TS (T3 / T4)	112	49	50	50	50	51	53	54	55	57	58	59	59	60	62	63	64	66	67	68	68	68
	Winona TS (T1 / T2)	89	48	50	52	53	55	56	57	57	58	59	60	61	62	63	64	66	67	69	70	70	70
	CTS		0	0	14	14	14	13	12	11	8	6	4	3	3	3	3	3	3	3	3	3	3
Greater Hamilton 230 kV	Beach TS (T3/T4)	135	17	17	18	19	19	20	20	21	21	21	22	22	22	23	23	24	24	25	25	25	25
	Beach TS (T5 / T6)	96	49	51	54	56	58	59	60	62	63	64	65	66	67	69	70	72	73	75	76	76	76
	Horning TS (T3 / T4)	113	60	62	64	66	68	70	72	73	75	76	77	79	80	82	83	85	87	89	91	91	91
	Lake TS (T1 / T2)	75	44	44	44	44	44	44	44	44	44	45	45	45	45	45	45	45	45	46	46	46	46
	Lake TS (T3 / T4)	113	48	50	52	52	52	52	53	55	56	57	58	59	59	61	62	63	65	66	67	67	67
	Nebo TS (T1/T2)	178	115	116	117	118	119	121	125	127	128	129	131	132	133	135	137	139	140	142	144	146	148
	Nebo TS (T3 / T4)	51	48	50	51	53	54	56	57	58	60	61	62	63	64	65	67	68	70	71	73	73	73
	CTS		197	195	193	192	191	189	188	187	186	185	184	183	182	182	181	181	181	181	181	181	181
Caledonia Norfolk 115 kV	Norfolk TS (T1/T2)	97	60	62	65	69	73	74	79	83	85	89	91	93	95	97	99	102	104	106	108	111	113
	Bloomsburg DS (T1/T2)	49	32	34	37	46	52	50	52	54	59	61	63	65	66	69	71	73	75	77	78	80	82
Caledonia Norfolk 230 kV	Caledonia TS (T1/T2)	99	56	61	67	77	82	83	93	96	98	100	103	105	108	110	113	115	118	121	124	126	129
	Jarvis TS (T3/T4)	105	28	30	31	34	38	39	40	41	43	44	46	47	49	50	52	53	55	56	57	59	60
	CTS		123	124	123	123	122	121	121	120	120	119	119	118	118	118	118	118	118	118	118	118	118

Table A.3: Burlington to Nanticoke Region Non-Coincident – High Growth Net Load Forecast

Area	Station	LTR	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Brant 115 kV	Brant TS (T1 / T2)	101	74	84	92	93	94	95	96	97	98	104	106	107	109	111	112	114	116	118	120	122	124
	Powerline MTS (T1 / T2)	114	85	72	72	84	104	105	107	108	109	111	112	114	116	119	121	123	125	128	130	133	135
Brant 230 kV	Brantford TS (T3 / T4)	188	159	159	165	170	155	167	168	169	173	174	176	178	180	183	185	188	191	194	197	201	204
Burlington and Oakville 115 kV	Bronte TS (T2 / T5 / T6)	198	138	133	129	130	131	131	132	133	134	136	135	134	133	133	133	133	133	133	133	133	133
Burlington and Oakville 230 kV	Burlington TS (T15 / T16)	185	141	153	166	164	163	161	159	158	157	156	155	154	153	153	152	152	152	152	152	152	152
	Cumberland TS (T3 / T4)	174	113	131	149	149	150	151	151	152	154	156	156	155	155	154	154	154	154	154	154	154	154
Greater Hamilton 115 kV	Birmingham TS (T1 / T2)	76	14	15	15	16	17	17	18	18	19	19	20	20	21	21	22	22	23	24	24	24	24
	Birmingham TS (T3 / T4)	91	65	67	69	73	75	77	79	80	82	84	86	88	90	92	95	98	101	103	106	106	106
	Dundas TS (T1 / T2)	99	104	105	105	107	108	109	110	111	112	113	114	116	117	132	134	136	138	140	142	143	144
	Dundas TS #2 (T5 / T6)	89	52	52	52	53	54	54	54	54	55	56	57	59	60	62	64	66	68	70	72	72	72
	Elgin TS (T1 / T2)	134	90	100	106	120	128	135	138	141	144	147	150	153	160	164	168	173	178	183	188	188	188
	Gage TS (T3 / T4)	57	21	21	21	33	46	45	45	44	44	45	46	47	48	49	50	52	53	55	56	56	56
	Gage TS (T5 / T6)	57	12	12	12	15	18	18	18	18	18	18	19	19	19	20	20	21	22	22	23	23	23
	Gage TS (T8 / T9)	123	16	15	15	19	23	22	22	22	22	22	23	23	24	25	25	26	27	28	28	28	28
	Kenilworth TS (T2 / T3)	124	67	70	73	77	79	82	85	87	90	91	93	95	98	100	103	106	109	112	115	115	115
	Mohawk TS (T1 / T2)	90	86	90	94	99	103	107	110	114	118	120	123	126	128	132	135	139	143	147	151	151	151
	Newton TS (T1 / T2)	75	48	49	54	67	69	71	72	74	76	77	79	81	83	85	87	90	92	95	97	97	97
	Stirton TS (T3 / T4)	112	55	55	55	56	58	61	63	65	67	69	70	72	73	75	77	80	82	84	87	87	87
	Winona TS (T1 / T2)	89	61	65	68	71	74	77	78	79	80	82	84	86	88	90	92	95	98	100	103	103	103
	CTS		1	1	34	34	35	33	31	28	22	19	16	13	13	12	12	12	12	12	12	12	12
Greater Hamilton 230 kV	Beach TS (T3/T4)	135	33	35	37	38	40	41	43	44	46	47	48	49	50	51	53	54	56	57	59	59	59
	Beach TS (T5 / T6)	96	62	65	71	74	77	79	82	85	88	89	91	93	95	98	100	103	106	109	112	112	112
	Horning TS (T3 / T4)	113	71	75	78	82	85	88	91	94	98	100	102	104	106	110	112	116	119	122	125	125	125
	Lake TS (T1 / T2)	75	50	50	50	50	50	50	50	50	50	50	50	50	50	51	51	51	52	52	52	53	53
	Lake TS (T3 / T4)	113	54	57	61	61	61	61	63	65	68	69	70	72	74	76	78	80	82	85	87	87	87
	Nebo TS (T1/T2)	178	129	132	133	135	137	140	147	149	151	154	156	158	161	163	166	169	173	176	179	182	186
	Nebo TS (T3 / T4)	51	56	58	61	64	66	69	71	74	76	78	80	81	83	86	88	90	93	95	98	98	98
	CTS		262	262	262	262	262	262	262	262	262	262	262	262	262	262	262	262	262	262	262	262	262
Caledonia Norfolk 115 kV	Norfolk TS (T1/T2)	97	71	75	80	87	94	94	103	109	113	119	123	126	130	134	137	142	146	150	154	158	162
	Bloomsburg DS (T1/T2)	49	35	38	43	57	68	65	68	70	79	82	85	88	91	95	98	101	104	107	110	113	116
Caledonia Norfolk 230 kV	Caledonia TS (T1/T2)	99	57	66	74	89	98	100	115	118	122	126	129	133	137	141	144	149	153	157	161	166	170
	Jarvis TS (T3/T4)	105	51	57	62	68	79	82	86	89	93	97	100	104	109	113	116	120	124	128	132	136	140
	CTS		195	195	195	195	195	195	195	195	195	195	195	195	195	195	195	195	195	195	195	195	195

Table A.4: Burlington to Nanticoke Region Region – Coincident – High Growth Net Load Forecast

Area	Station	LTR	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Brant 115 kV	Brant TS (T1 / T2)	101	57	64	70	71	72	73	73	74	75	81	82	83	85	86	87	89	90	92	93	95	96
	Powerline MTS (T1 / T2)	114	72	61	62	71	89	90	91	92	93	95	96	97	99	101	103	105	107	109	111	113	115
Brant 230 kV	Brantford TS (T3 / T4)	188	139	139	144	149	135	147	148	149	152	154	155	157	159	161	163	166	169	171	174	177	179
Burlington and Oakville 115 kV	Bronte TS (T2 / T5 / T6)	198	114	110	106	107	107	108	109	109	110	112	111	110	110	110	109	109	109	109	109	109	109
Burlington and Oakville 230 kV	Burlington TS (T15 / T16)	185	123	134	145	144	142	141	140	138	138	136	135	135	134	134	133	133	133	133	133	133	133
	Cumberland TS (T3 / T4)	174	98	114	130	130	131	131	132	132	134	136	136	135	135	135	134	134	134	134	134	134	134
Greater Hamilton 115 kV	Birmingham TS (T1 / T2)	76	4	4	5	5	5	5	5	5	6	6	6	6	6	6	6	7	7	7	7	7	7
	Birmingham TS (T3 / T4)	91	48	49	51	53	55	57	58	59	60	62	63	65	66	68	70	72	74	76	78	78	78
	Dundas TS (T1 / T2)	99	93	94	94	96	97	98	98	99	100	102	103	104	105	120	122	123	125	127	129	130	130
	Dundas TS #2 (T5 / T6)	89	46	46	46	47	48	47	48	48	48	50	51	52	53	55	57	58	60	62	64	64	64
	Elgin TS (T1 / T2)	134	72	80	84	95	102	107	110	112	114	117	119	122	128	131	134	138	142	146	150	150	150
	Gage TS (T3 / T4)	57	7	7	7	12	16	16	16	15	15	16	16	16	17	17	18	18	18	19	19	19	19
	Gage TS (T5 / T6)	57	8	8	8	11	13	13	13	13	12	13	13	13	14	14	14	15	15	16	16	16	16
	Gage TS (T8 / T9)	123	11	11	11	14	17	17	16	16	16	16	17	17	18	18	19	19	20	20	21	21	21
	Kenilworth TS (T2 / T3)	124	41	42	44	46	48	50	51	53	54	55	57	58	59	61	62	64	66	68	70	70	70
	Mohawk TS (T1 / T2)	90	69	72	75	79	82	85	88	91	94	96	98	100	103	105	108	111	114	118	121	121	121
	Newton TS (T1 / T2)	75	43	44	49	60	62	64	65	66	68	69	71	73	74	76	78	81	83	85	87	87	87
	Stirton TS (T3 / T4)	112	49	50	50	50	52	54	56	58	60	62	63	65	66	68	70	72	74	76	78	78	78
	Winona TS (T1 / T2)	89	48	51	54	56	58	60	61	62	63	65	66	68	69	71	73	75	77	79	81	81	81
	CTS		0	0	21	21	22	20	19	16	11	9	7	4	4	4	4	4	4	4	4	4	4
Greater Hamilton 230 kV	Beach TS (T3/T4)	135	17	18	19	19	20	21	22	22	23	24	24	25	25	26	27	27	28	29	30	30	30
	Beach TS (T5 / T6)	96	49	52	57	59	62	64	66	68	70	72	73	75	76	79	81	83	85	87	90	90	90
	Horning TS (T3 / T4)	113	60	63	66	69	72	75	77	80	83	84	86	88	90	93	95	98	100	103	106	106	106
	Lake TS (T1 / T2)	75	44	44	44	44	44	44	44	44	44	45	45	45	45	45	45	46	46	46	47	47	47
	Lake TS (T3 / T4)	113	48	51	54	54	54	54	56	58	60	61	62	64	65	67	69	71	73	75	77	77	77
	Nebo TS (T1/T2)	178	115	117	118	120	122	124	131	133	135	137	139	141	143	145	148	151	153	156	159	162	165
	Nebo TS (T3 / T4)	51	48	50	53	55	58	60	62	64	66	68	69	70	72	74	76	78	80	83	85	85	85
	CTS		201	201	201	201	201	201	201	201	201	201	201	201	201	201	201	201	201	201	201	201	201
Caledonia Norfolk 115 kV	Norfolk TS (T1/T2)	97	60	63	68	74	80	80	89	94	98	103	106	109	112	116	119	122	126	129	133	136	139
	Bloomsburg DS (T1/T2)	49	32	35	39	53	62	59	62	64	73	75	78	81	84	88	91	93	96	99	102	104	107
Caledonia Norfolk 230 kV	Caledonia TS (T1/T2)	99	56	64	72	87	95	97	112	115	119	123	126	130	134	137	141	145	149	154	158	162	166
	Jarvis TS (T3/T4)	105	28	31	33	37	43	44	46	48	50	53	55	57	60	62	64	66	68	70	72	74	77
	CTS		123	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125

Appendix B: Lists of Step-Down Transformer Stations

Sr. No.	Transformer Station	Voltage (kV)	Supply Circuits
1	CTS	230	H35D, H36D
2	Beach TS	230	Beach TS 230 kV Bus (1)
3	Birmingham TS	115	HL3, HL4
4	Bloomsburg DS	115	C9, C12
5	Brant TS	115	B12BL, B13BL
6	Brantford TS	230	M32W, M33W
7	Bronte TS	115	B7, B8
8	Burlington TS DESN	230	Q23BM, Q25BM
9	Caledonia TS	230	N5M, S39M
10	Cumberland TS	230	B40C, B41C
11	CTS	230	Q24HM, Q29HM
12	Dundas TS	115	B3, B4
13	Dundas TS #2	115	B12BL, B13BL
14	Elgin TS	115	HL3, HL4
15	Gage TS	115	B10, B11
16	Horning TS	230	M27B, M28B
17	CTS	230	N20K
18	Jarvis TS	230	N21J, N22J
19	Kenilworth TS	115	H5K, H6K
20	Lake TS	230	B18H, B20H
21	CTS	115	B3, B4
22	Mohawk TS	115	B3, B4
23	Nebo TS	230	Q24HM, Q29HM
24	Newton TS	115	Newton TS 115 kV Bus (2)
25	Norfolk TS	115	C9, C12
26	Powerline MTS	115	B12BL, B13BL
27	Stirton TS	115	HL3, HL4
28	CTS	230	N21J, N22J
29	Winona TS	115	Q2AH

(1) Beach TS 230 kV bus is supplied by five 230 kV B18H, B20H, Q24HM, Q29HM and M34H circuits

(2) Newton TS 115 kV bus is supplied by four 115 kV B3, B4, B12BL and B13BL circuits

Appendix C: Lists of Transmission Circuits

Sr. No.	Connecting Stations	Circuit ID	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 – Summerheaven 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	B12BL, B13BL	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 D: Acronyms

Acronym	Description
A	Ampere
BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
CEP	Community Energy Plan
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
MEP	Municipal Energy Plan
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
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 D

Scoping Assessment Outcome Report

Burlington Nanticoke Region Scoping Assessment Outcome Report

December 5, 2022

ieso
Connecting Today.
Powering Tomorrow.

Table of Contents

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 regional planning process and timelines through changes to the Transmission System Code and Distribution System Code in August 2013.

This is the third cycle of regional planning for the Burlington Nanticoke region, and was initiated in spring 2022. Information and links to earlier products are available on the IESO webpage, here. The Needs Assessment is the first step in the regional planning process and was carried out by the Study Team led by Hydro One. This report was finalized on September 6, 2022 and identified some needs that may require further regional coordination. This need information was an input into the Scoping Assessment. The Study Team reviewed the nature and timing of all the known needs in the region to determine the most appropriate planning approach. It also considered past or ongoing initiatives in the region.

The Scoping Assessment considers three potential planning approaches for the region (or sub-regions, if applicable), including: an IRRP – where both wires and non-wires options have potential to address needs; a 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.

This Scoping Assessment report:

- Lists the needs requiring more comprehensive planning, as identified in the Needs Assessment report;
- Reassesses the areas that need to be studied and the geographic grouping of the needs (if required);
- Determines the appropriate regional planning approach and scope where a need for regional coordination or more comprehensive planning is identified;
- Establishes a terms of reference for an IRRP, if an IRRP is required; and
- Establishes the composition of the Technical Working Group.

2. Study Team

The Scoping Assessment was carried out with the following participants:

- Independent Electricity System Operator (IESO)
- Hydro One Networks Inc. (Transmission)
- Hydro One Networks Inc. (Distribution)
- Alectra Utilities Corporation
- Burlington Hydro Inc.
- GrandBridge Energy Inc. (Formerly Energy+ and Brantford Power)
- Oakville Hydro Inc.

3. Categories of Needs, Analysis, and Results

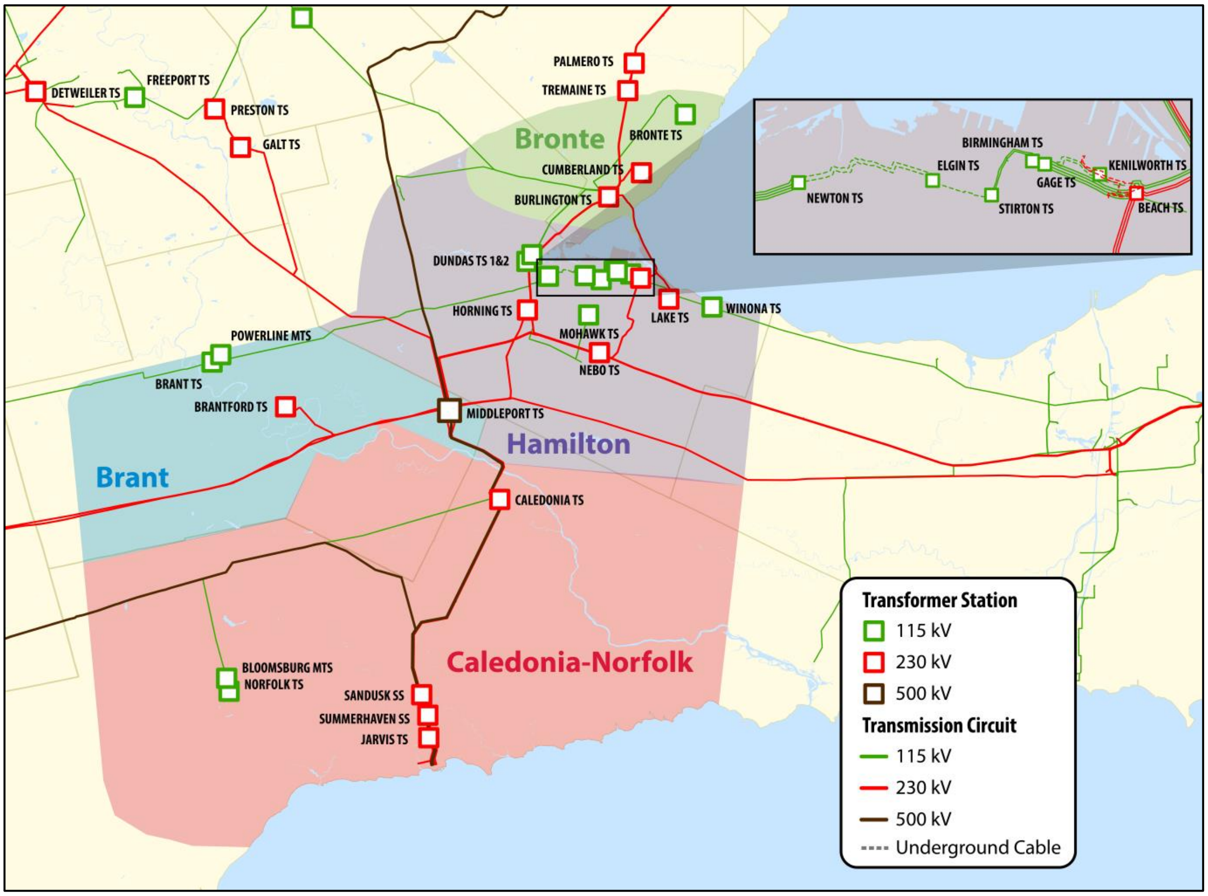
3.1 Overview of the Region

The Burlington to Nanticoke region is located in southwestern Ontario and includes all or part of the following Counties and Districts: City of Hamilton, Brant County, the City of Brantford, Haldimand County, Norfolk County, and the Regional Municipality of Halton. For electricity planning purposes, the planning region is defined by electricity infrastructure boundaries, not municipal boundaries.

Several Indigenous communities are located in or near the region including: Chippewas of the Thames, Mississaugas of the New Credit, Munsee-Delaware Nation, Oneida Nation of the Thames, Six Nations of the Grand River and the Haudenosaunee Confederacy Chiefs Council. The Huron Wendat Nation, now located in Wendake, Quebec, also has a historical interest in southern Ontario. A number of Métis Nation of Ontario (MNO) councils are also located within or near the region including MNO Clear Waters Métis Council (Brantford), MNO Credit River Métis Council (Mississauga) and MNO Niagara Region Métis Council.

The electricity infrastructure supplying the Burlington to Nanticoke region is shown in Figure 1. For the purposes of regional planning, the Burlington to Nanticoke region has historically been sub-divided into four sub-regions: Bronte, Hamilton, Brant, and Caledonia-Norfolk.

Figure 3-1 | Overview of the Burlington Nanticoke Region



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

The Bronte sub-region includes Burlington TS and the 230 kV and 115 kV supply northeast of the station which services Cumberland TS and Bronte TS, respectively. The 115 kV supply southwest from Burlington TS and the 230 kV supply from Beach TS service the 115 kV network in the Hamilton sub-region, while 230 kV circuits between Burlington TS and Beach TS, Beach TS and Middleport TS, and Middleport TS and Burlington TS supply the Hamilton sub-region's 230 kV connected load supply stations. The Brant sub-region is supplied from the 230 kV supply west from Middleport TS and a 115 kV supply from Burlington TS. The 230 kV supply south from Middleport TS supplies the 230 kV connected stations in the Caledonia-Norfolk sub-region, including Caledonia TS. The 115 kV supply from Caledonia TS then supplies Bloomsburg MTS and Norfolk TS.

3.2 Background of the Previous Planning Process

The regional planning process was formalized by the OEB in August 2013. To prioritize and manage the process, Ontario was organized into 21 regions based on electricity infrastructure boundaries; each of which were assigned to one of three groups based on urgency of need, where Group 1 Regions were being reviewed first. When the Board formalized the regional planning process in 2013 planning work was already ongoing in the Brant area, a sub-region of the Burlington to Nanticoke region. As such, Burlington to Nanticoke became one of the Group 1 planning regions, the first group to undergo the formalized regional planning process.

On May 23, 2014, Hydro One Transmission published the first needs assessment report for the region. Subsequently on September 25, 2014, the former OPA (now the IESO) published a scoping assessment report for the Burlington to Nanticoke region which specified the terms of reference for the Bronte IRRP, in addition to the already published terms of reference for the Brant IRRP which was already underway. No IRRP was required at the time for the Hamilton or Caledonia-Norfolk sub-regions. Regional plans were completed for the Brant and Bronte sub-regions in April 2015 and June 2016, respectively, and Hydro One completed a Local Planning Report for the broader region in October 2015, and a Burlington to Nanticoke RIP on February 7, 2017.

The second round of regional planning for Burlington-Nanticoke began with a Hydro One led Needs Assessment, completed in May of 2017. Based on these needs, the subsequent Scoping Assessment recommended the initiation of a Hamilton IRRP, which was completed in February 2019. This IRRP focused heavily on the large number of assets in the Hamilton area which were approaching their expected end-of-life. The IRRP explored opportunities to "right-size" equipment; that is, refurbish with a higher or lower rating depending on how capacity needs in the area have changed since it was originally installed. Capacity needs at two area stations were also studied, with recommendations ranging form upsizing at end-of life, and implementation and monitoring of CDM and non wires alternatives to defer the need for further infrastructure investment.

Additional information and links to reports form previous cycles are available on the IESO regional planning website for Burlington Nanticoke, available here.

Hydro One completed the most recent needs assessment for the Burlington to Nanticoke region on September 6th, 2022. The needs identified form the basis of the analysis for the scoping assessment and are discussed in further detail in section 3.3.

3.3 Needs Identified

Hydro One's Needs Assessment provided an update on needs identified in the previous planning cycle and the implementation of projects recommended to address them. It also identified new needs in the Burlington Nanticoke region based on the most up-to-date sustainment plans and a new 10-year demand forecast. A summary of the current projects and plans underway to respond to existing needs, plus the new needs, are outlined below.

3.3.1 Projects and Plans underway to address previously identified Needs

The Needs Assessment report lists the needs identified from the previous planning cycle, and provides an update on the status of project implementation. Table 3-1 below summarizes this. These projects provide a basis for future assessments and should be accounted for in this planning cycle.

Table 3-1 | Needs Identified in the Previous Cycle and Implementation Plan Update

Need	Solution and Timing
115kV B7/B8 section from Burlington TS to Nelson Jct	Planned refurbishment for 2024 in-service
Dundas TS	Load transfers and balancing Planned 2023 in-service
Gage TS	Replacement of T3/T4 and T5/T6 transformers and switchgear, planned Q4 2023 in-service
Kenilworth TS	Power factor correction planned for 2023-2024 timeframe
Norfolk area Supply Capacity[1]	Load transfers from Norfolk TS to Jarvis TS planned by the end of 2022 Additional reactive support planned for Norfolk TS in 2023-2024 timeframe Jarvis TS upgrade with additional feeders to enable additional Norfolk area transfers, planned for 2027-2032 timeframe

Since the previous regional planning cycle, solutions to address the following needs have also been implemented:

- Cumberland TS: Power factor correction
- 115kV B3/B4 section from Horning Mountain Jct to Glanford Jct refurbishment
- Elgin TS: Transformer & switchgear replacement
- Newton TS: Transformer replacement
- Kenilworth TS: Transformer & switchgear replacement

3.3.2 Needs identified in the Current Planning Cycle

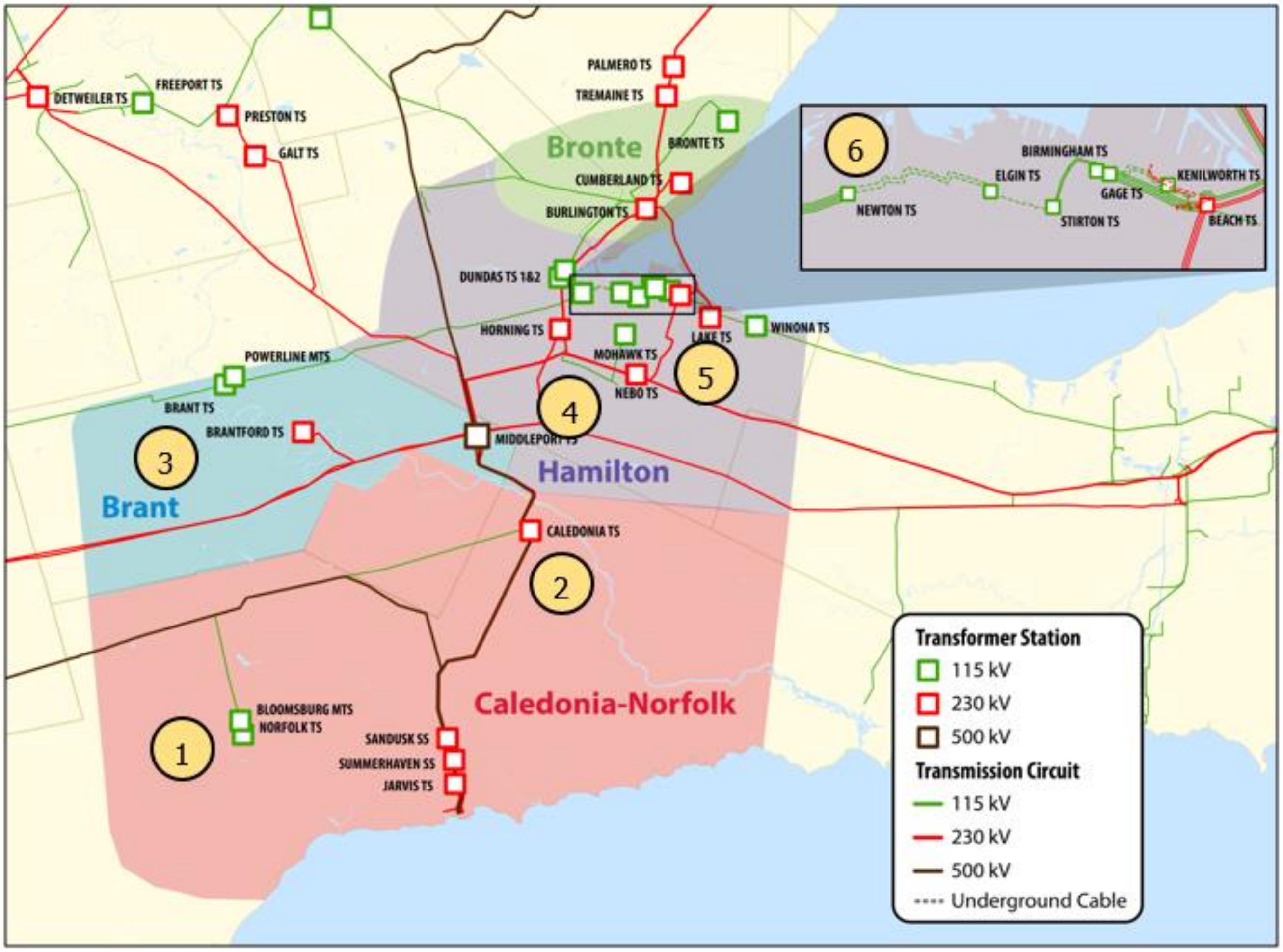
The Needs Assessment then identified new or updated needs in the Burlington to Nanticoke region using the 10-year station-level demand forecast provided by the local distribution companies (LDCs), updated end-of-life asset condition information from Hydro One, as well as the conservation and demand management (CDM) and distributed generation (DG) forecast provided by the IESO. Table 3-2 below lists these regional needs and their timing. Their locations are shown in Figure 3-3.

Table 3-2 | Updated Regional Needs Identified in the Needs Assessment

[1] These needs were identified between planning cycles due to changes in the forecast growth for the sub-region.

Need #	Station/Circuit	Description of Need
1	Norfolk TS and Bloomsburg DS	• Station capacity expected to be exceeded in 2030 and 2025, respectively. Currently planned to be addressed through load transfers to upgraded Jarvis TS and new feeder connections in the 2027-2032 timeframe
2	Caledonia TS	• Station capacity expected to be exceeded in 2030
3	Brant Area Supply	• The coincident load of the Brant area is expected to exceed the LMC of the three 115 kV supply circuits supplying the area within the study period (2022-2032)
4	Nebo TS	• Station capacity expected to be exceeded over planning horizon. However, this station is expected to be refurbished in the 2027-2032 timeframe, and 75 MVA transformers could potentially be replaced with 100 MVA units at that time to increase capacity
5	Mohawk TS	• Station capacity expected to be exceeded in 2024
6	Newton TS 115 kV breakers	• Have been identified for replacement based on asset condition assessment • Refurbishment recommended as part of Needs Assessment

Figure 3-3 | Geographic Location of Needs Identified in the Needs Assessment



3.3.3 Analysis of Needs and Identification of Region

The Study Team has discussed the needs in the Burlington Nanticoke region and potential planning approaches to address them. The preferred planning approach is generally informed by:

- Timing of the need, including lead time to develop solutions
- The potential linkages between needs and their required coordination, particularly if across overlapping LDC territories or planning Regions
- The opportunity for public engagement to inform outcomes
- The potential for exploring multiple types of options to meet the needs (including non-wires alternatives)
- The potential for regional changes having implications on the upstream bulk power system

In general, the more complex a series of needs and the greater the need for coordination and engagement, the more likely an IRRP will be selected. If needs have few available solutions, are relatively straight forward, and can be implemented without affecting neighbouring areas or the bulk power system, then a more streamlined planning approach with a narrower scope may be appropriate.

Of the six updated regional needs identified in the Needs Assessment, most have a fairly limited geographic impact, which makes them suitable to be considered in more discrete blocks:

1. Needs 1 and 2 (Norfolk TS, Bloomsburg DS, and Caledonia TS) are both primarily driven by increases in local peak electrical demand. Given the rate of growth is expected to be somewhat modest, these needs may be good candidates to consider non wires alternatives as a way to defer the need for infrastructure investments. The potential to shift load between stations in this pocket also makes it a good candidate for a shared scope of study.
2. Need 3 (Brant area supply), is another area whose needs are primarily driven by increases in peak demand. Because the need is expected to be triggered by the combined load of supply circuits, the combined step down stations in the sub region must be considered as a collective unit, and transfers between stations would not be an effective option to address supply needs. Instead, non wires alternatives may be considered as a potential deferment strategy compared to traditional wires infrastructure.
3. Needs 4, 5, and 6 (Hamilton area), are primarily driven by growth in peak capacity or aging infrastructure needs with consideration of a number of refurbishment opportunities within the planning timeline. The close proximity of loads, high anticipated growth rates from new development and intensification, and potential opportunity for right sizing of infrastructure during refurbishment all present opportunities to consider needs in a coordinated manner. Options to address needs would include conventional infrastructure and non wires alternatives. The area is also in close proximity, and shares key infrastructure, with parts of the bulk power system. This may require more detailed analysis during a study to understand potential impacts of needs or solutions on the regional vs bulk system.

The associated timelines for these needs vary, but are all within the near- (0-5 years) to mid-term (5-10 years), which suggests planning should be undertaken within the current regional planning cycle to ensure options can be evaluated and a preferred outcome selected and implemented in time.

Recommendation: Given the shared geographic impact of certain needs, and opportunities which may arise from considering solutions to those needs in a coordinated manner, separate studies should be undertaken for each of three sub-regions: Hamilton, Brant, and Caledonia-Norfolk. Due to the greater number of potential solutions to consider, the potential bulk system impact, and additional end of life opportunities, the full 18 months' timeline is expected to be required for the more complex Hamilton IRRP. The more limited number of needs and potential solutions, in addition to a smaller area of interest with limited bulk system impact, suggests the Brant and Caledonia-Norfolk IRRPs could be completed with an expedited 12-month timeline.

4. Conclusion and Next Steps

The Scoping Assessment concludes that:

- Further coordinated regional planning is required to identify, evaluate, and recommend solutions to address needs in three sub-regions of the Burlington-Nanticoke Region:
    1. A full scope IRRP is recommended for Hamilton, with a focus on accommodating overall demand growth, potential interactions with the local bulk system, and addressing options for equipment end of life. This will include needs identified in the Needs Assessment, as well as potential needs identified in the 2019 Hamilton IRRP as requiring monitoring.
    2. A reduced scope IRRP is recommended for Brant, with a focus on supply to the pocket and station capacity needs.
    3. A reduced scope IRRP for Caledonia-Norfolk, with a focus on station capacity and refurbishment needs.
- No further coordinated regional planning is required at this time for the Bronte sub-region

All IRRPs will include opportunities for engagement with local communities and stakeholders, as well as include discussion of any local initiatives focused on energy and/or reducing GHG emissions, and how the IRRP can coordinate with these plans. This could include Community Energy Plans, Net-Zero strategies, or similar. Particular attention will be paid to opportunities for information sharing and/or coordination of goals and outcomes.

The draft Terms of Reference for the Hamilton IRRP, Brant IRRP, and Caledonia-Norfolk IRRP are attached in Appendix 2.

Appendix 1 – List of Acronyms

Acronym	Definition
CDM	Conservation and Demand Management
DG	Distributed Generation
FIT	Feed-in-Tariff
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	kilovolt
LAPS	Local Achievable Potential Study
LDC	Local Distribution Company
MNO	Métis Nation of Ontario
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
TS	Transformer Station

Appendix 2 – Brant Sub-Region Integrated Regional Resource Plan (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 IRRP of the Brant sub-region.

Based on the potential for demand growth within this 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.

Brant Sub-region

The Brant sub-region is one of the four sub-regions within the larger Burlington to Nanticoke planning region. The Burlington to Nanticoke region includes the 500 kV, 230 kV, and 115 kV electricity infrastructure located in Southwestern Ontario. The region is split into four smaller sub-regions for planning purposes: Bronte, Brant, Hamilton, and Caledonia-Norfolk. The Brant sub-region is a summer-peaking region that is serviced by 230 kV, and 115 kV circuits and transformer stations. The approximate geographical boundaries of the sub-region are shown in Figure A-3.

Figure A-3 | Overview of the Sub-region

The Brant sub-region includes the County of Brant, City of Brantford, and the surrounding areas. For electricity planning purposes, the planning region is defined by electricity infrastructure boundaries, not municipal boundaries.

Indigenous communities located in or near the Brant sub-region are: Mississaugas of the New Credit, Six Nations of the Grand River and the Haudenosaunee Confederacy Chiefs Council. Three Métis Nation of Ontario (MNO) councils are also located within or near the region: MNO Clear Waters Métis Council (Brantford), MNO Credit River Métis Council (Mississauga) and MNO Niagara Region Métis Council.

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

Brant Sub-Region Electricity System

The electricity system supplying the Brant sub-region is shown in Figure A-4.

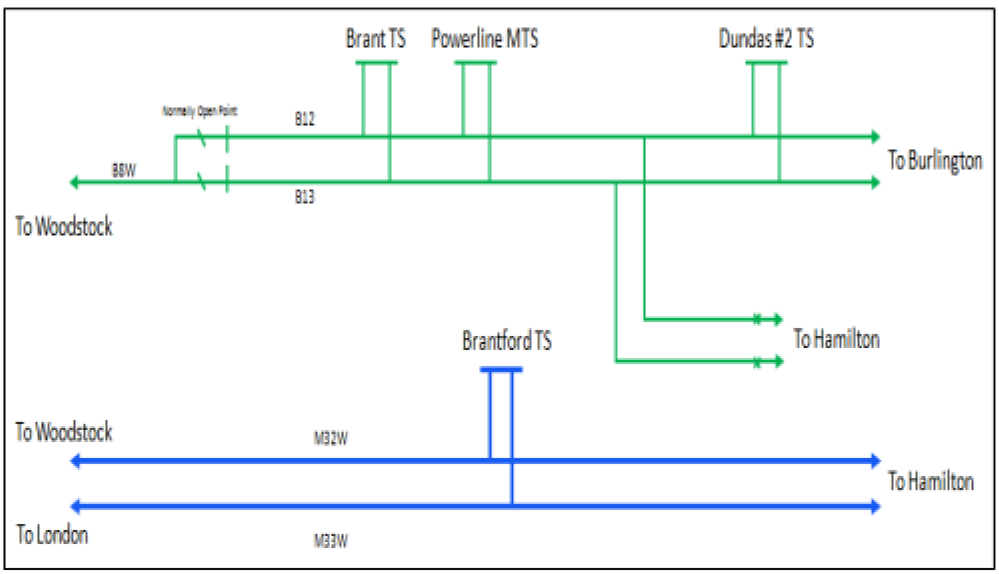


Figure A-4 | Brant Sub-Region Electricity System

The Brant sub-region is comprised of three transformer stations and a number of 115 kV and 230 kV circuits. The Brant sub-region is supplied from the 230 kV supply west from Middleport TS (located in Hamilton) and a 115 kV supply from Burlington TS (located in Bronte).

Background

In the last regional planning cycle for the Burlington to Nanticoke region, a needs assessment was conducted for the entire region and was published in 2017. This needs assessment concluded that further regional planning was required for the Hamilton sub-region only. The Hamilton sub-region IRRP was published in 2019, while local planning was implemented in the other three sub-regions.

In September 2022, Hydro One completed the 3rd Cycle Needs Assessment report for the Burlington to Nanticoke region. A system capacity need, for the 115 kV system that supplies the Brant area, was identified in the sub-region. This need is dependant on the load levels in Hamilton, specifically the load levels at the Dundas DESNs. It was determined that this need required regional coordination and the consideration of non-wires alternatives, and as such, an IRRP would be required for the sub-region. The load forecasting for the Brant IRRP will coincide with the Hamilton IRRP load forecast which will be incorporated in the load flow simulations to capture the impact on the supply capacity to the Brant area.

2. Objectives

1. To assess the adequacy of electricity supply to customers in the Brant sub-region over the next 20 years.
2. To address the sub-region's system capacity needs, and develop a flexible, comprehensive, integrated electricity plan for the sub-region.
3. To develop an implementation plan, while maintaining flexibility in order to accommodate changes in key assumptions over time. The implementation plan should identify actions for near-term needs, preparation work for mid-term needs, and the planning direction for long-term needs.

3. Scope

This IRRP will develop and recommend an integrated plan to meet the needs of the Brant sub-region. The plan is a joint initiative involving GrandBridge Energy Inc., Hydro One Distribution, Hydro One Transmission, and the IESO, and will incorporate input from community engagement. The plan will focus on the identified system capacity need in the sub-region. It will also integrate forecast electricity demand growth, conservation and demand management in the area with transmission and distribution system capability, end-of-life of major facilities in the area, relevant community plans, any relevant bulk system developments, and generation uptake.

This IRRP will address regional needs in the Brant sub-region. Specifically, the following existing infrastructure is included in the scope of this study:

- 115 kV connected transformer stations: Brant TS, Powerline MTS
- 230 kV connected transformer stations: Brantford TS
- 115 kV transmission circuits: double circuit B12BL(B12)/B13BL(B13), B2(B8W)
- 230 kV transmission circuits: double circuit M32W/M33W

The Brant IRRP will:

- Prepare a 20-year electricity demand forecast for the appropriate stations and establish needs over this timeframe;
- Examine the load meeting capability and reliability of the existing transmission system supplying the 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 sub-region; and
- Evaluate options using decision-making criteria including but not limited to: technical feasibility, economics, reliability performance, and 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 region
    - Historical weather correction, median and extreme conditions
    - Gross peak demand forecast scenarios by region and TS, etc.
    - Coincident peak demand data, including transmission-connected customers
    - Identified potential future load customers
    - Customer/load segmentation information (e.g. residential, commercial, industrial) by TS
- Conservation and Demand Management
    - Conservation forecast for LDC customers, based on region's share of current energy efficiency programs and/or those reflected in the forecast for the most recent Annual Planning Outlook
    - Potential for CDM at transmission-connected customers' facilities
- Local resources
    - Existing local generation, including distributed generation, 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
    - Indigenous Community Energy 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
- End-of-life asset considerations/sustainment plans
- Other considerations, as applicable

5. Technical Working Group

The core Technical Working Group will consist of planning representatives from the following organizations:

- GrandBridge Energy Inc.
- Independent Electricity System Operator *(Team Lead for IRRP)*
- Hydro One Networks Inc. (Distribution)
- Hydro One Networks Inc. (Transmission)

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.

6. 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 Technical Working Group is committed to conducting plan-level engagement throughout the development of the Brant Sub-region IRRP.

The first step in engagement will consist of the development of a public engagement plan, which will be made available for comment before it is finalized. The data and assumptions as outlined in Section 4.0 will help to inform the scope of community and stakeholder engagement to be considered for this IRRP.

7. Activities, Timeline, and Primary Accountability

Activity	**Lead Responsibility**	**Deliverable(s)**	**Timeframe**
1. Prepare Terms of Reference considering stakeholder input	IESO	Finalized Terms of Reference	Q4 2022
2. Develop the summer planning forecast for the sub-region[2]		Long-term planning forecast scenarios	Q1 2023
Establish historical coincident (for the sub-region and the 115 kV system) 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	IESO, LDCs		
Establish near- and long-term conservation forecast based on planned energy efficiency activities and codes and standards	IESO		

[2] Will be coordinated with the forecasting activities for the Hamilton IRRP.

Activity	Lead Responsibility	Deliverable(s)	Timeframe
Develop a high planning forecast scenario for sensitivity analyses, as appropriate (including but not limited to: consideration of electric vehicle/transportation trends and potential impact on Brant sub-region demand)	IESO		
3. Confirm load transfer capabilities under normal and emergency conditions – for the purpose of analyzing transmission system needs and identifying options for addressing these needs	LDCs	Load transfer capabilities under normal and emergency conditions	Q3 2023
4. Provide and review relevant community plans, if applicable	LDCs, public stakeholders, and IESO	Relevant community plans	Q3 2023
Complete system studies to identify needs over a 20-year time horizon Obtain PSS/E base case 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 2023
6. Develop options and alternatives		Develop flexible planning options for forecast scenarios	Q4 2023
Conduct a screening to identify which non-wires options warrant further analysis	IESO		
Verify the LMC of the 115 kV system to better determine timing of needs and support options development	IESO		

Activity	Lead Responsibility	Deliverable(s)	Timeframe
Develop screened-in energy efficiency options	IESO and LDCs		
Develop screened-in local generation/demand management options	IESO and LDCs		
Develop the transmission and distribution alternatives (i.e., alignment with EOL sustainment plans, load transfers)	IESO, Hydro One Transmission, and LDCs		
Develop portfolios of integrated alternatives	IESO, Hydro One Transmission, and LDCs		
Technical comparison and evaluation	IESO, Hydro One Transmission, and LDCs		
7. Plan and undertake community & stakeholder engagement		Community and Stakeholder Engagement Plan Input from local communities, First Nation communities, and Métis Nation of Ontario	Ongoing as required IRRP engagement would be launched in Q3 2023
Early engagement including 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	IESO, Hydro One Transmission, and LDCs		

Activity	Lead Responsibility	Deliverable(s)	Timeframe
Develop communications materials	IESO, Hydro One Transmission, and LDCs		
Undertake community and stakeholder engagement	IESO, Hydro One Transmission, and LDCs		
Summarize input and incorporate feedback	IESO, Hydro One Transmission, and LDCs		
8. Develop long-term recommendations and implementation plan based on community and stakeholder input	IESO	Implementation plan Monitoring activities and identification of decision triggers Procedures for annual review	Q1 2024
9. Prepare the IRRP report detailing the recommended near, medium, and long-term plan for approval by all parties	IESO	IRRP report	Q2 2024

Appendix 3 – Caledonia - Norfolk Sub-Region Integrated Regional Resource Plan (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 IRRP of the Caledonia-Norfolk sub-region.

Based on the potential for demand growth within this 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.

Caledonia-Norfolk Sub-region

The Caledonia-Norfolk sub-region is one of the four sub-regions within the larger Burlington to Nanticoke planning region. The Burlington to Nanticoke region includes the 500 kV, 230 kV, and 115 kV electricity infrastructure located in Southwestern Ontario. The region is split into four smaller sub-regions for planning purposes: Bronte, Brant, Hamilton, and Caledonia-Norfolk. The Caledonia-Norfolk sub-region is the southern-most portion of the Burlington to Nanticoke region, and includes 115 kV and 230 kV circuits and transformer stations. The approximate geographical boundaries of the sub-region are shown in Figure A-3.

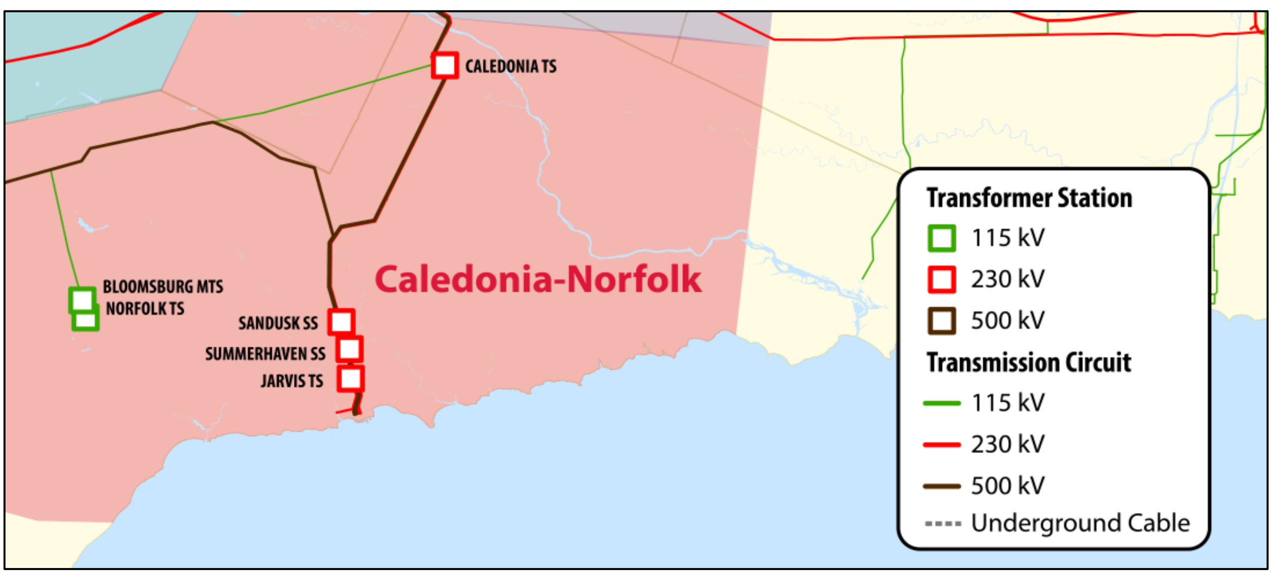


Figure A-3 | Overview of the Sub-region

The Caledonia-Norfolk sub-region covers the eastern part of Norfolk County and the western part of Haldimand County. For electricity planning purposes, the planning region is defined by electricity infrastructure boundaries, not municipal boundaries.

Indigenous communities located in or near the Caledonia-Norfolk sub-region are: Mississaugas of the New Credit, Six Nations of the Grand River and the Haudenosaunee Confederacy Chiefs Council. Three Métis Nation of Ontario (MNO) councils are also located within or near the region: MNO Clear Waters Métis Council (Brantford), MNO Credit River Métis Council (Mississauga) and MNO Niagara Region Métis Council.

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

Caledonia-Norfolk Sub-Region Electricity System

The electricity system supplying the Caledonia-Norfolk sub-region is shown in Figure A-4.

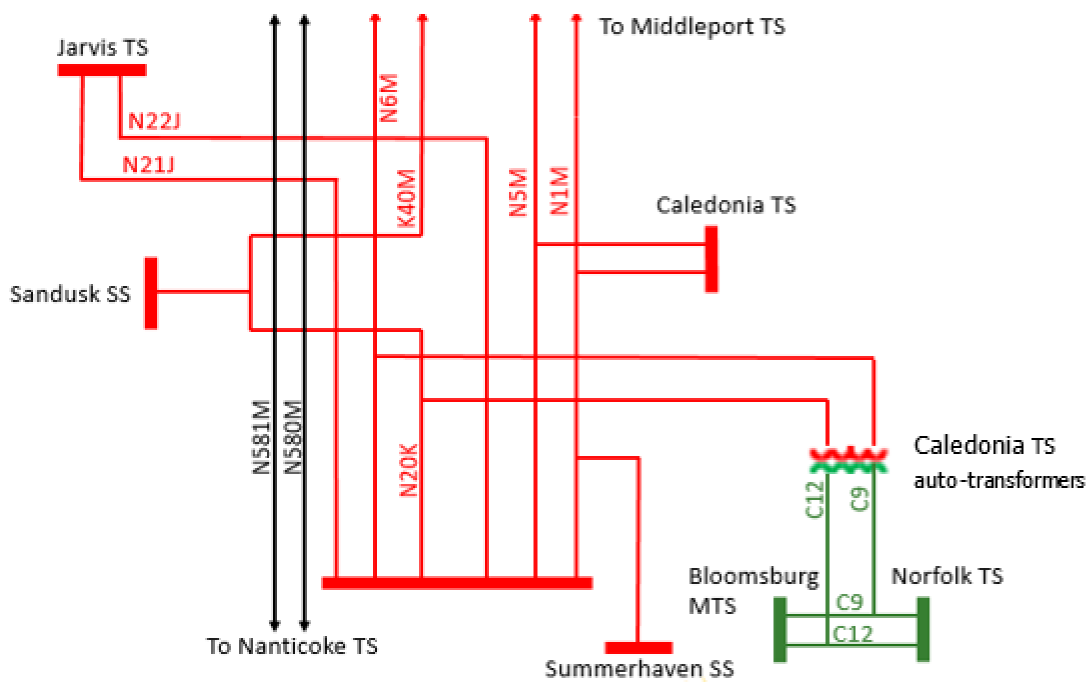


Figure A-4 | Burlington to Nanticoke Electricity System

The Caledonia-Norfolk sub-region is supplied by the 230 kV corridor that runs between Middleport TS, a 500/230 kV station located in the centre of the Burlington to Nanticoke region, and Nanticoke TS. The sub-region is comprised of six transformer stations. Specifically, the sub-region contains four 230 kV stations: Caledonia TS, Jarvis TS, and two customer owned transformer stations; in additon to two 115 kV transformer stations: Bloomsburg MTS and Norfolk TS. The 115 kV transformer stations are supplied by two 115 kV circuits: C9 and C12 which are supplied from Caledonia TS 230/115 kV autotransformers.

Background

In the last regional planning cycle for the Burlington to Nanticoke region, a Needs Assessment was conducted for the entire region and was published in 2017. This needs assessment concluded that further regional planning was required for the Hamilton sub-region only. The Hamilton sub-region

IRRP was published in 2019, while local planning was implemented in the other three sub-regions. Three needs were identified and recommended to be addressed through local planning in the Caledonia-Norfolk sub-region: the end-of-life of the LV switchgear at Norfolk TS, the end-of-life of the T1 transformers at Caledonia TS, and the end-of-life of the T3 and T4 transformers at Jarvis TS.

During the final step of regional planning in the last cycle – the Regional Infrastructure Plan ("RIP"), emerging capacity needs were identified in the Caledonia-Norfolk sub-region due to the new load growth in the Norfolk area. The RIP recommended near term solutions to address the overloads observed in the Norfolk area which include a new capacitor bank at Norfolk TS and load transfers from Norfolk TS to Jarvis TS. The RIP recommended a further assessment be carried out by the IESO and Hydro One to further examine the load growth, examine options and identify a recommended plan.

However, a large portion of the emerging capacity needs was driven by forecast load growth in the cannabis sector and load forecast uncertainty emerged before any planning reports were finalized, putting planning work on hold for the sub-region.

In September 2022, Hydro One completed the newest needs assessment for the Burlington to Nanticoke region. Two station capacity needs were identified in the Caledonia-Norfolk sub-region, at Norfolk TS (and Bloomsburg DS) and Caledonia TS. It was determined that these needs required regional coordination and as such, an IRRP would be required for the sub-region.

2. Objectives

1. To assess the adequacy of electricity supply to customers in the Caledonia-Norfolk sub-region over the next 20 years.
2. To address the sub-region's long-term capacity needs and demand forecast, and develop a flexible, comprehensive, integrated electricity plan for the sub-region.
3. To develop an implementation plan, while maintaining flexibility in order to accommodate changes in key assumptions over time. The implementation plan should identify actions for near-term needs, preparation work for mid-term needs, and the planning direction for long-term needs.

3. Scope

This IRRP will develop and recommend an integrated plan to meet the needs of the Caledonia-Norfolk sub-region. The plan is a joint initiative involving Hydro One Distribution, Hydro One Transmission, and the IESO, and will incorporate input from community engagement. The plan will focus on the identified capacity needs in the sub-region. It will also integrate forecast electricity demand growth, conservation and demand management in the area with transmission and distribution system capability, end-of-life of major facilities in the area, relevant community plans, any relevant bulk system developments, and generation uptake.

This IRRP will address regional needs in the Caledonia-Norfolk sub-region. Specifically, the following existing infrastructure is included in the scope of this study:

- 230 kV connected transformer stations: Caledonia TS, Jarvis TS and two customer owned transformer stations
- 115 kV connected transformer stations: Bloomsburg MTS and Norfolk TS
- 115 kV transmission circuits: C9 and C12
- 230 kV transmission circuits: N5M, N6M, N20K, N21J, N22J, K40M, and S39M

The Caledonia-Norfolk IRRP will:

- Prepare a 20-year electricity demand forecast for the appropriate stations and establish needs over this timeframe;
- Examine the load meeting capability and reliability of the existing transmission system supplying the 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 sub-region; and
- Evaluate options using decision-making criteria including but not limited to: technical feasibility, economics, reliability performance, and 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 region
    - Historical weather correction, median and extreme conditions
    - Gross peak demand forecast scenarios by region and TS, etc.
    - Coincident peak demand data, including transmission-connected customers
    - Identified potential future load customers
    - Customer/load segmentation information (e.g. residential, commercial, industrial) by TS
- Conservation and Demand Management
    - Conservation forecast for LDC customers, based on region's share of current energy efficiency programs and/or those reflected in the forecast for the most recent Annual Planning Outlook
    - Potential for CDM at transmission-connected customers' facilities
- Local resources
    - Existing local generation, including distributed generation, 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
    - Indigenous Community Energy 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
- End-of-life asset considerations/sustainment plans
- Other considerations, as applicable

5. Technical Working Group

The core Technical Working Group will consist of planning representatives from the following organizations:

- Independent Electricity System Operator *(Team Lead for IRRP)*

- Hydro One Networks Inc. (Distribution)
- Hydro One Networks Inc. (Transmission)

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.

6. 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 Technical Working Group is committed to conducting plan-level engagement throughout the development of the Caledonia-Norfolk IRRP.

The first step in engagement will consist of the development of a public engagement plan, which will be made available for comment before it is finalized. The data and assumptions as outlined in Section 4.0 will help to inform the scope of community and stakeholder engagement to be considered for this IRRP.

7. Activities, Timeline, and Primary Accountability

Activity	Lead Responsibility	Deliverable(s)	Timeframe
1. Prepare Terms of Reference considering stakeholder input	IESO	Finalized Terms of Reference	Q4 2022
2. Develop the summer planning forecast for the sub-region		Long-term planning forecast scenarios	Q4 –Q1 2023
Establish historical coincident (for the sub-region) and non-coincident (for Norfolk TS and Caledonia TS) peak demand information	IESO		
Establish historical weather correction, median and extreme conditions	IESO		
Establish gross peak demand forecast	LDCs		

Activity	Lead Responsibility	Deliverable(s)	Timeframe
Establish existing, committed, and potential DG	IESO, LDCs		
Establish near- and long-term conservation forecast based on planned energy efficiency activities and codes and standards	IESO		
Develop a high planning forecast scenario for sensitivity analyses, as appropriate (including but not limited to: consideration of electric vehicle/transportation trends and potential impact on Caledonia-Norfolk sub-region demand)	IESO		
3. Confirm load transfer capabilities under normal and emergency conditions – for the purpose of analyzing transmission system needs and identifying options for addressing these needs	LDCs	Load transfer capabilities under normal and emergency conditions	Q1 2023
4. Provide and review relevant community plans, if applicable	LDCs, public stakeholders, and IESO	Relevant community plans	Q1 2023
5. Complete system studies to identify needs over a 20-year time horizon - Obtain PSS/E base case - 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	Q1 – Q2 2023
6. Develop options and alternatives		Develop flexible planning options for forecast scenarios	Q2 2023

Activity	Lead Responsibility	Deliverable(s)	Timeframe
Conduct a screening to identify which non-wires options warrant further analysis	IESO		
Produce hourly forecasts for Norfolk TS and Caledonia TS to enable detailed needs characterization and support options development	IESO		
Develop screened-in energy efficiency options	IESO and LDCs		
Develop screened-in local generation/demand management options	IESO and LDCs		
Develop the transmission and distribution alternatives (i.e., alignment with EOL sustainment plans, load transfers)	IESO, Hydro One Transmission, and LDCs		
Develop portfolios of integrated alternatives	IESO, Hydro One Transmission, and LDCs		
Technical comparison and evaluation	IESO, Hydro One Transmission, and LDCs		
7. Plan and undertake community & stakeholder engagement		Community and Stakeholder Engagement Plan Input from local communities, First Nation communities, and Métis Nation of Ontario	Ongoing as required

Activity	Lead Responsibility	Deliverable(s)	Timeframe
Early engagement including 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	IESO, Hydro One Transmission, and LDCs		
Develop communications materials	IESO, Hydro One Transmission, and LDCs		
Undertake community and stakeholder engagement	IESO, Hydro One Transmission, and LDCs		
Summarize input and incorporate feedback	IESO, Hydro One Transmission, and LDCs		
8. Develop long-term recommendations and implementation plan based on community and stakeholder input	IESO	Implementation plan Monitoring activities and identification of decision triggers Procedures for annual review	Q2 – Q3 2023
9. Prepare the IRRP report detailing the recommended near, medium, and long-term plan for approval by all parties	IESO	IRRP report	Q2 – Q3 2023

Appendix 4 – Hamilton Sub-Region Integrated Regional Resource Plan (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 IRRP of the Hamilton sub-region.

Based on the potential for demand growth within this 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.

Hamilton Sub-region

The Hamilton sub-region is one of the four sub-regions within the larger Burlington to Nanticoke planning region. The Burlington to Nanticoke region includes the 500 kV, 230 kV, and 115 kV electricity infrastructure located in Southwestern Ontario. The region is split into four smaller sub-regions for planning purposes: Bronte, Brant, Hamilton, and Caledonia-Norfolk. The Hamilton sub-region is a summer-peaking region that includes the City of Hamilton and is serviced by 230 kV, and 115 kV circuits and transformer stations. The approximate geographical boundaries of the sub-region are shown in Figure A-3.

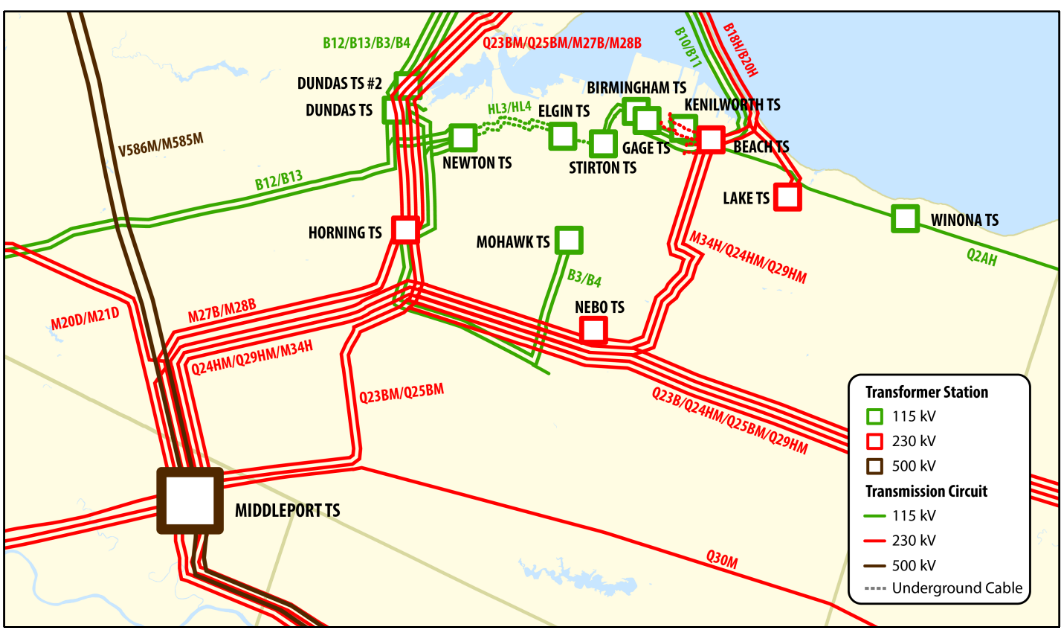


Figure A-3 | Overview of the Sub-region

The City of Hamilton includes the communities of Hamilton, Flamborough, Dundas, Ancaster, Glanbrook, Binbrook, Waterdown, and Stoney Creek. For electricity planning purposes, the planning region is defined by electricity infrastructure boundaries, not municipal boundaries.

Indigenous communities located in or near the Hamilton sub-region are: Mississaugas of the New Credit, Six Nations of the Grand River and the Haudenosaunee Confederacy Chiefs Council. Three Métis Nation of Ontario (MNO) councils are also located within or near the region: MNO Clear Waters Métis Council (Brantford), MNO Credit River Métis Council (Mississauga) and MNO Niagara Region Métis Council.

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

Hamilton Sub-Region Electricity System

The electricity system supplying the Hamilton sub-region is shown in Figure A-4.

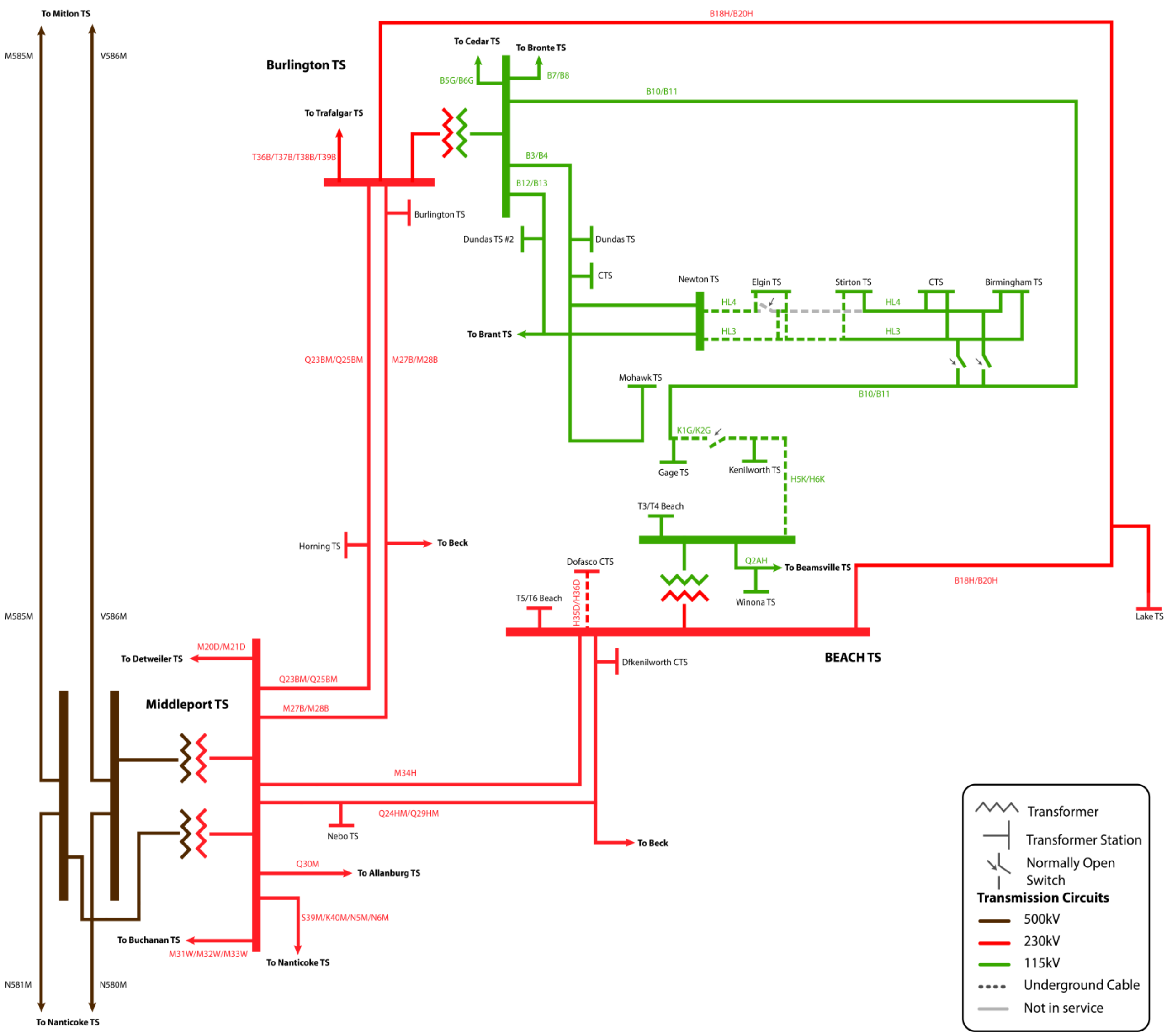


Figure A-4 | Hamilton Sub-Region Electricity System

The Hamilton sub-region is comprised of eighteen transformer stations and a number of 115 kV and 230 kV circuits. The 115 kV system in the sub-region is supplied by the 115 kV supply from Burlington TS (located north of Hamilton in Bronte) and the 230 kV supply from Beach TS. The primary 230 kV circuits between Burlington TS and Beach TS, Beach TS and Middleport TS, and Middleport TS and Burlington TS supply the sub-region's 230 kV connected load supply stations.

Background

In the last regional planning cycle for the Burlington to Nanticoke region, a needs assessment was conducted for the entire region and was published in 2017. This needs assessment concluded that further regional planning was required for the Hamilton sub-region only. The Hamilton sub-region IRRP was published in 2019, while local planning was implemented in the other three sub-regions. The 2019 Hamilton Sub-region IRRP recommended replacements of multiple pieces of equipment reaching the end-of-life, including the switchgear at Lake TS T1/T2, the transformers and the low voltage switchgear at Newton TS, the T5/T6 low voltage switchgear at Beach TS, the Beach TS 230 kV/115 kV autotransformers, and various underground cables (H5K/H6K, K1G/K2G, HL3/HL4).

In September 2022, Hydro One completed the newest needs assessment for the Burlington to Nanticoke region. Two station capacity needs, at Nebo TS and Mohawk TS, and one asset end-of-life need at Newton TS were identified in the Hamilton sub-region. It was determined that these needs required regional coordination. In the last cycle of regional planning, a study of the 115 kV cable in Hamilton was recommended, however, study work was postponed due to updated equipment condition information from Hydro One. An IRRP was identified as required for the sub-region to review needs requiring regional coordination along with conducting the deferred assessment of the 115 kV cable for the sub-region.

2. Objectives

To assess the adequacy of electricity supply to customers in the Hamilton sub-region over the next 20 years.

To address the sub-region's asset renewal and capacity needs, and develop a flexible, comprehensive, integrated electricity plan for the sub-region. To develop an implementation plan, while maintaining flexibility in order to accommodate changes in key assumptions over time. The implementation plan should identify actions for near-term needs, preparation work for mid-term needs, and the planning direction for long-term needs.

3. Scope

This IRRP will develop and recommend an integrated plan to meet the needs of the Hamilton sub-region. The plan is a joint initiative involving Alectra Utilities Inc., Hydro One Distribution, Hydro One Transmission, and the IESO, and will incorporate input from community engagement. The plan will focus on the identified asset end-of-life and capacity needs in the sub-region. It will also integrate forecast electricity demand growth, conservation and demand management in the area with transmission and distribution system capability, end-of-life of major facilities in the area, relevant community plans, any relevant bulk system developments, and generation uptake.

This IRRP will address regional needs in the Hamilton sub-region. Specifically, the following existing infrastructure is included in the scope of this study:

- 230 kV Connected Stations: Beach TS (T3/T4), Horning TS, Lake TS
- 115 kV Connected Stations: Newton TS, Dundas TS, Dundas #2 TS, Mohawk TS, Elgin TS, Stirton TS, Birmingham TS, Gage TS, Kenilworth TS, Beach TS (T5/T6), Winona TS
- 4 customer owned transformer stations
- 230 kV Transmission Lines: B18H/B20H, H35D/H36D, Q24HM/Q29HM, M27B/M28B
- 115 kV Transmission Lines: B12/B13, Q2AH, B10/B11, B3/B4, HL3/HL4
- 115 kV Transmission Cables: H5K/H6K, K1G/K2G, HL3/HL4
- 230/115 kV auto-transformers at Beach TS and Burlington TS

The Hamilton IRRP will:

- Prepare a 20-year electricity demand forecast for the appropriate stations and establish needs over this timeframe;
- Examine the load meeting capability and reliability of the existing transmission system supplying the 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 sub-region; and
- Evaluate options using decision-making criteria including but not limited to: technical feasibility, economics, reliability performance, and 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 region
    - Historical weather correction, median and extreme conditions
    - Gross peak demand forecast scenarios by region and TS, etc.
    - Coincident peak demand data, including transmission-connected customers
    - Identified potential future load customers
    - Customer/load segmentation information (e.g. residential, commercial, industrial) by TS
- Conservation and Demand Management
    - Conservation forecast for LDC customers, based on region’s share of current energy efficiency programs and/or those reflected in the forecast for the most recent Annual Planning Outlook
    - Potential for CDM at transmission-connected customers’ facilities

- Local resources
  - Existing local generation, including distributed generation, 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
  - Indigenous Community Energy 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
- End-of-life asset considerations/sustainment plans
- Other considerations, as applicable

5. Technical Working Group

The core Technical Working Group will consist of planning representatives from the following organizations:

- Alectra Utilities Inc.
- Independent Electricity System Operator *(Team Lead for IRRP)*
- Hydro One Networks Inc. (Distribution)
- Hydro One Networks Inc. (Transmission)

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.

6. 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 Technical Working Group is committed to conducting plan-level engagement throughout the development of the Hamilton Sub-region IRRP.

The first step in engagement will consist of the development of a public engagement plan, which will be made available for comment before it is finalized. The data and assumptions as outlined in Section 4.0 will help to inform the scope of community and stakeholder engagement to be considered for this IRRP.

7. Activities, Timeline, and Primary Accountability

Activity	Lead Responsibility	Deliverable(s)	Timeframe
1. Prepare Terms of Reference considering stakeholder input	IESO	Finalized Terms of Reference	Q4 2022
2. Develop the summer planning forecast for the sub-region		Long-term planning forecast scenarios	Q1 2023
Establish historical coincident (for the sub-region) and non-coincident (for Nebo TS and Mohawk TS) peak demand information	IESO		

Activity	Lead Responsibility	Deliverable(s)	Timeframe
Establish historical weather correction, median and extreme conditions	IESO		
Establish gross peak demand forecast	LDCs		
Establish existing, committed, and potential DG	IESO, LDCs		
Establish near- and long-term conservation forecast based on planned energy efficiency activities and codes and standards	IESO		
Develop a high planning forecast scenario for sensitivity analyses, as appropriate (including but not limited to: consideration of electric vehicle/transportation trends and potential impact on Hamilton sub-region demand)	IESO		
3. Confirm load transfer capabilities under normal and emergency conditions – for the purpose of analyzing transmission system needs and identifying options for addressing these needs	LDCs	Load transfer capabilities under normal and emergency conditions	Q1 2023
4. Provide and review relevant community plans, if applicable	LDCs, public stakeholders, and IESO	Relevant community plans	Q1 2023
5. Complete system studies to identify needs over a 20-year time horizon - Obtain PSS/E base case - 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	Q2 2023

Activity	Lead Responsibility	Deliverable(s)	Timeframe
6. Develop options and alternatives		Develop flexible planning options for forecast scenarios	Q3 2023
Conduct a screening to identify which non-wires options warrant further analysis	IESO		
Produce hourly forecasts for Nebo TS and Mohawk TS to enable detailed needs characterization and support options development	IESO		
Develop screened-in energy efficiency options	IESO and LDCs		
Develop screened-in local generation/demand management options	IESO and LDCs		
Develop the transmission and distribution alternatives (i.e., alignment with EOL sustainment plans, load transfers)	IESO, Hydro One Transmission, and LDCs		
Develop portfolios of integrated alternatives	IESO, Hydro One Transmission, and LDCs		
Technical comparison and evaluation	IESO, Hydro One Transmission, and LDCs		

Activity	Lead Responsibility	Deliverable(s)	Timeframe
7. Plan and undertake community & stakeholder engagement		Community and Stakeholder Engagement Plan Input from local communities, First Nation communities, and Métis Nation of Ontario	Ongoing as required
Early engagement including 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	IESO, Hydro One Transmission, and LDCs		
Develop communications materials	IESO, Hydro One Transmission, and LDCs		
Undertake community and stakeholder engagement	IESO, Hydro One Transmission, and LDCs		
Summarize input and incorporate feedback	IESO, Hydro One Transmission, and LDCs		
8. Develop long-term recommendations and implementation plan based on community and stakeholder input	IESO	Implementation plan Monitoring activities and identification of decision triggers Procedures for annual review	Q4 2023

Activity	Lead Responsibility	Deliverable(s)	Timeframe
9. Prepare the IRRP report detailing the recommended near, medium, and long-term plan for approval by all parties	IESO	IRRP report	Q1 2024

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Appendix E

Burlington to Nanticoke Integrated Regional Resource Plan

Burlington to Nanticoke Integrated Regional Resource Plan

December 18, 2024

Connecting Today.
Powering Tomorrow.

Disclaimer

This document and the information contained herein is provided for informational purposes only. The IESO has prepared this document based on information currently available to the IESO and reasonable assumptions associated therewith, including relating to electricity supply and demand. The information, statements and conclusions contained in this document are subject to risks, uncertainties and other factors that could cause actual results or circumstances to differ materially from the information, statements and assumptions contained herein. The IESO provides no guarantee, representation, or warranty, express or implied, with respect to any statement or information contained herein and disclaims any liability in connection therewith. Readers are cautioned not to place undue reliance on forward-looking information contained in this document, as actual results could differ materially from the plans, expectations, estimates, intentions and statements expressed herein. The IESO undertakes no obligation to revise or update any information contained in this document as a result of new information, future events or otherwise. In the event there is any conflict or inconsistency between this document and the IESO market rules, any IESO contract, any legislation or regulation, or any request for proposals or other procurement document, the terms in the market rules, or the subject contract, legislation, regulation, or procurement document, as applicable, govern.

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List of Acronyms

Acronym	Definition
BESS	Battery Energy Storage System
CDM	Conservation and Demand Management
DESN	Dual-Element Spot Network
DG	Distributed Generation
DLT	Distribution-level Load Transfers
DR	Demand Response
DS	Distribution Station
DVS	Dynamic Voltage Support
FIT	Feed-in-Tariff
GS	Generating Station
HV	High Voltage
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	kilovolt
LDC	Local Distribution Company
LMC	Load Meeting Capability
LTR	Limited Time Rating
NPV	Net-present value
MTS	Municipal Transformer Station
MVA	Megavolt ampere
Mvar	Megavolt ampere reactive
MW	Megawatt
NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council
ORTAC	Ontario Resource and Transmission Assessment Criteria
RIP	Regional Infrastructure Plan
TG	Transmission-connected Generation
TS	Transformer Station
TWG	Technical Working Group

List of Appendices

Executive Summary

The Burlington to Nanticoke Integrated Regional Resource Plan (IRRP) addresses the electricity needs of the Burlington to Nanticoke Region over a 20-year period, from 2023 to 2042. The Burlington to Nanticoke Region is located in southwestern Ontario and includes all or part of the following Counties and Districts: City of Hamilton, County of Brant, the City of Brantford, Haldimand County, Norfolk County, the City of Burlington and the town of Oakville.

For the purposes of the IRRP, the region has been divided into four subregions: Brant, Bronte, Caledonia-Norfolk, and Hamilton. The Scoping Assessment Outcome Report completed in December 2022, identified no needs for coordinated regional planning in the Bronte subregion, and most needs in the Hamilton subregion will be addressed in an upcoming addendum to be started in early 2025 (see Section 2.5.1). As a result, this IRRP largely focuses on the needs and recommendations for the Brant and Caledonia-Norfolk subregions.

Need assessments for the 115 kV subsystem in the Brant subregion (the "Brant 115 kV Subsystem") could not be conducted in isolation from the 115 kV subsystem in the Hamilton subregion and the 115 kV subsystem in the City of Woodstock (outside of the Burlington to Nanticoke Region). This is because of interconnections within the 115 kV subsystem. Therefore, the combined 115 kV subsystem spanning from Karn TS in Woodstock through the Brant subregion and into the Hamilton subregion was studied as whole. This combined subsystem is referred to as the "Brant 115 kV Extended Area", and consists of the: "Hamilton 115 kV Subsystem", the Brant 115 kV Subsystem, and the "Woodstock 115 kV Subsystem".

Studies on the Brant 115 kV Extended Area were used to identify needs, assess options, and produce recommendations for supply and station capacity needs in the Brant subregion, and for supply needs for the Hamilton 115 kV Subsystem. Supply needs for the 230 kV subsystem and station capacity needs in the Hamilton subregion will be addressed in the Hamilton addendum. The Woodstock 115 kV Subsystem falls outside of the Burlington to Nanticoke Region and is instead part of the London Area Region. As a result, needs of the Woodstock 115 kV Subsystem will be assessed and addressed in the ongoing cycle of regional planning for the London Area, with the Needs Assessment expected to be published by Hydro One by the end of 2024.

The electricity demand forecast shows substantial growth for the Burlington to Nanticoke Region, with demand forecasted to grow by 50%, 180%, and 80% for the Brant, Caledonia-Norfolk, and Hamilton subregions, respectively, by 2042, relative to 2023 demand. Growth is driven by industrial expansion, housing growth, and decarbonization initiatives. To meet long-term needs, the Load Meeting Capability (LMC) for each of the 115 kV subsystems in the Region must approximately double from its existing value. These 115 kV subsystems are: the combined Brant and Hamilton 115 kV Subsystems, the Brant 115 kV Subsystem, and the Norfolk-Bloomsburg Area. In addition, each of these 115 kV subsystems, and several substations supplied by these subsystems, have immediate capacity needs.

To address needs, wires and non-wires options were considered, and ultimately a combination is recommended by the Technical Working Group. Wires solutions are recommended to address long-term needs, as the most cost-effective and technically feasible solutions. Non-wires options are recommended to meet near-to-medium term needs, due to: their shorter lead times, the lower magnitude of needs in the near-to-medium term, and their system benefits.[1]

To address near-to-medium term needs, the Technical Working Group recommends the pre-contingency opening of bus-tie breakers, and load transfers between nearby stations at the distribution level, where viable and cost-effective. The opening of bus-tie breakers is needed to address near-to-medium term supply capacity needs for the combined Brant and Hamilton 115 kV subsystems, the Brant 115 kV Subsystem, and the Norfolk-Bloomsburg Area, and to address several station capacity needs where load transfers cannot resolve needs.

In the medium-term, the Technical Working Group recommends the procurement of a battery energy storage system, and the construction of a new substation[2] near Dundas TS. These recommendations will address supply capacity needs in the Norfolk-Bloomsburg Area, and on the Hamilton 115 kV Subsystem and at Dundas TS, respectively. The new substation will also address station capacity needs at Dundas TS.

In the long-term, the Technical Working Group recommends constructing two sets of new 230 kV transmission lines and associated substations, separating the Woodstock 115 kV Subsystem from the Brant 115 kV Subsystem:

- New 230 kV transmission lines from Nanticoke TS into the Simcoe community, and a new station[2] to entirely offload Norfolk and Bloomsburg 115 kV stations.
- A new double-circuit transmission line constructed as an extension from the existing Middleport-Detweiler corridor (in the Kitchener/Waterloo/Cambridge/Guelph region) into County of Brant, and two new stations[2] to entirely offload Brant and Powerline 115 kV stations.

Cost-effective CDM at Brantford TS and Caledonia TS is also recommended to defer station capacity needs. Once the Brant 115 kV Subsystem has been offloaded by the above recommendation, the Technical Working Group recommends separating the Woodstock 115 kV Subsystem from the Brant 115 kV Subsystem when the total net load in the Woodstock 115 kV Subsystem exceeds the limit.

Engagement is critical in the development of an IRRP. Providing opportunities for input in the regional planning process enables the views and perspectives of the public, market participants, municipalities, stakeholders, communities, Indigenous communities, and customers to be considered in the development of the plan. Furthermore, engagement helps lay the foundation for successful implementation.

The Technical Working Group will continue to monitor growth at Brantford TS and Caledonia TS, as well as across the region. This includes any future community energy planning, electrification trends, datacentres, or industrial load. The Technical Working Group will meet at regular intervals to complete the recommended Hamilton addendum, monitor developments and track progress toward plan deliverables. If underlying assumptions change significantly, local plans may be revisited through

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[1] Non-wires options, such as conservation and demand management (CDM), storage procurement, or generation procurement, help meet the CDM and procurement needs of the provincial grid, thereby providing benefits to the system while addressing local needs.

[2] Converting the existing 115 kV DESNs to 230 kV is equivalent to constructing new stations when addressing supply capacity needs. The subsequent Transmitter-led Regional Infrastructure Plan (RIP) will identify the most cost-effective solution and develop a detailed plan for implementation.

an amendment, or by initiating a new regional planning cycle sooner than the five-year schedule mandated by the Ontario Energy Board.

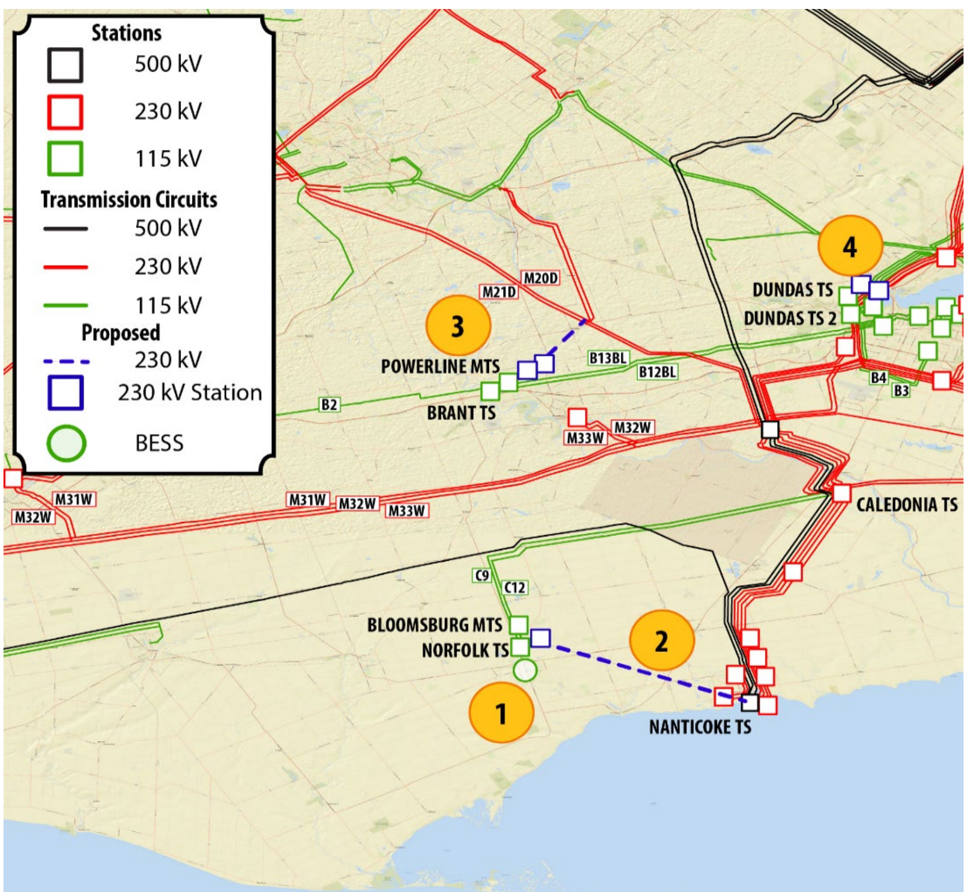
Summary of Recommendations

The medium and long-term recommendations for the Burlington to Nanticoke region are shown in the figure below and include:

1. Build a transmission-connected battery energy storage system (BESS) facility capable of continuously providing voltage support near Norfolk TS.
2. Build new transmission lines from Nanticoke TS into the Simcoe community, and a new station[2] to entirely offload Norfolk and Bloomsburg 115 kV stations.
3. Build a new double-circuit transmission line as an extension from the existing Middleport-Detweiler corridor (in the Kitchener/Waterloo/Cambridge/Guelph region) into County of Brant, and two new stations[2] to entirely offload Brant and Powerline 115 kV stations.
4. Build new 230kV stations[2] at Dundas TS connecting to the adjacent Middleport-Burlington circuits to entirely offload the Dundas load from the 115 kV stations to 230 kV.

In the interim, operational measures such as opening station bus-tie breakers combined with feasible and cost-effective load transfer between stations on a permanent or temporary basis are recommended to resolve supply and station capacity needs.

Medium/Long-Term Recommendations in the Burlington Nanticoke Region



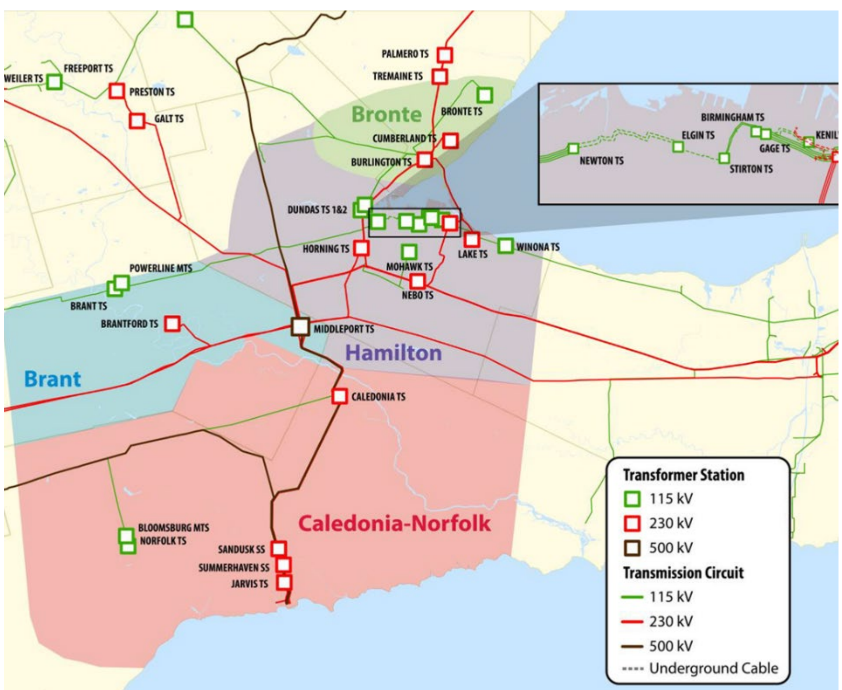
1 Introduction

This Integrated Regional Resource Plan (IRRP) addresses the electricity needs of the Burlington to Nanticoke Region (the "Region") over a 20-year period, from 2023 to 2042. The Burlington to Nanticoke Region is located in southwestern Ontario and includes all or part of the following Counties and Districts: City of Hamilton, County of Brant, the City of Brantford, Haldimand County, Norfolk County, the City of Burlington and the town of Oakville. For electricity planning purposes, the planning region is defined by electricity infrastructure boundaries, not municipal boundaries.

Several Indigenous communities are located in or near the Region including: Mississaugas of the Credit First Nation, Six Nations of the Grand River, and a number of Métis Nation of Ontario (MNO) councils including MNO Clear Waters Métis Council and MNO Grand River Métis Council.

For the purposes of regional planning, the Burlington to Nanticoke region has historically been sub-divided into four subregions: Brant, Bronte, Caledonia-Norfolk, and Hamilton. The electricity infrastructure supplying the Burlington to Nanticoke region and the subregions are shown in Figure 1. The Burlington Nanticoke Region is summer-peaking, and over 2019 to 2023, normal weather peak electrical demand has remained steady at approximately 1,825 MW.

Figure 1 | Overview of the Burlington Nanticoke Region[3]



The Bronte subregion includes Burlington TS and the 230 kV and 115 kV supply northeast of the station which services Cumberland TS and Bronte TS, respectively. The 115 kV supply southwest from Burlington TS and the 230 kV supply from Beach TS service the 115 kV network in the Hamilton subregion, while 230 kV circuits between Burlington TS and Beach TS, Beach TS and Middleport TS,

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[3] IRRP regions are defined by electricity infrastructure; geographical boundaries are approximate.

and Middleport TS and Burlington TS supply the Hamilton subregion's 230 kV connected load supply stations. The 230 kV supply south from Middleport TS supplies the 230 kV connected stations in the Caledonia-Norfolk subregion, including Caledonia TS. The 115 kV supply from Caledonia TS then supplies Bloomsburg DS and Norfolk TS. The Brant subregion is supplied from the 230 kV supply west from Middleport TS and a 115 kV supply from Burlington TS. Because of tight connection between i) the Brant 115 kV supply, ii) part of the Hamilton 115 kV supply and iii) the 115 kV supply to the City of Woodstock, the regional plan considered the capability of the broader Brant 115 kV Extended Area which includes theses three subsystems comprising the entire 115 kV network between Burlington TS and Karn TS.

The region's electricity is delivered by five local distribution companies (LDCs): Alectra Utilities Corporation, Burlington Hydro Inc. (BHI), GrandBridge Energy Inc., Hydro One Networks Inc. (Distribution), and Oakville Hydro Inc. Hydro One Networks Inc. (Transmission) is the primary transmission asset owner. This IRRP report was prepared by the Independent Electricity System Operator (IESO) on behalf of a Technical Working Group, composed of the LDCs, Hydro One, and the IESO.

Development of the Burlington Nanticoke IRRP was initiated in December 2022, following the publication of the Needs Assessment report in September 2022 by Hydro One and the Scoping Assessment Outcome Report in December 2022 by the IESO. The Scoping Assessment identified the area's needs should be further assessed through an IRRP. The Technical Working Group was then formed to gather data, identify near- to long-term needs in the region, and develop the recommended actions included in this IRRP.

This report is organized as follows:

- A summary of the recommended plan for the 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 region and the study scope are discussed in Section 4;
- Demand forecast scenarios, and conservation and demand management and distributed generation assumptions, are described in Section 5;
- Electricity needs in the region are presented in Section 6;
- Alternatives and recommendations for meeting needs are addressed in Section 7;
- A summary of engagement activities is provided in Section 8; and
- The conclusion is provided in Section 9.

2 The Integrated Regional Resource Plan

This IRRP provides recommendations to address the electricity needs of the Burlington to Nanticoke Region over the next 20 years. The needs identified are based on the demand growth anticipated in the region and the capability of the existing transmission system, as evaluated through application of the IESO's Ontario Resource and Transmission Assessment Criteria (ORTAC) and reliability standards governed by the North American Electric Reliability Corporation (NERC). The IRRP's recommendations are informed by an evaluation of different options to meet the needs and consider reliability, cost, technical feasibility, maximizing the use of the existing electricity system (where economic), and feedback from stakeholders.

The Burlington to Nanticoke electricity demand forecast, provided by the LDCs, anticipates sustained growth driven by industrial expansion, housing growth, and decarbonization initiatives. These drivers are present across all municipalities in the Region.

In the Brant subregion, residential housing is a primary driving factor in the forecast along with industrial customers which have shown interest and purchased property both within City of Brantford and County of Brant. One customer has already scheduled an expansion project with a significant quantity of new load. With the annexation of 2,720 hectares of land from County of Brant to the City of Brantford, there is an expectation of intense development in the north of Brantford. Beyond 2030, 4 per cent growth is expected for electrification.

In the Caledonia-Norfolk subregion, the forecast is mainly driven by economic factors, e.g. housing and GDP, and community/municipal energy and decarbonization plans. Industrial and residential development in Courtland has a large effect in the Norfolk forecast. New residential and employment growth is forecasted to be 1% per annum into the future.

In the Hamilton subregion, the forecast is driven primarily by economic factors, and supplemented by electric vehicle growth. Economic factors include: population and employment growth, housing activities, and commercial and industrial development.

Following a review on the status of the plans recommended in the last cycles of IRRP, the recommendations in this cycle of IRRP are organized under interim and permanent plans. This distinction reflects the different levels of lead time for development and planning commitment required. This approach ensures that the IRRP provides clear direction on investments needed in the near and medium term, while initiating projects with long lead times that are ultimately needed.

2.1 Status of Plans from Previous IRRP Cycles

Following the previous cycle of region planning, and concluding with the 2nd Cycle RIP report, several projects were recommended which have now been completed or are presently underway. The projects consisted largely of replacements, in addition to two capacitor bank installations, and two sets of distribution-level load transfers. The status of these projects is summarized in Table 1 below.

Table 1 | Summary of Ongoing and Recently Completed Plans

Station/Line Section	Need	Expected In-Service
Cumberland TS	Power factor correction: capacitor bank installed at customer level	2019 (Completed)
115 kV B3/B4	Line section Horning Mountain Jct. X Glanford Jct. replacement	2020 (Completed)
Elgin TS	Transformer and switchgear replacement	2022 (Completed)
Gage TS	Transformer and switchgear replacement	2024 (Completed)
Newton TS	Transformer replacement	2020 (Completed)
Norfolk-Bloomsburg Area Supply Capacity	Load transfers to Jarvis TS: 3 MW	2026
Kenilworth TS	Transformer and switchgear replacement	2023 (Completed)
Kenilworth TS	Power factor correction: capacitor bank installation	2025 (Completed)
115 kV B7/B8	Line section Burlington TS X Nelson Jct. replacement	2024
Dundas TS	Load transfers to Dundas 2 TS: 20 MW	2025
Newton TS	115 kV breaker refurbishment	2022 (Completed)

2.2 Interim Plans

For the interim, until permanent solutions are placed in service, the Technical Working Group recommends operational measures to address near-/medium-term supply and station capacity needs. This includes the pre-contingency opening of bus-tie breakers, as needed, to secure the system and resolve the needs.

The recommended operational measures also include load transfers between nearby stations at the distribution level. The Technical Working Group recommends that LDCs assess the feasibility and cost-effectiveness of transferring loads on a temporary or permanent basis with consideration to the recommended long-term solutions which resolve supply or station capacity needs. Moreover, coordination between load transfer and opening station bus-tie breakers is necessary since opening bus-tie breakers may still be required either to make the system secure or because the amount of load transferred is not sufficient to resolve the needs. Where viable and cost-effective, the Technical Working Group prefers transferring loads since opening station bus-tie breakers may interrupt electricity service to a higher number of customers following a network outage.

Note that the Technical Working Group makes these interim recommendations strictly on a provisional basis, until solutions with longer lead times are in place.

Table 2 | Interim Plans for Station and Supply Capacity Needs

Need	Recommendation	Lead Responsibility
Various station and supply capacity	As required, open bus-tie breakers at Bloomsburg DS, Norfolk TS, Brant TS, Powerline MTS, Dundas 1 and 2 TS, Newton TS, Mohawk TS, Nebo, Woodstock TS and Commerce Way TS	Hydro One, GrandBridge Energy, Alectra
Various station and supply capacity	If feasible and cost-effective, permanently/temporarily transfer load from Bloomsburg DS, Norfolk TS, Brant TS, Powerline MTS, Dundas 1 and 2 TS, Newton TS, Mohawk TS, and Nebo to nearby stations	Hydro One, GrandBridge Energy, Alectra

2.3 Medium-Term Plans

The Technical Working Group recommends the medium-term plans summarized in Table 3 to bridge the gap between the interim and long-term solutions. Multiple needs are grouped together when they will be resolved by the same solution. The following sections discuss these medium-term plans.

2.3.1 Battery Energy Storage System in the Norfolk-Bloomsburg Area

To address the Norfolk-Bloomsburg Area supply capacity in the medium term ahead of a long-term wires solution, the Technical Working Group recommends a battery energy storage system (BESS). The BESS should be connected to both 115 kV supply circuits (C9 and C12) between the Bloomsburg junctions and Norfolk TS, preferably at Norfolk TS.

To be a viable solution, the BESS must always remain connected to the transmission system and provide reactive power (Mvar) support for extended periods of time, irrespective of its active power output. The continuous reactive power capability would determine the minimum requirements of rated capacity and storage (MW/MWh) for a viable BESS solution. Because of the timing, specific location and combination of active and reactive power requirements, the IESO will investigate the most appropriate implementation mechanism to procure the BESS.

The operational measures described in the previous section may be necessary to secure the system under outages on the BESS solution.

2.3.2 Two New 230 kV DESNs at Dundas Station

As part of the long-term solution, discussed in the next section, and to address the supply capacity needs for the Hamilton 115 kV Subsystem within the Brant 115 kV Extended Area, the Technical

Working Group recommends transferring the loads of both Dundas TS DESNs from the 115 kV subsystem to the 230 kV subsystem. This may be achieved by either: constructing two new 230 kV Dual Element Spot Network (DESN) at the Dundas switchyard, or converting the existing DESNs from 115 kV to 230 kV supply. In either case, the 230 kV supply will be the existing 230 kV Middleport to Burlington circuits, M27B and M28B, which pass next to the station.

If the new DESNs are pursued, each should have an approximate LTR of 200 MVA, and the LDCs (Hydro One Distribution and Alectra Utilities Corporation) should entirely transfer the loads from the existing Dundas TS DESNs onto the new 230 kV DESNs.

The choice between constructing new DESNs or converting existing DESNs will be determined in the upcoming Regional Infrastructure Planning (RIP) led by the transmitter. However, constructing new DESNs will also resolve the Dundas station capacity needs, whereas converting the existing DESNs will not resolve these needs.

Table 3 | Medium-Term Plans for Supply and Station Capacity Needs

Need	Recommendation	Lead Responsibility	Expected In-Service
Norfolk-Bloomsburg Area Supply Capacity	Procure BESSs* capable of always providing reactive power support** connecting to C9 and C12 between the Bloomsburg junctions and Norfolk TS	IESO	2029 or earlier***
Hamilton 115 kV Subsystem Supply Capacity and Dundas 1 and 2 Station Capacity	Construct two new 230 kV DESNs**** each with an LTR of ~200 MVA at the Dundas switchyard connecting to the nearby Middleport to Burlington circuits (M27B and M28B)	Hydro One	2032 or earlier***
	Entirely transfer the Dundas loads from the existing 115 kV DESNs to the new 230 kV DESNs	Hydro One and Alectra	

* Under BESS outage conditions, operational measures discussed in Section 2.2 for the Norfolk-Bloomsburg Area may be required to secure the system.

** Depending on the amount of reactive power (Mvar) support the BESSs can constantly provide, minimum requirements on the rated capacity and storage (MW/MWh) of the BESSs are specified and the BESSs may potentially be combined with other NWAs, e.g., renewables, CDM or load transfer, to make this option viable and cost-effective.

*** Provided years are estimated maximum timelines to bring solution in-service; however, implementation should be expedited to bring in-service as soon as possible.

**** Rather than building a new DESN, the existing DESNs may be converted from a 115 kV supply to a 230 kV supply by replacing all 115 kV station equipment. The subsequent Transmitter-led Regional Infrastructure Plan (RIP) will identify the most cost-effective approach that addresses the needs and develop a detailed plan for implementation.

2.4 Long-Term Plans

The long-term plans comprise several recommendations to resolve needs and to support long-term load growth. These recommendations are summarized in Table 3 and further discussed below. The recommended wires solutions will need to be initiated as soon as possible, starting with the upcoming Regional Infrastructure Planning (RIP) led by the transmitter.

The operational procedures which were recommended as the interim solutions will no longer be required after the needs are addressed with the long-term plans.

Table 4 | Long-Term Plans for Supply and Station Capacity Needs

Need	Recommendation	Lead Responsibility	Expected In-Service
Norfolk-Bloomsburg Area Supply and Station Capacity	Construct one new 230 kV DESN* with an LTR of ~200 MVA within or in the vicinity of Simcoe connecting to the Nanticoke TS with a new 230 kV double-circuit line*	Hydro One	2035
	Entirely transfer the Norfolk and Bloomsburg loads to the new 230 kV DESN	Hydro One	
Brant 115 kV Subsystem Supply Capacity and Brant and Powerline Station Capacity	Construct two new 230 kV DESNs* each with an LTR of ~200 MVA within or in the vicinity of County of Brant connecting to the Middleport to Detweiler corridor with new 230 kV extensions**	Hydro One	2035
	Entirely transfer the Brant and Powerline loads to the new 230 kV DESNs	GrandBridge Energy	
Woodstock 115 kV Subsystem	If the Woodstock Subsystem total net load exceeds 113 MW, separate it from Brant Subsystem by pre-contingency opening the Brant DB2 breaker	IESO and Hydro One	***
Caledonia Station Capacity	Implement targeted and cost-effective CDM to defer the need from 2034 and monitor the demand growth for advancing the need	IESO	****
Brantford Station Capacity	Implement targeted and cost-effective CDM to defer the need from 2035 and monitor the demand growth for advancing the need	IESO	****

* Rather than building a new DESN, the existing DESNs may be converted from a 115 kV supply to a 230 kV supply by replacing all 115 kV station equipment. The subsequent Transmitter-led Regional Infrastructure Plan (RIP) will identify the most cost-effective solution and develop a detailed plan for implementation.

** Since new DESNs are connected to the lines in the Kitchener/Waterloo/Cambridge/Guelph (KWCG) region, the ongoing KWCG IRRP will finalize the connection arrangement and details of this option.

*** The timing of this option is after the load transfers of Dundas 1 and 2, Brant and Powerline Stations from the existing 115 kV to new 230 kV DESNs are complete.

**** CDM program design and implementation start after the IRRP is finished and continue over the planning horizon.

2.4.1 One New 230 kV DESN and Transmission Line into Simcoe

To address the supply capacity need to the Norfolk-Bloomsburg Area and to address station capacity needs at Bloomsburg DS and Norfolk TS, the Technical Working Group recommends constructing a new 230 kV double-circuit transmission line from Nanticoke TS into the vicinity of Simcoe, and either:

constructing one new 230 kV DESN, or converting Bloomsburg DS and Norfolk TS from 115 kV to 230 kV supply.

If the new DESN is pursued, it should have an approximate LTR of 200 MVA, and Hydro One Distribution should entirely transfer the loads from Bloomsburg DS and Norfolk TS onto the new 230 kV DESN.

The line routing and choice between constructing a new DESN or converting existing DESNs will be determined in the upcoming Regional Infrastructure Planning (RIP) led by the transmitter. However, constructing new DESNs will also resolve the Bloomsburg DS and Norfolk TS station capacity needs, whereas converting the existing DESNs will not resolve these needs.

2.4.2 Two New 230 kV DESNs and Transmission Line into County of Brant

To address supply capacity needs to the Brant 115 kV Subsystem and to address station capacity needs at Brant TS and Powerline MTS, the Technical Working Group recommends constructing a new 230 kV double circuit extension of the Middleport to Detweiler corridor into the vicinity of County of Brant, and either: constructing two new 230 kV DESNs, or converting Brant TS and Powerline MTS from 115 kV to 230 kV supply. However, constructing new DESNs will also resolve the Brant TS and Powerline MTS station capacity needs, whereas converting the existing DESNs will not resolve these needs.

If the new DESNs are pursued, each should have an approximate LTR of 200 MVA, and GrandBridge Energy Inc. should entirely transfer the loads from Brant TS and Powerline MTS onto the new 230 kV DESNs.

Since the DESNs (new or converted) are connected to the lines in the KWCG region, the ongoing KWCG IRRP will finalize the connection arrangement and details of this option.

Please note that this plan in combination with the new Dundas 230 kV DESNs (see Section 2.3.2) will address the supply capacity need in the Hamilton 115 kV Subsystem up to the sum of the capacities of the remaining stations, namely, Elgin, Mohawk and Newton TS and CTS3.

2.4.3 Separate Woodstock 115 kV Subsystem from Brant 115 kV Subsystem

To address the supply capacity need to the Woodstock 115 kV Subsystem after transferring the loads to new 230 kV DESNs as explained in Section 2.3.2 and 2.4.2, the Technical Working Group recommends that the Brant DB2 115 kV circuit breaker be opened pre-contingency for a total net load in the Woodstock Subsystem above 113 MW. This will separate the Woodstock from Brant 115 kV Subsystem and increase the LMC of the Woodstock 115 kV Subsystem to 210 MW.

2.5 Ongoing Initiatives

In addition to the plans above, four ongoing actions were identified to manage long-term needs for the Burlington to Nanticoke Region in general and for the Hamilton subregion, in particular.

2.5.1 Undertake a Comprehensive Study of the Hamilton Subregion

Following Public Webinar #1 for the Burlington to Nanticoke IRRP in September 2023, electrification and decarbonization plans were identified which will have a significant impact on the Hamilton area.

In response, a new forecast for Hamilton was produced in June 2024, which resulted in a 230 MW or 11 per cent increase relative to the previous forecast.

Based on the new Hamilton demand forecast, several station capacity needs were identified. To the extent possible, some of these needs were assessed as part of this IRRP. Specifically, assessment of the Hamilton 115 kV Subsystem within the Brant 115 kV Extended Area and subsequent long-term recommendation will help address some of these supply and station capacity needs, namely at Dundas TS. The remaining needs warrant a more fulsome assessment of needs, which were too significant to fully assess and address within the IRRP timelines. Given the rapid growth in the Area, collecting more information on supply options and conducting integrated planning for the revised needs is critical to ensuring the continued reliability of this subregion. Thus, the Technical Working Group recommends that a Hamilton Addendum be undertaken, to fully assess and address the needs of the Hamilton subregion. Please see Appendix J for an initial scope of the Addendum.

The Addendum will kick-off in 2025 and finish within 12 months of formal kick-off. In early 2025, the terms of reference will be published by the TWG and will build upon the scope outlined in Appendix J, by confirming the objectives and establishing timelines. An engagement plan will also be created, which will outline expectations for webinars and targeted outreach with key stakeholders over the 12-month addendum process.

2.5.2 Monitor Load Growth and Continue to Explore Opportunities for Targeted CDM

The Technical Working Group recommends that the LDCs and IESO continue to monitor long-term growth at Brantford TS and Caledonia TS between regional planning cycles to determine when decisions on the long-term plan are required and inform the next cycle of regional planning for the region, as required.

In addition, the Technical Working Group recommends continuing to consider opportunities for targeted CDM, identifying the benefits and potential of incremental, cost-effective CDM particularly if targeted to help manage near-term needs until transmission reinforcements are in-service or to defer long-term needs. The Technical Working Group should continue to support and monitor CDM uptake and bring these insights into the next cycle of regional planning for the Burlington to Nanticoke Region.

2.5.3 Data Centre and Industrial Load Growth

The IESO has been made aware of a growing number of large data centre connection requests (100-1000 MW each) throughout the province, as well as an increase in requests for industrial load growth (see Section 6.2.4). At the time of this IRRP publication, the Technical Working Group is aware of significant interest from multiple potential customers throughout the region at various commitment levels, with interest from 700-1,700 MW of data centre connections within the Caledonia-Norfolk Subregion alone, which have not been captured in this IRRP forecast. Given the magnitude of such load growth, wires solutions are commonly the only technically feasible solution but require a lead time of 7-10 years.

To help mitigate the risks posed by these large but uncertain connection requests, the IESO will continue to monitor data centre and industrial growth patterns within the Burlington to Nanticoke Region and the province at large. The IESO is also undertaking a South and Central Bulk Plan to review the capability of the bulk system to support future generation connections and demand growth in key areas throughout southern and central Ontario to enable a decarbonized power system in the future. This study will continue the assessment of the bulk transmission system between the Hamilton and Windsor areas to understand future transmission needs that could result from further economic development. In addition, when developing solutions to address needs, the IESO will evaluate different scenarios, to support more complex considerations, to ensure that recommendations are optimal under a range of future scenarios.

3 Development of the Plan

3.1 The Regional Planning Process

In Ontario, preparing to meet the electricity needs of customers at a regional level is achieved 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 results in a plan to ensure cost-effective and reliable electricity supply. A regional plan considers the existing electricity infrastructure in an area, forecasts growth and customer reliability, evaluates options for addressing needs, and recommends actions.

The current regional planning process was formalized by the Ontario Energy Board in 2013 and is performed on a five-year cycle for each of the 21 planning regions in the province. The process is carried out by the IESO, in collaboration with the transmitters and LDCs in each region. The process consists of four main components:

1. A Needs Assessment, led by the transmitter, which completes an initial screening of a region's electricity needs and determines if there are electricity needs requiring regional coordination;
2. A Scoping Assessment, led by the IESO, which identifies the appropriate planning approach for the identified needs and the scope of any recommended planning activities;
3. An IRRP, led by the IESO, which proposes recommendations to meet the identified needs requiring coordinated planning; and/or
4. A RIP, led by the transmitter, which provides further details on recommended wires solutions.

Regional planning is not the only type of electricity planning in Ontario. Other types include bulk system planning and distribution system planning. There are inherent overlaps in all three levels of electricity infrastructure planning. Further details on the regional planning process and the IESO's approach to it can be found in Appendix A.

The IESO has recently completed a review of the regional planning process, following the completion of the first cycle of regional planning for all 21 regions. Additional information on the Regional Planning Process Review, along with the final report is posted on the IESO's website.

3.2 Burlington to Nanticoke IRRP Development

The process to develop the Burlington to Nanticoke IRRP was initiated in December 2022, following the publications of the Needs Assessment Report in September 2022 by Hydro One and the Scoping Assessment Outcome Report in December 2022 by the IESO. The Scoping Assessment recommended that the needs identified for the Burlington to Nanticoke Region be considered through an IRRP in a coordinated regional approach, supported with public engagement. The Technical Working Group was then formed to develop the terms of reference for this IRRP, gather data, identify needs, develop options, and recommend solutions for the region.

4 Background and Study Scope

This is the third cycle of regional planning for the Burlington to Nanticoke Region. This Region is located in southwestern Ontario and includes all or part of the following Counties and Districts:

City of Hamilton	City of Brantford	Norfolk County	Town of Oakville
County of Brant	Haldimand County	City of Burlington	

For electricity planning purposes, the planning region is defined by electricity infrastructure boundaries, not municipal boundaries.

This Region also includes several Indigenous communities, located within or near the Region:

Mississaugas of the Credit First Nation	Métis Nation of Ontario:
Six Nations of the Grand River	Clear Waters Métis Council
Haudenosaunee Confederacy Chiefs Council	Grand River Métis Council

Following a Needs Assessment and Scoping Assessment in 2017, an IRRP and subsequent RIP were initiated and published in 2019, concluding the second planning cycle for the Region.

This IRRP develops and recommends options to meet the electricity needs of the Burlington to Nanticoke Region in the near, medium, and long term. The plan was prepared by the IESO on behalf of the Technical Working Group, and includes consideration of forecast electricity demand growth, CDM, distributed generation (DG), transmission and distribution system capability, relevant community plans, condition of transmission assets, and developments on the bulk transmission system.

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

Transformer stations:

Beach TS	Bronte TS	Dundas 2 TS	Kenilworth TS	Norfolk TS
Birmingham TS	Burlington TS	Elgin TS	Lake TS	Powerline MTS
Bloomsburg DS	Caledonia TS	Gage TS	Mohawk TS	Stirton TS
Brant TS	Cumberland TS	Horning TS	Nebo TS	Winona TS
Brantford TS	Dundas TS	Jarvis TS	Newton TS	CTS1 to CTS6

115 kV transmission circuits:

B3	B6G	B10	B13BL	HL3	H6K	K2G
B4	B7	B11	C9	HL4	H9W	Q2AH
B5G	B8	B12BL	C12	H5K	K1G	

230 kV transmission circuits:

B18H	M34H	M20D	M31W	N6M	N20K	Q30M
B20H	H35D	M21D	M32W	N21J	Q24HM	Q29HM
B40C	H36D	M27B	M33W	N22J	Q23BM	S39M
B41C	K40M	M28B	N5M	N37S	Q25BM	

The Burlington to Nanticoke Region covers a large portion of the transmission system in southwest Ontario, and for this reason it has been broken up into four subregions:

- Brant Subregion
- Bronte Subregion
- Caledonia-Norfolk Subregion
- Hamilton Subregion

Based on the Needs Assessment led by Hydro One in the beginning of the planning process, regional planning was required for the Burlington to Nanticoke Region except for the Bronte Subregion. Figure 2 to Figure 4 show single line diagrams of the subregions and subsystems for which the regional plan was conducted.

The Brant subregion consists of the following stations:

Brant TS	Brantford TS	Powerline MTS.

The Caledonia-Norfolk subregion consists of the following stations:

Bloomsburg DS	Jarvis TS	Caledonia TS
Norfolk TS	CTS1	CTS2

The Hamilton subregion consists of the following stations:

Beach TS	Dundas 2 TS	Horning TS	Mohawk TS	Stirton TS
Birmingham TS	Elgin TS	Kenilworth TS	Nebo TS	Winona TS
Dundas TS	Gage TS	Lake TS	Newton TS	CTS3 to CTS5

Note need assessments for the Brant 115 kV Subsystem, that includes Brant TS and Powerline MTS, could not be conducted in isolation and the area of study was extended to the entire 115 kV system enclosed between the Burlington and Karn 115 kV stations. Therefore, in addition to the Woodstock 115 kV Subsystem in the London Area, CTS3, Dundas, Dundas 2, Mohawk, Newton and Elgin stations in the Hamilton 115 kV Subsystem were also included in the studies. This is referred to as the Brant 115 kV Extended Area and is shown in Figure 2.

The Woodstock 115 kV Subsystem is not part of the Burlington to Nanticoke Region and was considered in the analysis of this IRRP because of its impact on the 115 kV Subsystems in the Brant and Hamilton subregions (please see "Brant 115kV Extended Area" in Section 6.3). The Woodstock subregion is part of the London Area Region, and consists of Commerce Way TS, Woodstock TS and CTS6.

Note that the bulk system transfer capabilities on the Buchanan Longwood Input (BLIP) and Queenston Flow West (QFW) interfaces through the region is not within the scope of the IRRP and would be separately studied in a bulk transmission plan, as required. The schedule of bulk planning activities is identified through the IESO's Annual Planning Outlook.

Figure 2 | Single Line Diagram of Brant 115 kV Extended Area, the Brant 115 kV Subsystem, the Hamilton 115 kV Subsystem, and the Woodstock 115 kV Subsystem

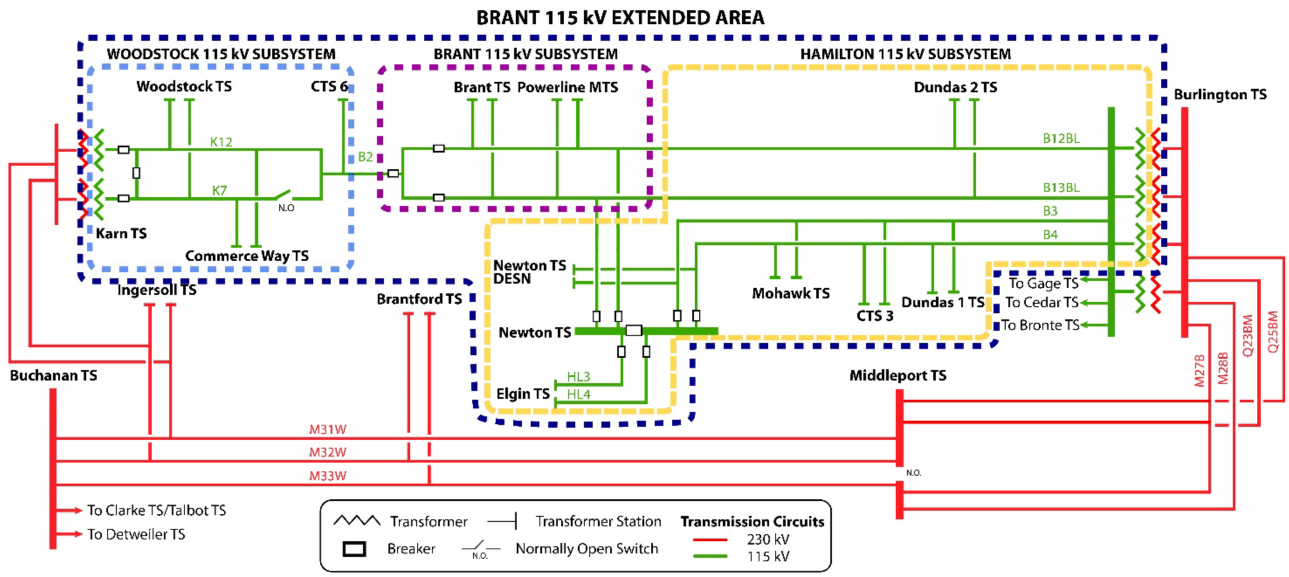


Figure 3 | Single Line Diagram of the Caledonia-Norfolk Subregion and Norfolk-Bloomsburg Area

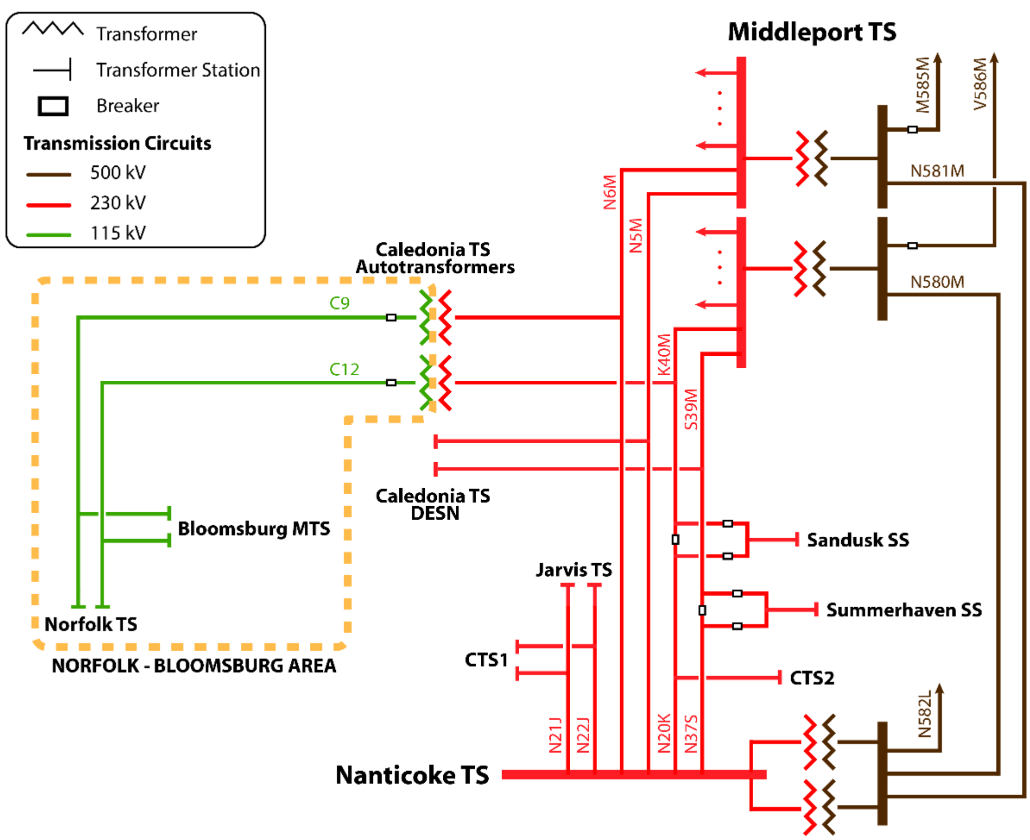
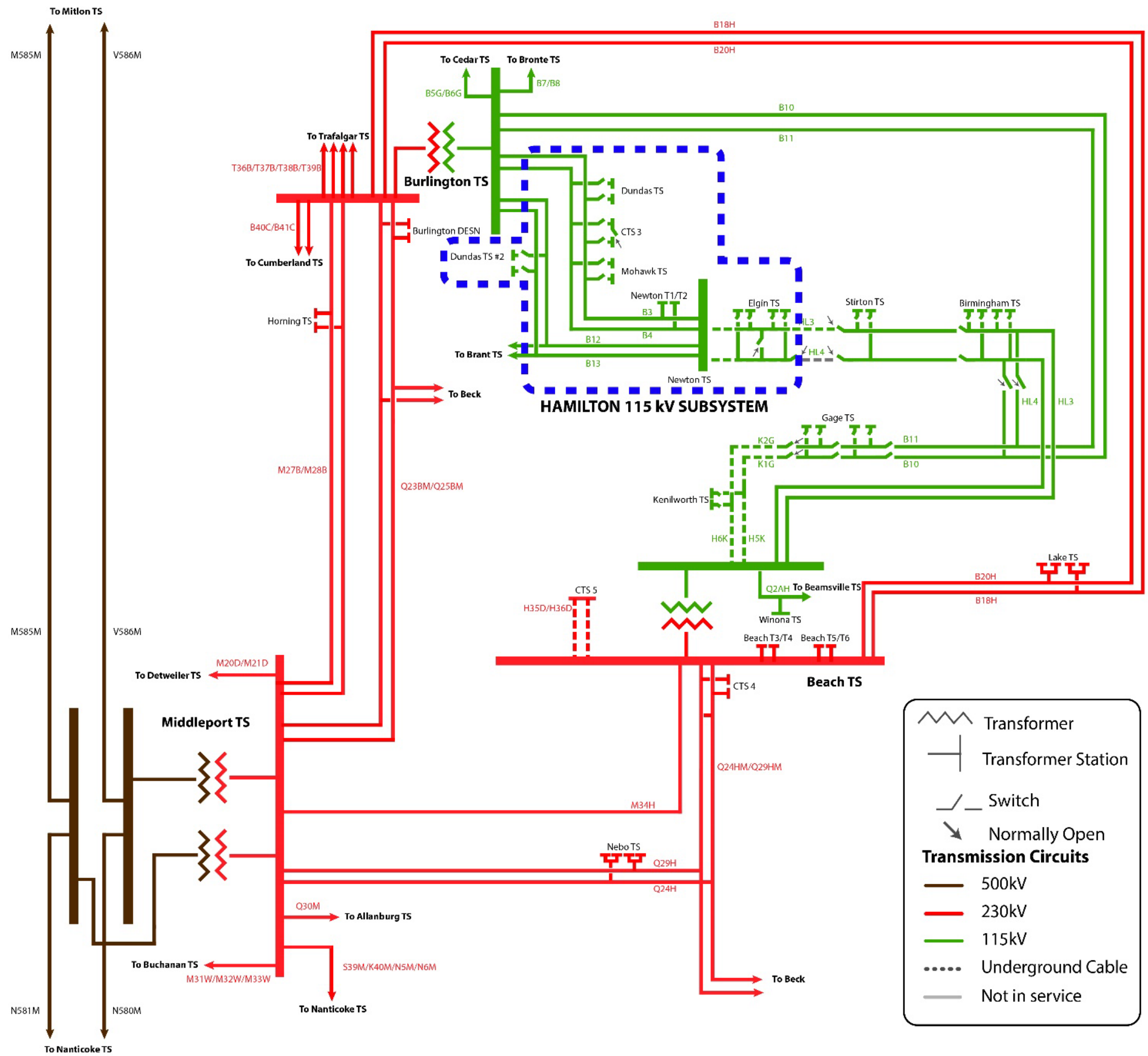


Figure 4 | Single Line Diagram of the Hamilton Subregion and Hamilton 115 kV Subsystem



The Burlington to Nanticoke IRRP was developed by completing the following steps:

- Preparing a 20-year electricity demand forecast and establishing needs over this timeframe (as described in the following steps);
- Examining the load meeting capability (LMC) and reliability of the existing transmission system, 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 and NERC criteria.
- Assessing system needs by applying a contingency-based assessment and reliability performance standards for transmission supply in the IESO-controlled grid.
- Confirming identified asset replacement needs and timing with the transmitter and LDCs.

- Establishing alternatives to address system needs including, where feasible and applicable, generation, transmission and/or distribution, and other approaches such as non-wire alternatives including CDM.
- Engaging with the community on needs and possible alternatives.
- Evaluating alternatives to address near- to long-term needs; and
- Communicating findings, conclusions, and recommendations within a detailed plan.

5 Electricity Demand Forecast

Regional planning in Ontario is driven by having to meet peak electricity demand requirements in the region. This section describes the development of the demand forecast for the Burlington to Nanticoke Region. It highlights the assumptions made for peak demand forecasts, including weather correction, and the contribution of CDM and DG. Both a reference and high growth scenario were provided by Hydro Onde Distribution for their service territory, while the other LDCs only provided a reference scenario. Compared with their reference scenario, Hydro One Distribution's high growth scenario additionally considered potential upcoming load connections with a lower degree of commitment (e.g., capacity inquiries, long-term assumptions from municipal plans, etc.). The high growth scenario from Hydro One Distribution was used for the "planning" forecast, since the difference with the reference scenario they provided was only marginal.

To evaluate the reliability of the electricity system, the regional planning process is typically concerned with the coincident peak demand for a given area. This is the demand observed at each station for the hour of the year in which overall demand in the study area is at its maximum. In the case of this IRRP, three study areas were developed corresponding to the three subregions: Brant, Caledonia-Norfolk, and Hamilton.

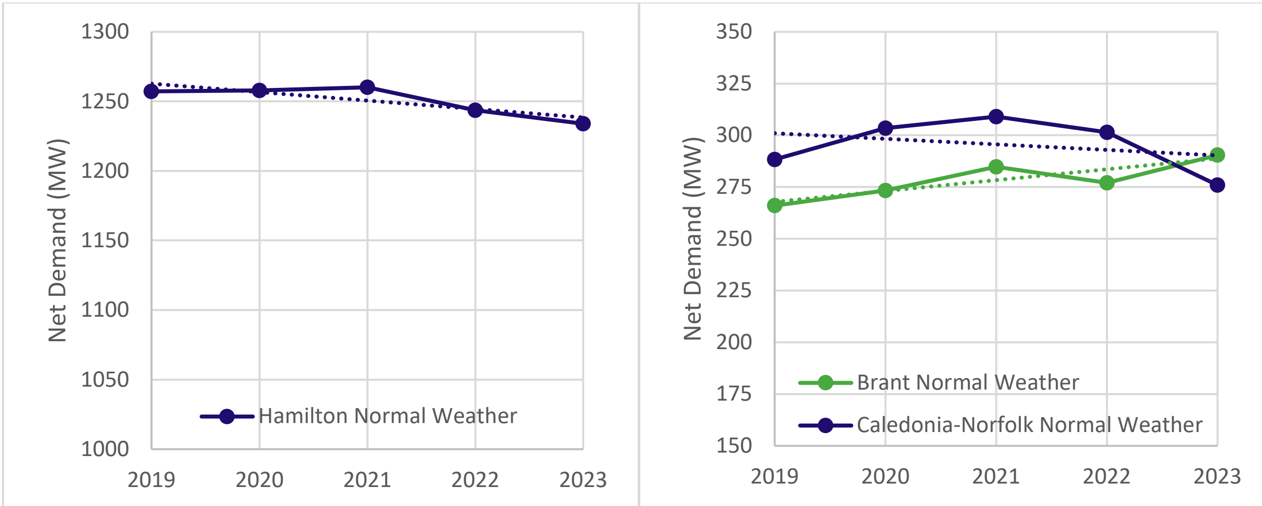
The coincident peak differs from a non-coincident peak, which refers to each station's individual peak, regardless of whether these peaks occur at different times. Each subregion of the Burlington to Nanticoke Region is summer peaking.

5.1 Historical Demand

Peak electricity demand within the Burlington to Nanticoke Region has been on average steady over 2019 to 2023. Figure 5 below shows the coincident net normal weather-corrected (adjusted to reflect normal weather conditions) historical demand for each subregion, which have unique trends. Weather-corrected historical demands have been shown to remove the effect of weather on annual changes in demand. Weather-corrected demand is more appropriate for evaluating growth trends. The peak demand hour for each year occurred consistently in the summer between approximately 2 PM to 7 PM.

The net weather-corrected demand for the Brant, Caledonia-Norfolk, and Hamilton subregions has averaged 278 MW, 296 MW, and 1251 MW, respectively, over the last five years with negligible upward or downward trends. Demand has slightly been increasing for the Brant subregion while slightly declining for the Caledonia-Norfolk and Hamilton subregions.

Figure 5 | Historical Subregion Normal-Weather Demands

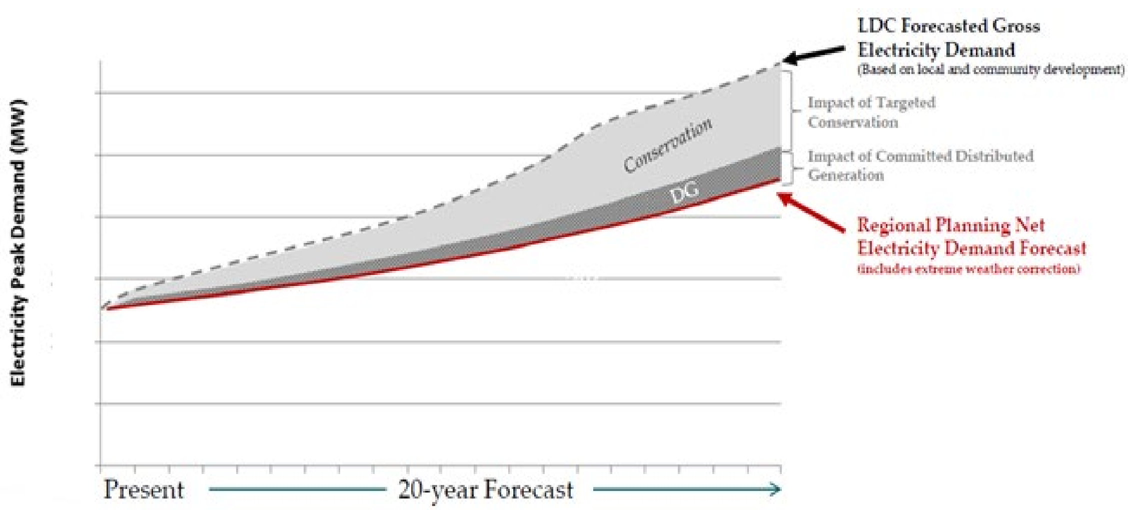


5.2 Demand Forecast Methodology

The methodology used to develop a 20-year IRRP peak demand forecast starting from LDC forecasts is illustrated in Figure 6. Gross demand forecasts, which assume the weather conditions of a normal year based on historical weather conditions (referred to as "normal weather"), were developed by the LDCs. These forecasts were then modified to reflect the peak demand impacts of provincial conservation targets and DG contracted through previous provincial programs, such as Feed-In Tariff (FIT) and microFIT, and adjusted to reflect extreme weather conditions in order to produce a reference forecast for planning assessments. This net forecast was then used to assess the electricity needs in the region.

Additional details related to the development of the demand forecast are provided in Appendix B. The Ontario Energy Board also since published a Load Forecast Guideline for regional planning, through the Regional Planning Process Advisory Group.

Figure 6 | Illustrative Development of Demand Forecast



5.3 Gross LDC Forecast

Each participating LDC in the Burlington to Nanticoke Region prepared gross demand forecasts at the station level, or at the station bus level for multi-bus stations. These gross demand forecasts account for increases in demand from new or intensified development, plus known connection applications. In addition, when producing these gross demand forecasts, the impact of existing DG was removed, as DG impacts are accounted for later (see Section 5.5). Therefore, gross demand forecasts show the demand expected without any DG contributions, new or existing. Please see Section B.1 of Appendix B for more detail.

The LDCs cited alignment with municipal and regional plans and credited them as a source for input data. LDCs were also expected to account for changes in consumer demand resulting from typical efficiency improvements and response to increasing electricity prices (natural conservation), but not for the impact of future DG or new conservation measures (such as codes and standards and CDM programs), which are accounted for by the IESO (discussed in Section 5.4). The gross LDC forecast assumes normal weather conditions (e.g. median weather, expected 1 in 2 years), and peak station loading which may be non-coincident to the regional peak.

LDCs have a better understanding of future local demand growth and drivers than the IESO, since they have the most direct involvement with their customers, connection applicants, municipalities and communities which they serve. The IESO typically carries out demand forecasting at the provincial level. More details on the LDCs' load forecast assumptions can be found in Appendix B.

5.4 Contribution of Conservation to the Forecast

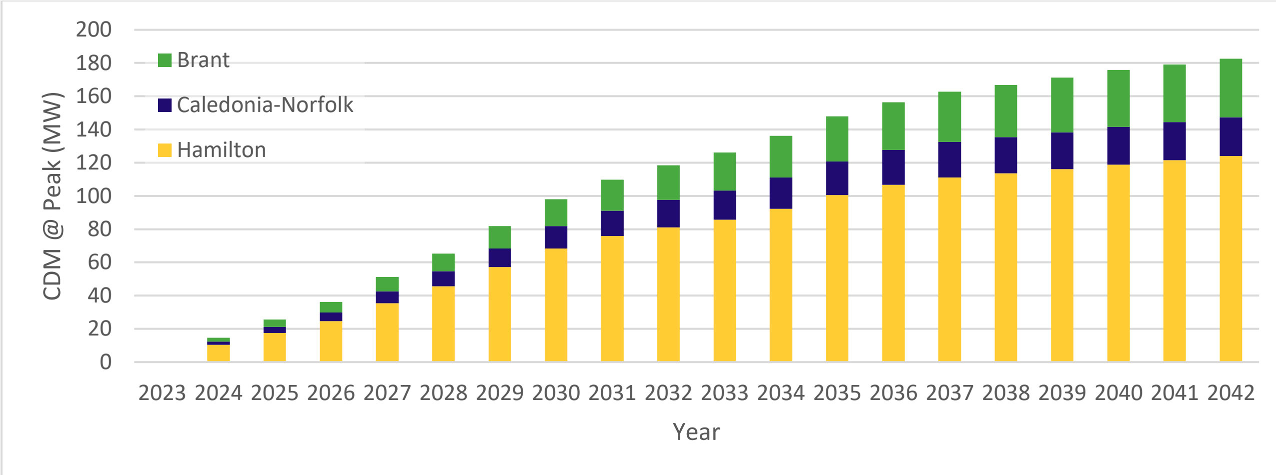
Conservation and demand management is a non-emitting and cost-effective resource that helps meet Ontario's electricity needs by reducing electricity consumption and peak-demand, and has been an integral component of provincial and regional planning. Conservation is achieved through a mix of codes and standards amendments, as well as CDM program-related activities. These approaches complement each other to maximize conservation results.

The estimated demand reduction from codes and standards is based on expected improvement in the codes for new and renovated buildings, and through regulation of minimum efficiency standards for equipment used by specified categories of consumers (i.e., residential, commercial and industrial consumers).

The estimated demand reduction from program-related activities is based on the 2021-2024 CDM Framework, federal programs that result in electricity savings in Ontario, and forecasted long-term energy efficiency programs assumed to be consistent with current framework savings levels. Through the ongoing 2021-2024 CDM Framework the IESO centrally delivers programs on a province-wide basis to serve business and low-income customers, as well as Indigenous communities. At the time of forecast development and IRRP publication, actual energy and peak demand savings targets for the new 2025-2036 framework are not confirmed. Should the new savings targets be higher, it may push out the timing or reduced the magnitude of identified needs.

Figure 7 shows the estimated total yearly reduction to the demand forecast due to conservation (from codes, standards, and CDM programs) for each subregion. Additional details are provided in Appendix B.

Figure 7 | Peak Demand Reduction Due to Conservation and Demand Management



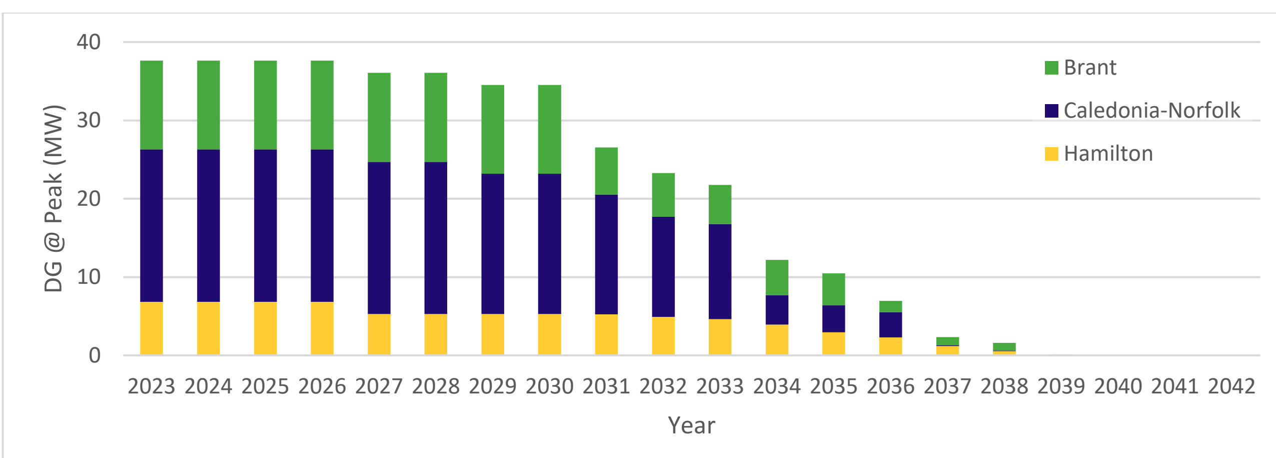
5.5 Contribution of Distributed Generation to the Forecast

In addition to conservation resources, DG is also forecasted to offset peak-demand requirements. The introduction of Ontario's FIT and microFIT Programs increased the significance of distributed renewable generation which, while intermittent, contributes to meeting the province's electricity demands. The installed DG capacity by fuel type and the associated contribution factor assumptions can be found in Appendix B. Most of the total contracted installed DG capacity in the Burlington to Nanticoke Region is solar generation, but there is a comparable quantity of non-renewable generation. In the Brant and Hamilton subregions, the split is approximately equal, but in the Caledonia-Norfolk region there is only renewable generation, which is almost entirely solar.

Figure 8 shows the estimated impact of DG on the Burlington to Nanticoke Region demand forecast. Note that any facilities without a contract with the IESO are not currently included in the DG peak demand reduction forecast.

In the long term, the contribution of DG is expected to diminish as their contracts expire. A total of 38 MW of peak contribution is identified for the Burlington to Nanticoke Region in 2023, reducing to zero by 2039 throughout the 2030s. This reduction is reflected in the Planning forecast as discussed in the next section.

Figure 8 | Peak Demand Reduction Due to Distributed Generation



5.6 Net Extreme Weather (Planning) Forecast

The net extreme weather forecast, also known as the "planning" forecast, is traditionally a region-wide coincident forecast, meaning that each station forecast reflects its expected contribution to the regional peak demand. This supports the identification of need dates for regional needs that are driven by more than one station.

Due to the specific needs of the three subregions within the Burlington to Nanticoke Region (the Brant, Caledonia-Norfolk, and Hamilton subregions), and due to the small or lack of excess capacity remaining on these subregions, the "planning" forecast was produced as a subregion coincident forecast. This means that each station forecast reflects its expected contribution to its subregion 's peak demand rather than the regional peak demand. This puts a greater focus on identifying subregion needs, which was required due to the high level of loading in these subregions.

The planning forecast is produced from three main steps: converting to a coincident forecast, adjusting for extreme weather, and converting to a net forecast.

As discussed in Section 5.3, LDCs provide gross forecasts assuming normal weather conditions, and peak station loading that is non-coincident to the region or subregion. Therefore, the first step is to convert this non-coincident forecast to a coincident forecast, by applying a coincidence factor to each station. The factor is based on the station's historical contribution to the subregion peak demand compared to the station's non-coincident peaks over the past five years (2018-2022 in this case). This results in a subregion coincident gross forecast which assumes normal weather.

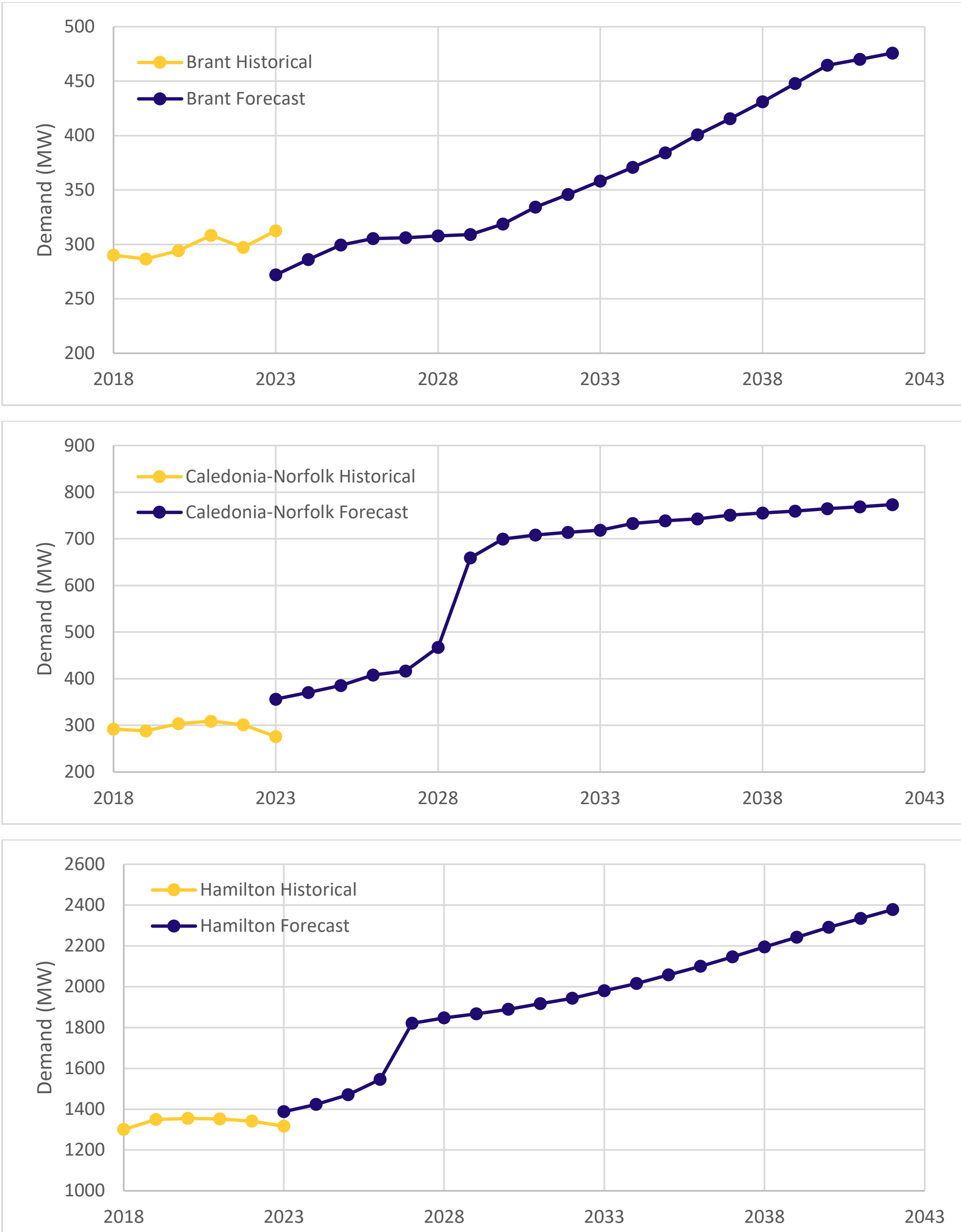
The second step is to adjust the resulting coincident gross normal weather forecast for extreme weather conditions. The weather correction methodology is described in Appendix B. This results in a coincident gross forecast which assumes extreme weather.

The last step is to adjust the resulting coincident gross extreme weather forecast for DG and conservation impacts. This is done by subtracting the forecasted DG and conservation impacts (as described in the above Sections) from the coincident gross extreme weather forecast. Finally, this results in a (subregional) coincident net extreme weather forecast, which is the "planning" forecast used to identify needs.

For station-specific needs, a non-coincident net extreme weather forecast used instead. The process for producing this forecast is similar as described above, except the first step is skipped.

The subregion coincident net extreme weather forecast ("planning" forecast) for each subregion in the Burlington to Nanticoke Region is shown in Figure 9 below. Historical net extreme weather demands have also been added for reference. The large increases in demand between 2026 to 2030 in the Caledonia-Norfolk and Hamilton subregions are caused by demand increases from a small number of existing industrial customers supplied by the 230 kV subsystems. These demand increases are unrelated to the needs and recommendations discussed in the following sections, which concern the 115 kV subsystems.

Figure 9 | Historical Demand and Planning Forecast for the Subregions



5.7 Hourly Forecast Profiles

In addition to the annual peak demand forecast, hourly demand profiles (8,760 hours per year over the 20-year forecast horizon) for the Bloomsburg DS and Norfolk TS stations were developed to better assess non-wire alternatives to address needs at these stations. In particular, these profiles were used to quantify the magnitude, frequency, and duration of needs, as described later in Section

7. The profiles were based on historical demand data, adjusted for variables that impact demand such as calendar day (i.e., holidays and weekends) and weather. The profiles were then scaled to match the IRRP peak planning forecast for each year.

Additional load profile details including hourly heat maps for each need can be found in Appendix D. Note that this data is used to roughly inform the overall energy requirements needed to develop and evaluate alternatives; it cannot be used to deterministically specify the precise hourly energy requirements. Real-time loading is subject to various factors like actual weather, customer operation strategies, and future customer segmentation. Demand patterns can change significantly as consumer behaviour evolves, new industries emerge, and trends like electrification are more widely adopted. Hence, these hourly forecasts are only used to select suitable technology types and roughly estimate costs for the needs and options studied in the IRRP. The Technical Working Group will continue to monitor forecast changes as part of implementation of the plan.

6 Needs

6.1 Needs Assessment Methodology

Based on the planning demand forecast, system capability, the transmitter's identified asset replacement plans, and the application of ORTAC, NERC TPL-001-4, and Northeast Power Coordinating Council (NPCC) Directory #1 standards, the Technical Working Group identified electricity needs in the near-, medium- and long-term timeframes. These needs can be categorized according to the following:

Station Capacity Needs describe the electricity system's inability to deliver power to the local distribution network through the regional step-down transformer stations during peak demand. The capacity rating of a transformer station is the maximum demand that can be supplied by the station and is limited by station equipment. Station ratings are often determined based on the 10-day Limited Time Rating (LTR) of a station's smallest transformer under the assumption that the largest transformer is out of service. A transformer station can also be more limited by the thermal ratings of downstream or upstream equipment, i.e., breakers, disconnect switches, medium-voltage bus or high voltage circuits; or, by voltage drop limitations, which are independent of thermal ratings.

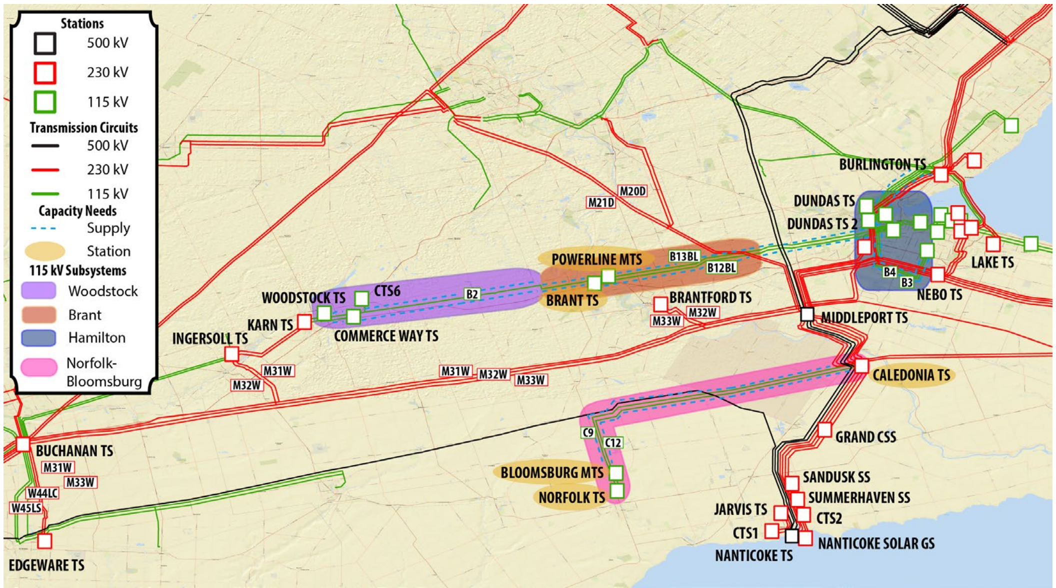
Supply Capacity Needs describe the electricity system's inability to provide continuous supply to a local area during peak demand. This is limited by the LMC of the transmission supply. The LMC is determined by evaluating the maximum demand that can be supplied to an area after accounting for limitations of the transmission elements (i.e., a transmission line, group of lines, or autotransformer), when subjected to contingencies and criteria prescribed by ORTAC, TPL-001-4, and NPCC Directory #1. LMC studies are conducted using power system simulation analyses.

Asset Replacement Needs are identified by the transmitter by an asset condition assessment, which is based on a range of considerations such as equipment deterioration due to aging infrastructure or other factors; technical obsolescence due to outdated design; lack of spare parts availability or manufacturer support; and/or potential health and safety hazards, etc. Replacement needs identified in the near- and early mid-term timeframe would typically reflect more condition-based information, while replacement needs identified in the medium to long term are often based on the equipment's expected service life. As such, any recommendations for medium- to long-term needs should reflect the potential for the need date to change as condition information is routinely updated.

Load Security and Restoration Needs describe the electricity system's inability 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 are prescribed by Section 7 of ORTAC.

Technical study results for the Burlington to Nanticoke IRRP can be found in Appendices G and H. The needs identified are discussed in the following sections, and are shown in Figure 10 below.

Figure 10 | Needs Identified in the Burlington to Nanticoke Region



6.2 Station Capacity Needs

Many station capacity needs emerge in the Burlington to Nanticoke region as shown in Table 5 with the majority in the near-/medium-term. Please see Appendix I, Figures of Station and Supply Capacity Needs, for graphical representation of these needs.

Table 5 | Station Capacity Needs

Time Horizon	Station	Subregion	Emerging Year	2042 Need (MW)
Near-term	Bloomsburg DS	Caledonia-Norfolk	2023	16
	Dundas 2 TS	Hamilton	2023	40
	Nebo TS (T1/T2)*	Hamilton	2023	142
	Nebo TS (T3/T4) *	Hamilton	2023	50
	Dundas TS	Hamilton	2025	59
	Powerline MTS	Brant	2026	68
	Mohawk TS	Hamilton	2026	46
	Brant TS	Brant	2027	41
Medium-term	Norfolk TS	Caledonia-Norfolk	2031	16
	Newton TS	Hamilton	2031	31

Time Horizon	Station	Subregion	Emerging Year	2042 Need (MW)
Long-term	Caledonia TS	Caledonia-Norfolk	2034	20
	Brantford TS	Brant	2035	54
	Lake TS (T1/T2) *	Hamilton	2035	19
	Elgin TS	Hamilton	2037	23
	Horning TS*	Hamilton	2038	14
	Beach TS (T5/T6) *	Hamilton	2042	2

*The station capacity needs were identified using the station load meeting capabilities (LMC) calculated by the IESO from load flow studies, or, if the LMC calculations were deferred to the addendum, using the station limited time ratings (LTR) provided in the transmitter-led Needs Assessment report.

6.2.1 Brant Subregion Station Capacity Needs

The three stations supplying the Brant subregion, Powerline MTS, Brant TS and Brantford TS, are forecasted to exceed their station capacity within the next decade. For a time, overloading at Brant TS and Powerline MTS can be addressed through distribution-level load transfers to Brantford TS until Brantford TS exceeds its capacity. However, by 2031 Brantford TS would no longer have capacity to provide relief, and new capacity is needed in the subregion. Additionally, the technical requirements and cost of upgrading the distribution system may limit the feasibility or viability of load transfer to Brantford TS.

6.2.2 Caledonia-Norfolk Subregion Station Capacity Needs

Half of the stations supplying the Caledonia-Norfolk subregion, Bloomsburg DS, Norfolk TS and Caledonia TS, are forecasted to exceed their station capacity within the next decade. For a time, overloading at these stations can be lessened through distribution-level load transfers to Jarvis TS. However, by 2035 Jarvis TS would no longer have capacity to provide relief, and new station capacity is needed in the subregion. Additionally, feasibility and economic reasons may restrict the amount of the load transfers.

6.2.3 Hamilton Subregion Station Capacity Needs

In the Hamilton subregion, ten out of 19 DESNs are forecasted to exceed their station capacity within the planning horizon. Notably six of these DESNs, i.e., Dundas TS, Dundas 2 TS, Mohawk TS, Nebo TS (T1/T2) and (T3/T4) and Newton TS, are identified with station capacity needs with a near- or medium-term timeframe.

The majority of needs for the Hamilton subregion will be addressed in the Hamilton Addendum as discussed in Section 2.5.1. However, the needs of the Dundas stations will be addressed by the Technical Working Group recommendations as part of the Brant 115 kV Extended Area as described in Section 6.3.

6.2.4 Customer-Owned Transformer Stations

Two customer-owned transformer stations (CTS) within the Burlington to Nanticoke Region are forecasted to exceed their station capacity. Since these stations are privately owned, the private owners will need to coordinate their solution with the IESO and transmitter (Hydro One) via the Connection Assessment and Approval (CAA) process.

6.3 Supply Capacity Needs

Supply capacity needs for the majority of the Hamilton subregion will be assessed and addressed in the addendum as discussed in Section 2.5.1. However, a portion of the Hamilton 115 kV system was included in the need assessments for the Brant subregion because of their impact on one another. This larger area is referred to as the Brant 115 kV Extended Area which, similarly, was further extended on the opposite side to include the Woodstock 115 kV Subsystem. In summary, the Brant 115 kV Extended Area consists of:

- **Brant 115 kV Subsystem:** the Powerline and Brant stations in the Brant subregion supplied via B12BL, B13BL, and B2
- **Hamilton 115 kV Subsystem:** the Dundas, Dundas 2, Mohawk, Newton, Elgin and CTS3 stations in the Hamilton subregion supplied via B12BL, B13BL, B3, and B4
- **Woodstock 115 kV Subsystem:** the Woodstock, Commerce Way and CTS6 stations in the Woodstock subregion of the London Area supplied via K7, K12 and B2

Table 6 shows the supply capacity needs identified for the Norfolk-Bloomsburg Area in the Caledonia-Norfolk subregion and various Subsystems in the Brant 115 kV Extended Area. Please see Appendix I, Figures of Station and Supply Capacity Needs, for graphical representation of these needs.

The LMC of the Norfolk-Bloomsburg Area, which is radially supplied via circuits C9 and C12, is limited by voltage constraints to 80 MW, well below the thermal limitation of the circuits at 150 MW. This Area has an immediate need of 33 MW in 2023 which increases to 78 MW in 2042.

Supply capacity needs for the Brant 115 kV Extended Area were identified based on its Subsystems: the Brant, Hamilton and Woodstock 115 kV Subsystems.

- The Brant 115 kV Subsystem has an immediate need of 3 MW in 2023 and a long-term need of 129 MW in 2042. The LMC of the Brant 115 kV Subsystem is presently limited by thermal limitations on circuits B12BL and B13BL to 134 MW, but following that, voltage constraints limit the LMC to nearly the same limit of 137 MW.
- The combined Brant and Hamilton 115 kV Subsystems has an immediate need of 66 MW in 2023 which increases to 483 MW in 2042. The LMC of the combined Subsystems is presently limited by thermal limitations on circuits B12BL and B13BL to 500 MW, but following that, voltage constraints limit the LMC to nearly the same limit of 535 MW.
- The Woodstock 115 kV Subsystem has an immediate need of 20 MW in 2023 which increases to 47 MW in 2042. The LMC of the Woodstock 115 kV Subsystem is presently limited by voltage constraints to 85 MW.

The magnitudes of the needs shown in Table 6 can reach approximately 100 per cent of the LMC. This indicates that significant reinforcements that are required for the 115 kV Subsystems listed in this table.

Table 6 | Supply Capacity Needs

			Need	Magnitude
Subregion	**Subsystem**	**LMC (MW)**	**2023 (MW)**	**2042 (MW)**
Caledonia-Norfolk Subregion	Norfolk-Bloomsburg Area	80	33	78
Brant 115 kV Extended Area	Brant 115 kV Subsystem	134	3	129
	Combined Brant and Hamilton 115 kV Subsystems	500	66	483
	Woodstock 115 kV Subsystem	85	20	47

6.4 Asset Replacement Needs

At the time of the Burlington to Nanticoke Region Needs Assessment, Hydro One identified a number of assets requiring replacement in the next 10 years. These needs and recommendations from the Technical Working Group have been included in Table 7.

Table 7 | Asset Replacement Needs

Timeframe	Station	Asset	Recommendation
Medium-term	Beach TS	230/115 kV autotransformers DESN transformers	Proceed with like-for-like replacement
	Birmingham TS	DESN transformers and switchgear	Proceed with like-for-like replacement
	Caledonia TS	DESN transformer (T1)	Station capacity need identified; replace with maximum-rated unit
	Gage TS (T8/T9)	DESN transformers and switchgear	Proceed with replacement with nearest standard units
	Jarvis TS	DESN transformers	Proceed with like-for-like replacement; assess if current-limiting reactors can be removed*
	Lake TS	DESN transformers and switchgear	Station capacity need identified; replace with maximum-rated unit

Timeframe	Station	Asset	Recommendation
	Nebo TS (T3/T4)	DESN transformers	Station capacity need identified; replace with maximum-rated unit
	Norfolk TS	DESN switchgear	Defer replacement if possible, New 230 kV DESNs recommended (Section 7.3.2.3)
Long-term	Dundas TS	DESN switchgear	Defer replacement if possible, New 230 kV DESNs recommended (Section 7.3.2.3)

* The current-limiting reactors reduce the station LMC by 25 MW from ~125 MW to ~100 MW.

6.5 Load Security and Load Restoration Needs

The recommended interim solutions to open station bus-tie breakers can be violations to the load security criteria. However, the LDCs and transmitter can apply for exemptions until the medium-/long-term plans to address the needs are placed in service after which opening bus-tie breakers would not be needed.

The Technical Working Group did not identify any restoration needs.

7 Plan Options and Recommendations

This section describes the options considered and recommendations to address the needs in the Burlington to Nanticoke Region. In developing the plan, the Technical Working Group considered a range of integrated options. Considerations in assessing alternatives included feasibility, cost, lead time, system benefits, and consistency with longer-term needs in the area.

Generally speaking, there are two approaches for addressing regional needs that arise as electricity demand increases:

- Build new transmission or distribution infrastructure. These are commonly referred to as "wire" options and can include things like new transmission lines, autotransformers, step-down transformer stations, voltage control devices, upgrades to existing infrastructure, or distribution-level load transfers. Wire options may also include control actions or protection schemes that influence how the system is operated to avoid or mitigate certain reliability concerns.
- Install or implement measures to reduce the net peak demand to maintain loading within the system's existing LMC. These are commonly referred to as "non-wire" options and can include things like local utility-scale generation or storage, distributed energy resources (including distribution-connected generation and demand response), or CDM.

Section 7.1 begins with a more in-depth overview of all option types considered in IRRPs. Section 7.2 describes the screening approach used to assess which needs would be best suited for a more detailed assessment for non-wire option. Subsequently, Section 7.3 to Section 7.4 present the options that were ultimately developed and evaluated (including a cost comparison) before the Technical Working Group made a recommendation.

7.1 Options Considered in IRRPs

Wire options are always considered in regional planning and while they are always viable options for regional needs, non-wire option may be more suitable for specific need types and characteristics. Hence, to select and appropriately size non-wire option such as generation or battery storage, additional work is required – including creation of an hourly load profile, as described in Section 5.7. The most suitable technology type and capacity is chosen by examining the "unserved energy" profile, which is the hourly demand above the existing LMC. The profile indicates the duration, frequency, magnitude, and total energy associated with each need. Some of these characteristics are shown visually in Appendix D for the Burlington to Nanticoke Region needs.

High-level cost estimates for wire options are based on input provided by the transmitter and transmission benchmark costs. In contrast, cost estimates for non-wire options are based on benchmark capital and operating cost characteristics for each resource type and size. Due to policy considerations and decarbonization efforts, new natural gas-fired generation was not considered as a generation option for local needs identified by the regional plan. Battery energy storage, solar generation, and wind generation were considered for generation options.

New CDM measures can also help decrease the net electricity demand. Centrally delivered energy efficiency measures under the 2021-2024 CDM Framework and Save on Energy brand are already included in the load forecast, as discussed in the Section 5.4. As part of this current Framework, the IESO was directed to deliver a new program to address regional and/or local system needs. The Local Initiative Program is now one tool that is available to target the delivery of additional CDM savings at specific areas of the province with identified system needs. LDCs can also use the Ontario Energy Board's Non-Wires Solutions Guidelines for Electricity Distributors (previously "CDM Guidelines) to leverage distribution rates to help address distribution and transmission system needs using non-wire alternatives. Generally, incremental CDM measures are suitable for needs where growth is slow and the magnitude of the overload relative to the total demand is very small (i.e., on the order of few percent per year). These considerations are discussed further in Section 7.2, as part of the screening of options that was conducted.

For both wire and non-wire options, the upfront capital and operating are compiled to generate levelized annual capacity costs ($/kW-year). A cash flow of the levelized costs for the options are compared over the lifespan of the wire option (typically 70 years for transmission infrastructure). The net present value (in 2024 CAD for this report) of these levelized costs is the primary basis through which feasible options are compared.

It is important to recognize that there is a significant error margin around cost estimates at the planning stage, as they are only intended to enable comparison between options during the IRRP. The transmitter-led RIP (which is conducted after the IRRP) performs additional detailed analysis and allows the opportunity to refine cost estimates of wire options before implementation work begins. The IESO continues to participate in the Technical Working Group during the RIP and revisits these recommendations if costs estimates differ significantly. Furthermore, pilot or demonstration projects can be explored in cases where other barriers (e.g., regulatory frameworks for cost-sharing and recovery, or operationalization to meet local reliability constraints) impede the adoption of some of these cost-effective options following the completion of the IRRP.

The list of assumptions made in the economic analysis can be found in Appendix F.

7.2 Screening Options

As explained in the previous section, an array of options is developed to meet local needs during an IRRP and then each option is evaluated to recommend the option which is the most cost effective or the option which best balances cost and risk mitigation when substantial additional risks not captured by the Planning forecast are present. This process is complemented by considerations for stakeholder preferences and feedback.

Screening occurs early in the IRRP study after local reliability needs are known but before options analysis. It helps direct time-intensive aspects of detailed non-wires analysis (hourly need characterization, options development, financial analysis, and engagement) towards the most promising options. The three-step, high-level approach is shown in Figure 11 and further discussed in the next sections for the needs identified in the Burlington to Nanticoke region.

Station capacity needs identified for the Hamilton subregion in Section 6.2.3 are not included here, as the needs for the Hamilton subregion will be addressed in the addendum (see Section 2.5.1). More details on the steps and inputs used in the screening mechanism can be found in Appendix C, and a summary of the options screening results for Burlington to Nanticoke Region is provided in Table 8 for station capacity needs, and in Table 9 for supply capacity needs.

Figure 11 | IRRP NWAs Screening Mechanism

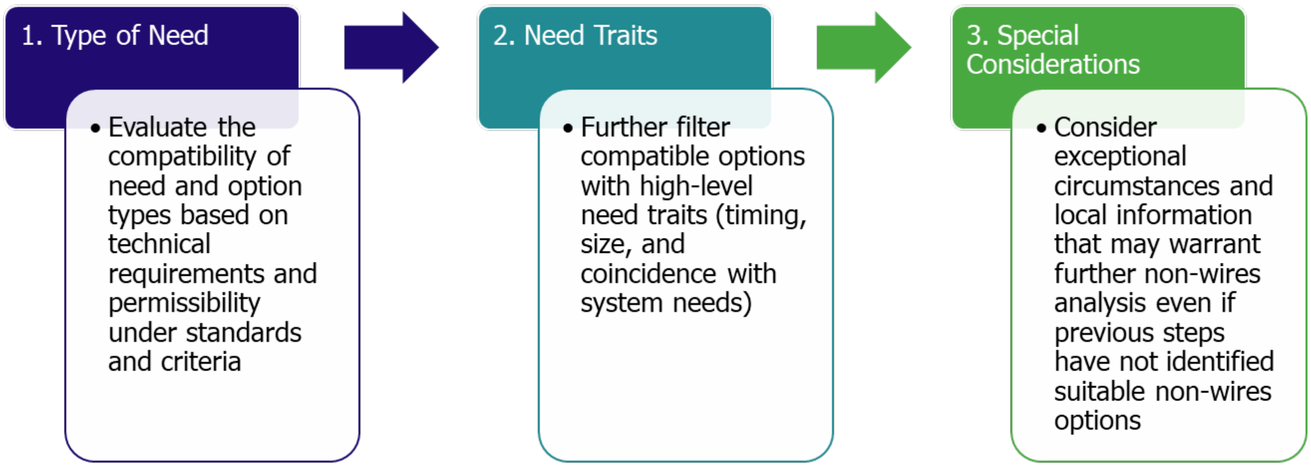


Table 8 | Options Screening Results for Station Capacity Needs

Need	Screened In	Screened Out
Station Capacity: Bloomsburg DS, Norfolk TS, Caledonia TS, Brant TS, Powerline MTS	• Operational measures • CDM • Distributed generation[4] • Wires options	• Demand response – due to magnitude and timing of need

Table 9 | Options Screening Results for Supply Capacity Needs

Need	Screened In	Screened Out
Supply Capacity: Line C9 and C12, Brant 115 kV Subsystem, Hamilton 115 kV Subsystem, Woodstock 115 kV Subsystem	• Operational measures • CDM • Distributed generation[4] • Transmission-connected generation • Wires options	• Demand response – due to magnitude and timing of need

7.2.1 Non-Wires Options for the Station Capacity Needs

[4] Later found to be technically infeasible due to short circuit limitations

Non-wires options cannot typically resolve the station capacity needs for the Burlington to Nanticoke region. The magnitude of the needs is too great to be addressed via CDM and DR and significantly exceeds the amount of DG that is technically feasible to connect at the distribution level due to short circuit and thermal constraints. Transmission-connected generation was also excluded because resources must be connected downstream of the limiting step-down transformer to have an impact on the station capacity needs.

Nevertheless, CDM has been considered for deferring long-term station capacity needs.

7.2.2 Non-Wires Options for the Supply Capacity Needs

Non-wires options, except transmission-connected resources, cannot resolve the supply capacity needs for the Burlington to Nanticoke Region since these needs are large in magnitude. Nevertheless, non-wire options can be explored in combination with wire options.

Only non-emitting resources such as battery storage and renewables were included in the option assessments.

7.3 Options and Recommendations for the Brant Subregion

7.3.1 Station Capacity Needs

The three stations supplying the Brant subregion, Powerline MTS, Brant TS and Brantford TS, are forecasted to exceed their station capacity, in the same order, within the next decade.

The needs at Powerline MTS and Brant TS are too large to be addressed by CDM or DR and DG is not viable because of short-circuit and thermal limitations at the stations. For a time, overloading at Powerline MTS and Brant TS can be addressed through distribution-level load transfers to Brantford TS until Brantford TS exceeds its capacity. The technical requirements and cost of upgrading the distribution system may limit the feasibility or viability of this load transfer.

Normally, the wire option, that is to upgrade the Powerline and Brant transformers, is recommended at this point. However, since there is also a supply capacity need for these stations, it would be more efficient and cost-effective to recommend a solution that resolves all supply and station capacity needs in the area, as discussed in the next section.

Therefore, as an interim solution, it is recommended to open bus-tie breakers at Powerline MTS and Brant TS, as required, to resolve their station capacity needs.

Load transfer to Brantford TS on a permanent or temporary basis may be used to reduce or resolve the station capacity needs but should be coordinated with the recommended interim option for resolving the supply capacity needs for the area explained in Section 7.3.2.1.

Since the Brantford station capacity need is in the long term, no immediate action is required. The Technical Working Group will monitor the load growth at the station for any change that can advance the need to take an appropriate action.

7.3.2 Supply Capacity Needs

No supply capacity need was identified for Brantford TS which is supplied from M32W and M33W, the 230 kV double-circuit line between Middleport and Buchanan.

Needs for the Brant 115 kV Subsystem, 115 kV circuits B12BL, B13BL and B2 supplying Powerline MTS and Brant TS, could not be identified and addressed in isolation due to its tight connectivity with the neighboring subregions. As such, the area of study was extended to the entire 115 kV system enclosed between the Burlington and Karn 115 kV stations. This study area is referred to as the Brant 115 kV Extended Area which, in addition to the Brant 115 kV Subsystem, consists of the Hamilton 115 kV Subsystem plus Woodstock 115 kV Subsystem, which are the Dundas, Dundas 2, Mohawk, Newton, Elgin and CTS3 stations in the Hamilton subregion supplied via B12BL, B13BL, B3 and B4 plus the Woodstock, Commerce Way and CTS6 stations in the Woodstock subregion of the London Area supplied via K7, K12 and B2.

7.3.2.1 Interim Solution – Operational Measures

As presented in Section 6.3, there are immediate supply capacity needs in the Brant 115 kV Extended Area.

Therefore, as an interim solution, it is recommended to take some operational measures to maintain system security by opening station bus-tie breakers within each Subsystem to maintain the post-contingency total load within the applicable load meeting capability. Effort should be taken to minimize the overall number of bus-tie breakers that must be open based on system conditions.

7.3.2.2 Non-Wire Options

Due to the large magnitude of the supply capacity needs in the Brant 115 kV Extended Area, CDM, DR and DG were not found to be adequate to resolve the needs. Transmission-connected resources, such as battery storage, are the only non-wire options with the potential to address these needs.

Due to the large area spanned when evaluating the resource option, a minimum of two facilities were needed, one at Brant TS and one at Newton TS with a total capacity of 450-600 MW. To be viable, the battery storage at both places should be paired with wind and solar generation because there are extended periods of time when the batteries cannot be charged from the grid due to extremely limited supply capacities. This implies having 600-1,500 MW wind and solar farms within the densely populated urban areas of Hamilton, which is not practical. As a result, transmission-connected resources were not considered feasible to meet this need and are not recommended.

7.3.2.3 Wire Options

Wire options listed in Table 10 were considered for resolving supply capacity needs in the Brant 115 kV Extended Area with additional information provided in the following sections.

Option 1: Reinforcing 115 kV and Dynamic Voltage Support

Based on load flow studies, almost all the 115 kV lines – 30 km of a single-circuit lines and 80 km of double/quadruple-circuit lines – must be reinforced with higher capacity wires by a factor ranging from 1.35 to 3 in various sections. Additionally, dynamic voltage support devices, e.g. STATCOM, SVC or synchronous condenser, with a total post-contingency capacity of 500 Mvar at the Karn, Brant and Powerline stations are required to stabilize the voltage. It can take up to $790 M and 10 years to implement this option and still the long-term needs are not resolved let alone enabling future load growth.

Option 2: Upgrading 115 kV to 230 kV

This option entails replacing towers and wires on 85 km of double/quadruple-circuit lines and 2x8 stepdown transformers serving loads at eight stations. In addition to being prohibitively costly and lengthy, implementing this option is not practical since the lines pass through dense urban areas or along busy roads with a tight right of way.

Option 3: Adding New Supply Point Via 230/115 kV Autotransformers

None of the three alternatives considered for this option showed better load meeting capabilities than Option 1 although similar 115 kV reinforcements and dynamic voltage support were necessary and reinforcing 230 kV system might also be required. This implies this option has a higher cost and longer implementation time than Option 1 with no additional benefits.

Option 4a: Offloading 115 kV System to MxD and MxB 230 kV Circuits

Option 4a is the recommended solution since it can resolve both supply and station capacity needs for the Brant and Powerline and Dundas and Dundas 2 stations within an acceptable cost and timeframe without any negative impact on major bulk interfaces. Furthermore, the 115 kV system can supply the remaining Hamilton stations, CTS3, Mohawk, Newton and Elgin TS, up to their capacities without any additional reinforcement. Supply and station capacity needs, which would still limit the expected load growth for these remaining Hamilton stations, will be further assessed and addressed in the addendum discussed in Section 2.5.1.

To address supply capacity needs, rather than constructing new DESNs, it is possible to convert the existing DESNs at Brant TS and Powerline MTS from 115 kV to 230 kV supply. However, this will not resolve station capacity needs, and additional measures will be needed.

The choice between constructing new DESNs or converting existing DESNs, and the siting of potential new DESNs will be determined in the upcoming Regional Infrastructure Planning (RIP) led by the transmitter. The point of connections to Middleport-Detweiler corridor will be finalized via the ongoing KWCG IRRP since these circuits are in the KWCG region.

Option 4b: Offloading 115 kV System to MxW and QxBM 230 kV Circuits

Option 4b is an alternative to Option 4a with similar benefits. However, the circuits to which load is transferred are part of major interfaces. Addition of load to these circuits negatively affect power transfer across the province and should be avoided. Otherwise, reinforcements are required to compensate for the negative impact.

Table 10 | Wire Options for Brant 115 kV Extended Area*

#	Description	Cost ($M)	Note
1	Reinforce 115 kV lines and add dynamic voltage support at Karn, Brant and Powerline	750-800	Does not resolve the long-term needs or enable future growth
2	Upgrade 115 kV lines and stations to 230 kV	1,000-1,500	Impractical and prohibitively costly and lengthy
3	Add new supply point via 230/115 kV autotransformers using either of the following alternative connections: - from Brantford TS to Brant TS on B12BL and B13BL - from Brantford TS to Alford Junctions on B12BL and B13BL - from Horning Mountain Junctions on M27B and M28B to Newton TS	850-1,000	Worse than Option 1; does not resolve the long-term needs or enable future growth; requires similar 115 kV reinforcements and dynamic voltage support as Option 1; may require 230 kV reinforcements
4a	Offloading 115 kV system to 230 kV: - Transfer Brant and Powerline loads to new 230 kV DESNs supplied from new taps on The Middleport-Detweiler corridor** - Transfer Dundas and Dundas 2 loads to new 230 kV DESNs at Dundas switchyard supplied from M27B and M28B***	200-300	**Recommended option.** Resolve supply and station capacity needs for Brant and Powerline and Dundas and Dundas 2; 115 kV system can supply the remaining Hamilton stations up to their capacities with no additional reinforcement****
4b	Offloading 115 kV system to 230 kV: - Transfer Brant and Powerline loads to new 230 kV DESNs supplied from Brantford TS or new taps on M32W and M33W - Transfer Dundas 1 and 2 loads to new 230 kV DESNs at Dundas switchyard supplied from Q23BM and Q25BM	300-400	Same benefits as Option 4a but not recommended due to negative impact on power transfer across the province as the circuits are part of major interfaces

* Line notations:
B12BL and B13BL: 115 kV circuits between Burlington, Brant and Newton, supplying Brant and Powerline loads
M27B and M28B: 230 kV circuits between Middleport and Burlington
M20D and M21D: 230 kV circuits between Middleport and Detweiler
M32W and M33W: 230 kV circuits between Middleport and Buchanan, part of a major interface transferring power across Ontario
Q23BM and Q25BM: 230 kV circuits between Beck 2, Burlington and Middleport, part of a major interface transferring power across Ontario

** DESN placements and point of connection to the Middleport-Detweiler corridor will be finalized via ongoing KWCG IRRP.

*** Transmitter-led Regional Infrastructure Plan (RIP) assesses and develops a detailed plan for implementation.

**** Woodstock 115 kV System LMC increases to 113 MW after which operational measures should be used to secure the system. Opening Brant DB2 115 kV breaker is recommended.

7.4 Options and Recommendations for the Caledonia-Norfolk Subregion

7.4.1 Station Capacity Needs

Three out of six stations supplying the Caledonia-Norfolk subregion, Bloomsburg DS, Norfolk TS and Caledonia TS, are forecasted to exceed their station capacity, in the same order, within the next decade.

The needs at Bloomsburg DS and Norfolk TS are too large to be addressed by CDM or DR and DG is not viable because of short-circuit and thermal limitations at the stations. For a time, overloading at Bloomsburg DS can be addressed through distribution-level load transfers to Norfolk TS until Norfolk TS exceeds its capacity after which Bloomsburg and Norfolk loads may be transferred to Jarvis TS. However, Hydro One Distribution has indicated limited ability to cost-effectively transfer load to Jarvis TS, and estimates that more than 20 km of new distribution line is needed meet long term needs.

Normally, the wire option, that is to upgrade the Bloomsburg and Norfolk transformers, is recommended at this point. However, since there is also a supply capacity need for these stations, it would be more efficient and cost-effective to recommend a solution that resolves all supply and station capacity needs in the area, as discussed in the next section.

Therefore, as an interim solution, it is recommended to open bus-tie breakers at Bloomsburg DS and Norfolk TS, as required, to resolve their station capacity needs.

Load transfer from Bloomsburg DS to Norfolk TS and additional load transfer from any of these stations to Jarvis TS on a permanent or temporary basis may be used to reduce or resolve the station capacity needs but should be coordinated with the recommended interim solution for resolving the supply capacity needs for the area explained in Section 7.4.2.1.

Since the Caledonia station capacity need is in the long term, no immediate action is required. The Technical Working Group will monitor the load growth at the station for any change that can advance the need, and consider the use of CDM closer towards the needs date to defer needs.

7.4.2 Supply Capacity Needs

As presented in Section 6.3, there is a supply capacity need in the Norfolk-Bloomsburg Area. No supply capacity need was identified for Caledonia TS or Jarvis TS.

7.4.2.1 Interim Solution – Operational Measures

To address the immediate supply capacity need in the Norfolk-Bloomsburg Area, an immediate interim solution is needed until permanent solutions can be put in place.

Therefore, as an interim solution, it is recommended to take some operational measures and open station bus-tie breakers at Bloomsburg DS or Norfolk TS, as required, to ensure the security of the system by maintaining the post-contingency total load within the applicable load meeting capability.

Permanent or temporary load transfer to Jarvis TS may be used to reduce reliance on opening bus-tie breakers.

7.4.2.2 Non-Wire Options

Due to the large magnitude of the supply capacity needs in the Norfolk-Bloomsburg Area, CDM, DR and DG were not found to be adequate to resolve the needs. Transmission-connected resources, such as battery storage, are the only non-wire options with the potential to address these needs. However, due to the sizeable capacity required to meet needs, this non-wire option is only economically viable when considering the system benefit that resources provide to the provincial system.

Load flow analyses showed battery energy storage systems (BESS) are viable if they:

- constantly control the voltage of the points of interconnection (POI) to the grid by providing enough reactive power (Mvar) support to the system.
- connect on both 115 kV lines, C9 and C12, between Bloomsburg Junctions and Norfolk TS, preferably at Norfolk TS.
- have enough redundancy in components and connections not to lose active/reactive power support and voltage control under any outage conditions; otherwise, the operational measures recommended as the interim solution in the previous section must be taken.

Minimum requirements for the rated capacity (MW) and energy (MWh) of a viable BESS are dependent on the minimum reactive power (Mvar) support that the BESS can constantly provide. Higher constant reactive power support results in lower rated capacity and energy requirements which may imply the BESS reactive power support exceeds the reactive power requirement from Market Rules Appended 4.2 – Category 5.

If the BESS option is found unviable because of low reactive power support, it may be possible to make it viable by pairing with renewables. Further analyses are needed to determine the capacity of wind and solar generation needed for this, and the associated feasibility of building sufficient wind and solar farms in the area.

As discussed in the next section, the recommended long-term solution for the Norfolk-Bloomsburg Area is a 230 kV wire option. However, since the needs are immediate and the implementation of the wire option can take up to 10 years, to bridge the gap until the Norfolk-Bloomsburg long-term wire solution is placed in service, a medium-term solution is also recommended.

Therefore, as a medium-term solution, a BESS capable of continually providing reactive support to control the voltage at the points of interconnection is recommended. The BESS may potentially be combined with other NWAs such as renewables.

7.4.2.3 Wire Options

The transmission-connected resources recommended in the previous section would not enable future long-term growth in the Area. In addition, a heavily loaded Norfolk-Bloomsburg 115 kV system would significantly restrict the load meeting capabilities of the upstream 230 kV system. Connecting new large loads, such as industrial projects or AI/data centres, with a magnitude of 1,000-2,000 MW to the Nanticoke-Middleport corridor or Nanticoke 230 kV TS may not be feasible unless the Norfolk-Bloomsburg Area is offloaded. As such, wire options listed in Table 10 were explored. Additional information is provided in the following sections.

Option 1: Dynamic Voltage Support and CDM

Based on load flow studies, dynamic voltage support devices, e.g. STATCOM, SVC or synchronous condenser, with a total post-contingency capacity of 100 Mvar are required to stabilize the voltage and increase the load meeting capability of the Norfolk-Bloomsburg Area to its thermal limit of 150 MW. Combined with new CDM programs, this option can meet the supply capacity need for the 20-year forecast without enabling any further growth. However, it does not resolve the station capacity needs at Bloomsburg DS and Norfolk TS. In addition, a limitation on the upstream 230 kV system is also present.

Option 2: Upgrading 115 kV System to 230 kV

This option entails replacing 115 kV wires along 45 km of double-circuit lines and adding two sets of stepdown transformers serving loads at the two stations. Implementing this upgrade would require frequent outages to the system including the 500 kV circuit that shares towers with the 115 kV circuits. The cost and lead time of this option are the largest among the wire options without providing any additional benefits comparing to Options 3a and 3b.

Option 3a and 3b: Transferring Load to a New 230 kV DESN Supplied Via New Lines Connecting to the Nanticoke-Middleport 230 kV Corridor or Nanticoke TS

Option 3 has two alternatives, a and b, with similar cost, timeline, and benefits.

> Option 3b, constructing a new DESN and connecting to Nanticoke TS, is recommended because it addresses the long-term supply and station capacity needs and enables future growth for the Norfolk-Bloomsburg Area. Option 3b is preferred over 3a, since it can address the needs for multiple areas, including possible growth due to industrial projects or AI/data centers in the vicinity of Nanticoke TS.

To address supply capacity needs, rather than constructing a new DESN, it is possible to convert the existing DESNs at Bloomsburg DS and Norfolk TS from 115 kV to 230 kV supply. However, this will not resolve station capacity needs, and additional measures will be needed.

The choice between constructing a new DESN or converting existing DESNs, the siting of new transmission lines, and the siting of potential new DESNs will be determined in the upcoming Regional Infrastructure Planning (RIP) led by the transmitter.

Depending on the implementation of the medium-term recommendation for a BESS in the Norfolk area, and the pace of load growth and distributed generation connections in the area over the near and medium term, there may be an opportunity to further defer the need for the long-term solution. However, given the interest from large loads in the Nanticoke area and the long lead time of the solution, it is recommended that as the work proceeds on the long-term solution, the TWG continues to monitor interest from load connections in the area. In the next planning cycle, the TWG will review the proposed in-service date and determine if any changes are needed.

Table 11 | Wire Options for Norfolk-Bloomsburg Area

#	Description	Cost ($M)	Note
1	Add dynamic voltage support + new CDM at Norfolk and Bloomsburg	100-200	Barely meets the 20-year supply capacity need; does not resolve station capacity needs; does not enable future growth; limits upstream 230 kV system
2	Upgrade 115 kV lines and stations to 230 kV	250-350	Resolves supply and station capacity needs and enable future growth at highest cost
3a	Transfer Norfolk and Bloomsburg loads to a new 230 kV DESN supplied via new lines connecting to the Nanticoke-Middleport 230 kV corridor	150-200	Resolves supply and station capacity needs; enable future growth
3b	Transfer Norfolk and Bloomsburg loads to a new 230 kV DESN supplied via new lines connecting to Nanticoke TS*	150-200	**Recommended long-term option.** Same benefits as Option 3; additionally, can address needs in multiple areas

* Transmitter-led Regional Infrastructure Plan (RIP) assesses and develops a detailed plan for implementation.

For a summary of recommendations with timing and lead responsibility, please refer Table 2, Table 3, and Table 4 in Sections 2.2 to 2.4.

8 Community and Stakeholder Engagement

Engagement is critical in the development of an IRRP. Providing opportunities for input in the regional planning process enables the views and perspectives of the public, which for these purposes, refers to market participants, municipalities, stakeholders, communities, Indigenous communities, customers and the general public, to be considered in the development of the plan, and helps lay the foundation for successful implementation. This section outlines the engagement principles and activities undertaken to date for the Burlington to Nanticoke IRRP.

8.1 Engagement Principles

The IESO's External Relations Engagement Framework is built on a series of key principles that respond to the needs of the electricity sector, communities and the broader economy. These principles ensure that diverse and unique perspectives are valued in the IESO's processes and decision-making. We are committed to engaging with purpose with external audiences to foster trust and build understanding as the energy transition continues.

Figure 12 | The IESO's Engagement Principles

8.2 Engagement Approach

To ensure that the Plan reflects the needs of market participants, municipalities, stakeholders, communities, Indigenous communities, customers and the general public, engagement involved:

- Leveraging the Burlington to Nanticoke engagement webpage to post updated information, engagement opportunities, meeting materials, input received and IESO responses to feedback.
- Timely and targeted discussions with transmission-connected loads and municipalities to help inform the engagement approach for this planning cycle;
- Hosted a series of public webinars at major junctions in the plan development to share plan details, understand feedback and answer questions, and
- Communications and other engagement tactics to enable a broad participation through email and IESO's weekly Bulletin updates.

As a result, the engagement plan for this IRRP included:

- A dedicated webpage on the IESO website to post all meeting materials, feedback received and IESO responses to the feedback throughout the engagement process;
- Regular communication with interested communities and stakeholders by email or through the IESO weekly Bulletin;
- Public webinars; and
- Targeted one-on-one outreach with specific communities and stakeholders to ensure that their identified needs are addressed (see Section 8.4).

8.3 Engage Early and Often

The IESO held preliminary discussions to help inform the engagement approach for the third round of planning, and to establish new relationships and dialogue in this region where there has been no active engagement previously. This started with the Scoping Assessment Outcome Report for the Burlington to Nanticoke Region. An invitation was sent to targeted municipalities, Indigenous communities, and those with an identified interest in regional issues, to announce the commencement of a new planning cycle and invite interested parties to provide input on the Burlington to Nanticoke Region Scoping Assessment Report finalization. A public webinar was held in November 2022 to provide an overview of the regional electricity planning process and seek input on the high-level needs identified and proposed approach. The final Scoping Assessment was posted later in December 2022, identifying the need for a coordinated regional planning approach and an IRRP.

Following finalizing the Scoping Assessment, several targeted outreach meetings then began to involve large customers and municipalities in the region to ensure growth and development plans have been accurately captured in the Technical Working Group's draft demand forecast and solicit early feedback on the IESO's approach to engagement. The launch of a broader engagement initiative followed, with an invitation to IESO subscribers of the Burlington to Nanticoke Region to ensure that all interested parties were made aware of this opportunity for input. Three public webinars were held at major stages during the IRRP development to give interested parties an opportunity to hear about its progress and provide comments on key components of the plan. These webinars were attended by a cross-representation of community representatives, businesses, and other stakeholders, and written feedback was collected following a comment period after each webinar.

The three stages of engagement at which input was invited:

1. The draft engagement plan, electricity demand forecast, and early identified needs – to set the foundation of this planning work.
2. The defined electricity needs for the region and high-level screening of potential options to meet the identified needs.
3. The analysis of options and draft IRRP recommendations.

Comments received during this engagement primarily focused on:

- Organic growth and economic development projects across the region;
- Interest in leveraging existing and local generation; and
- Interest in ensuring electricity infrastructure can accommodate economic development.

Feedback received during the written comment periods for these webinars helped to guide further discussions throughout the development of this IRRP, as well as add due consideration to the final recommendations.

All interested parties were kept informed throughout this engagement initiative via email to Burlington to Nanticoke's Region subscribers, municipalities, and Indigenous communities.

Based on the discussions through this engagement initiative, a key priority was to ensure the IRRP and recommended actions aligned with strong forecast growth and development both within specific municipalities and the region more broadly (e.g. future urban expansion as shared by Norfolk County, residential growth as shared by Haldimand County, and capacity concerns as shared by Hamilton). These insights have been valuable to the IESO – as they supported an understanding of local growth and an accurate electricity demand forecast, the determination of needs, and the recommendation of solutions to ensure adequate and reliable long-term supply.

Additionally, participants would like to be engaged when there is additional information to share regarding Hamilton's needs, options and draft recommendations as well as progress in-between planning cycles. To that end, ongoing discussions will continue through the Hamilton Addendum to keep interested parties engaged in a two-way dialogue. Additionally, municipalities are encouraged to ensure their local distribution company is aware of any changes and updates to their growth and development plans.

All background information, including engagement presentations, recorded webinars, detailed feedback submissions, and responses to comments received, are available on the IESO's Burlington to Nanticoke IRRP engagement webpage.

8.4 Involving Municipalities in the Plan

The IESO held meetings with municipalities to seek input on their planning and to ensure that key local information about growth and development and energy-related initiatives were taken into consideration in the development of this IRRP. At major milestones in the IRRP process, meetings were held with the upper- and lower-tier municipalities in the region to discuss key issues of concern, including forecast regional electricity needs, options for meeting the region's future needs, and broader community engagement. These meetings helped to inform the municipal/community electricity needs and priorities, establish new relationships, and provided opportunities for ongoing dialogue beyond this IRRP process.

Through these discussions valuable feedback was received around strong anticipated growth in major growth centres in the region and community preferences around solutions:

- Over the next 20 years, significant residential growth in Caledonia with 4,000 to 5,000 residential dwellings, Hagersville with 3,000 to 3,500 residential dwellings and Jarvis and Dunnville with 500.
- There is a potential urban boundary expansion in Norfolk County and a new employment area in Delhi.
- Significant growth is anticipated for St. George (when wastewater treatment plant expansion is completed), Burford (servicing master plan is underway) and Oakland/Scotland areas in the County of Brant.
- Electrification initiatives within City of Brantford are underway such as the construction of a transit hub.
- Capacity concerns for Dundas and Dundas 2 were raised by the City of Hamilton prompting those station capacity needs to be explored in this study rather than the Hamilton Addendum.
- Several municipalities are exploring local energy projects to support their energy needs and would like to have these, or other non-wire alternatives, considered as solutions for the IRRP.

8.5 Engaging with Indigenous Communities

To raise awareness about the regional planning activities underway and invite participation in the engagement process, regular outreach was made to Indigenous communities within the Region throughout the development of the plan. This includes the Mississaugas of the Credit First Nation, Six Nations of the Grand River as represented by Six Nations Elected Council as well as the Haudenosaunee Confederacy Chiefs Council, and a number of MNO councils located within or near the Region including MNO Clear Waters Métis Council and MNO Grand River Métis Council.

The IESO remains committed to an ongoing, effective dialogue with communities to help shape long-term planning in regions all across Ontario.

9 Conclusions

The Burlington to Nanticoke IRRP identifies electricity needs in the region over the 20-year period from 2023 to 2042, and recommends a plan to address needs from the immediate to long-term. The IESO will continue to participate in the Technical Working Group during the next phase of regional planning, the RIP, to provide input and ensure a coordinated approach.

In the near-to-medium term, the Technical Working Group recommends the pre-contingency opening of bus-tie breakers, and load transfers between nearby stations at the distribution level, where viable and cost-effective. These recommendations are needed at several stations supplied by the 115 kV transmission system and one by the 230 kV transmission system.

In the medium-term, the Technical Working Group recommends the procurement of a BESS in the Norfolk-Bloomsburg Area, and the construction of a new substation[5] near Dundas TS. These recommendations will respectively address needs in the Norfolk-Bloomsburg Area, and on the Hamilton 115 kV Subsystem and at the Dundas and Dundas 2 stations.

Finally, in the long term, the Technical Working Group recommends constructing two new double-circuit transmission lines and associated substations[5], separating the Woodstock 115 kV Subsystem from the Brant 115 kV Subsystem, and considering cost-effective CDM at Brantford TS and Caledonia TS closer to needs dates to defer capacity needs at these stations. A map outlining the medium- and long-term recommendations is provided in Figure 13.

The first transmission line is recommended from Nanticoke TS into the Norfolk-Bloomsburg Area, and a new station with an LTR of approximately 200 MVA is recommended at the end of the line. The Technical Working Group then recommends that Norfolk TS and Bloomsburg TS be entirely offloaded onto the new substation[5]. The second transmission line is recommended as an extension from the existing Middleport-Detweiler corridor in the Kitchener/Waterloo/Cambridge/Guelph region into County of Brant, and a new station with an LTR of approximately 400 MVA is recommended at the end of this line. The Technical Working Group then recommends that Brant TS and Powerline MTS be entirely offloaded onto the new substation[5]. Last, the Woodstock 115 kV Subsystem is recommended to be separated from the Brant 115 kV Subsystem by opening the Brant DB2 breaker.

The Technical Working Group will continue to monitor growth at Brantford TS and Caledonia TS and across the region. This includes any future community energy planning, electrification trends, datacentres, or industrial load. Additionally, there are benefits to investigating opportunities to target incremental CDM to the region. The Technical Working Group will meet at regular intervals to complete the Hamilton addendum, monitor developments and track progress toward plan deliverables. 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 five-year schedule mandated by the Ontario Energy Board.

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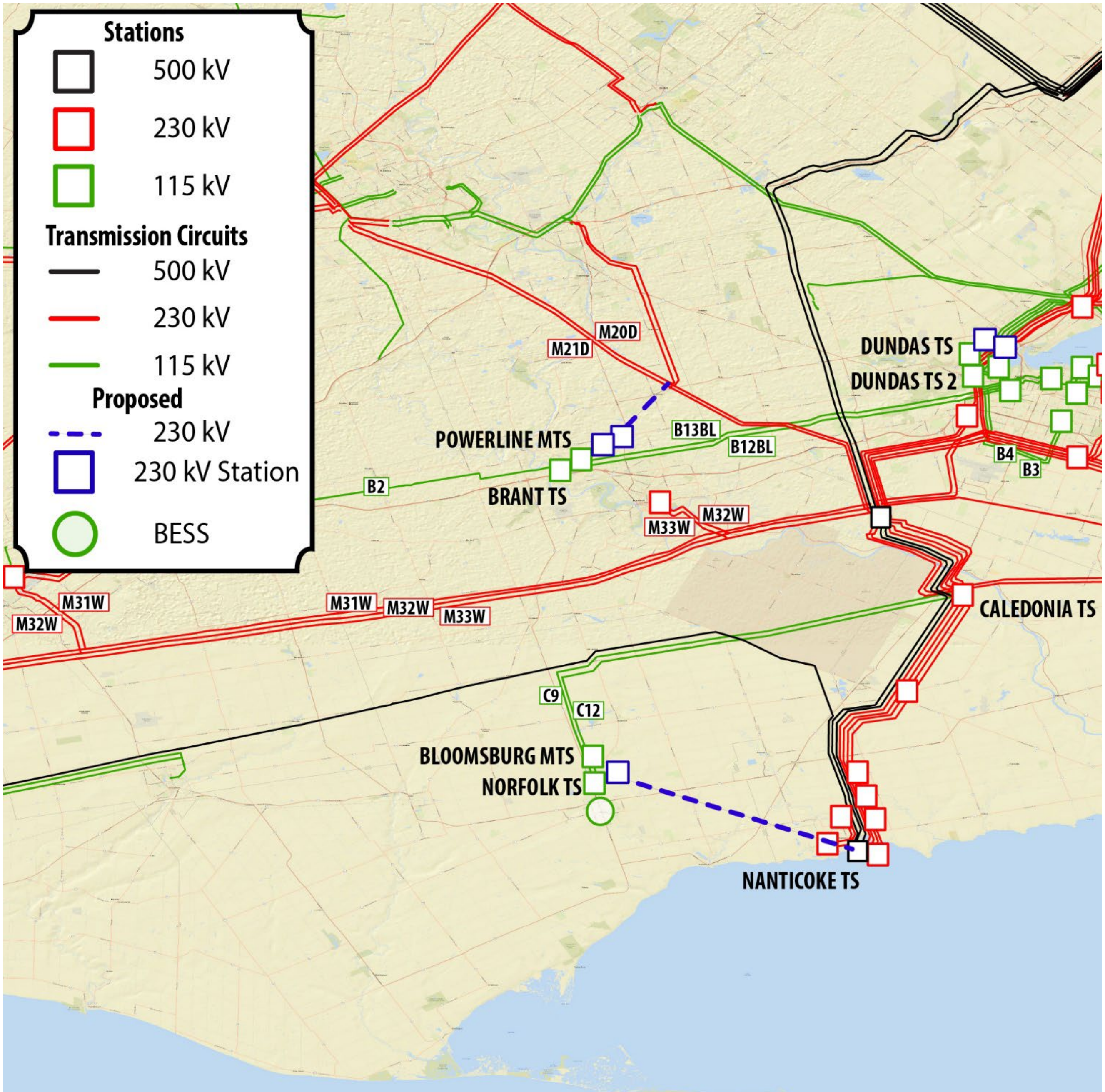
[5] Rather than building a new station, the existing DESNs may be converted from a 115 kV supply to a 230 kV supply by replacing all 115 kV station equipment. The subsequent Transmitter-led Regional Infrastructure Plan (RIP) will identify the most cost-effective solution and develop a detailed plan for implementation.

Figure 13 | Medium/Long-Term Recommendations in the Burlington to Nanticoke Region



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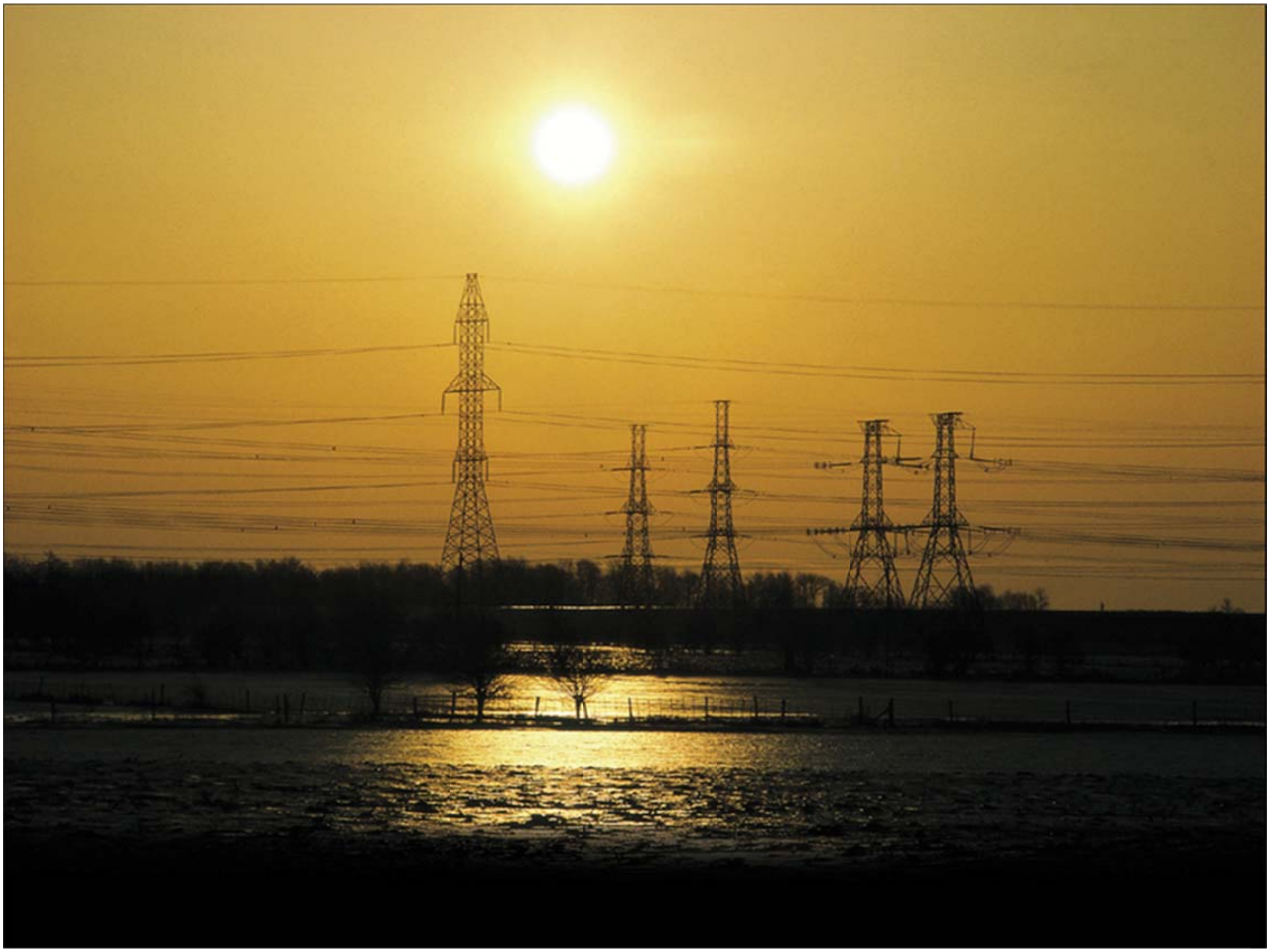
Appendix F

Burlington to Nanticoke Regional Infrastructure Plan



Burlington to Nanticoke

REGIONAL INFRASTRUCTURE PLAN

October 08, 2019

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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 (2019-2029) identified in previous planning phases and any additional needs identified based on new and/or updated information provided by the RIP Study Team.

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 Study Team.

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 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 STUDY TEAM 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 Regional Infrastructure Plan ("RIP") Study Team included members from the following organizations:

- Alectra Utilities Corporation (former Horizon Utilities Inc.)
- Brantford Power Inc.
- Burlington Hydro Inc.
- Energy + Inc.
- Hydro One Networks Inc. (Distribution)
- Hydro One Networks Inc. (Lead Transmitter)
- Independent Electricity System Operator (IESO)
- Oakville Hydro

The first regional planning cycle for the Burlington to Nanticoke Region was completed in February 2017 with the publication of the RIP report. Due to several sustainment needs arising during the final phase of the 1st cycle regional planning, the Study Team and the RIP recommended to trigger 2nd regional planning cycle.

This RIP is the final phase of the 2nd regional planning cycle and follows the completion of the Integrated Regional Resource Plans ("IRRP") for Hamilton sub-region in February 2019 and the 2nd Cycle Burlington to Nanticoke Region's Needs Assessment ("NA") in May 2017. This RIP provides a consolidated summary of the needs and recommended plans for the Burlington to Nanticoke Region in 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 IRRP, also identifies additional needs related to load growth and end-of-life facilities in the Burlington to Nanticoke Region.

This RIP discusses needs identified in the previous regional planning cycle, the Needs Assessment report for this cycle and the Hamilton Sub-region IRRP; and the projects developed to address these needs. Implementation plans to address some of these needs are already completed or are underway. Since the previous regional planning cycle, following projects have been completed:

1- Bronte TS: 115 kV B7/B8 Transmission line capacity
2- Beach TS: Replace EOL T3/T4 transformers
3- Horning TS: Refurbish EOL transformers T1/T2 & switchgears
4- Mohawk TS: Replace EOL T1/T2 transformers
5- Brant Switching Station: 115 kV B12BL/ B13BL Transmission line capacity
6- Bronte TS (T5/T6 DESN): Refurbish EOL transformers T5/T6 & switchgears
7- Cumberland TS: Power Factor Correction

The major infrastructure investments recommended by the Study Team in the near and mid -term planning horizon are provided below in Table 1 and 2 respectively, along with their planned in-service date and budgetary estimates for planning purpose.

Table 1: Near-Term Needs in Burlington to Nanticoke Region

No.	Need	Recommended Action Plan	Planned I/S Date	Budgetary Estimate ($M)
1	115 kV B7/B8: EOL line section from Burlington TS to Nelson Jct.	Refurbish the EOL B7/B8 line section	2020	2
2	115 kV B3/B4: EOL line section from Horning Mountain Jct. to Glanford Jct.	Refurbish the EOL B3/B4 line section conductor	2020	22
3	Elgin TS: EOL transformers & switchgears	Replace transformers and reduce 2 DESNs to 1 DESN	2021	81
4	Newton TS: EOL transformers	Replace EOL transformers	2021	22
5	Kenilworth TS: EOL transformer & switchgear	Reconfigure from 2 DESNs to single DESN and replace EOL equipment	2021	36
6	Dundas TS: Load transfer	Add two new feeders at Dundas TS #2	2021	2
7	Gage TS: EOL transformers & switchgear	Reduce from 3 DESNs to 2 DESNs and replace EOL equipment	2021	55
8	Kenilworth TS: Power factor correction	LDC is developing distribution option	2022	1
9	Norfolk area supply capacity	Norfolk TS: Install capacitor bank	2022	3

Table 2: Mid- and Long-Term Needs in Burlington to Nanticoke Region

No.	Needs	Recommended Plan of action	Planned I/S Date	Budgetary Estimate ($M)
1	Birmingham TS: EOL transformer and metalclad switchgears	Replace EOL equipment	2025	29
2	Mid-Term EOL transformers at Nebo TS (T3/T4), Caledonia TS (T1) and Jarvis TS (T3/T4)	Monitor and review in next planning cycle	2025-29	69
3	Mid-Term EOL switchgear at Norfolk TS and Burlington TS[1]	Monitor and review in next planning cycle	2026	57
4	EOL cables in Hamilton sub-region: H5K/H6K, K1G/K2G, HL3/HL4[2]	To further assess the options in this RIP by the Study Team and addendum issued to Hamilton IRRP and RIP	2026	28
5	Norfolk area supply capacity	To further assess the options in this RIP by the Study Team in advance of next planning cycle and addendum issued to RIP	2026	80
6	Beach TS: EOL 230 kV auto-transformers[3] and DESN transformers	To be assessed as part of Middleport Bulk Study by the IESO in coordination with Hydro One	2027	71
7	Lake TS: EOL transformers and switchgears	Monitor and review in next planning cycle	2027	45
8	Burlington TS: EOL 230 kV auto-transformer [3]	To be assessed as part of Middleport Bulk Study by the IESO in coordination with Hydro One	2030	14

[1] Further condition assessment did not confirm the earlier need of refurbishing Brantford switchgear
[2] To be finalized after the completion of Hamilton IRRP Addendum by the IESO
[3] To be finalized after the completion of Middleport Bulk Study by the IESO

The Study Team recommends that:

- Hydro One to continue with the implementation of major infrastructure investments listed in Table 1 while keeping the Study Team apprised of project status;
- Hydro One to continue with the implementation of infrastructure investment at Birmingham TS for replacement of EOL transformers and switchgears;
- The EOL 230 kV autotransformer options at Beach TS and Burlington TS will be assessed through the IESO Middleport Bulk Study in coordination with Hydro One to develop a final recommended plan;
- The EOL 115 kV Hamilton area cables options are included in this RIP. It will be further assessed by the Study Team to develop a recommended plan to be included as an addendum to the Hamilton IRRP and this RIP;
- The options to reinforce supply to the Norfolk area are included in this RIP and will be further assessed by the Study Team in advance of the next planning cycle to develop a recommended plan and an addendum be made to the RIP; and
- All the other identified needs/options in the mid and long-term will be further reviewed by the Study Team in the next regional planning cycle.

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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 joint study carried out by Burlington o Nanticoke RIP Study Team. . In addition to Hydro One representatives, other members of the RIP Study Team 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 twenty-nine 230 kV and 115 kV step-down transformer stations. The sum of 2018 non-coincident summer station peak load of the Region was about 2381 MW. The boundaries of the Region are shown in Figure 1-1 below.

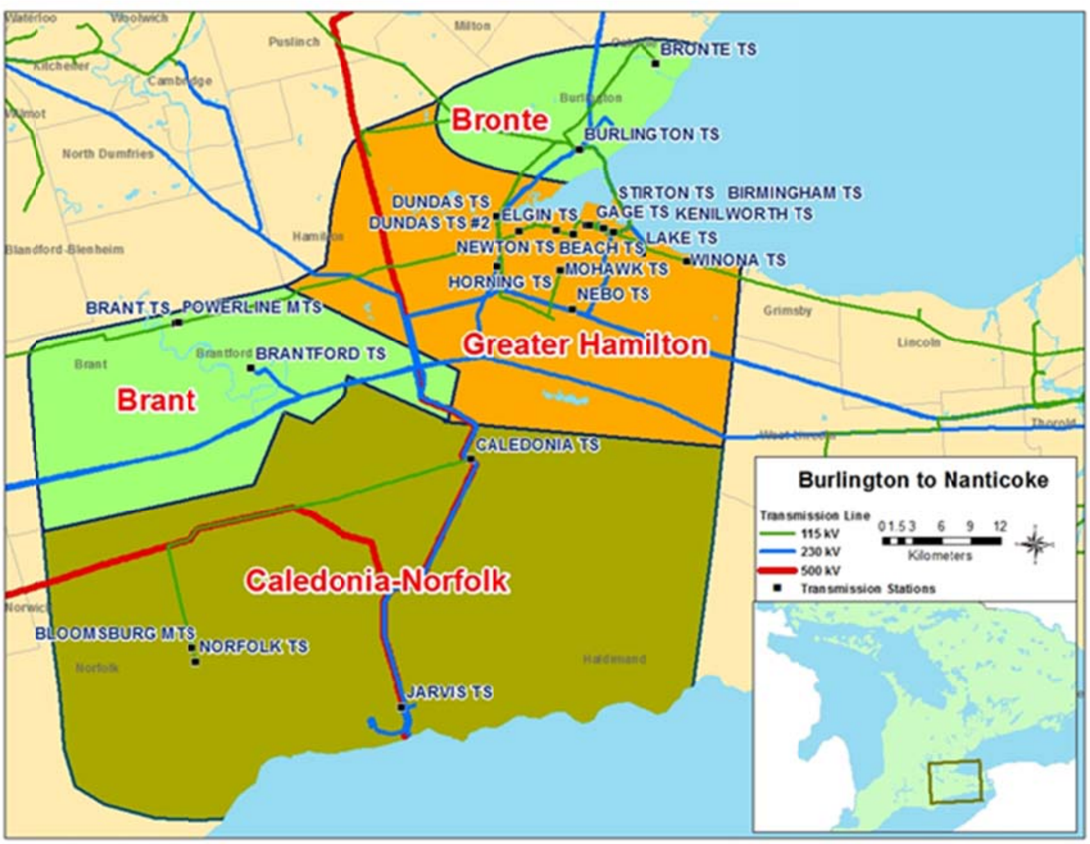

Figure 1-1 Burlington to Nanticoke Region

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 near, mid- and long-term horizon, transmission and distribution system capability along with any updates to local plans, conservation and demand management ("CDM") forecasts, 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 phase.
- Discussion of any other major transmission infrastructure investment plans over the near to mid-term planning horizon(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 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[4] ("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 Study Team 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.

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 a preferred wires solution. Similarly, resource options that the IRRP identifies as best suited to meet a

[4] Also referred to as Needs Screening

need are then further planned in greater detail by the IESO. The IRRP phase also includes IESO led stakeholder engagement with municipalities, Indigenous communities, business sectors and other interested stakeholders in the region. The Hamilton IRRP was identified in the Scoping Assessment phase of the Burlington to Nanticoke Region's second regional planning cycle and was completed in February 2019.

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.

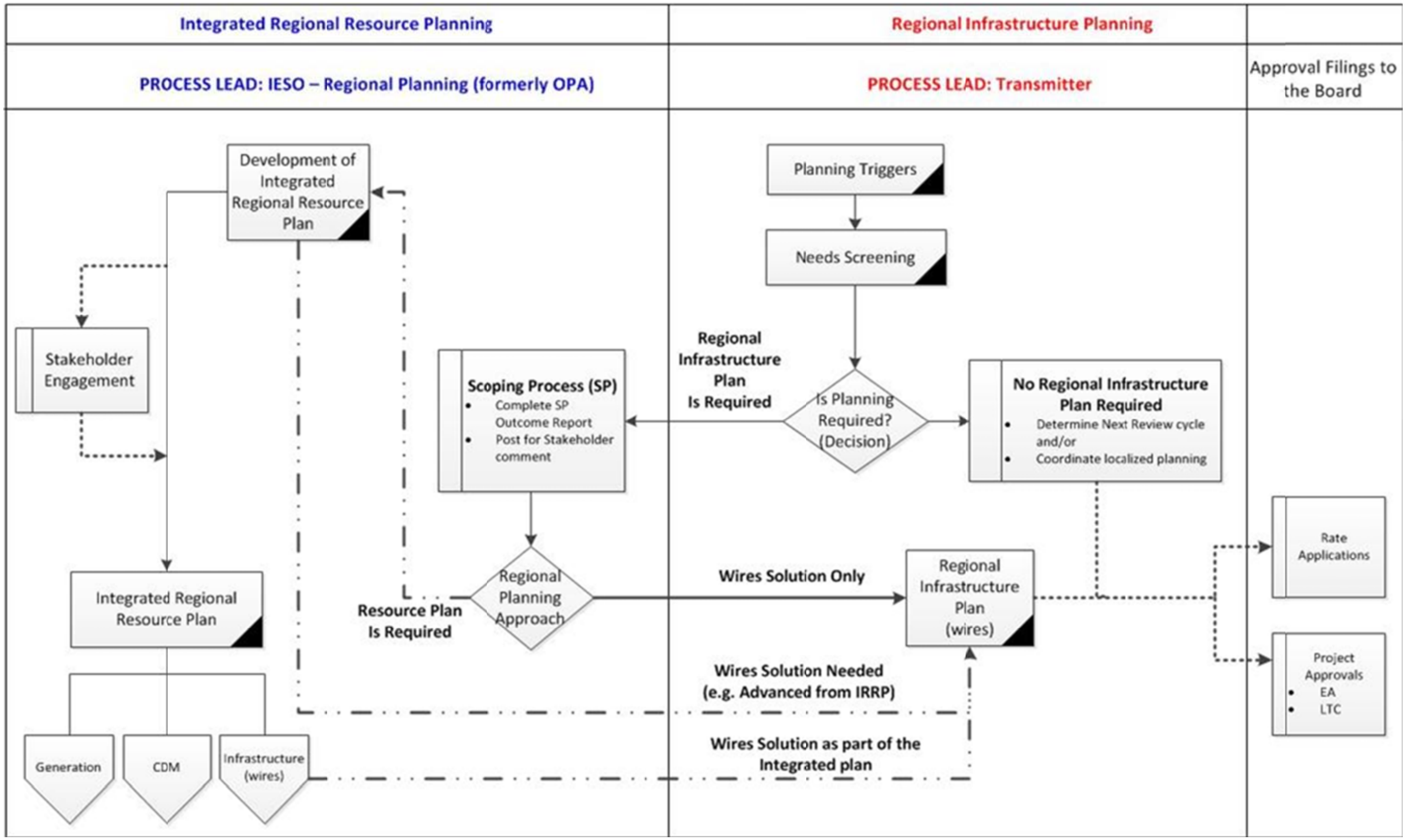

Figure 2-1 Regional Planning Process Flowchart

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 Study Team 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.

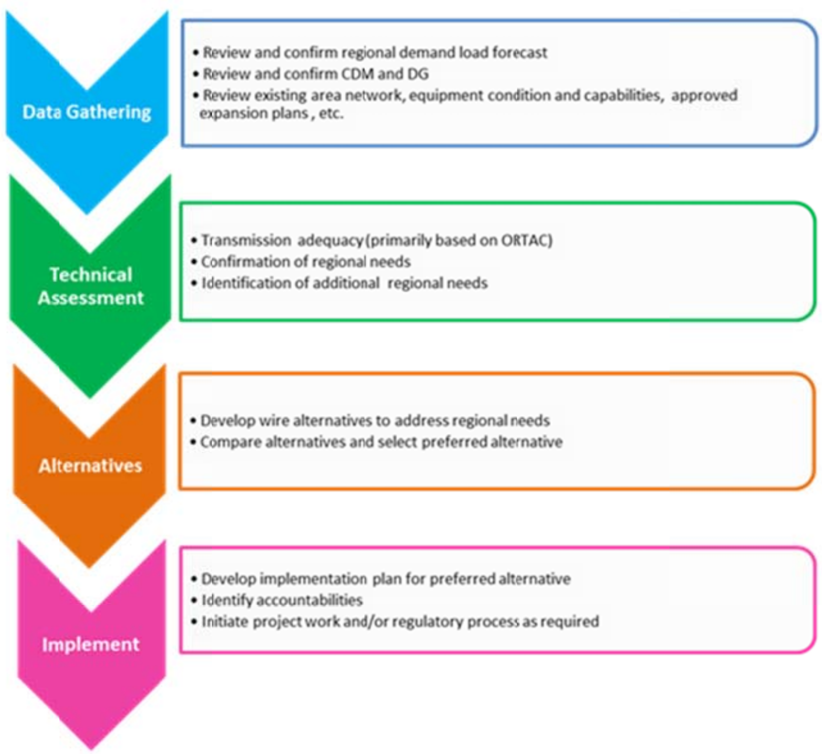

Figure 2-2 RIP Methodology

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 autotransformers at 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 B12BL/B13BL line and B2 single circuit line.
  - 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.

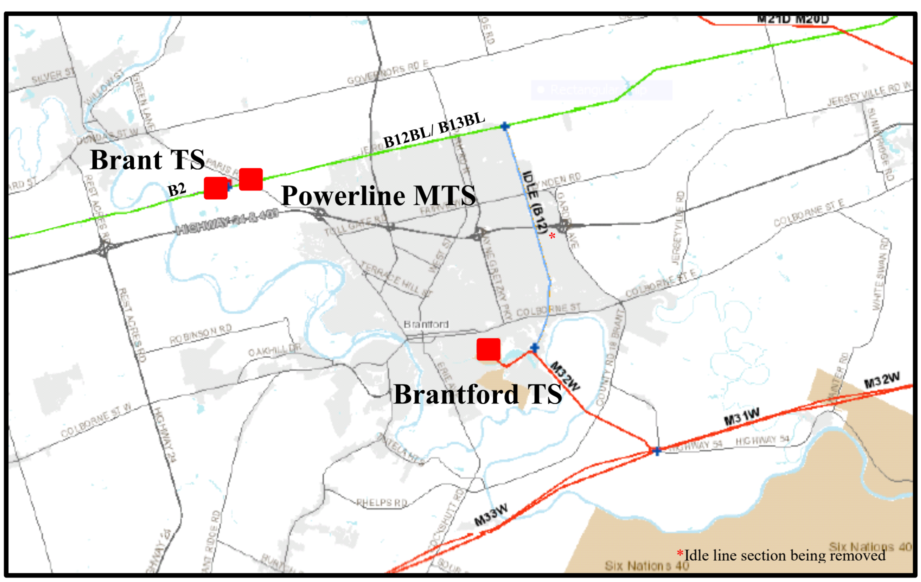

Figure 3-1 Brant sub-region

The total 2018 non-coincident peak demand of the three stations was 289 MW. 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.

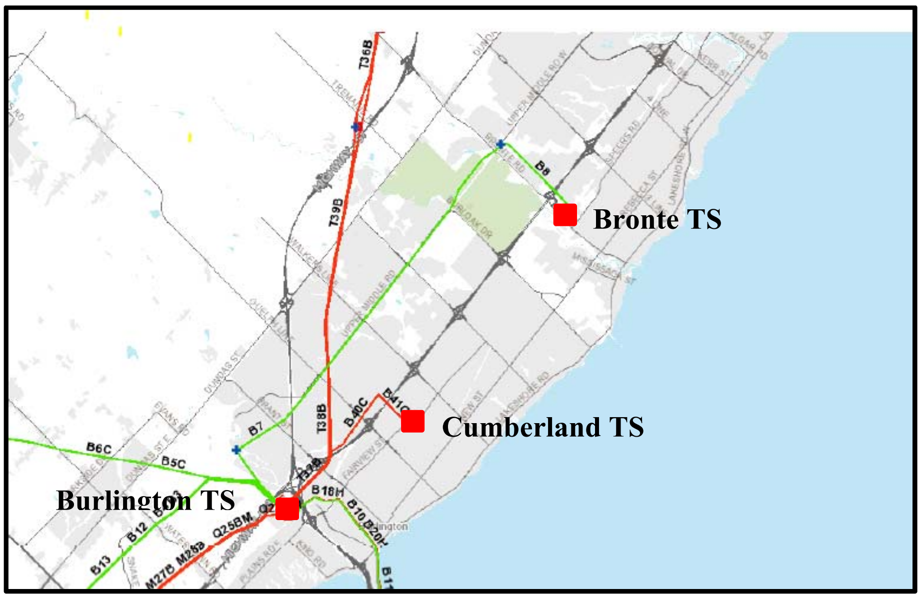

Figure 3-2 Bronte sub-region

The area is served by Burlington Hydro and Oakville Hydro. The electricity demand is comprised of residential, commercial and industrial customers. The total 2018 non-coincident peak station demand of the three stations was 401 MW.

- 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 four 115 kV step down stations Birmingham TS, Kenilworth TS, Stirton TS and Winona TS 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 (T3/T4 & T5/T6 DESNs), 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.

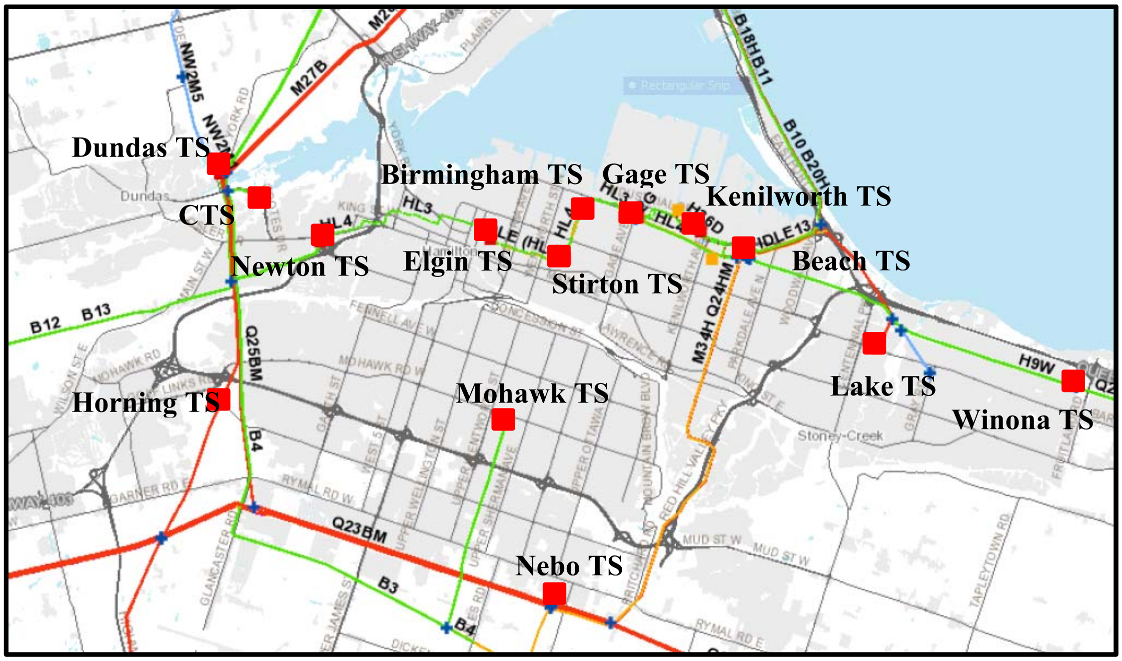

Figure 3-3 Greater Hamilton sub-region

The total 2018 non-coincident peak demand of the Greater Hamilton sub-region was 1371 MW. 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 and a CTS supplied from the 230 kV double circuit line N21J/N22J.
- One CTS supplied from the 230 kV single circuit N20K.
- 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 2018 non-coincident peak demand of this sub-region was 320 MW.

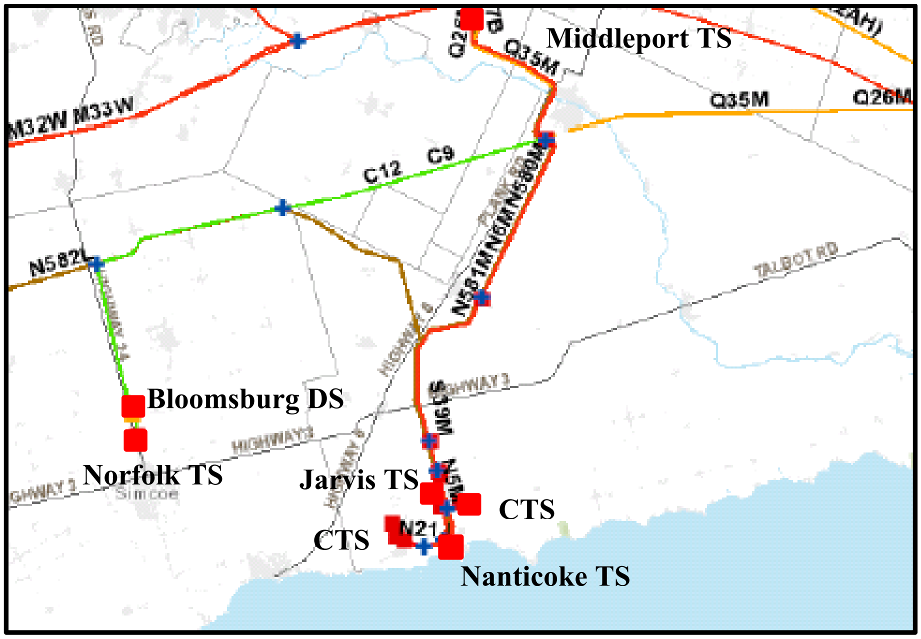

Figure 3-4 Caledonia Norfolk sub-region

Electrical single line diagrams for the Burlington to Nanticoke region's 500 kV/ 230 kV facilities and 115 kV facilities are shown below in Figure 3-5 and Figure 3-6.

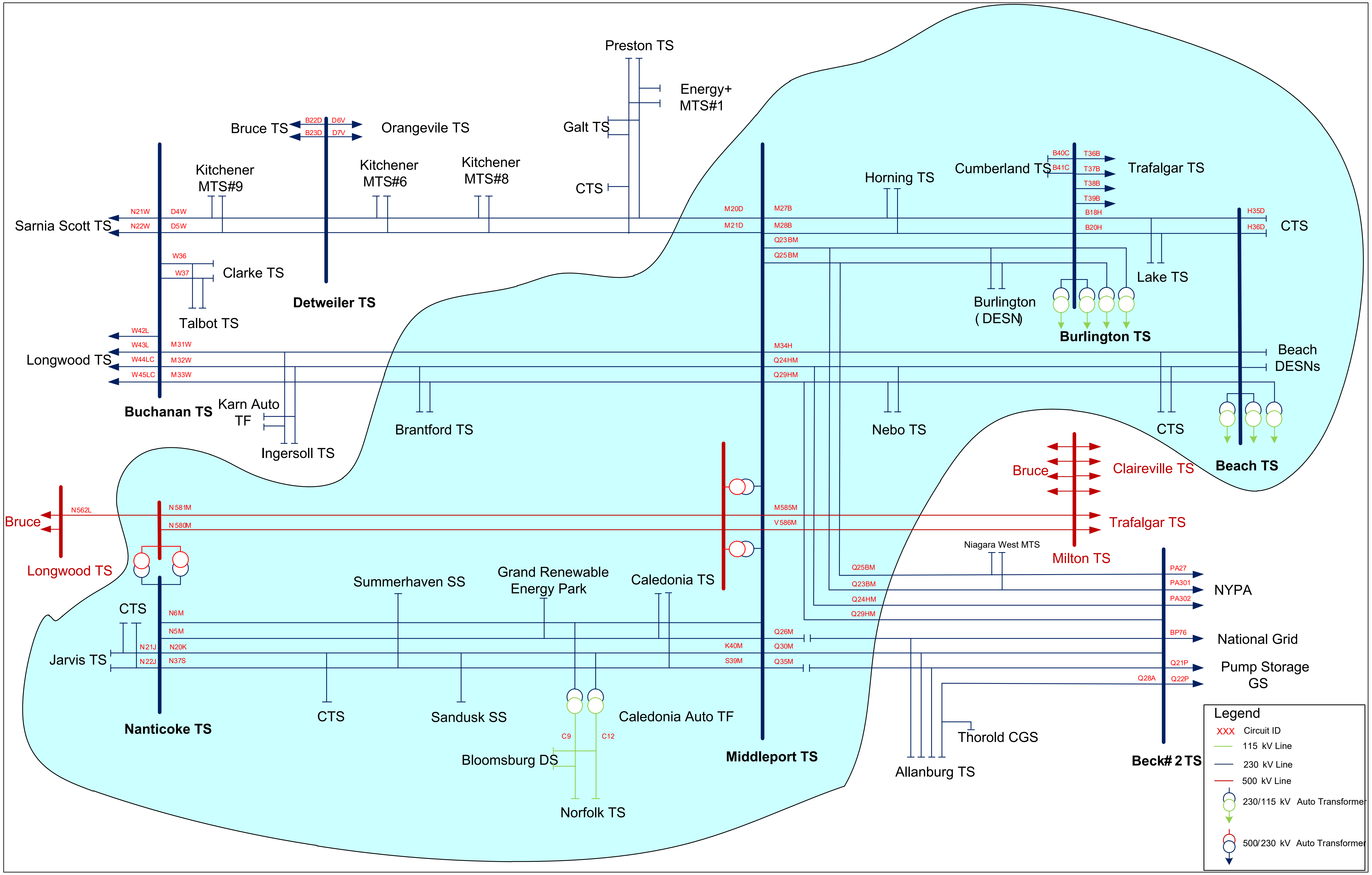

Figure 3-5 Burlington to Nanticoke Region 500 & 230 kV and Caledonia-Norfolk 115 kV Network

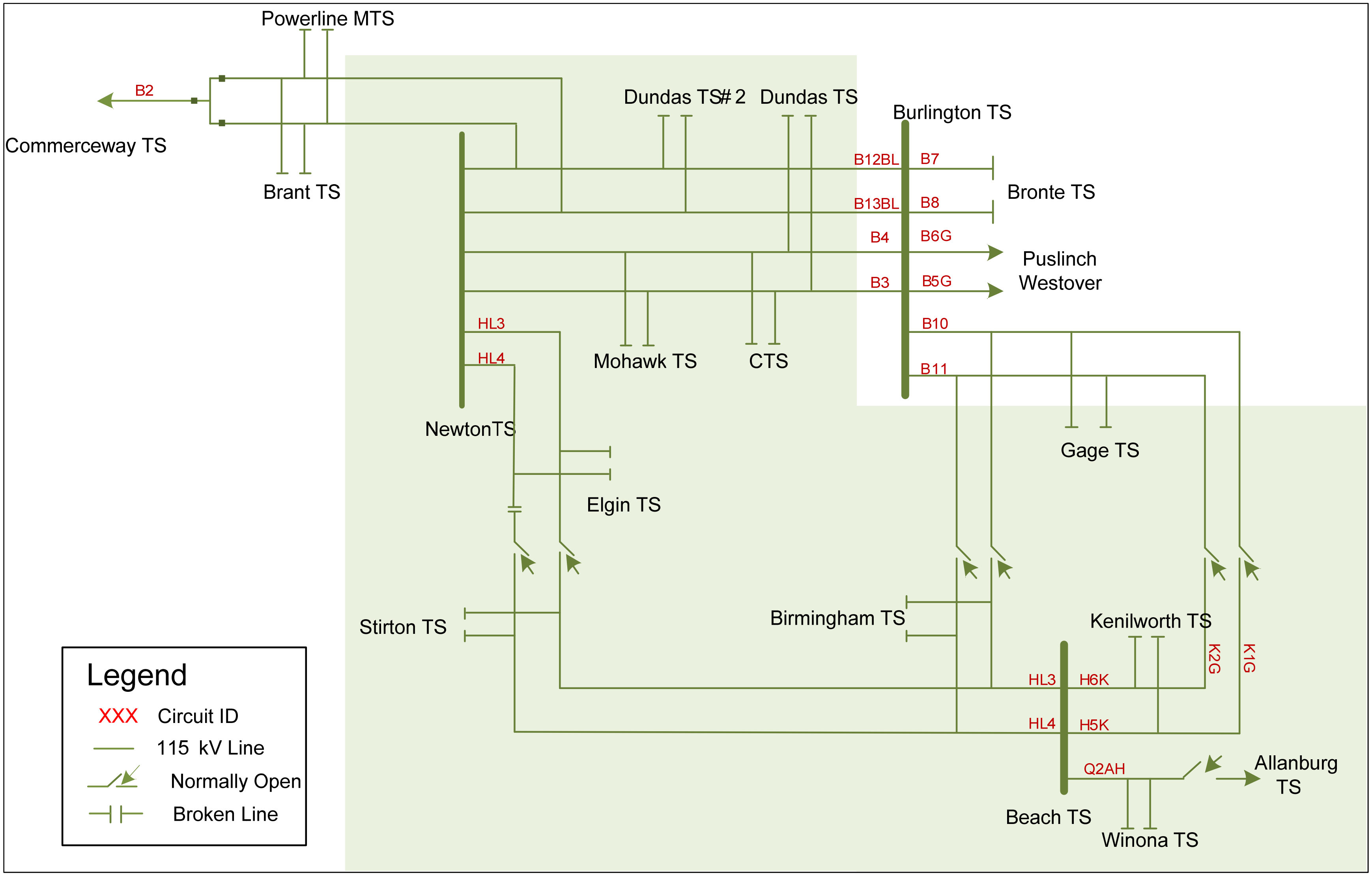

Figure 3-6 115 kV Network Supplied by Burlington TS and Beach TS

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:

- Burlington TS (2009) - replaced 230/115 kV autotransformer T6 following failure.
- Second 115 kV supply to Norfolk TS and Bloomsburg DS (2009) – Built 12 km of new 115 kV circuit to provide second 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 230/ 27.6 kV transformers (T1/T2) 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 to improve supply reliability of the stations supplied from 115 kV bus.
- Transformer replacement at stations: Norfolk TS (2009), Birmingham TS (2010), Cumberland TS (2012), Brantford TS (2013), Kenilworth TS (2014), Dundas TS (2015), Brant TS (2016), Beach TS (2018) and Mohawk TS (2018).
- B7/B8 115 kV Transmission line capacity (2018) – addressed supply capacity constraint to Bronte TS through distribution load transfers (Ongoing)
- Horning TS (2018) – replaced 230/ 13.8 kV transformers (T1/T2) & LV switchgears
- Bronte TS (2019) – replaced 115/ 27.6 kV transformers (T5/T6) & associated LV switchgears
- Brant Switching Station (2019) – installed three (3) 115 kV breakers at Brant TS integrating 115 kV B12BL/B13BL circuits with 115 kV B2 circuit from Karn TS, to provide additional supply capacity for Brant TS and Powerline MTS.

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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 of about 1% annually. However the loads at Norfolk TS and Bloomsburg DS mark a significant growth over the study period due to the high penetration of greenhouse loads and developments in Brant and Hamilton sub-regions.

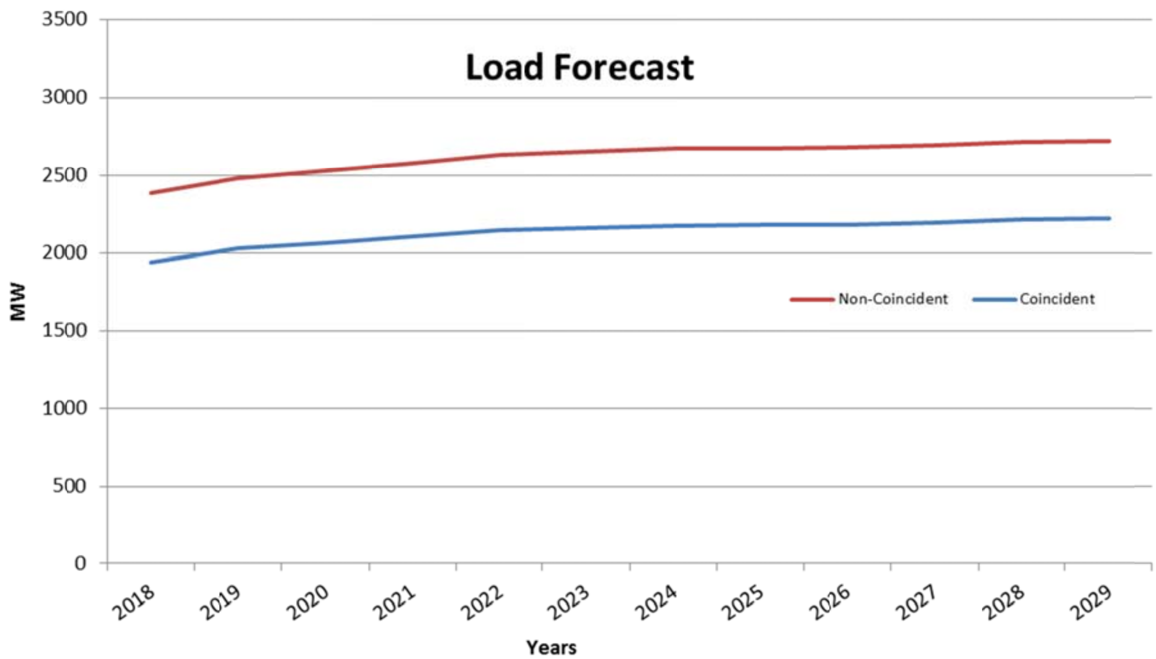

Figure 5-1 Burlington to Nanticoke Region Summer Extreme Weather Peak Forecast

Figure 5-1 shows the Burlington to Nanticoke Region peak summer non-coincident load forecast. The non-coincident and coincident load forecasts were prepared based on the 2018 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 the coincident load forecast was used to determine line capacity needs. Regional non-coincident and coincident load forecasts for the Burlington to Nanticoke Region are given in Appendix D.

The RIP load forecast was developed as follows:

- Load forecast for all stations was developed using the summer 2018 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 2019-2029.
- All planned facilities 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 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.
- Line capacity adequacy is assessed by using coincident peak loads in the area.
- 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 2019-2029 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 15 , 2017
2) SA Report – Burlington to Nanticoke Region, August 25, 2017
3) IRRP Report – Hamilton sub-region, February 25, 2019

The NA and IRRP reports identified a number of needs to meet the forecast load demands and asset approaching EOL. 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 assessment using the latest regional load forecast provided 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):

Terminal Stations	Circuits	Connected Supply Stations
Middleport TS to Burlington TS	M27B/ M28B	Horning TS
Middleport TS to Beck #2 TS to Burlington TS	Q23BM/ Q25BM /Q24HM/ Q29HM	Burlington (DESN) TS, Nebo TS and a CTS
Middleport TS to Buchanan TS	M32W/ M33W	Brantford TS
Middleport TS to Nanticoke TS	N5M/ S39M/ N20K	Caledonia TS and a CTS
Burlington TS to Beach TS	B18H/ B20H	Lake TS
Nanticoke TS to Jarvis TS	N21J/ N22J	Jarvis TS and a CTS
Beach TS to a CTS	H35D/ H36D	CTS
Burlington TS to Cumberland	B40C/ B41C	Cumberland TS

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

Facilities	MVA Load Meeting Capability	2018 MVA Loading	Need Date
Burlington TS 230/115 kV autotransformers	912	560	-[1]
Beach TS 230/115 kV autotransformers	582	268	-[1]
Caledonia TS 230/115 kV autotransformer	187	104	-[1]

[1] Adequate over the study period (2019- 2029)

The autotransformers in the Burlington to Nanticoke region are of adequate capacity over the study period (2019-2029). The installation of the 230/115 kV autotransformers at Cedar TS in 2017 have reduced the loading on the Burlington autotransformers. The recently in-service 115 kV switching at Brant TS 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, B12BL/B13BL and HL3/ HL4. The supply capacity of Burlington 115 kV lines is adequate over the study period (2019-2029). 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 (2019-2029).

2. Beach 115 kV– has five 115 kV circuits H5K/ H6K, HL3/ HL4 and Q2AH out of Beach TS serving the area. In addition there are two115kV circuits K1G and K2G connecting Kenilworth TS to Gage TS. These circuits are normally open and provide backup supply.

   The supply capacity of Beach 115 kV cables and lines is adequate over the study period (2019-2029).

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 exceeds the 87 MW supply capacity of C9/ C12 line. This need is further discussed in this RIP (Section 7).

   The loading on the limiting 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	2018 Loading (MW)	Need Date
Caledonia TS to Norfolk TS	C9/ C12	Section 7.9	87	C9/ C12	94*	2019

*Local coincident peak. Excess loads being transferred to Jarvis TS

The adequacy of 115 kV lines capacity was assessed using 2018 Summer Peak base case updated with 2029 loading.

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 29 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

sub-region	Capacity (MW)	2018 Loading (MW)	Need Date
Brant sub-region	403	289	-(2)
Bronte sub-region	540	401	-(2)
Greater Hamilton sub-region (1)	2017	1092	-(2)
Caledonia Norfolk sub-region (1)	344	203	-(3)

(1) Excludes Customer Transformer Stations (CTS)
(2) Adequate over the study period (2019-2029)
(3) Near term and mid to long term needs, for details refer to section 7.

Dundas TS has two DESN units T1/T2 and T5/T6. The T1/T2 DESN at Dundas TS is loaded over its supply capacity due to unbalanced loading between the two Dundas TS DESNs. The total supply capacity of both the Dundas TS DESNs is sufficient over the study period. The loading between the two Dundas TS DESNs is required to be balanced.

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 around its supply capacity during the study period. No further action is required.

Bloomsburg DS is currently forecasted to reach its limit by 2022 but Norfolk TS has adequate station supply capacity over the study period. However, the supply circuit C9/C12 is constrained and a mid-term to long term solution will be 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:

- B3/ B4
- B12BL/ B13BL
- H35D/ H36D

- M32W/ M33W
- Q23BM/ Q25BM

These circuits are located in urban and semi urban areas and are well accessible in the events of emergencies. Therefore based on the past performance and reliability data, the restoration criteria are met and the Study Team recommends that no further action is required at this time.

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7. REGIONAL NEEDS & PLANS

THIS SECTION DISCUSSES ELECTRICAL INFRASTRUCTURE NEEDS IDENTIFIED IN THE PREVIOUS REGIONAL PLANNING CYCLE, THE NEEDS ASSESSMENT REPORT FOR THIS CYCLE, SCOPING ASSESSMENT AND THE HAMILTON SUB-REGION IRRP; AND SUMMARIZES THE PLANS DEVELOPED TO ADDRESS THESE NEEDS.

This section outlines and discusses infrastructure needs and plans to address these needs for the near-term (up to 5 years) and the mid-to long-term (beyond 5 years) planning horizon. This includes long-term needs associated with sustainment plan. The long term needs will be assessed in the next planning cycle.

The near-term (2019-2024) electrical infrastructure needs in the Burlington to Nanticoke Region are summarized below in Table 7-1.

Table 7-1 Identified Near-Term Needs in Burlington to Nanticoke Region

No.	Needs	Section	Timing
1	Cumberland TS: Power factor correction	7.1	2019
2	115 kV B7/B8: EOL line section from Burlington TS to Nelson Jct.	7.2	2020
3	115 kV B3/B4: EOL line section from Horning Mountain Jct. to Glanford Jct.	7.3	2020
4	Elgin TS: EOL transformers & switchgears	7.4	2021
5	Newton TS: EOL transformers	7.5	2021
6	Kenilworth TS: EOL transformer & switchgear	7.6	2021
7	Dundas TS: Load transfers	7.7	2021
8	Gage TS: EOL transformers & switchgear	7.8	2021
9	Kenilworth TS: Power factor correction	7.9	2022
10	Norfolk area supply capacity	7.10	2023

Note: Further condition assessment did not confirm the earlier identified need of refurbishing Brantford switchgear.

The mid- and long-term (beyond 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 transformer and metalclad switchgears	7.11	2025
2	Mid-Term EOL transformers at Nebo TS (T3/T4), Caledonia TS (T1) and Jarvis TS (T3/T4)	7.12	2025-29
3	Mid-Term EOL switchgears at Norfolk TS and Burlington TS	7.13	2026
4	EOL cables in Hamilton sub-region: H5K/H6K, K1G/K2G, HL3/HL4	7.14	2026
5	Norfolk area supply capacity: Install new 230 kV double circuit lines and a new DESN	7.10	2026
6	Beach TS: EOL 230 kV auto-transformers and DESN transformers	7.15	2027
7	Lake TS: EOL transformers and switchgear	7.16	2027
8	Burlington TS: EOL 230 kV auto-transformer	7.17	2030

The needs identified in the Burlington to Nanticoke Region in the above Tables 7-1 and 7-2 are further discussed below.

7.1 Cumberland TS: Power Factor Correction

7.1.1 Description

The Cumberland TS supplies about 120 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.

7.1.2 Recommended Plan and Current Status

The Needs Assessment report identified this need and Study Team recommended Burlington Hydro to work with their load customers supplied by Cumberland TS and install capacitor banks on distribution system required to meet the minimum power factor requirement of 0.9.

A Burlington Hydro customer supplied by Cumberland TS has recently installed capacitor banks within its facilities to improve the power factor. This is expected to address the power factor need at Cumberland TS. However, the Study Team recommends that Hydro One and Burlington Hydro continue monitoring the power factor at this station.

7.2 115 kV Circuits B7/B8: End of Life Section (Burlington TS to Nelson Junction)

7.2.1 Description

The 115 kV double circuit line B7/B8 line supplies about 140 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.

7.2.2 Alternatives and Recommended Plan

The following alternatives were 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 Study Team recommendation is to refurbish the 115 kV B7/ B8 line section from Burlington TS to Nelson junction supplying Bronte TS using similar ACSR conductor. The refurbishment work is expected by Hydro One to be completed by 2020 at an estimated cost of approximately $2 million.

7.3 115 kV Circuits B3/B4: End of Life Section (Horning Mountain Jct. to Glanford Jct.)

7.3.1 Description

The 115 kV B3/B4 line supplies Hamilton sub-region loads including Dundas TS (T1/T2 DESN) and Mohawk TS. The 11 km long from Horning Mountain Jct. to Glanford Jct. section of this line has a solid copper conductor which is approximately 100 years old and at end of useful life.

7.3.2 Alternatives and Recommended Plan

The following alternatives were 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: Refurbish this line section and replacing EOL copper conductor with 605 kcmil ACSR conductor on this line tap section.

The Study Team recommends Hydro One to continue refurbishment of this line section and replace copper conductor with 605 kcmil ACSR from Horning Mountain Jct. to Glanford Jct. supplying Mohawk TS. This work is currently expected to be completed in 2020 at an estimated cost of $21 million.

7.4 Elgin TS: End of Life Transformers and Switchgears

7.4.1 Description

Elgin TS consists of two DESNs (T1/T2 and T3/T4) built in 1960's supplying loads in the city of Hamilton through three switchgears. The 2018 peak load at Elgin TS was approximately 98 MW.

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.

7.4.2 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.
- Station/load consolidation: Moving loads to neighboring station(s) and retiring Elgin TS. This alternative was considered but is not feasible due to limited load transfer capacity with neighboring stations and higher costs associated with load transfers.
- 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 Study Team recommends 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. This plan is expected to cost $81 million with an expected in service of 2021.

7.5 Newton TS: End of Life Transformers

7.5.1 Description

Newton TS is a 115 / 13.8 kV DESN station built in 1956 and supplies Alectra Utilities loads in the city of Hamilton. The current load at Newton TS is approximately 52 MW, and is expected to stay at this level over the study period.

The T1/T2 transformers are 67 MVA nonstandard units, supplying loads through 13.8 kV switchgears. Both these transformers have been identified as EOL requiring replacement. Recently the transformer T2 has failed and is being replaced on an emergency basis and transformer T1 is also showing signs of deterioration.

7.5.2 Alternatives and Recommended Plan

The following alternatives are considered in the light of recent developments with regards to end of life asset at Newton 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 cost.
- Station/load consolidation: Moving loads to neighboring station(s) and retiring Newton TS. This alternative was considered but is not feasible due to stations' geographic location separating it from the neighboring 13.8 kV distribution system.
- Replacement of the assets: Replace existing 67 MVA Newton TS companion transformer T1 with 75 MVA units built to current standards.

The Study Team recommends to replace existing 67 MVA Newton TS transformer T1 with 75 MVA unit similar to T2 built to current standards to ensure reliability of supply for the customers in the area. This replacement work at Newton TS is currently planned to be completed by 2021.

7.6 Kenilworth TS: End of Life Transformer and Switchgear

7.6.1 Description

The two DESNs at Kenilworth TS are over 60 years old, supplying 52 MW load in the city of Hamilton. The T1/T4 DESN transformers are non-standard 67 MVA units. The transformer T2 of second DESN is rated at 100 MVA while T3 is a non-standard 120 MVA unit.

The original T2 transformer failed in 2014 and was replaced with a standard 100 MVA unit. The remaining three transformers (T1, T3, and T4) and one of the two in service switchgears at Kenilworth TS have been identified as approaching end of their useful life.

7.6.2 Alternatives and Recommended Plan

The following alternatives were 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 Study Team recommends Hydro One proceed with the last option above and reconfigure the station, reducing it to a single DESN with two transformers and two switchgears. The recently replaced transformer and one of the existing metalclad switchgear will be utilized while one transformer and switchgear will be replaced. The new transformer T3 will be a standard unit similar to T2 that was replaced in 2014. This refurbishment project is currently expected to be completed by the year 2021 at an estimated cost of $35.8 million.

7.7 Dundas TS: Load Transfer

7.7.1 Description

Dundas TS (T1/T2) and Dundas TS #2 (T5/T6) are supplying a total peak load of 150 MW in the city of Hamilton. The total supply capacity of both stations is 188 MW which is sufficient over the study period.

The loading at Dundas TS will be capped at its supply capacity of 99 MW and any additional loads will be supplied from Dundas TS #2. Hydro One distribution currently supplied from the Dundas TS is planning to transfer any excess load to Dundas TS #2.

7.7.2 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 DESN's load balancing and customer's needs.
- Transfer customer load to Dundas TS #2: Move off loads in excess to the supply capacity of Dundas TS to Dundas TS #2. To facilitate this, two new feeder positions are required at Dundas TS #2. These new breaker positions will be also used to meet future load growths. This option will require reconfiguring of distribution assets by the LDCs.

The Study Team recommends the option to transfer excess load from Dundas TS to Dundas TS #2 by the LDCs utilizing two additional breaker positions at an estimated cost of $2 million, by 2021. It is estimated that LDCs will have to invest approximately $9 million in distribution infrastructure to fully implement this plan.

7.8 Gage TS: End of Life Transformers and Switchgear

7.8.1 Descriptions

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 units meeting unique high short circuit requirements of the customers. The transformers T3, T4, T5, and T6, as well as T8/T9 DESN switchgear at Gage TS have been identified at their EOL. The refurbishment of these assets has been previously deferred to better understand customer load requirements. Transformer T5 and breakers in the T5/T6 DESN have experienced recurring problems.

The load at Gage TS has reduced over the years to approximately 50 MW, and is currently expected to stay at around 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:

- <u>Maintain status quo</u>: 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.
- <u>"Like-for-Like" replacement of the assets</u>: 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.
- <u>Station/load consolidation</u>: 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.
- <u>Reconfiguration of the station and downsize the station from three DESN to two DESN station:</u> In this option, the station will be reconfigured and downsized from the existing six transformers to four transformers.

The Study Team recommends that Hydro One proceed with the reconfiguration of the station, reducing it from 3 DESNs to 2 DESNs. This plan also provides future flexibility to eliminate the T8/T9 DESN when it approaches EOL. Under this plan, T3/T4 and T5/T6 DESNs will be replaced by a single T10/T11 DESN with two 100 MVA standard units. It also includes replacement of switchgear currently supplied from the T5/T6 transformers.

The refurbishment of Gage TS is expected to be completed in 2021 at an estimated cost of $55 million.

7.9 Kenilworth TS: Power Factor Correction

7.9.1 Description

There are two supply stations inside Kenilworth TS T1/T4 and T2/T3 supplying about 52 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.

7.9.2 Alternatives and Recommended Plan

The following alternatives were considered to address the power factor need at Kenilworth TS:

- Maintain status quo: This alternative was considered and rejected as it does not address the need to meet the ORTAC power factor requirement.
- Improve power factor on distribution system: Install capacitor bank/s and/or work with load customers supplied by Kenilworth TS.

This need was identified during the last Regional Planning cycle and the Study Team recommended Alectra Utilities to install capacitor bank and/or work with load customers supplied by Kenilworth TS to meet ORTAC power factor requirement of 0.9.

The installation of capacitor bank will be initiated after completion of refurbishment of Kenilworth TS in 2021 at an estimated cost of $1 million in 2022.

7.10 Norfolk Area Supply Capacity

7.10.1 Description

Norfolk area is currently supplied by two 115 / 27.6 kV DESNs, Norfolk TS and Bloomsburg DS through 115 kV double circuit supply (C9/C12) from Caledonia TS. Both Norfolk TS and Bloomsburg DS have two identical 115 / 27.6 kV transformers of 83 MVA and 42 MVA respectively and are less than 20 years old. The area supply capacity is limited to 87 MW by voltage decline limit in the event of loss of one the two (C9 or C12) supply circuits. The 2018 total peak load of Norfolk area was 94 MW, approximately 7 MW over the supply capacity.

This area has recently seen a significant interest from greenhouse developers and the loads are expected to grow significantly over the study period as identified during this RIP by the study team.

By the year 2021-22, the net load growth of around 20 MW is envisaged and will require supplementing the 115 kV supply system. Over the study period, the net load growth of about 55 MW is forecasted which would be above the thermal limit of 139 MVA for the existing 115 kV transmission line.

7.10.2 Alternatives and Recommended Plan

The following alternatives are considered to address the future supply needs of Norfolk area:

- Maintain status quo: This alternative was considered and rejected as it does not address the customer's needs in the area.
- Near Term Options/Solutions:
    - Install capacitor banks: Install capacitor banks at Norfolk TS to improve voltage profile increasing supply capacity of area to accommodate approximately 10 MW of expected load increases in the near term
    - Transfer loads from Norfolk area to nearby stations using existing feeders: There is limited load transfer capacity available between the Norfolk area stations and Jarvis TS. New feeder inter-ties may need to be built to transfer around 5 MW of load from Norfolk area to Jarvis TS.
- Mid- to Long Term Options/Solution:
    - Converting C9/ C12 115 kV circuits to 230 kV: Upgrading 115 kV C9/C12 circuits to 230 kV will impart additional transmission capacity beyond the current capacity of 87 MW. However, this option will have line capacity limitation along with implementation challenges.
    - New 230 kV double circuit line about 20-25 km long and a new 230/ 27.6 kV DESN: A new station in Norfolk area supplied by a new 230 kV double circuit line by either tapping two 230 kV circuits in the Middleport TS to Nanticoke TS or Middleport TS to Buchanan TS corridor.

The Study Team recommends that in the near term a) Hydro One install new additional capacitor bank at Norfolk TS in 2022 and b) LDCs build feeder inter-ties to transfer load between the Norfolk area stations and Jarvis TS. Hydro One transmission will plan capacitor bank to be connected in 2022 at an estimated cost of $3 million.

The Study Team recommends further assessment be carried out by the IESO and Hydro One to review that mid to long term options identified above and develop a recommended plan to address the capacity needs for the Norfolk Area in advance of the next planning cycle. Following the assessment, an addendum will be included to the IRRP and RIP reports in 2020.

7.11 Birmingham TS: End of Life Transformer and Switchgears

7.11.1 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 90 MW over the study period.

At this time one 115 / 13.8 kV transformer and three 13.8 kV LV metalclad switchgears are at EOL and have been identified by Hydro One for refurbishment.

7.11.2 Alternatives and Recommended Plan

The following alternatives are considered to address Birmingham TS end of life asset needs:

- 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.
- Station/load consolidation: Moving loads to neighboring station(s) and retiring Birmingham TS. This alternative was considered but is not feasible due to customer's unique needs.
- Replacement of the assets: Replace existing T1 EOL transformer with similar unit and three metalclad switchgears to current standards.

The Study Team recommends to replace the end of life T1 transformer and three 13.8 kV LV metalclad switchgears at Birmingham TS to meet the unique connection needs of the customer at this station with similar equipment and. Currently, Hydro One expects to complete this replacement by 2025.

7.12 Mid-Term End of Life Transformer Replacements

7.12.1 Description

Hydro One has identified the following transformers reaching end-of-life in the 2025 – 2029 timeframe:

1. Nebo TS (T3/T4)
2. Caledonia TS (T1)
3. Jarvis TS (T3/T4)

7.12.2 Alternatives and Recommended Plan

The following alternatives are considered to address the above end of life asset needs:

- 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.
- Station/load consolidation: Moving loads to neighboring station(s) and retiring these stations. This alternative was considered but is not feasible as there were no nearby stations that can accommodate their loads.
- Replacement of the assets: Replace existing transformers with similar units built to current standards.

The option for these needs is like-for-like replacement of transformers. However, as these needs are far in future, the Study Team recommends reviewing these needs again in the next regional planning cycle.

7.13 Mid-Term End of Life LV Switchgear Replacement

7.13.1 Description

Hydro One has identified that the LV switchgears at a number of stations are reaching end-of-life in the 2025 – 2029 timeframe and need to be replaced. These stations are:

1. Norfolk TS
2. Burlington TS

7.13.2 Alternatives and Recommended Plan

The following alternatives are considered to address the above end of life asset needs:

- 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 switchgear with one's built to current standards.

The option for these needs is like-for-like replacement of switchgear. However, as these needs are far in future, the Study Team recommends reviewing these needs in the next regional planning cycle.

7.14 End of Life Cables in Hamilton Sub-region: HL3/HL4, K1G/K2G, H5K/H6K

7.14.1 Description

The Hamilton sub-region has following four (4) pairs of 115 kV underground cable circuits that are around 50 years old and approaching end of life over the next 10 years. These cables primarily supply industrial, residential and commercial loads in the City of Hamilton. These cables are also used as alternate supply during outages and emergency conditions.

i. 115 kV K1G/K2G Cable (Kenilworth TS to Gage TS)
ii. 115 kV HL3/HL4 Cable (Elgin TS to Stirton TS)
iii. 115 kV HL3/HL4 Cable (Newton TS to Elgin TS)
iv. 115 kV H5K/H6K Cable (Beach TS to Kenilworth TS)

The replacement and/or reconfiguration of these high voltage underground cables was identified in the previous cycle because it will be complicated and expensive and therefore requires assessment of alternative/s at the earliest possible as mentioned in the last regional planning.

i. 115 kV K1G/K2G Cables (Kenilworth TS to Gage TS)

These cables are 1.8 km long, of 1973 vintage connecting Gage TS and Kenilworth TS. Each of these cables is rated to supply 180 MW of loads and are used for providing backup supply to Gage TS (from Beach TS) and to Kenilworth TS (from Burlington TS) during outages and emergencies. These cables do not carry load under normal operating configuration.

Alternatives/Options

- Maintain status quo: This alternative was considered and rejected as it does not address the risk of failure due to asset age and would reduce reliability of supply to the customers.
- Building a new 1.8 km overhead 115 kV double circuit corridor between Kenilworth TS and Gage TS: This option will be the least expensive but the existing route passes along the narrow road allowances and through private properties. Building new overhead line section may not be feasible due difficulty in meeting required clearances and obtaining easement rights.
- "Like-for-Like" replacement of the assets: This alternative would require replacing the existing end of life 115 kV cables with the ones of similar capacity. Although it may not be the least cost option, it is the only practical alternative.

ii. 115 kV HL3/HL4 Cable (Elgin TS to Stirton TS)

These cables are 1.9 km long, of 1968 vintage connecting Elgin TS to Stirton TS. One of the two cables (HL4) was damaged in 1998 and since then it has been out-of-service. The HL3 cable is rated at 170 MW and is used for providing backup supply to Elgin TS (from Beach TS) and to Stirton TS (from Burlington TS) during outages and emergencies. HL3 cable does not carry load under normal operating configuration.

Alternatives/Options

- Maintain status quo: This alternative was considered and rejected as it does not address the risk of failure due to asset age and would reduce reliability of supply to the customers. Unavailability of this HL3 circuit at the time of need will be catastrophic.
- Building a new 1.9 km overhead long 115 kV double circuit line between Stirton TS and Elgin TS: This option will be the least expensive but the existing route passes through densely populated areas with narrow road allowances. Therefore building new overhead line section is not feasible.
- "Like-for-Like" replacement of the assets: This alternative would require replacing the existing end of life 115 kV cables with the ones of similar capacity. This is the only practical alternative but the replacement of these cables will be challenging as it passes through a densely populated areas with a number of other utilities crossing or sharing the same corridor. Further project specific assessment and details will have to be undertaken prior to initiating the project including consultation with other stakeholders, such as, municipality and other utilities on the same ROW.

iii. 115 kV HL3/HL4 Cables (Newton TS to Elgin TS)

These cables are 4.6 km long, of 1975 vintage connecting Newton TS and Elgin TS. Each of these cables is rated to supply 176 MW of loads and used for providing primary supply to Elgin TS (from Burlington TS). These cables supply about 100 MW of load at Elgin TS. For the loss of a single HL3/HL4 cable, the companion cable is sufficient to supply Elgin TS loads forecasted over the study period.

Alternatives /Options

- Maintain status quo: This alternative was considered and rejected as it does not address the risk of failure due to asset age and would reduce reliability of supply to the customers.
- Building a new 4.6 km overhead 115 kV double circuit line between Newton TS and Elgin TS: This option will be the least expensive but the existing route passes through densely populated areas with narrow road allowances. This option will require section-92 application, acquiring easement rights and may still be not be feasible due to difficulty in meeting required clearances.
- "Like-for-Like" replacement of the assets: This alternative would require replacing the existing end of life 115 kV cables with the ones of similar capacity. This is the only practical alternative but the replacement of these cables will be challenging as it passes through a densely populated areas with a number of other utilities crossing or sharing the same corridor. Further project specific assessment and details will be undertaken prior to initiating the project including consultation with other stakeholders, such as, municipality and other utilities on the same ROW.

iv. 115 kV H5K/H6K Cables (Beach TS to Kenilworth TS)

These cables are 1.5 km long, of 1973 vintage connecting Beach TS and Kenilworth TS. Each of these cables is rated to supply 180 MW of loads and used for providing primary supply to Kenilworth TS (from Beach TS). These cables supply about 50 MW of load at Kenilworth TS. For the loss of a single H5K/H6K cable, the companion cable is sufficient to supply Kenilworth TS loads forecasted over the study period.

Kenilworth TS has a backup supply from Burlington TS through 115 kV K1G/ K2G cables between Kenilworth TS and Gage TS.

Alternatives /Options

- Maintain status quo: This alternative was considered and rejected as it does not address the risk of failure due to asset age and would reduce reliability of supply to the customers.
- Building a new 1.5 km overhead 115 kV double circuit corridor between Kenilworth TS and Beach TS: This option will be the least expensive but the existing route passes along the narrow road allowances and through private properties. Building new overhead line section may not be feasible due difficulty in meeting required clearances and obtaining easement rights.

- "Like-for-Like" replacement of the assets: This alternative would require replacing the existing end of life 115 kV cables with the ones of similar capacity. Although it may not be the least cost option, it may be the only practical alternative.

7.14.2 Recommendation

The Study Team recommends that the above options to replace these 115 kV cables in the Hamilton Area be further assessed by Hydro One and the IESO to develop a recommended plan. After the completion of this assessment, an addendum to Hamilton Area IRRP and RIP will be incorporated in 2020.

7.15 Beach TS: End of Life 230 kV Autotransformers and DESN Transformers

7.15.1 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 and two T3/T4 and T5/T6 230/13.8 kV DESNs.

Hydro One has determined that all the three T1/T7/T8 autotransformers and the T5/T6 DESN transformers are expected to reach end of life by 2027 and may need to be replaced.

7.15.2 Recommended Plan

The Study Team recommends that the replacement of autotransformers to be assessed as part of the Middleport area bulk transmission planning study by the IESO in coordination with Hydro One. Since the Beach TS autotransformers are expected to require replacement in 2027, the bulk study should be planned at the earliest.

7.16 Lake TS: End of Life Transformers and Switchgears

7.16.1 Description

Lake TS is located in the city of Hamilton having two DESN units. T1/T2 DESN is a 230/27.6 kV and T3/T4 230/13.8 kV of 83 MVA and 75 MVA transformers respectively. Both the DESNs at Lake TS can supply a total load of about 230 MVA (LTR). The load at Lake TS is forecasted at about 105 MW.

At this time the T1/T2 230 / 27.6 kV transformers and both 13.8 kV and 27.6 kV LV switchgears are at their EOL and have been identified by Hydro One expected to require refurbishment in 2027.

7.16.2 Alternatives and Recommended Plan

The following alternatives are considered to address Lake 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 transformers with similarly sized units and to meet current standards.

The Study Team is recommending that this need can be further assessed in the next regional planning cycle.

7.17 Burlington TS: End of Life 230 kV Autotransformer

7.17.1 Description

Burlington TS is a major switching and transformer station in Burlington. Station facilities include a 230 kV switchyard, four 230/115 kV autotransformers (T4/T6/T9/T12), 115 kV switchyard and a 230/27.6 kV DESN.

Hydro One has determined that autotransformer T12 is expected to reach end of life by 2030 and will need to be replaced.

7.17.2 Recommended Plan

The Study Team recommends that Burlington TS autotransformer replacement options and plan be studied as part of the Middleport area bulk transmission planning study by the IESO in coordination with Hydro One to develop a recommended plan.

7.18 Other Considerations

Municipalities in region may develop 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 may plan 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 may be situations where behind the meter battery storage cannot be connected due to current connection requirements and constraints. The LDCs in Ontario and Hydro One, outside the regional planning forum, have undertaken the task of exploring the issue to assess technical constraints and /or other solutions that can facilitate connection of additional battery storage.

Some of the communities in Ontario are 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 over the next 25 to 30 years.

Community energy plans may have potential to supplement and/or defer future transmission infrastructure development needs. The Study Team therefore recommends reviewing the updated regional community energy plans 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.

The major infrastructure investments recommended by the Study Team for the Burlington to Nanticoke region over the near and mid -term are provided in below Table 8-1 and 8-2 respectively, along with their planned in-service date and budgetary estimates for planning purpose.

Table 8-1 Near-Term Needs/Plans in Burlington to Nanticoke Region

No.	Needs	Plans	Planned I/S Date	Budgetary Estimate ($M)
1	115 kV B7/B8: EOL line section from Burlington TS to Nelson Jct.	Refurbish the EOL B7/B8 line section	2020	2
2	115 kV B3/B4: EOL line section from Horning Mountain Jct. to Glanford Jct.	Refurbish the EOL B3/B4 line section conductor	2020	22
3	Elgin TS: EOL transformers & switchgears	Replace transformers and reduce 2 DESNs to 1 DESN	2021	81
4	Newton TS: EOL transformers	Replace EOL transformers	2021	22
5	Kenilworth TS: EOL transformer & switchgear	Reconfigure from 2 DESNs to single DESN and replace EOL equipment	2021	36
6	Dundas TS: Load transfer	Add two new feeders at Dundas TS #2	2021	2
7	Gage TS: EOL transformers & switchgear	Reduce from 3 DESNs to 2 DESNs and replace EOL equipment	2021	55
8	Kenilworth TS: Power factor correction	LDC is developing distribution option	2022	1
9	Norfolk area supply capacity	Norfolk TS: Install capacitor bank	2022	3

Table 8-2 Mid- and Long-Term Needs/Plans in Burlington to Nanticoke Region

No.	Needs	Plans	Planned I/S Date	Budgetar y Estimate ($M)
1	Birmingham TS EOL transformer and metalclad switchgears	Replace EOL equipment	2025	29
2	Mid-Term EOL transformers at Nebo TS (T3/T4), Caledonia TS (T1) and Jarvis TS (T3/T4)	Monitor and review in next planning cycle	2025-29	69
3	Mid-Term EOL switchgear at Norfolk TS and Burlington TS[5]	Monitor and review in next planning cycle	2026	57
4	EOL cables in Hamilton sub-region: H5K/H6K, K1G/K2G, HL3/HL4[6]	To further assess the options in this RIP by the Study Team and addendum issued to Hamilton IRRP and RIP	2026	28
5	Norfolk area supply capacity	To further assess the options in this RIP by the Study Team in advance of next planning cycle and addendum issued to RIP	2026	80
6	Beach TS: EOL 230 kV auto-transformers[7] and DESN transformers	To be assessed as part of Middleport Bulk Study by the IESO in coordination with Hydro One	2027	71
7	Lake TS: EOL transformers and switchgears	Monitor and review in next planning cycle	2027	45
8	Burlington TS: EOL 230 kV auto-transformer [8]	To be assessed as part of Middleport Bulk Study by the IESO in coordination with Hydro One	2030	14

Further details, alternatives, and recommended plans for the above needs are provided in Section 7.

[5] Further condition assessment did not confirm the earlier need of refurbishing Brantford switchgear.
[6] To be finalized through Hamilton IRRP Addendum by the IESO
[7] To be finalized through Middleport Bulk Study by the IESO

The Study Team recommends:

- Hydro One to continue with the implementation of major infrastructure investments listed in Table 8-1;
- Hydro One to continue with the implementation of infrastructure investments at Birmingham TS for replacement of EOL transformers and switchgears;
- The EOL 230 kV autotransformer options at Beach TS and Burlington TS will be assessed through the IESO Middleport Bulk Study in coordination with Hydro One to develop a final recommended plan;
- The EOL 115 kV Hamilton area cables options are included in this RIP. It will be further assessed by the Study Team to develop a recommended plan to be included as an addendum to the Hamilton IRRP and this RIP;
- The options to reinforce supply to the Norfolk area are included in this RIP and will be further assessed by the Study Team in advance of the next planning cycle to develop a recommended plan and an addendum be made to the RIP; and
- All the other identified needs/options in the mid and long-term will be further reviewed by the Study Team in the next regional planning cycle as discussed in Section 7.

9. REFERENCES

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[2]. Hydro One, "Needs Assessment Report, Burlington to Nanticoke Region", 15 May 2017
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[3]. Hydro One, "Regional Infrastructure Plan", 07 February 2017
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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	B12BL, B13BL	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	Birmingham TS	115	HL3, HL4
4	Bloomsburg DS	115	C9, C12
5	Brant TS	115	B12BL, B13BL
6	Brantford TS	230	M32W, M33W
7	Bronte TS	115	B7, B8
8	Burlington TS DESN	230	Q23BM, Q25BM
9	Caledonia TS	230	N5M, S39M
10	Cumberland TS	230	B40C, B41C
11	CTS	230	Q24HM, Q29HM
12	Dundas TS	115	B3, B4
13	Dundas TS #2	115	B12BL, B13BL
14	Elgin TS	115	HL3, HL4
15	Gage TS	115	B10, B11
16	Horning TS	230	M27B, M28B
17	CTS	230	N20K
18	Jarvis TS	230	N21J, N22J
19	Kenilworth TS	115	H5K, H6K
20	Lake TS	230	B18H, B20H
21	CTS	115	B3, B4
22	Mohawk TS	115	B3, B4
23	Nebo TS	230	Q24HM, Q29HM
24	Newton TS	115	Newton TS 115 kV Bus (2)
25	Norfolk TS	115	C9, C12
26	Powerline MTS	115	B12BL, B13BL
27	Stirton TS	115	HL3, HL4
28	CTS	230	N21J, N22J
29	Winona TS	115	Q2AH

(1) Beach TS 230 kV bus is supplied by five 230 kV B18H, B20H, Q24HM, Q29HM and M34H circuits

(2) Newton TS 115 kV bus is supplied by four 115 kV B3, B4, B12BL and B13BL 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: REGIONAL LOAD FORECASTS (MW)

Table – 1 Burlington to Nanticoke Region - Non-Coincident Load Forecast (Extreme Weather Corrected)

Area	Station	LTR	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Brant 115 kV	Brant TS (T1 / T2)	101	70	75	81	81	82	83	84	85	86	86	87	88	89	93	94	95	96	98	99	100	101	102
	Powerline MTS (T1 / T2)	114	78	78	82	83	85	86	87	88	89	90	92	93	94	96	97	99	100	103	104	106	108	110
	Total		**148**	**153**	**164**	**165**	**167**	**169**	**171**	**173**	**175**	**177**	**179**	**181**	**183**	**189**	**191**	**194**	**197**	**200**	**203**	**206**	**209**	**212**
Brant 230 kV	Brantford TS (T3 / T4)	188	141	164	166	170	172	175	177	179	180	187	189	191	194	196	198	199	202	205	208	210	213	215
	Total		**141**	**164**	**166**	**170**	**172**	**175**	**177**	**179**	**180**	**187**	**189**	**191**	**194**	**196**	**198**	**199**	**202**	**205**	**208**	**210**	**213**	**215**
Burlington and Oakville 115 kV	Bronte TS (T2 / T5 / T6)	180	141	133	134	136	137	138	139	140	141	143	144	143	143	143	143	143	143	143	143	143	143	143
	Total		**141**	**133**	**134**	**136**	**137**	**138**	**139**	**140**	**141**	**143**	**144**	**143**	**143**	**143**	**143**	**143**	**143**	**143**	**143**	**143**	**143**	**143**
Burlington and Oakville 230 kV	Burlington TS (T15 / T16)	185	141	154	154	154	153	153	153	152	152	151	151	151	151	150	150	150	150	150	150	150	150	150
	Cumberland TS (T3 / T4)	174	120	123	124	125	126	127	128	129	130	131	132	133	135	136	137	137	137	137	137	137	137	137
	Total		**260**	**277**	**278**	**279**	**279**	**280**	**280**	**281**	**282**	**282**	**283**	**284**	**285**	**287**	**287**	**286**	**287**	**287**	**287**	**287**	**287**	**287**
Greater Hamilton 115 kV	Birmingham TS (T1 / T2)	76	21	29	33	33	33	33	33	32	32	32	32	32	32	31	31	31	31	31	31	31	31	31
	Birmingham TS (T3 / T4)	91	59	60	63	63	62	62	62	61	61	61	61	60	60	60	59	59	59	59	59	59	58	58
	Dundas TS (T1 / T2)	99	100	106	111	112	113	114	114	115	116	116	117	118	119	119	120	121	122	131	132	133	134	135
	Dundas TS #2 (T5 / T6)	89	50	53	54	56	57	57	57	56	56	56	55	55	55	55	55	55	54	54	54	54	54	54
	Elgin TS (T1 / T2)	135	98	105	111	114	118	118	117	116	116	115	115	114	114	113	113	112	114	113	113	113	113	113
	Gage TS (T3 / T4)	57	21	21	21	21	21	21	20	20	20	20	20	20	20	20	20	20	20	20	19	19	19	19
	Gage TS (T5 / T6)	57	13	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
	Gage TS (T8 / T9)	123	16	16	16	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	14	14	14
	Kenilworth TS (T2 / T3)	127	52	52	52	52	52	51	51	51	50	50	50	50	50	49	49	49	49	49	48	48	48	48
	Mohawk TS (T1 / T2)	104	75	77	77	77	77	77	76	76	76	75	75	75	74	74	73	73	73	73	73	73	73	72
	Newton TS (T1 / T2)	78	52	53	54	60	62	62	62	61	61	61	60	60	60	60	60	59	59	59	59	59	59	59
	Stirton TS (T3 / T4)	112	44	46	48	50	53	53	52	52	52	52	51	51	51	51	51	50	50	50	50	50	50	50
	Winona TS (T1 / T2)	89	49	52	52	56	58	58	57	57	57	56	56	56	56	56	56	55	55	55	55	55	55	55
	Total CTS		24	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26
	Total		**675**	**706**	**729**	**747**	**761**	**759**	**756**	**753**	**750**	**747**	**745**	**743**	**742**	**741**	**738**	**736**	**737**	**746**	**746**	**745**	**745**	**745**
Greater Hamilton 230 kV	Beach TS (T3/T4)	135	24	36	36	36	36	35	35	35	35	35	35	34	34	34	34	34	34	34	34	33	33	33
	Beach TS (T5 / T6)	96	57	64	65	65	66	65	67	66	66	66	65	65	65	65	64	64	64	64	64	64	64	63
	Horning TS (T3 / T4)	113	77	79	79	79	80	79	79	78	78	78	77	77	76	76	76	75	75	75	75	75	75	75
	Lake TS (T1 / T2)	94	50	51	51	58	58	57	57	57	56	56	56	56	55	56	55	55	55	55	55	55	55	54
	Lake TS (T3 / T4)	113	54	54	55	52	54	53	53	53	53	52	52	52	52	51	51	51	51	50	50	50	50	50
	Nebo TS (T1/T2)	178	127	127	135	140	144	148	151	154	157	160	166	168	170	172	174	176	179	181	184	186	188	191
	Nebo TS (T3 / T4)	51	52	53	53	53	53	53	53	52	52	52	52	51	51	51	51	51	51	51	51	50	50	50
	Total CTS		255	249	230	228	244	244	242	241	241	240	240	239	239	238	238	237	237	237	237	237	237	237
	Total		**695**	**714**	**703**	**711**	**735**	**736**	**737**	**737**	**738**	**739**	**742**	**742**	**742**	**743**	**743**	**743**	**744**	**747**	**749**	**750**	**753**	**754**
Caledonia Norfolk 115 kV	Norfolk TS (T1/T2)	97	57	61	67	68	69	69	74	74	74	78	82	84	85	86	87	87	87	88	88	89	89	90
	Bloomsburg DS (T1/T2)	49	38	40	41	44	52	61	69	69	69	69	69	69	73	74	74	74	74	76	76	76	76	77
	Total		**95**	**101**	**108**	**112**	**120**	**130**	**143**	**143**	**143**	**147**	**151**	**153**	**158**	**160**	**161**	**161**	**162**	**164**	**165**	**165**	**166**	**166**
Caledonia Norfolk 230 kV	Caledonia TS (T1/T2)	99	41	43	52	62	67	69	70	72	74	75	85	85	86	87	88	88	89	90	91	92	93	94
	Jarvis TS (T3/T4)	100	67	74	76	78	79	79	80	80	81	81	82	82	83	84	84	85	86	87	87	88	89	89
	Total CTS		117	115	116	118	117	117	117	116	116	116	115	115	115	115	114	114	114	114	114	114	114	114
	Total		**225**	**232**	**245**	**257**	**263**	**265**	**267**	**268**	**270**	**272**	**282**	**283**	**284**	**285**	**286**	**287**	**290**	**291**	**293**	**294**	**296**	**297**
Regional Total			2381	2480	2527	2577	2633	2652	2669	2673	2680	2694	2715	2720	2732	2744	2748	2751	2761	2782	2793	2801	2812	2820

Table – 2 Burlington to Nanticoke Region - Coincident Load Forecast (Extreme Weather Corrected)

Area	Station	LTR	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Brant 115 kV	Brant TS (T1 / T2)	101	50	54	58	58	59	60	60	61	61	62	63	63	64	68	69	69	70	71	72	73	74	75
	Powerline MTS (T1 / T2)	114	64	64	67	68	69	70	71	72	73	74	75	76	77	79	80	81	82	84	86	87	89	90
	Total		**114**	**118**	**126**	**127**	**128**	**130**	**131**	**133**	**134**	**136**	**138**	**139**	**141**	**146**	**148**	**150**	**153**	**155**	**158**	**160**	**162**	**165**
Brant 230 kV	Brantford TS (T3 / T4)	188	132	153	155	159	161	164	166	167	169	176	177	179	182	184	186	187	190	192	195	197	199	202
	Total		**132**	**153**	**155**	**159**	**161**	**164**	**166**	**167**	**169**	**176**	**177**	**179**	**182**	**184**	**186**	**187**	**190**	**192**	**195**	**197**	**199**	**202**
Burlington and Oakville 115 Kv	Bronte TS (T2 / T5 / T6)	180	106	105	106	107	108	109	109	110	111	112	113	113	113	113	113	112	112	113	113	113	113	113
	Total		**106**	**105**	**106**	**107**	**108**	**109**	**109**	**110**	**111**	**112**	**113**	**113**	**113**	**113**	**113**	**112**	**112**	**113**	**113**	**113**	**113**	**113**
Burlington and Oakville 230 kV	Burlington TS (T15 / T16)	185	133	146	146	145	145	145	144	144	143	143	143	142	142	142	142	142	141	142	142	142	142	142
	Cumberland TS (T3 / T4)	174	106	109	110	111	111	112	113	114	115	116	117	118	119	121	121	121	121	121	121	121	122	122
	Total		**239**	**254**	**255**	**256**	**257**	**257**	**257**	**258**	**258**	**259**	**259**	**260**	**262**	**263**	**263**	**263**	**263**	**263**	**263**	**263**	**263**	**263**
Greater Hamilton 115 kV	Birmingham TS (T1 / T2)	76	13	13	15	15	15	15	15	15	15	15	15	15	15	14	14	14	14	14	14	14	14	14
	Birmingham TS (T3 / T4)	91	48	49	51	51	51	51	50	50	50	49	49	49	49	49	48	48	48	48	48	48	48	47
	Dundas TS (T1 / T2)	99	79	84	88	89	89	90	91	91	92	92	93	93	94	95	95	96	96	106	107	107	108	109
	Dundas TS #2 (T5 / T6)	89	43	46	48	49	50	50	49	49	49	49	48	48	48	48	48	48	48	48	48	48	47	47
	Elgin TS (T1 / T2)	135	77	82	87	89	93	93	92	91	91	91	90	90	89	89	89	88	90	90	89	89	89	89
	Gage TS (T3 / T4)	57	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
	Gage TS (T5 / T6)	57	8	8	8	8	8	8	8	8	8	7	7	7	7	7	7	7	7	7	7	7	7	7
	Gage TS (T8 / T9)	123	13	13	13	13	13	13	13	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
	Kenilworth TS (T2 / T3)	127	48	48	48	48	48	47	47	47	47	46	46	46	46	45	45	45	45	45	45	45	44	44
	Mohawk TS (T1 / T2)	104	61	62	62	63	63	62	62	62	61	61	61	60	60	60	60	59	59	59	59	59	59	59
	Newton TS (T1 / T2)	78	49	50	50	56	58	58	58	57	57	57	56	56	56	56	56	55	55	55	55	55	55	55
	Stirton TS (T3 / T4)	112	42	43	45	47	50	50	50	49	49	49	49	49	48	48	48	48	48	47	47	47	47	47
	Winona TS (T1 / T2)	89	47	50	51	55	56	56	55	55	55	55	54	54	54	54	54	54	53	53	53	53	53	53
	Total CTS	50	14	16	16	17	17	17	17	17	17	16	16	16	16	16	16	16	16	16	16	16	16	16
	Total		**549**	**569**	**587**	**603**	**615**	**613**	**611**	**608**	**607**	**604**	**603**	**601**	**600**	**599**	**597**	**596**	**596**	**605**	**605**	**605**	**605**	**604**
Greater Hamilton 230 kV	Beach TS (T3/T4)	135	16	16	16	16	16	16	16	16	16	16	15	15	15	15	15	15	15	15	15	15	15	15
	Beach TS (T5 / T6)	96	53	59	60	60	61	61	62	62	61	61	61	61	60	60	60	60	59	59	59	59	59	59
	Horning TS (T3 / T4)	113	63	64	65	65	65	65	64	64	64	63	63	63	62	62	62	62	61	62	61	61	61	61
	Lake TS (T1 / T2)	94	50	51	51	58	58	58	58	57	57	57	56	56	56	56	56	56	55	55	55	55	55	55
	Lake TS (T3 / T4)	113	50	51	51	48	50	50	50	49	49	49	49	48	48	48	48	48	47	47	47	47	47	47
	Nebo TS (T1/T2)	178	120	120	126	132	136	139	142	145	148	151	156	158	160	162	164	166	168	170	173	175	177	179
	Nebo TS (T3 / T4)	51	38	39	39	39	39	39	39	38	38	38	38	38	37	37	37	37	37	37	37	37	37	37
	Total CTS	305	185	189	172	171	185	185	184	183	183	182	182	181	181	181	180	180	180	180	180	180	180	180
	Total		**574**	**589**	**581**	**589**	**610**	**612**	**613**	**614**	**615**	**616**	**620**	**620**	**621**	**622**	**622**	**622**	**623**	**626**	**628**	**629**	**631**	**633**
Caledonia Norfolk 115 kV	Norfolk TS (T1/T2)	97	33	35	39	39	39	39	42	42	43	46	50	52	52	54	54	55	55	55	55	56	56	56
	Bloomsburg DS (T1/T2)	49	26	27	28	30	35	41	46	46	46	47	47	47	51	51	51	51	51	53	53	53	53	53
	Total		**58**	**62**	**66**	**69**	**74**	**80**	**89**	**89**	**89**	**93**	**97**	**98**	**103**	**105**	**105**	**106**	**106**	**108**	**108**	**109**	**109**	**109**
Caledonia Norfolk 230 kV	Caledonia TS (T1/T2)	99	20	21	26	31	33	34	35	36	37	37	46	46	47	47	48	48	49	49	49	50	50	51
	Jarvis TS (T3/T4)	100	53	59	60	61	62	63	63	64	64	64	65	65	66	67	67	67	69	69	70	70	70	71
	Total CTS	225	92	97	97	99	98	98	98	98	97	97	97	97	96	96	96	96	96	96	96	96	96	96
	Total		**166**	**177**	**184**	**191**	**194**	**195**	**196**	**197**	**198**	**199**	**208**	**208**	**209**	**210**	**210**	**211**	**213**	**214**	**215**	**216**	**217**	**218**
Regional Total			**1937**	**2027**	**2060**	**2101**	**2147**	**2160**	**2173**	**2176**	**2182**	**2194**	**2214**	**2219**	**2229**	**2241**	**2245**	**2247**	**2256**	**2276**	**2285**	**2291**	**2300**	**2307**

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

Appendix G

Renewable Energy Generation Investment Plan

BURLINGTON HYDRO INC.

Renewable Energy Generation Investments Plan

Prepared for the

Independent Electricity System Operator

To accompany

Burlington Hydro Inc.,

2026 Cost of Service Application

October 25, 2024

1 Executive Summary

This Renewable Energy Generation (REG) Investments Plan, identifying investment requirements for accommodating Renewable Energy Generation connections, provides information to the Ontario Energy Board (OEB) and interested stakeholders regarding the readiness of Burlington Hydro Inc.'s (BHI's) distribution system to connect renewable energy generation. This includes investment requirements for any expansion or reinforcement necessary to remove grid constraints in order to accommodate the connections of renewable energy generation over the forecast period of 2026-2030.

There are approximately 8,720 kilowatts (kW) of renewable energy installations connected to BHI's distribution system, and 7,580 kW of renewable energy installations connected to BHI's distribution system under Feed-in-Tariff (FIT) and microFIT programs, all of which are solar photovoltaic projects. This includes 27 FIT projects and 197 microFIT projects. There are currently no FIT nor MicroFIT projects that have been issued an Offer to Connect by BHI. There are currently 94 NetMetering Projects connected to BHI's distribution system. Additionally, there are currently 32 NetMetering projects with a combined capacity of approximately 415 kW that we have sent Offer to Connect and 8 NetMetering projects with a combined capacity of approximately 60 kW that we have received applications and Offer to Connect is pending. BHI has analyzed its circuits for REG connectivity to calculate available capacity for REG connection on each feeder. Based on current allocated capacity and proposed DERS, BHI does not forecast any restrictions in the short term. No investment is required.

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2 INTRODUCTION

BHI is preparing to file a Cost of Service (COS) Application for the prospective rate year of 2026. In accordance with the Ontario Energy Board (OEB) *Filing Requirements for Electricity Transmission and Distribution Applications*, BHI has prepared this Renewable Energy Generation (REG) Investments Plan to accompany its Distribution System Plan (DSP) and COS Application.

This REG Investments Plan provides information on BHI's ability to accommodate new REG connections to its distribution system. The purpose of this REG Investments Plan is to inform the Independent Electricity System Operator (IESO) of any REG investments over the DSP period (2026-2030) and to request the IESO to provide a letter commenting on this information.

Section 3 of this REG Investments Plan provides background information regarding BHI's distribution system. Section 4 lists the existing and proposed REG connections. Section 5 contains the system assessment to identify constraints. Finally, Section 6 summarizes the proposed investments to facilitate new REG connections.

3 BHI's Distribution Grid

BHI owns, operates, and maintains a distribution system currently serving approximately 69,100 residential and commercial customers in the City of Burlington over the span of 188 square kilometres. BHI's service territory is depicted in Figure 1.

BHI's industrial customer base is minimal in comparison to residential customers (refer to Table 1 below). BHI has had a modest growth within its service territory in the past 5 years and expect this trend to continue in the following years.

Table 1: Changing Trends in Customer Base

Annual Year	Residential	General Service <50 kW	General Service ≥50kW	Total
2023	62,297	5,903	971	69,171
2022	62,027	5,909	943	68,879
2021	61,915	5,842	985	68,742
2020	61,803	5,776	989	68,568
2019	61,502	5,681	1,022	68,205

BHI operates its three-phase distribution system at 4160, 13800 and 27600 volts and BHI owns, operates and maintains 32 municipal substations.

BHI owns and maintains 1,516 km of 4160, 13800 & 27600-volt distribution conductors combined.

BHI is supplied by Hydro One Networks Inc. (HONI) from five Transformer Stations (TSs), namely Burlington TS, Cumberland TS, Bronte TS, Palermo TS and Tremaine TS. BHI owns, operates, and maintains thirty four (34) distribution feeders at 27.6kV from its border connection points. All of these feeders have been identified by HONI to have available capacity to connect FIT ,micro-FIT generators, NetMetering and Load Displacement.

Figure 1: BHI's Service Territory Map

3.1 Transformer Stations (HONI owned)

There are 5 Transformer Stations (HONI owned) serving the community. The total design capacity is 478 MW. The distribution system (27.6kV) allows for transfer of loads between stations as required.

Table 2: 27.6 KV Distribution Feeder Data

SUBSTATION	LOCATION	BHI ALOCATED CAPACITY (MW)	OWNER	TOTAL FEEDER #	Volt (kV)
Palermo	Oakville	29	HONI	2	27.6
Bronte	Oakville	30	HONI	4	27.6
Tremaine	Burlington	114.75	HONI	6	27.6
Cumberland	Burlington	148.2	HONI	10	27.6
Burlington	Burlington	156	HONI	12	27.6

3.1.2 Available Capacity

There is sufficient capacity to connect new REG at five TSs: Bronte, Burlington, Cumberland, Palermo and Tremaine – as detailed in Table 2. The short circuit and thermal capacity at Palermo TS have recently been lifted and BHI is working with HONI to determine the allocated capacity to BHI for DERs, through a Threshold Capacity Allocation Application. (TAA)

Table 3: 27.6 KV Distribution Feeders Capacity Status for DG Connectivity (BHI owned feeders)

Station Name	Feeder	Total Capacity (kW)	Used Capacity (kW)	Available Capacity (kW)
Bronte TS	13M25	4500	20	
Bronte TS	13M26		78	
Bronte TS	13M27		750	
Bronte TS	13M28		493	
Bronte TS	Total	4500	1341	3159
Burlington TS	39M1	5000	145	
Burlington TS	39M2		244	
Burlington TS	39M3		0	
Burlington TS	39M4		378	
Burlington TS	39M5		699	
Burlington TS	39M6		44	
Burlington TS	39M31	5000	27.5	
Burlington TS	39M32		356	

Burlington TS	39M33		436.4	
Burlington TS	39M34		595	
Burlington TS	39M35		110	
Burlington TS	39M36		48	
Burlington TS	Total	10000	3082.9	6917.1
Cumberland TS	76M21	5000	150	
Cumberland TS	76M23		387	
Cumberland TS	76M25		144.1	
Cumberland TS	76M27		0	
Cumberland TS	76M29		2.25	
Cumberland TS	76M22	5000	84.1	
Cumberland TS	76M24		566.2	
Cumberland TS	76M26		83	
Cumberland TS	76M28		142.5	
Cumberland TS	76M30		2315.3	
Cumberland TS	Total	10000	3874.45	6125.55
Tremaine TS	280M3	2000	280.5	
Tremaine TS	280M5		103.4	
Tremaine TS	280M4	5000	97	
Tremaine TS	280M6		164.1	
Tremaine TS	280M8		120.3	
Tremaine TS	Total	7000	765.3	6234.7
TOTAL		**31500**	**9063.65**	**22436.35**

3.2 Constraints – Distribution and Upstream

BHI was not able to connect any new generation to the Palermo TS until October 2024.- BHI has recently received approval from HONI to connect a limited capacity of DERs to feeders A4M5 and A4M6. BHI is working on the application to HONI to establish the allocated capacity & short circuit for BHI Feeders.

3.3 Thermal Capacity Constraints

The thermal capacity of the distribution system is the ability of its equipment to carry current. Cables and conductors are rated for the load current they carry (BHI designs for feeders to be loaded to 50% of their rating such that two feeders can be tied together), therefore the anti-islanding constraints prevent the thermal capacity of cables and conductors from being exceeded due to DG. Transformers are more sensitive to reverse power flow; therefore, BHI calculates thermal capacity as 60% of the transformer’s nameplate rating added to the minimum load of the transformer; based on Hydro One Networks Inc. (HONI) guidelines.

The table below presents the available thermal capacity for DG at each Transformer Station that feeds BHI’s distribution system. The 2023 minimum load is estimated as 25% of the lesser of the summer and winter peaks. The connected and in-progress DG includes both micro-FIT, Fit and Net Metering for the purpose of the thermal capacity calculation. As shown, the DG nameplate ratings do not come close to the thermal capacity of the transformers. All 5 TS are owned by HONI. The total thermal capacities for all 5 TS transformers were obtained from HONI's and BHI TAA agreements Calculator.

Table 4: Available Thermal Capacity for DG

Transformer Station	Nominal Rating (MW)	2023 Minimum Load (MW) System Coincident	Total Thermal Capacity (MW)	Connected and In-Progress DG (MW)	Available Thermal Capacity (MW)
Bronte TS	29	12.2	4.5	1.341	3.159
Palermo TS	30	7.2	*	0	*
Tremaine TS	114.75	21.4	7	0.765	6.234
Cumberland TS	148.2	25.3	10	3.874	6.125
Burlington TS	156	44.5	10	3.082	6.917

*BHI will work with HONI to define the allocated thermal capacity for BHI owned Feeders

4 EXISTING AND PROPOSED CONNECTIONS

As of this report date, there are a total of 318 renewable energy generation installations presently connected to BHI's distribution system under the Province's Feed-in-Tariff (FIT), micro-FIT and Net Metering programs, as summarized below in Table 5 and 6. In summary, BHI has:

- 27 FIT installations with generating capacity of 6,018 kW, listed in Table 5.
- 197 micro-FIT installations with 1,562 kW installed capacity, as shown in Table 6.
- 94 solar net-metering installations with 1,140 kW installed capacity.

In addition to the above, there are 32 Net Metering Applications that BHI has sent Offer to Connect to, as shown in Table 7. There are currently no applications in the queue under the FIT and MicroFIT program waiting for connections.

Table 5 – REG Installations under the FIT Program

Name	Fuel Source	Rating (kW)	Address	TS/Feeder	DS/Feeder	Phase	Generation Start Date
Longo Power Generation Inc.	Solar	100	1225 Fairview St	39M1	MAPL_F8	3-Phase	11/2/2012
Firelight Solar L.P.	Solar	250	2025 Guelph Line	39M4	N/A	3-Phase	6/26/2012
PNUC Renewable Energy Co-operative Inc.	Solar	60	3132 South Dr	39M5	PTNL_F2	3-Phase	12/11/2014
IKEA Properties	Solar	500	1065 Plains Rd E (IKEA)	39M5	N/A	3-Phase	2/28/2018
Sunnyside Up Investments Inc.	Solar	250	1141 King Rd	39M32	EAST_F3	3-Phase	12/19/2013
N. Fine Investments Ltd.	Solar	50	3141 Mainway	39M34	TYAN_F3	3-Phase	10/30/2012
Mountain Equipment Co-operative	Solar	48	1030 Brant Street	39M33	BRAN_F3	3-Phase	1/20/2016
Solar Cell LP (2205 Mount Forest Dr)	Solar	222	2205 Mount Forest Dr	39M33	BRAN_F4	3-Phase	7/6/2018
SPN LP 3.	Solar	432	1295 North Service Rd	39M34	N/A	3-Phase	12/4/2015
2395410 Ontario Inc.	Solar	250	3450 Landmark Rd	76M24	N/A	3-Phase	5/15/2014

OSPS (001463-3430 South Service) Limited Partnership	Solar	50	3430 South Service Rd	76M22	INTR_F2	3-Phase	12/19/2013
Menkes Barnett Burlington Inc.	Solar	425	1185 Corporate Dr	76M30	N/A	3-Phase	6/25/2012
M07-1111 Corporate	Solar	500	4390 Paletta Court	76M30	N/A	3-Phase	12/17/2014
WC Enerco Inc.	Solar	320	4350 Harvester Rd	76M30	N/A	3-Phase	7/15/2015
8180792 Canada Inc.	Solar	500	1205 Corporate Dr	76M30	N/A	3-Phase	8/14/2015
G04-835 Harrington	Solar	50	3330 Harvester Rd	76M30	N/A	3-Phase	1/8/2015
Impetus Solar LP (3332 Harvester Rd)	Solar	368	3332 Harvester Rd	76M30	N/A	3-Phase	7/6/2018
OZZ (OSDI) Limited Partnership	Solar	250	3167 North Service Rd	76M24	N/A	3-Phase	2/4/2015
Longo Power Generation Inc.	Solar	100	2900 Walkers Ln	76M23	N/A	3-Phase	6/5/2014
Samuel, Son & Co., Ltd.	Solar	100	1250 Appleby Ln	76M21	N/A	3-Phase	9/18/2014
Halton Standard Condominium Corporation #550	Solar	30	1980 Imperial Way	76M21	N/A	3-Phase	9/2/2010
A10-4305 Fairview	Solar	100	4305 Fairview St	76M25	FRVW_F3	3-Phase	2/2/2015
Walkers Mews	Solar	63	1831 Walker's Line	76M23	N/A	3-Phase	5/26/2017
NorthGrid Ventures (2010) Inc.	Solar	250	5070 Benson Dr	13M27	N/A	3-Phase	10/29/2010

Melrose Investments Inc.	Solar	250	5295 John Lucas Dr	13M28	N/A	3-Phase	11/22/2013
	Solar	250	1050 Pachino Court	13M27	N/A	3-Phase	12/19/2014
Rowhedge Construction Limited	Solar	250	1080 Clay Ave	13M27	N/A	3-Phase	12/19/2014

Table 6 – REG Installations under the Micro-FIT Program

Address	Capacity (kW)	Fuel Source	Station-TS	Feeder	Year
5441 Sheldon Park Dr	9.765	Solar Rooftop	Bronte	13M25	3/28/2017
638 Bridle Wood	9.8	Solar Rooftop	Bronte	13M25	5/30/2018
378 Bevan Dr	3.5	Solar Rooftop	Bronte	13M26	12/24/2010
5417 Windermere Crt	8.6	Solar Rooftop	Bronte	13M26	10/18/2013
311 Melores Dr	9.75	Solar Rooftop	Bronte	13M26	12/19/2013
567 Fothergill Blvd	5.375	Solar Rooftop	Bronte	13M26	10/8/2014
5179 Hunter Dr	10	Solar Rooftop	Bronte	13M26	6/19/2015
5134 Bayfield Cres	10	Solar Rooftop	Bronte	13M26	12/17/2015
239 Kent Cres	9.57	Solar Rooftop	Bronte	13M26	6/13/2017
225 Teddington Pl	7.6	Solar Rooftop	Bronte	13M26	4/11/2018
5972 Blue Spruce Ave	6	Solar Rooftop	Bronte	13M28	9/27/2013
5612 Thorn Ave	3	Solar Rooftop	Bronte	13M28	5/22/2014
1311 Richmond Rd	5	Solar Rooftop	Burlington	39M1	10/24/2011
1249 Hammond St	10	Solar Rooftop	Burlington	39M1	10/23/2015
1380 Olga Drive	10	Solar Rooftop	Burlington	39M1	10/29/2015
2092 Maplewood Dr.	10	Solar Rooftop	Burlington	39M1	3/15/2018
2377 Colling Road	9.9	Solar Rooftop	Burlington	39M2	5/20/2011
6634 Guelph Line	10	Solar Ground mount	Burlington	39M2	8/9/2011
2411 Malcolm Crescent	3.3	Solar Rooftop	Burlington	39M2	4/7/2010
6508 McNiven Road	10	Solar Rooftop	Burlington	39M2	1/26/2012
6115 GUELPH LINE	10	Solar Rooftop	Burlington	39M2	8/9/2012
4651 Brittania Road	10	Solar Rooftop	Burlington	39M2	4/24/2012
2419 Overton drive	6.5	Solar Rooftop	Burlington	39M2	1/30/2012

2273 Dundas Street	10	Solar Rooftop	Burlington	39M2	2/2/2010
2458 Whitaker Drive	2.925	Solar Rooftop	Burlington	39M2	5/13/2012
2304 Malcolm Cres	8	Solar Rooftop	Burlington	39M2	6/25/2013
5123 Mount Nemo Crescent	10	Solar Rooftop	Burlington	39M2	8/9/2013
5327 Britannia Road	5	Solar Rooftop	Burlington	39M2	5/16/2014
4229 Cedar Springs Rd	8	Solar Rooftop	Burlington	39M2	11/28/2014
2025 Cutters Place	8.6	Solar Rooftop	Burlington	39M2	6/24/2015
6700 Guelph Line	8.6	Solar Rooftop	Burlington	39M2	2/11/2014
5327 Britannia Rd	10	Solar Rooftop	Burlington	39M2	5/16/2014
3027 Sandlewood Crt	8	Solar Rooftop	Burlington	39M2	4/27/2015
4225 1 Side Road	8.2	Solar Rooftop	Burlington	39M2	5/17/2016
2338 Glastonbury	6	Solar Rooftop	Burlington	39M2	5/26/2016
5163 Mount Nemo	10	Solar Rooftop	Burlington	39M2	11/16/2016
4472 Guelph Line	7.6	Solar Rooftop	Burlington	39M2	3/22/2017
6427 Chelsea Rd	5	Solar Rooftop	Burlington	39M2	5/12/2017
5350 Walkers Line	7.815	Solar Rooftop	Burlington	39M2	7/10/2017
3119 Autumn Hill Dr	5	Solar Rooftop	Burlington	39M2	7/17/2017
2559 Whittaker Dr	5	Solar Rooftop	Burlington	39M2	10/25/2017
6380 Breckenridge Pl.	7.6	Solar Rooftop	Burlington	39M2	10/27/2017
2544 Cavendish Dr	7.5	Solar Rooftop	Burlington	39M2	2/16/2018
2497 Whittaker Dr	5	Solar Rooftop	Burlington	39M2	2/12/2018
2346 Arnold Cres	7.5	Solar Rooftop	Burlington	39M2	4/4/2018
2450 No 2 Sideroad	7.6	Solar Rooftop	Burlington	39M2	4/30/2018
2542 Cavendish	5	Solar Rooftop	Burlington	39M2	5/17/2018
2425 UPPER MIDDLE RD	10	Solar Rooftop	Burlington	39M4	12/20/2010
2333 Headon Forest Drive	9.88	Solar Rooftop	Burlington	39M4	5/11/2011
2192 Charnwood Drive	10	Solar Rooftop	Burlington	39M4	1/16/2013
3226 Folkway Dr	10	Solar Rooftop	Burlington	39M4	1/16/2013
3200 Berkshire Lane	10	Solar Rooftop	Burlington	39M4	5/24/2013
2415 Headon Forest Dr.	4.2	Solar Rooftop	Burlington	39M4	7/24/2013
2210 HUNT CRES	4.2	Solar Rooftop	Burlington	39M4	7/24/2013
3214 Edenwood Crescent	5.5	Solar Rooftop	Burlington	39M4	1/27/2014
2427 Butternut Cres	8.5	Solar Rooftop	Burlington	39M4	5/17/2017
2526 Headon Forest Dr	5	Solar Rooftop	Burlington	39M4	11/13/2017
3011 Sandlewood Crt	7.5	Solar Rooftop	Burlington	39M4	4/13/2018

2424 Baxter Cres	7.6	Solar Rooftop	Burlington	39M4	6/4/2018
516 Mayzel Road	10	Solar Rooftop	Burlington	39M5	9/22/2011
402 Guelph Line	4	Solar Rooftop	Burlington	39M5	8/23/2011
2193 Ghent Ave	10	Solar Rooftop	Burlington	39M5	3/27/2013
1072 Stepheson Dr	8.58	Solar Rooftop	Burlington	39M5	4/15/2013
1253 Bellview St	10	Solar Rooftop	Burlington	39M5	11/6/2014
713 Rambo Cres	8.2	Solar Rooftop	Burlington	39M5	5/25/2016
1113 Carol St	10	Solar Rooftop	Burlington	39M5	3/28/2018
1220 Homewood Dr	9.9	Solar Rooftop	Burlington	39M6	12/24/2011
2272 Parkway Dr	8.6	Solar Rooftop	Burlington	39M6	12/18/2013
1147 Homewood DR	5.5	Solar Rooftop	Burlington	39M6	10/2/2013
1194 Nottingham Ave	7.6	Solar Rooftop	Burlington	39M6	5/11/2017
2372 Tait Ave	7.6	Solar Rooftop	Burlington	39M6	8/15/2017
1-1550 Yorkton Ct.	10	Solar Rooftop	Burlington	39M31	2/2/2011
958 Kingsway Dr	7.6	Solar Rooftop	Burlington	39M31	10/25/2017
842 Danforth Place	5	Solar Rooftop	Burlington	39M32	3/3/2010
870 Eagle Drive	4.4	Solar Rooftop	Burlington	39M32	4/7/2010
834 Danforth Place	5.3	Solar Rooftop	Burlington	39M32	1/16/2012
156 Plains Rd E	4	Solar Rooftop	Burlington	39M32	7/31/2013
456 Townsend Ave	10	Solar Rooftop	Burlington	39M32	12/13/2013
409 Dorchester Cres	10	Solar Rooftop	Burlington	39M32	4/23/2015
858 Danforth Pl	7.6	Solar Rooftop	Burlington	39M32	5/26/2017
892 North Shore Blvd W	10	Solar Rooftop	Burlington	39M32	11/16/2017
696 Auburn Cres	7.6	Solar Rooftop	Burlington	39M32	2/8/2018
1293 Coric Ave	4.6	Solar Rooftop	Burlington	39M33	7/27/2010
1321 Fairway Court	10	Solar Rooftop	Burlington	39M33	10/12/2012
1414 Winterberry Drive	9.75	Solar Rooftop	Burlington	39M33	8/21/2015
1062 Forestvale Dr	7.6	Solar Rooftop	Burlington	39M33	5/5/2017
1423 Leighland Rd	8	Solar Rooftop	Burlington	39M33	2/15/2018
1336 Hazelton Blvd	2.52	Solar Rooftop	Burlington	39M34	10/25/2010
1346 Hazelton Blvd	2.6	Solar Rooftop	Burlington	39M34	2/11/2010
2520 Beaufort Court	9	Solar Rooftop	Burlington	39M34	4/2/2012
3134 Cedar Springs	10	Solar Ground mount	Burlington	39M34	5/22/2012
2031 Watson Drive	10	Solar Ground	Burlington	39M34	12/5/2012

		mount			
1265 Rosseau Pl	10	Solar Rooftop	Burlington	39M34	12/14/2012
2112 Highview Drive	10	Solar Rooftop	Burlington	39M34	5/17/2012
2597 Cavendish Dr	8.6	Solar Rooftop	Burlington	39M34	7/8/2015
2184 Fairchild Blvd.	6.5	Solar Rooftop	Burlington	39M34	6/30/2015
2163 Alconbury Cres	9.75	Solar Rooftop	Burlington	39M34	8/26/2015
2469 No. 1 Side Rd	8.8	Solar Rooftop	Burlington	39M34	12/21/2016
2575 Cavendish Dr	7.6	Solar Rooftop	Burlington	39M34	7/19/2017
2012 Keller Crt	7.7	Solar Rooftop	Burlington	39M34	5/14/2018
2225 New Street	10	Solar Rooftop	Burlington	39M35	11/2/2011
318 Pepper DR	10	Solar Rooftop	Burlington	39M35	12/19/2012
414 Smith Ave	10	Solar Rooftop	Burlington	39M35	10/30/2015
366 Newbold Dr	10	Solar Rooftop	Burlington	39M35	9/22/2017
463 Woodland Ave	5	Solar Rooftop	Burlington	39M35	11/8/2017
716 Bateman Crt	10	Solar Rooftop	Burlington	39M36	3/11/2013
640 Greenwood Dr	8.38	Solar Rooftop	Burlington	39M36	6/12/2015
1441 Mountain Grove Ave	7.6	Solar Rooftop	Burlington	39M36	10/26/2017
1227 Appleby Line	10	Solar Rooftop	Cumberland	76M21	8/25/2011
1837 Ironstone Dr	10	Solar Rooftop	Cumberland	76M21	1/19/2012
2277 Glenwood School Dr	6.25	Solar Rooftop	Cumberland	76M22	4/10/2015
2320 Brinell Ave	2.66	Solar Rooftop	Cumberland	76M22	5/11/2011
4106 Medland Dr	4	Solar Rooftop	Cumberland	76M22	7/22/2010
1328 Consort Cres	7.6	Solar Rooftop	Cumberland	76M22	10/25/2017
1349 Vancouver Cres	7.74	Solar Rooftop	Cumberland	76M23	12/6/2013
2180 Donald Rd	6.8	Solar Rooftop	Cumberland	76M23	7/11/2014
3362 Lansdown Drive	10	Solar Rooftop	Cumberland	76M23	7/31/2015
1345 Vancouver Cres.	7.56	Solar Rooftop	Cumberland	76M23	5/16/2017
1360 Vancouver Cres	7.6	Solar Rooftop	Cumberland	76M23	5/25/2017
3248 Lansdown Dr	5	Solar Rooftop	Cumberland	76M23	6/23/2017
3475 Mainway	8.25	Solar Rooftop	Cumberland	76M23	10/18/2018
3474 Mainway Dr	10	Solar Rooftop	Cumberland	76M24	7/20/2011
2228 Greenway Ter	3.6	Solar Rooftop	Cumberland	76M24	7/25/2013
2145 Crosswinds Crt	10	Solar Rooftop	Cumberland	76M24	7/26/2013
2139 Greenway Terr	10	Solar Rooftop	Cumberland	76M24	2/25/2015
2142 Cleaver Ave	5	Solar Rooftop	Cumberland	76M24	6/12/2017

3155 Bentworth Dr	5	Solar Rooftop	Cumberland	76M24	8/31/2017
2088 Kevin Cres	5	Solar Rooftop	Cumberland	76M24	2/21/2018
2160 Heidi Ave	10	Solar Rooftop	Cumberland	76M24	4/11/2018
1311 Renfield Dr	7.6	Solar Rooftop	Cumberland	76M24	4/19/2018
232 Penn Drive	7.01	Solar Rooftop	Cumberland	76M25	12/22/2009
484 Scarlett Cr	8.6	Solar Rooftop	Cumberland	76M25	3/17/2014
3055 Eva Dr	10	Solar Rooftop	Cumberland	76M25	7/22/2014
2322 Woodward Ave	6	Solar Rooftop	Cumberland	76M25	6/20/2016
700 Auburn Cres	7.5	Solar Rooftop	Cumberland	76M25	5/23/2018
3230 Woodward Ave	9.88	Solar Rooftop	Cumberland	76M26	5/12/2011
3141 Keswick Court	3.04	Solar Rooftop	Cumberland	76M26	9/26/2011
394 Oakwood Dr.	7.6	Solar Rooftop	Cumberland	76M26	6/17/2015
193 Pine Cove Rd	10	Solar Rooftop	Cumberland	76M26	1/13/2016
660 Sheraton Rd	10	Solar Rooftop	Cumberland	76M28	4/15/2015
662 Blue Forest Hill	6.08	Solar Rooftop	Cumberland	76M28	7/11/2011
641 Bridle Wood	6	Solar Rooftop	Cumberland	76M28	8/24/2011
339 Wilson Avenue	2.85	Solar Rooftop	Cumberland	76M28	8/11/2010
4408 New St	8.6	Solar Rooftop	Cumberland	76M28	10/16/2013
3455 Lakeshore Rd	9	Solar Rooftop	Cumberland	76M28	3/20/2014
455 Wicklow Rd	10	Solar Rooftop	Cumberland	76M28	1/14/2016
344 Erindale Dr	10	Solar Rooftop	Cumberland	76M28	5/3/2016
4392 Bennett Rd	7.815	Solar Rooftop	Cumberland	76M28	8/22/2017
3412 Lakeshore Rd	10	Solar Rooftop	Cumberland	76M28	10/27/2017
227 Tuck Dr	7.5	Solar Rooftop	Cumberland	76M28	2/28/2018
467 Wicklow Rd	7.5	Solar Rooftop	Cumberland	76M28	3/27/2018
4136 Bianca Forest Drive	5	Solar Rooftop	Cumberland	76M30	10/22/2010
1324 Silvan Forest Drive	7.84	Solar Rooftop	Cumberland	76M30	4/8/2011
4124 Pincay Oaks Lane	9.5	Solar Rooftop	Cumberland	76M30	8/15/2016
4256 Price Ct	5.32	Solar Rooftop	Palermo	A4M6	11/4/2010
5105 Milburough Line	6.45	Solar Rooftop	Dundas	M1	2/14/2014
5111 Dryden Ave	10	Solar Rooftop	Tremaine	280M3	9/16/2014
5355 Jameson Cres	10	Solar Rooftop	Tremaine	280M3	6/22/2015
4108 Montrose Cres	8.6	Solar Rooftop	Tremaine	280M3	6/23/2015
2347 Heslop St.	8.6	Solar Rooftop	Tremaine	280M3	6/24/2015
5432 Valleyhigh Dr	9.8	Solar Rooftop	Tremaine	280M3	7/11/2017

2131 Turnberry Rd	9.945	Solar Rooftop	Tremaine	280M3	8/11/2017
4180 Arbourfield Dr	7.815	Solar Rooftop	Tremaine	280M3	10/17/2017
5517 Twelve Mile Trail	7.6	Solar Rooftop	Tremaine	280M3	10/20/2017
2218 Orchard Rd	7.6	Solar Rooftop	Tremaine	280M3	12/21/2017
4622 Ashlar Cres.	7.6	Solar Rooftop	Tremaine	280M3	2/7/2018
4186 Millcroft Park Dr	7.5	Solar Rooftop	Tremaine	280M3	4/30/2018
2207 Turnberry Rd	7.25	Solar Rooftop	Tremaine	280M3	7/9/2018
1825 Hobson Dr	7.59	Solar Rooftop	Tremaine	280M4	6/5/2017
1805 Creek Way	7.6	Solar Rooftop	Tremaine	280M4	10/4/2017
2914 Hill St	5	Solar Rooftop	Tremaine	280M4	1/11/2018
3352 Minerva Way	10	Solar Rooftop	Tremaine	280M5	10/14/2014
3277 Steeplechase Dr	10	Solar Rooftop	Tremaine	280M5	4/9/2015
3359 Roma Ave	10	Solar Rooftop	Tremaine	280M5	5/6/2015
3185 Sorrento Cres	9.88	Solar Rooftop	Tremaine	280M5	4/18/2016
3242 Sharp Rd	7.6	Solar Rooftop	Tremaine	280M5	4/20/2016
4737 Deforest Cres	8	Solar Rooftop	Tremaine	280M5	7/31/2017
3198 Cotter Rd	7.6	Solar Rooftop	Tremaine	280M5	9/6/2017
3362 Roma Ave	7.6	Solar Rooftop	Tremaine	280M5	8/24/2017
4664 Kurtz Rd	7.5	Solar Rooftop	Tremaine	280M5	2/12/2018
3354 Minerva Way	7.6	Solar Rooftop	Tremaine	280M5	6/4/2018
4678 Erwin Dr	7.6	Solar Rooftop	Tremaine	280M5	4/18/2018
3253 Steeplechase Dr	9.36	Solar Rooftop	Tremaine	280M6	9/10/2014
3184 Sorrento Cres	10	Solar Rooftop	Tremaine	280M6	9/15/2014
4684 Huffman Rd	8	Solar Rooftop	Tremaine	280M6	7/19/2017
4131 Prentice Common	8	Solar Rooftop	Tremaine	280M6	7/28/2017
3138 Jenn Ave	7.815	Solar Rooftop	Tremaine	280M6	8/16/2017
3150 Ferguson Dr	7.6	Solar Rooftop	Tremaine	280M6	10/30/2017
3085 Ferguson Dr.	6	Solar Rooftop	Tremaine	280M6	10/16/2017
4074 Gunby Cres	5	Solar Rooftop	Tremaine	280M6	11/8/2017
3095 Britannia Rd	7.5	Solar Rooftop	Tremaine	280M6	1/12/2018
4060 Thomas Alton Blvd	6	Solar Rooftop	Tremaine	280M6	2/16/2018
4617 Drever Rd	7.6	Solar Rooftop	Tremaine	280M6	4/30/2018
5577 Walkers Line	10	Solar Rooftop	Tremaine	280M6	6/11/2018
2438 Orchard Rd	7.6	Solar Rooftop	Tremaine	280M8	3/30/2017
334 Erindale	7.815	Solar Rooftop	Tremaine	280M8	8/17/2017

2378 Pathfinder Dr	9.9	Solar Rooftop	Tremaine	280M8	11/13/2017
Total	**1,562**				

Table 7 – REG Applications Awaiting Connection for Grid Connection under the Net Metering Program

Address	Capacity (kW)	Fuel Source	Station-TS	Feeder	Offer to Connect Sent Date
2451 Britannia Rd	10	Solar	Tremaine	280M6	4/3/2023
3525 Regal Rd	10	Solar	Cumberland	76M25	8/8/2023
1130 Guelph Ln	185	Solar	Burlington	39M1	10/5/2023
2038 Mountain Grove Ave	7.6	Solar	Burlington	39M34	9/27/2023
14-2345 Cotswold Cres	3.875	Solar	Tremaine	280M6	10/13/2023
233 Euston Rd	4.48	Solar	Cumberland	76M28	10/18/2023
2158 Sunnydale Dr	6.4	Solar	Burlington	39M33	11/15/2023
298 Belvenia Rd	6	Solar	Cumberland	76M28	11/15/2023
5602 Thorn Ln	5	Solar	Bronte	13M28	11/15/2023
3360 Cardiff Cres	5.67	Solar	Burlington	39M4	12/13/2023
232 Penn Dr	10	Solar	Cumberland	76M25	3/27/2024
2074 Newell Cres	10	Solar	Tremaine	280M8	1/16/2024
4838 Verdi St	4.48	Solar	Tremaine	280M4	1/24/2024
4644 Erwin Rd	5	Solar	Tremaine	280M3	1/24/2024
2137 Clipper Cres	7.68	Solar	Burlington	39M4	4/24/2024
5117 Oakley Dr	4.8	Solar	Tremaine	280M6	2/6/2024
3181 Centennial Dr	3.84	Solar	Cumberland	76M24	4/10/2024
361 Strathallan Ave	9.6	Solar	Burlington	39M35	2/6/2024
633 Sandcherry Dr	7.38	Solar	Burlington	39M32	3/19/2024
5328 Mericourt Rd	10	Solar	Bronte	13M26	7/15/2024
2110 Dalecroft Cres	7.6	Solar	Tremaine	280M4	4/11/2024
3288 Old Coach Rd	6	Solar	Cumberland	76M25	5/29/2024
3188 Nixon Gate	7.6	Solar	Tremaine	280M4	6/5/2024
2115 Headon Rd	8.1	Solar	Burlington	39M4	6/5/2024
2338 Gillingham Dr	9.5	Solar	Tremaine	280M6	6/5/2024
6423 Chelsea Rd	10	Solar	Tremaine	280M6	7/30/2024
3232 Palmer Dr	5.12	Solar	Tremaine	280M3	7/11/2024

5663 Roseville Crt	9.43	Solar	Tremaine	280M8	7/15/2024
3277 Star Ln	10	Solar	Burlington	39M4	7/15/2024
258 Walkers Ln	10	Solar	Cumberland	76M27	7/30/2024
2348 Brinell Ave	6	Solar	Cumberland	76M22	9/5/2024
627 Sandcherry Dr	10	Solar	Burlington	39M32	9/5/2024
Total	**416**				

The number of REG connections over the five-year historical period is shown in Table 8. Approximately 65 new net-metering services have been installed in the 2019-2023 historical period. Hence, BHI forecasts that the connection of new Net Metering services will be similar to historical levels over the 2026-2030 forecast period.

Table 8 – Connections for Services over the Historical Period (2019-2023)

Service	**2019**	**2020**	**2021**	**2022**	**2023**
	Count (#)	**Count (#)**	**Count (#)**	**Count (#)**	**Count (#)**
Micro-FIT	0	0	0	0	0
FIT	0	0	0	0	0
Net Metering - Solar	6	4	6	21	28

BHI has produced a five-year forecast of future REG connections >10kW. For the 2026-2030 period, projections have been based on:

- local economic and population data
- macro-economic conditions
- awareness of information from IESO and OEB regarding connection rates and programs
- historical uptake and connection frequency

Based on those factors, the five-year forecast in Table below has been established with an anticipated connection of one 250 kW generator every second year for a total connection of 1.85 MW over the next five years.

Table 9: Forecast REG for 2026-2030

Year	**Projected # of Connections**	**Installed MW**
2026	2	0.4
2027	2	0.4
2028	2	0.4
2029	2	0.4
2030	2	0.5
2026-2030 Totals	**10**	**2.1**

5 SYSTEM ASSESSMENT TO IDENTIFY CONSTRAINTS

BHI has analyzed its circuits for REG connectivity and calculated available capacity for REG connection on each feeder (refer to Table 3).
BHI was not able to connect any new generation to the Palermo TS until October 2024.- BHI has recently received approval from HONI to connect a limited capacity of DERs to feeders A4M5 and A4M6. BHI is working on the application to HONI to establish the allocated capacity & short circuit for BHI Feeders. Based on these evaluations, and considering the sum of both connections and applications, none of BHI's distribution feeders have been identified as having reached the allocated threshold capacity for distributed generation connectivity.

5.1 FUTURE GROWTH AND ITS IMPACT ON REG CONNECTIVITY

The projected modest increase in its customer base in the following years has required BHI to expand and/or upgrade several circuits in its long-term capital plan to meets new load requirements (i.e., system expansions done in the Downtown area and future system expansions required in the major rtransit station areas). This infrastructure investment will further enhance REG connectivity, thus enabling more BHI customers to participate in the Net-Metering program.

6 PROPOSED INVESTMENTS TO FACILITATE NEW CONNECTIONS

At the moment, BHI does not plan to have any significant investment to facilitate new connections based on current allocated capacity and trends on the number of applications.

Appendix H

IESO Comment Letter

IESO response to Burlington Hydro Inc REG Investments Plan 2026-2030

As part of the OEB's Filing Requirements for Electricity Distribution Rate Applications, a distributor must submit a letter of comment from the Independent Electricity System Operator (IESO) on its Renewable Energy Generation (REG) Integration Plan, which is part of its Distribution System Plan. On October 28, 2024, Burlington Hydro Inc. (BHI) sent its REG Integration Plan (the "Plan") to the IESO for comment. The IESO has reviewed Burlington Hydro's Plan and reports that it contains no investments specific to connecting REG over 2026 to 2030.

The IESO notes that BHI's service territory falls within two Regional Planning regions:

- Burlington to Nanticoke (specifically the Bronte sub-region), and
- GTA West.

The IESO published the Burlington to Nanticoke Scoping Assessment on November 3, 2022,[1] which concluded that no further coordinated regional planning was required for the Bronte sub-region. The IESO also published the GTA West Scoping Assessment on November 28, 2024[2], which recommended an IRRP be undertaken for the region. The IRRP is currently ongoing, and BHI is a member of the Technical Working Group.

On Page 19 of its Plan, under the heading Proposed Investments to Facilitate New Connections, BHI states that "At the moment, BHI does not plan to have any significant investment to facilitate new connections based on current allocated capacity and trends on the number of applications".

As BHI has determined it requires no system investments to connect REG over the 2026-2030 Plan period, the IESO submits that no comment letter from the IESO is required to address the REG requirements in the OEB's Filing Requirements for Electricity Distribution Rate Applications – Chapter 5, Section 5.2.2 Coordinated Planning with Third Parties.[3]

The IESO appreciates the opportunity provided to review the REG Integration Plan of BHI and looks forward to working together in further regional planning processes.

[1] IESO's 2022 Burlington to Nanticoke Scoping Assessment Outcome Report

[2] IESO's 2024 GTA West Scoping Assessment Outcome Report

[3] OEB's Filing Requirements for Electricity Distribution Rate Applications - Chapter 5, Section 5.2.2, page 10.

Appendix I

2024 Asset Condition Assessment

Burlington Hydro Inc.

Asset Condition Assessment

Burlington, Ontario

Technical Report

ACA Report

May 17th, 2024

FINAL

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Client Project No.: 7964001

Asset Condition Assessment
Technical Report
ACA Report

2024-10-28
FINAL

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RCC	Draft issued for review	2024-05-16
RDD	Final Draft Issued	2024-05-17

Executive Summary

Context of the Study

Burlington Hydro Inc. ("BHI") is an electricity distributor serving approximately 69,000 customers in the City of Burlington. BHI engaged BBA E&C Inc. ("BBA"), formerly METSCO Energy Solutions Inc., to prepare a comprehensive Asset Condition Assessment ("ACA") study for the major assets comprising BHI's distribution system. The ACA is one of the key inputs in the preparation of BHI's five-year Distribution System Plan ("DSP"), developed in accordance with the filing requirements enacted by the Ontario Energy Board ("OEB").

Scope of the Study

BBA's work included consultations with BHI subject matter experts to define the Health Indices ("HI") appropriate for the asset types, review and consolidation of the client's data sets, analysis of BHI's asset records to calculate the HI values, and preparation of the final document. In total, BBA assessed the following asset classes:

- Distribution wood poles;
- Distribution concrete poles;
- Distribution steel poles;
- Overhead primary conductors;
- Underground primary cables;
- Pole-mount distribution transformers;
- Underground distribution transformers (pad-mount, submersible, and vault);
- Distribution switchgear (pad-mount, submersible, and vault);
- Overhead switches (fused cutouts, load-break, and air-break switches);
- SCADA switches;
- Overhead line reclosers (e.g. IntelliRupter);
- Station power transformers;
- Station medium-voltage circuit breakers;
- Station feeder egress cables;
- Station battery banks;
- Station battery chargers;
- Station primary switchgears;
- Station protection relays; and
- Station buildings.

All data used in the study is maintained by BHI as part of its regular asset management practices and was collected by BHI or its contractors in compliance with Distribution System Code requirements. Data used in this study are valid as of April 2024.

Methodology and Findings

For all asset classes that underwent assessment, BBA used a consistent scale of asset health from "Very Good" to "Very Poor". The numerical HI corresponding to each condition category serves as an indicator of an asset's remaining life, expressed as a percentage. Table 0-1 presents the HI ranges corresponding to each condition score, along with their corresponding implications as to the follow-up actions recommended for the asset management team at BHI.

Table 0-1: Health Index Ranges and Corresponding Implications for the Asset Condition

Health Index Score (%)	Condition	Description	Implications
[85-100]	Very Good	Some evidence of aging or minor deterioration of a limited number of components	Normal or no maintenance
[70-85)	Good	Significant Deterioration of some components	Normal or no maintenance
[50-70)	Fair	Widespread significant deterioration or serious deterioration of specific components	Increase diagnostic testing; possible remedial work or replacement needed depending on the unit's criticality
[30-50)	Poor	Widespread serious deterioration	Start the planning process to replace or rehabilitate, considering the risk and consequences of failure
[0-30)	Very Poor	Extensive serious deterioration	The asset has reached its end-of-life; immediately assess risk and replace or refurbish based on assessment

Using this scale, BBA calculated Health Indices for every asset class in the scope of its assessment using a selected HI model. The HI for each asset class is made up of available and relevant "Degradation Factors" – individual characteristics of the state of an asset's components – each with its own sub-scale of assessment, and a weighting contribution that represents the percentage in the overall HI made up by the parameter. BBA's findings for each asset class were developed using this methodology, as described in more detail in Section 4. The consolidated results of the ACA are summarized in Figure 0-1.

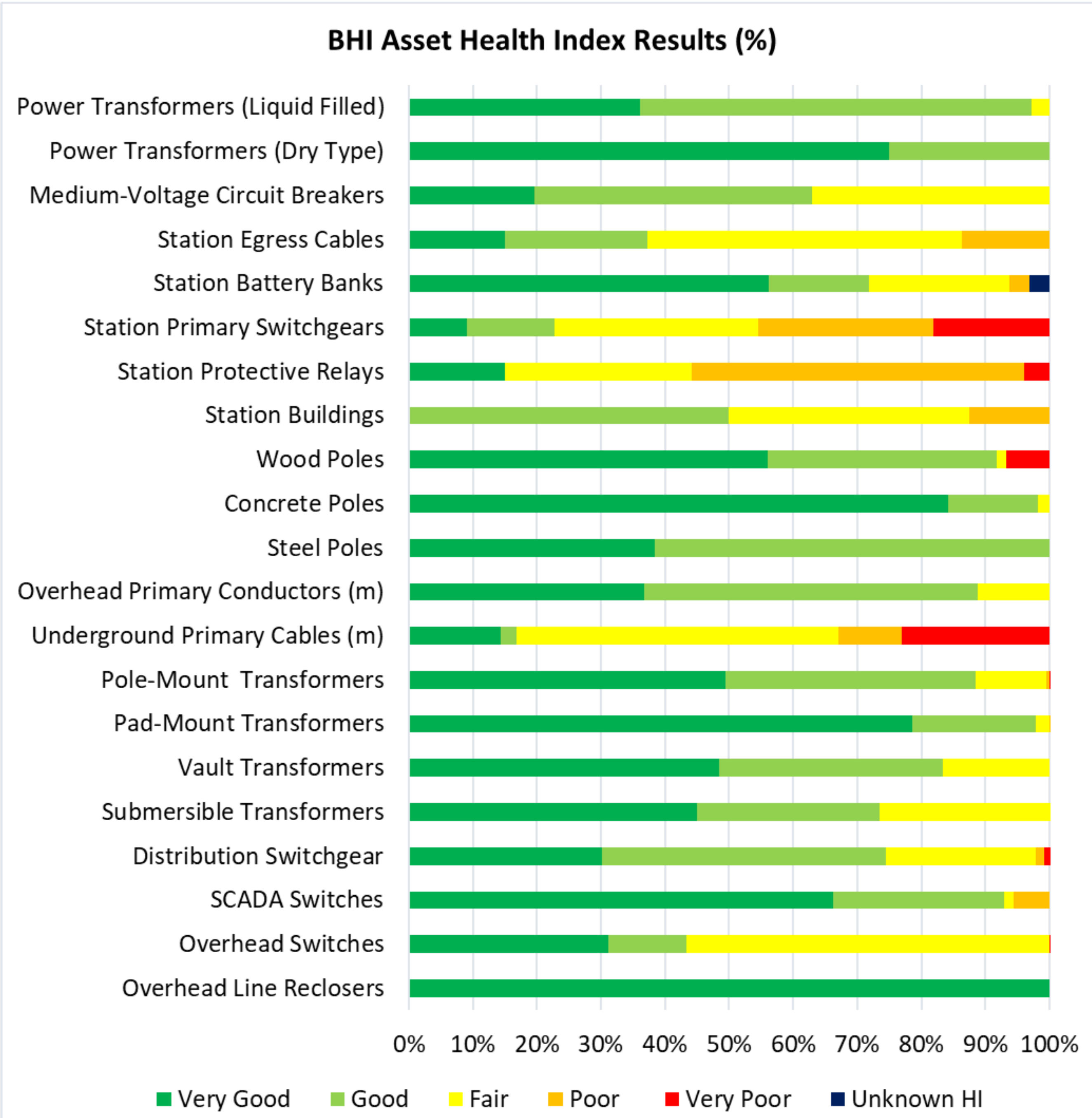

Figure 0-1: Health Index Results

As the figure above indicates, the majority of BHI's distribution system is in "Fair" or better condition. Several asset classes contain units found to be in "Poor" and "Very Poor" condition – most notably primary station switchgear and underground primary cables. For station chargers, only service age data was available, therefore it was not possible to develop a HI formulation. As such, the HI results for Chargers are not presented in the figure above or Table 0-2.

Table 0-2 on the following page presents the numerical HI summary for each asset class. For each asset class, the following details are listed: total population, average Data Availability Index ("DAI"), and the HI distribution. A DAI is a percentage of Degradation Factor data available for an asset or asset class, weighted by their contributions to the HI formulation. A DAI of 100% for an asset indicates that all data is available. As discussed in Section 2.3, if the DAI for an asset is less than 70%, a valid HI cannot be calculated.

Table 0-2: Asset Condition Assessment Overall Results

Asset Category	Population	HI Distribution (%)						Average DAI
		Very Good	Good	Fair	Poor	Very Poor	Unknown HI	
Station Assets								
Power Transformers (Liquid Filled)	36	36%	61%	3%	0%	0%	0%	100%
Power Transformers (Dry Type)	8	75%	25%	0%	0%	0%	0%	100%
Medium-Voltage Circuit Breakers	132	20%	43%	37%	0%	0%	0%	99%
Station Egress Cables	23	15%	22%	49%	14%	0%	0%	95%
Station Battery Banks	32	56%	16%	22%	3%	0%	3%	84%
Station Primary Switchgears	44	9%	14%	32%	27%	18%	0%	86%
Station Protective Relays	127	15%	0%	29%	52%	4%	0%	100%
Station Buildings	32	0%	50%	38%	13%	0%	0%	100%
Distribution Assets								
Wood Poles	15037	56%	36%	2%	0%	7%	0%	91%
Concrete Poles	227	84%	14%	2%	0%	0%	0%	97%
Steel Poles	26	38%	62%	0%	0%	0%	0%	98%
Overhead Primary Voltage Conductors (m)	830146	37%	52%	11%	0%	0%	0%	100%
Underground Primary Voltage Cables (m)	686319	14%	3%	50%	10%	23%	0%	98%
Pole-Mount Transformers	3179	50%	39%	11%	1%	0%	0%	98%
Pad-Mount Transformers	4066	79%	19%	2%	0%	0%	0%	99%
Vault Transformers	66	48%	35%	17%	0%	0%	0%	100%
Submersible Transformers	768	45%	29%	27%	0%	0%	0%	99%
Distribution Switchgear	239	30%	44%	23%	1%	1%	0%	81%
SCADA Switches	71	66%	27%	1%	6%	0%	0%	100%
Overhead Switches	4049	31%	12%	57%	0%	0%	0%	99%
Overhead Line Reclosers	14	100%	0%	0%	0%	0%	0%	100%

BHI's Current Health Index Maturity and Continuous Improvement

Overall, BHI's asset data collection practices are sufficiently robust to enable calculation of recommended ACA that is consistent with industry best practices. BHI has made notable improvements in the availability and quality of data since its previous ACA study, further detailed in Section 3.1. Section 5 of this report identifies further opportunity for HI and data availability improvements.

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LIST OF ACRONYMS

Acronym	Description
ACA	Asset Condition Assessment
AM	Asset Management
BBA	BBA E&C Inc.
BHI	Burlington Hydro Inc.
DAI	Data Availability Index
DGA	Dissolved Gas Analysis
EOL	End of Life
GIS	Geographic Information System
HI	Health Index
IR	Infrared
ISO	International Organization for Standardization
PD	Partial Discharge
SAMPs	Strategic Asset Management Plans
TD	Tan-Delta
TDR	Time Domain Reflectometry
VLF	Very-Low Frequency

1. Introduction

This report summarizes the results of an Asset Condition Assessment ("ACA") carried out by BBA E&C Inc. ("BBA"), formerly METSCO Energy Solutions Inc., on behalf of Burlington Hydro Inc. ("BHI"). BBA is an industry expert in ACA and Asset Management ("AM") practices, with extensive experience conducting ACAs, developing AM plans, and implementing AM frameworks for organizations across North America. BBA's collective record of experience in these areas is among the most extensive in the world, with our AM frameworks gaining acceptance across multiple regulatory jurisdictions.

BHI is an electricity distributor operating in the City of Burlington, serving approximately 69,000 customers. BHI owns and operates 32 substations at various distribution voltages (27.6kV, 13.8kV, and 4.16kV) within its service territory. BHI does not own any Transmission stations, as its distribution system assets are fed from Hydro One owned Transmission Stations. BHI engaged BBA to prepare a comprehensive Asset Condition Assessment ("ACA") study for the major assets comprising BHI's distribution system. The ACA is one of the key inputs in the preparation of BHI's five-year Distribution System Plan ("DSP"), developed in accordance with the filing requirements enacted by the Ontario Energy Board ("OEB").

To assist BHI with further asset condition data integration efforts, Section 5 of this report contains a set of recommendations for the utility's management to consider going forward.

The asset classes covered in the report include the following:

- Distribution assets:
  - Wood poles;
  - Concrete poles;
  - Steel poles;
  - Overhead conductors;
  - Underground cables;
  - Pole-mount distribution transformers;
  - Pad-mount distribution transformers;
  - Vault distribution transformers;
  - Submersible distribution transformers;
  - Distribution switchgear;

  - Overhead switches;
  - SCADA switches; and
  - Overhead line reclosers (e.g. IntelliRupter).

- Station Assets
  - Power transformers;
  - Medium-voltage circuit breakers;
  - Egress cables;
  - Battery banks;
  - Battery Chargers;
  - Primary switchgear;
  - Protection relays; and
  - Station buildings.

2. Asset Condition Assessment Methodology

2.1 Degradation Factors

To determine the overall HI for an asset, formulations are developed based on "Degradation Factors" that can be expected to contribute to the degradation and eventual failure of that asset. A weight is assigned to each Degradation Factor to indicate the amount of influence the condition has on the overall health of the asset. Figure 2-1 provides an example of an HI formulation table.

Figure 2-1: HI Formulation Components

Degradation Factor:
The asset aging mechanisms, tests, or failure modes.

Condition Indicator Numerical Score:
The converted numerical score associated with the degradation factor, which corresponds directly with the indicator letter score.

Condition Max Score:
The highest obtainable Score for each degradation factor. (4 x Weight)

#	Degradation Factor	Weight	Condition Indicator Letter Score	Condition Indicator Numerical Score	Condition Max Score
1	Degradation Factor 1	4	A-E	4-0	16
2	Degradation Factor 2	6	A,C,E	4,2,0	24
3	Degradation Factor 3	6	A-E	4-0	24
				Asset Max Score	64

Condition Weight:
The impact of the condition with respect to asset failure and/or the safe operation of the asset. Higher impact results in higher weight

Condition Indicator Letter Score:
The letter grade associated with the degradation factor – this is typically captured from the raw inspection data.

Asset Max Score:
The highest numerical grade that can be assigned to the asset / asset class, given the associated degradation factors and weights.

Degradation Factors of the asset are characteristic properties that are used to derive the overall HI. They are specific and uniquely graded to each asset class. Additionally, some Degradation Factors can be comprised of "Sub-Degradation Factors". For example, the Degradation Factor "Oil Quality" for power transformers includes multiple Sub-Degradation Factors: "Interfacial Tension", "Dielectric strength", and "Water Content". In this case, the lowest Sub-Degradation Factor score is used as the score for the Degradation Factor.

The scale used to determine an asset's score for a Degradation Factor is called the "Condition Indicator". Each Degradation Factor is ranked from A to E and each rank corresponds to a numerical grade. In the above example, a Condition Indicator of 4 represents the best grade, whereas a Condition Indicator of 0 represents the worst grade.

The conversion from alphabetic ranking to numerical grade and a brief characteristic description of the grade is provided below:

Table 2-1: HI Score Grading

A – 4	Best Condition
B – 3	Normal Wear
C – 2	Requires Remediation
D – 1	Rapidly Deteriorating
E – 0	Beyond Repair

The final HI, which is a function of the condition scores and weightings, is calculated based on the following formula:

$$HI = \left(\frac{\sum_{i=1} Weight_i * Numerical\ Grade_i}{Total\ Score}\right) x\ 100\% \qquad (1)$$

where *i* corresponds to the Degradation Factor number, and the HI is a percentage representing the remaining life of the asset.

A gating approach is used for Degradation Factors that have a significant influence on the health of an asset. If the Degradation Factor that has been flagged as a gating parameter is below a pre-defined threshold value, the overall HI is reduced by 50%. An example would be the "Remaining Strength" Degradation Factor for the wood pole asset class. If the remaining strength of a wood pole is less than 60%, the final HI for that asset would be divided by two. This approach enables utilities to efficiently flag severely degraded assets through identification of Degradation Factors acknowledged to be critical indicators of overall asset health.

2.2 Health Index Interpretation

BBA's assessment of asset condition uses a consistent five-point scale along the expected degradation path for every asset. To assign each asset into one of the categories, BBA constructs numerical HI for each asset class that captures information on individual Degradation Factors contributing to that asset's declining condition over time. Condition Indicators assigned to each Degradation Factor are expressed as numerical or letter grades along with pre-defined scales. The final HI – expressed as a value between 0% and 100% - is a weighted sum of scores of individual Condition Indicators, with each of the five condition categories ("Very Good", "Good", "Fair", "Poor", "Very Poor") corresponding to a numerical band that are roughly equivalent to the percentage of remaining useful life for the given asset. For example, the condition score of Very Good indicates assets with HI between 100% and 85%, whereas the condition score of Very Poor indicates assets with calculated HI between 0% and 30%. Generating an HI provides a succinct measure of the long-term health of an asset. Table 2-2 presents the HI ranges with the corresponding asset condition, its description as well as implications for maintaining, refurbishing, or replacing the asset prior to failure.

Table 2-2: HI Ranges and Corresponding Asset Condition

Health Index Score (%)	Condition	Description	Implications
[85-100]	Very Good	Some evidence of aging or minor deterioration of a limited number of components	Normal or no maintenance
[70-85)	Good	Significant Deterioration of some components	Normal or no maintenance
[50-70)	Fair	Widespread significant deterioration or serious deterioration of specific components	Increase diagnostic testing; possible remedial work or replacement needed depending on the unit's criticality
[30-50)	Poor	Widespread serious deterioration	Start the planning process to replace or rehabilitate, considering the risk and consequences of failure
[0-30)	Very Poor	Extensive serious deterioration	The asset has reached its end-of-life; immediately assess risk and replace or refurbish based on assessment

2.3 Data Availability

BBA supplemented its HI findings with the calculation of a Data Availability Index ("DAI"), which is a measure of the availability of Degradation Factor data for a specific asset scaled by their weights in the HI formulation. The DAI is determined by comparing the sum of the weights of the Degradation Factors available to the total weight of the Degradation Factors used to construct the HI for an asset class. The formula is given by:

$$DAI = \left(\frac{\sum_{i=1} Weight_i * \alpha_i}{\sum_{i=1} Weight_i}\right) x\ 100\% \qquad (2)$$

where *i* corresponds to the Degradation Factor number and *a* is the availability of coefficient (*a* =1 when datum is available *a* =0 when datum is unavailable).

An asset with all Degradation Factor data available will have a DAI value of 100%, independent of the asset's HI score. Assets with a high DAI will correlate to HI scores that describe the asset condition with a high degree of confidence. In the case where the DAI for an asset is less than 70%, a valid HI cannot be calculated. Assets without a valid HI were extrapolated based on the known HI within the same ten-year age bands to estimate the distribution of health across the entire asset class. In cases where both age is unknown and the HI is invalid, the extrapolation is done based on the full set of assets with known HI scores instead of using ten-year age bands.

2.4 Project execution

The HI formulations calculated in this study are based only on available data provided by BHI. BBA's execution path in completing the ACA study can be separated into four phases described below:

1. *Initial Information Gathering* – including initial interviews with BHI staff to investigate system configuration and the prominence of certain asset classes, establish the range of available condition data sources at the beginning of the engagement, and confirm the key assumptions regarding these factors with BHI subject matter experts through a series of interviews.

2. *Database Construction* – activities to construct a database of condition-related information for each BHI asset amongst the in-scope asset classes using the provided data sources. This includes consolidation of BHI's asset inspection and maintenance records, databases containing results of technical tests performed by BHI and its contractors, and the entire database from the Geographic Information System ("GIS").

3. *HI and DAI Calculation* – upon confirming the integrity of its condition dataset along with the accuracy of assumptions made in its preparation, BBA calculated the Health Indices and DAI for all asset classes. Additional data sources were requested from BHI to improve the accuracy of the asset health calculation, where applicable.
4. *Results Reporting* – the final phase of the project scope was the creation of the ACA report.

3. Input Data

To assess the demographics and establish the unit population of BHI's distribution system assets, BBA was provided with BHI's asset demographics from their current Geographic Information System ("GIS"), asset inspection and maintenance records, test records stored in a Microsoft Access database, and PDF copies of test reports. Historical records for the assets were dated to complete a full lifecycle of the asset population. This means that if an asset class has an inspection lifecycle of three years, BHI provided BBA with three years of historical data covering the entirety of the service territory to have a complete set of available data. This dataset contained the last calculated degradation score for a particular asset as well as the most recent test results which were translated to a score and ultimately a HI. Most of this data came from sources such as equipment inspection forms completed by BHI staff or contractors or results of specific technical tests such as Dissolved Gas Analysis ("DGA") of transformer oil.

Additionally, BBA was provided with historical operating data for assets that required operating information for the HI calculation. Examples of operating data used include historical loading information for transformers and counter readings for overhead line reclosers.

3.1 Continuous Improvement

Since the 2019 ACA study, BHI has refined its data collection and management. As such, the asset population counts have become more accurate over time and the HI methodology has been updated to be more comprehensive for several asset classes. These improvements include:

- Including more specific visual condition data parameters and electrical test results for station power transformers;
- Including cell voltage test results and compartment visual condition for station battery banks;
- Including obsolescence for station relays;
- Including service age for station buildings;
- Including pole treatment degradation parameter for distribution wood poles and a more accurate asset population count;
- Including condition of civil structure/pad and oil leaks for underground distribution transformers;
- Including condition of terminations for distribution switchgears; and
- Adjusting the weighting of various degradation parameters across several asset classes to better align with current industry best practices.

The application of rigorous AM processes can provide several benefits to an organization including, but not limited to: realized financial savings; better classified and managed risk among assets; better-informed investment decisions; demonstrated compliance to standards and mandates among the asset base; increased public and worker safety; as well as working towards corporate reliability targets.

AM processes are ideally integrated throughout the entire organization. This requires a well-documented AM framework that is shared between all relevant stakeholders. In this way, the organization stands to benefit the most from its internal resources, whether it be via technical expertise, those operating and maintaining the assets or those with an understanding of the financial operations and constraints on the organization. As a future-state goal, utilities and other organizations alike should strive to document their AM guiding principles within a Strategic Asset Management Plan ("SAMP"). The SAMP should be used as a guide for the organization to apply its AM principles and practices for its specific use case. Distribution of the SAMP should be well-publicized within an organization and updated on a regular basis, to best quantify the most current and comprehensive AM practices being implemented. Just as the asset base performance is subject to an in-depth review, the AM process and system should be reviewed with the same rigor. [1]

Adopting a framework and an idealized set of practices does not bind the organization or restrict its agency to effectively manage its distribution infrastructure. With time, the goal of any AM system is to continually improve and realize benefits within the organization through better management of its asset portfolio, continuous improvement in the quantity and quality of asset data and data collection procedures , SAMPs, and further integration into all aspects of an organization's activities as it grows and evolves over time.

[1] ISO 55000 – Asset management – Overview, principles and terminology

4. Asset Condition Assessment Results

This section presents the current HI formulation, age assessment, and ACA results for each asset class. The age assessment graphs are presented in the following categories based on the asset class's TUL:

- 0%-33% of TUL
- 34%-66% of TUL
- 67%-99% of TUL
- 100%-133% of TUL
- >133% of TUL

4.1 Distribution Assets

4.1.1 Wood Poles

Wood poles are an integral part of BHI overhead distribution system. They support the majority of overhead distribution lines, overhead transformers, switches, streetlights, all third party attachments as per BHI's Joint Use Agreements, and majority of BHI's underground system. The HI for wood poles is estimated by considering a combination of EOL criteria summarized in Table 4-1.

Table 4-1: Wood Pole HI Algorithm

Degradation Factor	Weight	Ranking	Numerical Grade	Max Score
Service Age	8	A,B,C,D,E	4,3,2,1,0	32
Pole Treatment	2	A,C,E	4,2,0	8
Remaining Strength	16	A,C,E	4,2,0	64
Wood Rot	5	A,E	4,0	20
Out of Plumb	3	A,C,E	4,2,0	12
Defects	2	A,B,C,D,E	4,3,2,1,0	8
Cracks	3	A,B,C,E	4,3,2,0	12
			Total score	156

Wood, being a natural material, has degradation processes that are different from other assets in distribution systems. The most critical degradation process for wood poles involves biological and environmental mechanisms such as fungal decay, wildlife damage, and effects of weather, which can impact the mechanical strength of the pole (Fiber strength). Any loss in the strength of the pole can compromise the integrity of the overhead distribution system and potentially present safety and environmental risks to the public and to BHI. The remaining strength Degradation Factor is a quantitative measurement that provides evidence of the deterioration of the operational health of the asset.

The HI formulation for wood poles is a combination between the additive and gateway model; with the gateway applied to the remaining strength Degradation Factor. When a pole is found to have failed its remaining strength test, the final HI for that pole is reduced by half. A failed remaining strength indicates significant degradation of the pole which can present a risk to safety and the possibility of failure to meet its intended function of holding the overhead line. A pole is considered to have a failed remaining strength when its remaining strength has deteriorated to 60%, after which it should be reinforced or replaced[2].

Additional Degradation Factors include service age, pole treatment, wood rot presence, mechanical defects, cracks and pole lean. A visual inspection record notes the presence of wood rot/decay developed on the pole's external surface. The presence of wood rot signifies there is a high moisture content surrounding the pole and impacts the pole's strength. Additionally, visual inspections note for the following mechanical defects found on wood poles:

- Anchor issues;
- Infrared;
- Crossarms;
- Pole top;
- Riser issues;
- Vegetation;
- Insect damage; and
- Woodpecker damage

[2] *C22.3 No.1-10: Overhead Systems,* Mississauga, Ontario: Canadian Standards Association, 2011, p. 41.

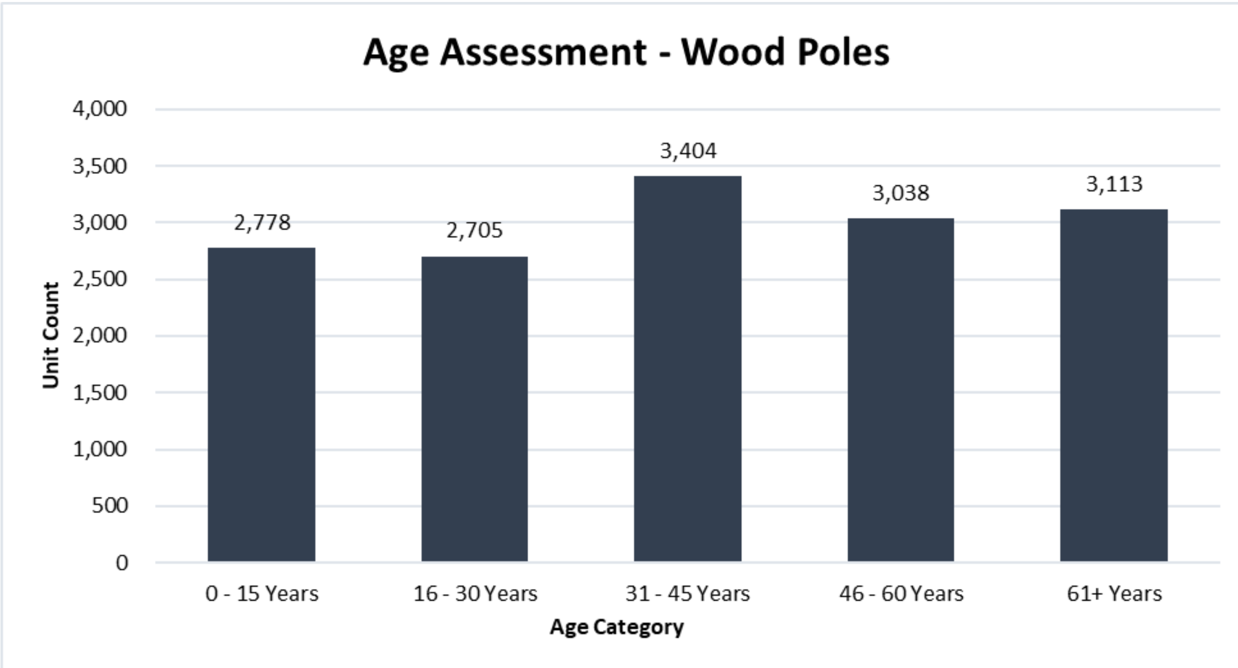
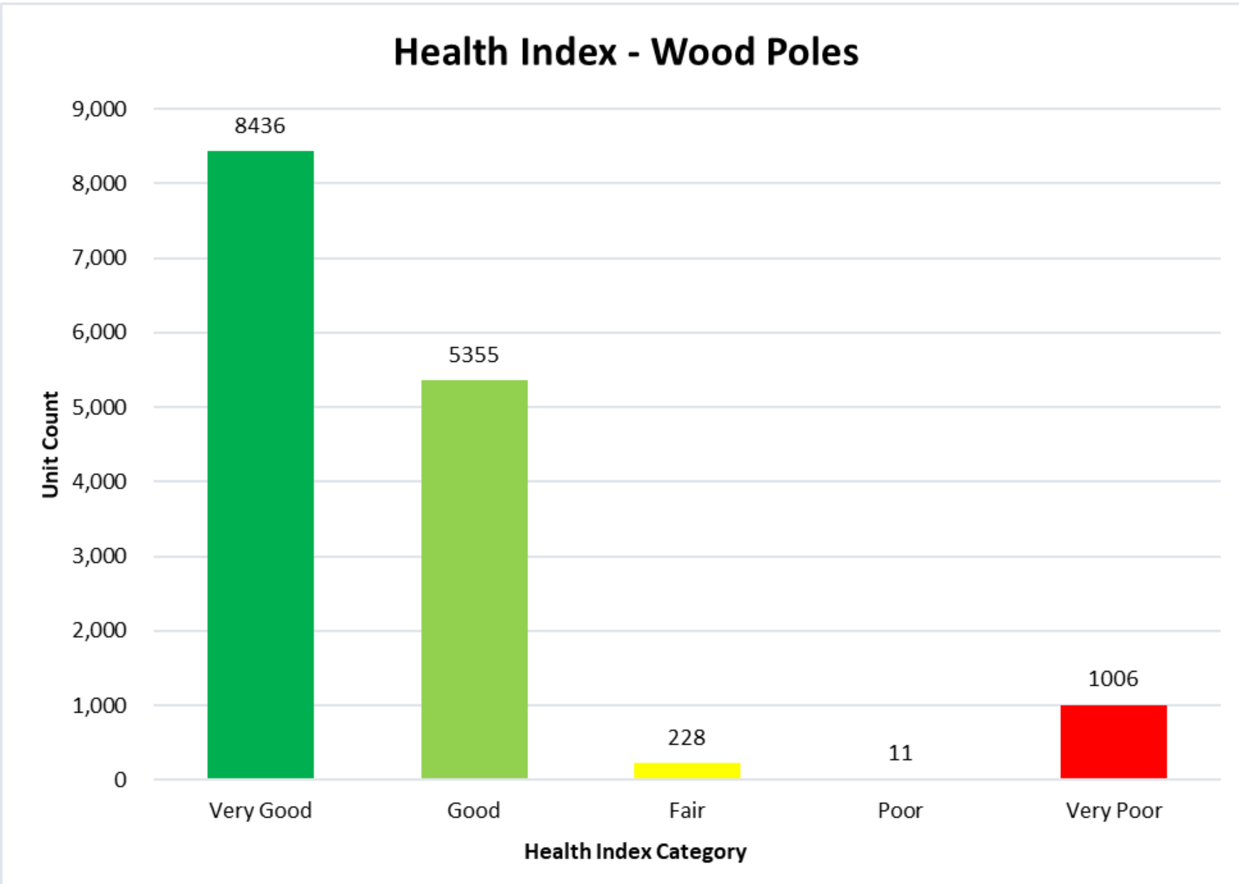


Figure 4-1: Wood Pole Age Demographics

BHI owns 15,037 wood poles within its service territory. Installation date is known for approximately 98% of the total in-service population. The assets with unknown installation dates were extrapolated using the breakdown across the age bands of assets with known ages. These extrapolated results are used to show a general breakdown across different age bands of the population; the extrapolated age results were not used as part of the HI calculation. Figure 4-1 presents the age distribution for in-service wood poles.

Figure 4-2: Wood Pole HI Results



BHI's pole maintenance and nameplate data were used to calculate the HI based on the criteria provided in Table 4-1. Poles are inspected within the 3-year patrolled inspection cycle and to date, BHI has maintained wood pole inspection records for the last fourteen years. A valid HI was calculated for 79% of the wood poles. To complete the full analysis, the HI for the remaining 21% has been extrapolated based on the HI distribution of the asset population with a valid HI score. The overall HI distribution for the wood poles is presented in Figure 4-2. The HI results show 7% of assets in Poor or Very Poor condition, 2% in Fair condition, and the remainder in Good or Very Good condition.

The average DAI for the asset class is 91%. Table 4-2 presents the DAI of individual Degradation Factors used for the wood poles HI framework. Based on BHI's testing program where remaining strength is tested for poles aged 30 or higher, a missing remaining strength score only affects an asset's DAI if the asset is over 30 years old.

Table 4-2: Wood Pole Degradation Factor Data Availability

Degradation Factor	% of Assets with Data
Service Age	98%
Pole Treatment	70%
Remaining Strength	45%
Wood Rot	100%
Out of Plumb	100%
Defects	100%
Cracks	100%

4.1.2 Concrete Poles

Like wood poles, concrete poles support the overhead distribution system. Concrete poles have significantly greater strength than typical wood poles and have a longer service life. However, concrete poles are very heavy and are costlier to transport and install, hence fewer are in-service compared to wood poles. The HI for concrete poles is calculated by considering a combination of EOL criteria summarized in Table 4-3.

Table 4-3: Concrete Pole HI Algorithm

Degradation Factor	Weight	Ranking	Numerical Grade	Max Score
Service Age	3	A,B,C,D,E	4,3,2,1,0	12
Out of Plumb	1	A,C,E	4,2,0	4
Defects	2	A,B,C,D,E	4,3,2,1,0	8
			Total score	24

Degradation Factors include service age, defects, and evidence of leaning for concrete poles. The HI formulation for concrete poles does not contain a quantitative measure of remaining strength as found with the wood poles. Hence, it is more dependent on visual inspection of defects. Visual inspections note for the following defects found on concrete poles:

- Anchor issues;
- Infrared;
- Crossarms;
- Pole top;

- Riser issues
- Vegetation; and
- Cracking.

BHI owns 227 concrete poles within its service territory. Installation date is unknown for approximately 5% of the total in-service population. The assets with unknown installation dates were extrapolated by weight onto the asset population with a recorded installation date to show an approximate representation of the age distribution. Extrapolated age results were not used as part of the HI calculation. Figure 4-3 presents the age distribution for concrete poles.

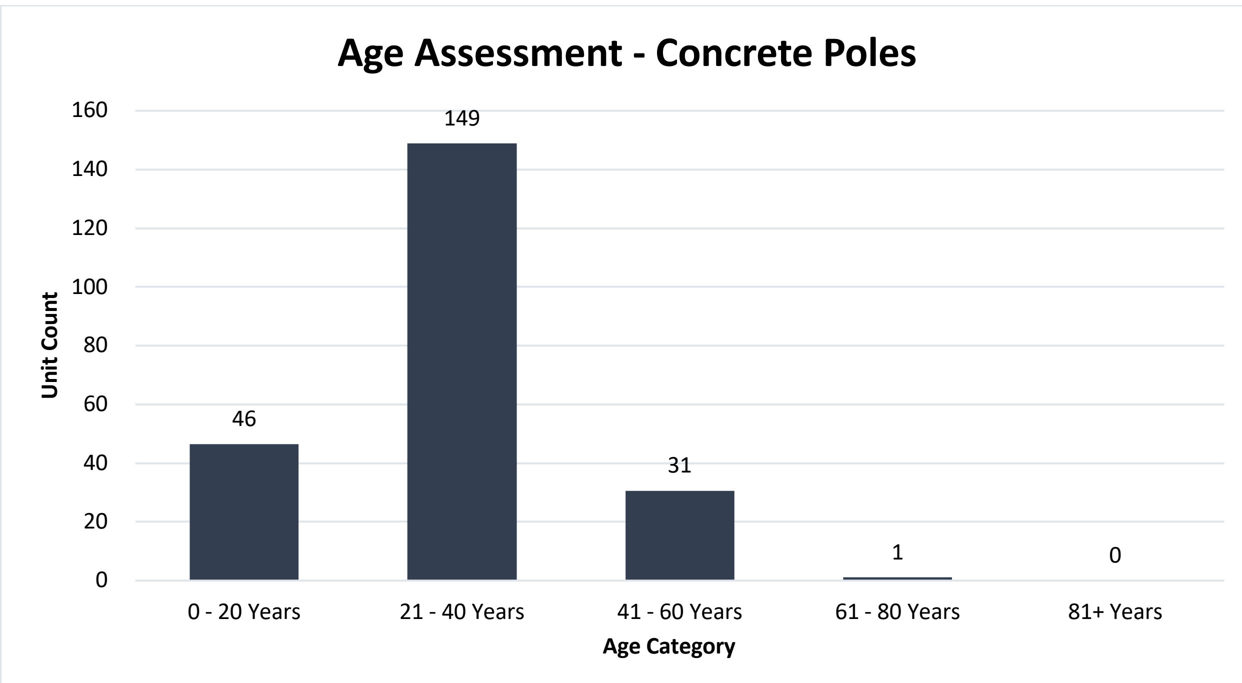


Figure 4-3: Concrete Pole Age Demographics

BHI's maintenance and nameplate information was used to calculate the HI based on the criteria provided in Table 4-3. An estimated 5% of the population does not have a valid HI score. To complete the full analysis, the HI for the remaining 5% has been extrapolated based on the HI distribution of the asset population with a valid HI score. The overall Health Index distribution for the concrete poles is presented in Figure 4-4. Around 2% of concrete poles are in Fair condition, and the remainder are in Good or Very Good condition.

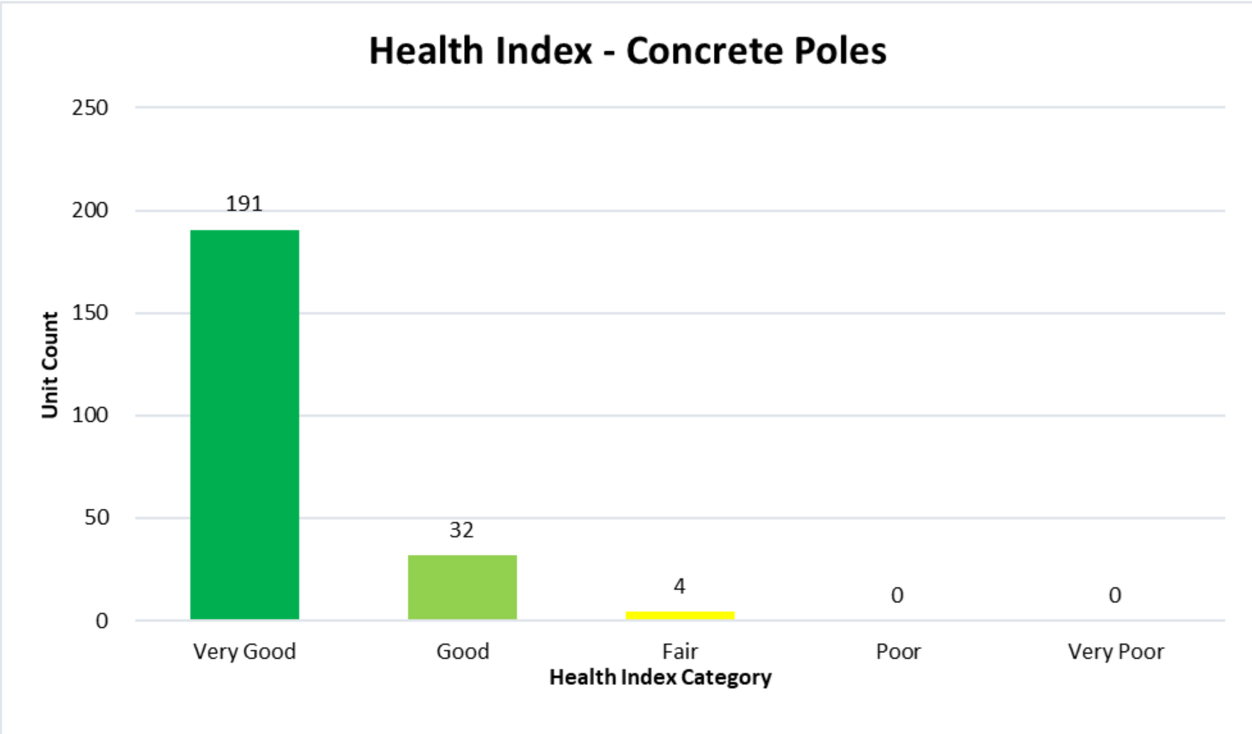


Figure 4-4: Concrete Pole HI Results

The average DAI for the asset class is 97%. Table 4-4 presents the DAI of individual Degradation Factors used for the concrete poles HI framework.

Table 4-4: Concrete Pole Degradation Factor Data Availability

Degradation Factor	% of Assets with Data
Service Age	95%
Out of Plumb	100%
Defects	100%

4.1.3 Steel Poles

Steel poles are similar to concrete poles in terms of their increased strength, lifespan, weight, and cost compared to wood poles. The HI for steel poles is calculated by considering a combination of EOL criteria summarized in Table 4-5.

Table 4-5: Steel Pole HI Algorithm

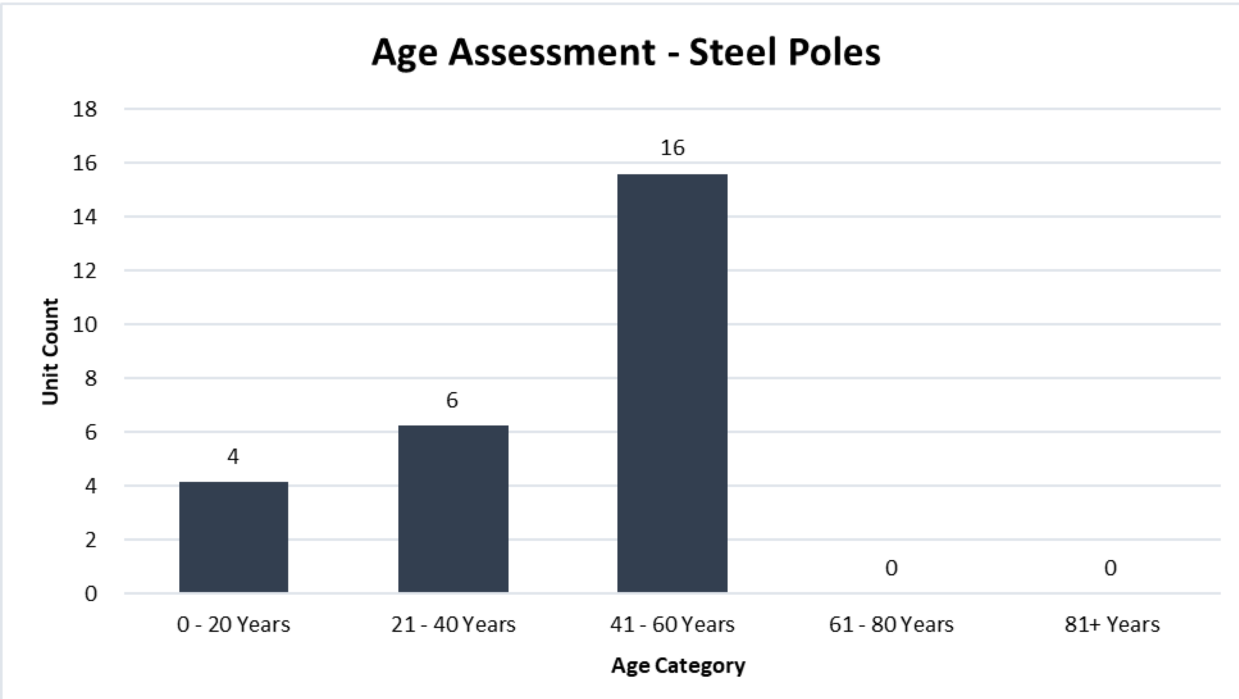
Degradation Factor	Weight	Ranking	Numerical Grade	Max Score
Service Age	3	A,B,C,D,E	4,3,2,1,0	12
Out of Plumb	1	A,C,E	4,2,0	4
Defects	2	A,B,C,D,E	4,3,2,1,0	8
			Total score	24

Each Degradation Factor represents a factor critical in determining the asset's condition relative to a potential failure to occur. Aside from service age, Degradation Factors include defects, and evidence of leaning for steel poles. The HI formulation for steel poles does not contain a quantitative measure of remaining strength as found with the wood poles. Hence, it is more dependent on visual inspection of defects. All the Degradation Factors have similar weightings. Visual inspections note for the following defects found on steel poles:

- Anchor issues;
- Infrared;
- Crossarms;
- Pole top;
- Riser issues; and
- Vegetation.

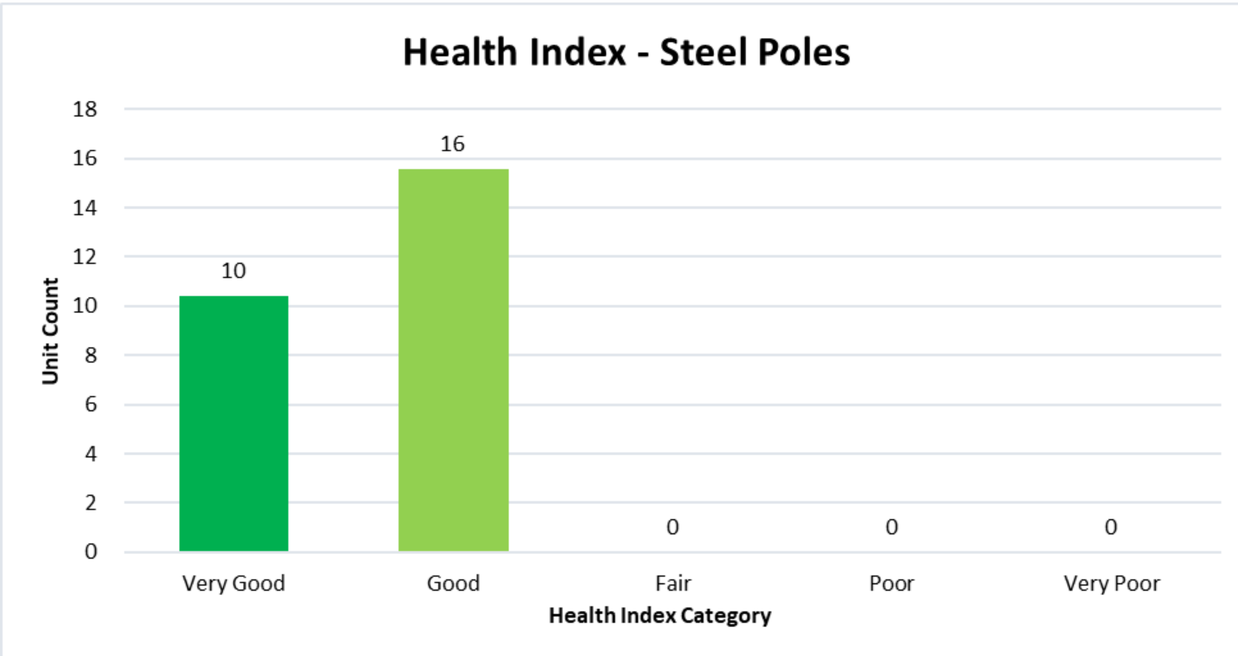
BHI owns 26 steel poles within its service territory. Installation date is unknown for one steel pole (approximately 4% of the total in-service population). The pole with an unknown installation date was extrapolated by weight onto the asset population with a recorded installation date to show an approximate representation of the age distribution. Extrapolated age results were not used as part of the HI calculation. Figure 4-5 presents the age distribution for steel poles.

Figure 4-5: Steel Pole Age Demographics



BHI's maintenance and nameplate information was used to calculate the HI based on the criteria provided in Table 4-5. An estimated 4% of the population does not have a valid HI score. To complete the full analysis, the HI for the remaining 4% has been extrapolated based on the HI distribution of the asset population with a valid HI score. The overall HI distribution for steel poles is presented in Figure 4-6. All the poles are in either Very Good or Good condition.

Figure 4-6: Steel Pole HI Results



The average DAI for the asset class is 98%. Table 4-6 presents the DAI of individual Degradation Factors used for the steel poles HI framework.

Table 4-6: Steel Pole Degradation Factors Data Availability

Degradation Factor	% of Assets with Data (conductor length)
Service Age	96%
Out of Plumb	100%
Defects	100%

4.1.4 Overhead Primary Voltage Conductors

Overhead primary voltage conductors distribute electricity from TS to customers and substations, and from substations to customer premises. They are supported by wood, concrete, or steel poles. The HI formulation for overhead primary conductors is summarized in Table 4-7. Although laboratory tests are available to determine the tensile strength and assess the remaining useful life of conductors, distribution line conductors rarely require testing. An appropriate proxy for the tensile strength of the conductor and to determine the remaining life of the asset is the use of service age. In addition to age, an undersized conductor presents a greater risk of failure. Undersized conductors carrying large loads can result in sub-optimal system operation due to high line losses and are susceptible to frequent breakdowns.

Table 4-7: Overhead Conductor HI Algorithm

Degradation Factor	Weight	Ranking	Numerical Grade	Max Score
Service Age	1	A,B,C,D,E	4,3,2,1,0	4
Small Conductor Risk	1	A,E	4,0	4
			Total score	8

BHI owns approximately 830 km of overhead primary conductor within its service territory. Where installation date was unknown, the corresponding feeder installation date was used as a proxy. However, age was still unknown for approximately 1% of conductors and was extrapolated by weight onto the asset population with a known age to show an approximate representation of the age distribution. Figure 4-7 presents the total length of overhead primary conductors for each age band. Extrapolated age results were not used as part of the HI calculation. Figure 4-7 presents the overall overhead primary conductor age demographics.

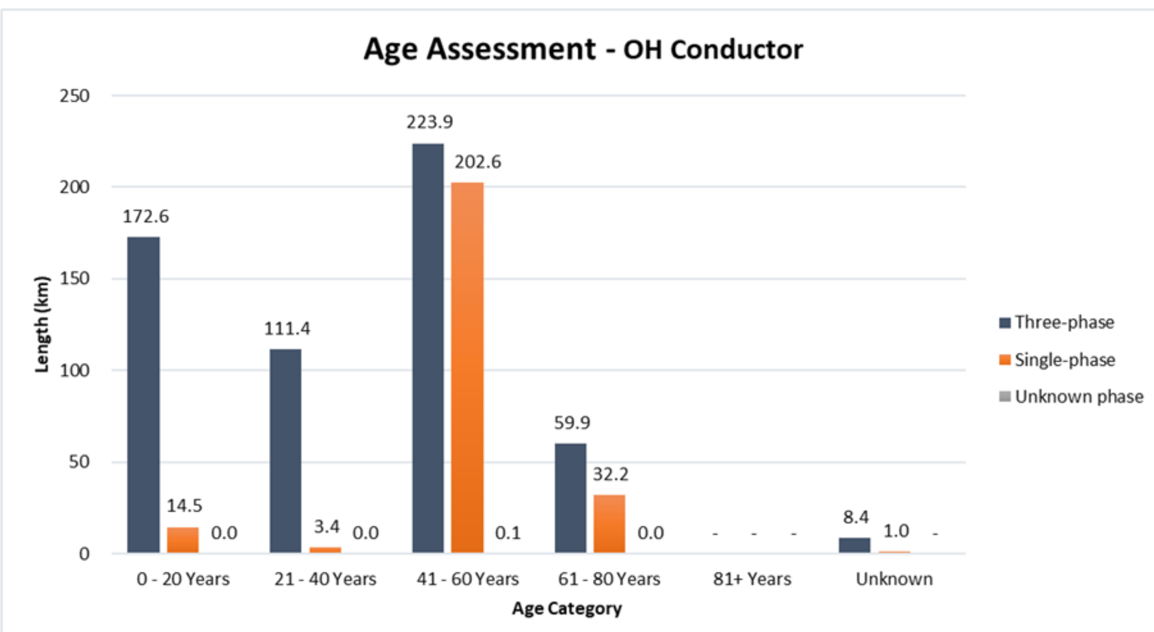


Figure 4-7: Overhead Primary Conductor Age Demographics

The overall HI for overhead primary conductors is illustrated in Figure 4-8. A valid HI was calculated for 99% of the conductors. To complete the full analysis, the HI for the remaining 1% has been extrapolated based on the HI distribution of the asset population with a valid HI score. Most of the primary conductors are in Very Good and Good condition with 11% in Fair condition.

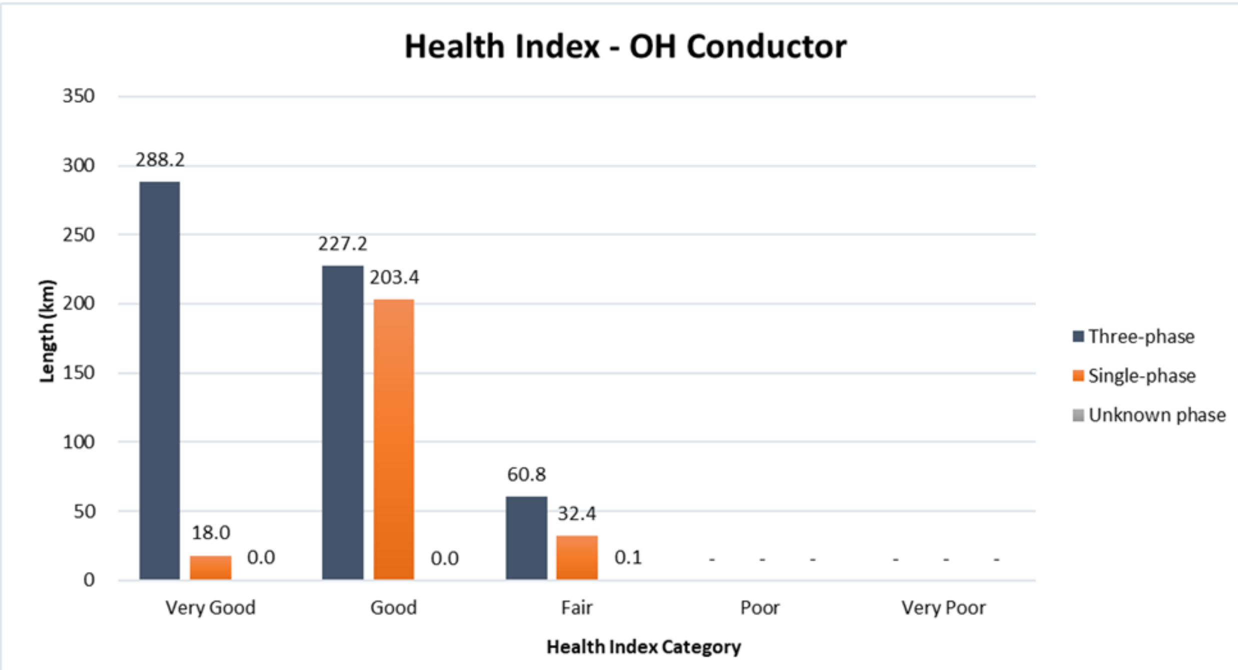


Figure 4-8: Overhead Primary Conductor HI Results

The average DAI for the asset class is ~100%. Table 4-8 presents the DAI of individual Degradation Factors used for the overhead primary conductor HI framework.

Table 4-8: Overhead Conductor Degradation Factor Data Availability

Degradation Factor	% of Assets with Data (conductor length)
Service Age	100%
Small Conductor Risk	100%

4.1.5 Underground Primary Voltage Cables

Like overhead conductors, underground primary voltage cables also distribute electricity along the electrical distribution system; however, they are located below ground. BHI's underground system typically consists of TR-XLPE type cables. Compared to overhead lines, they are much more reliable since they are not exposed to severe weather conditions, tree contacts, or foreign interference. However, distribution underground cables are more expensive and are one of the more challenging assets in electricity systems from a condition assessment and asset management viewpoint. Several test techniques, such as partial discharge ("PD") and water tree diagnostic testing have become available over recent years to identify the condition and performance of the asset class. Some tests can be destructive to the asset and hence are used less frequently. Accordingly, BHI conducts non-destructive testing.

The HI for underground primary cable is calculated by considering the service age and historic failure data. Since the service age provides a reasonably good measure of the remaining life of the asset, it may be employed as an assessment parameter for identifying assets for replacement. Table 4-9 summarizes the methodology to combine these criteria into an overall HI.

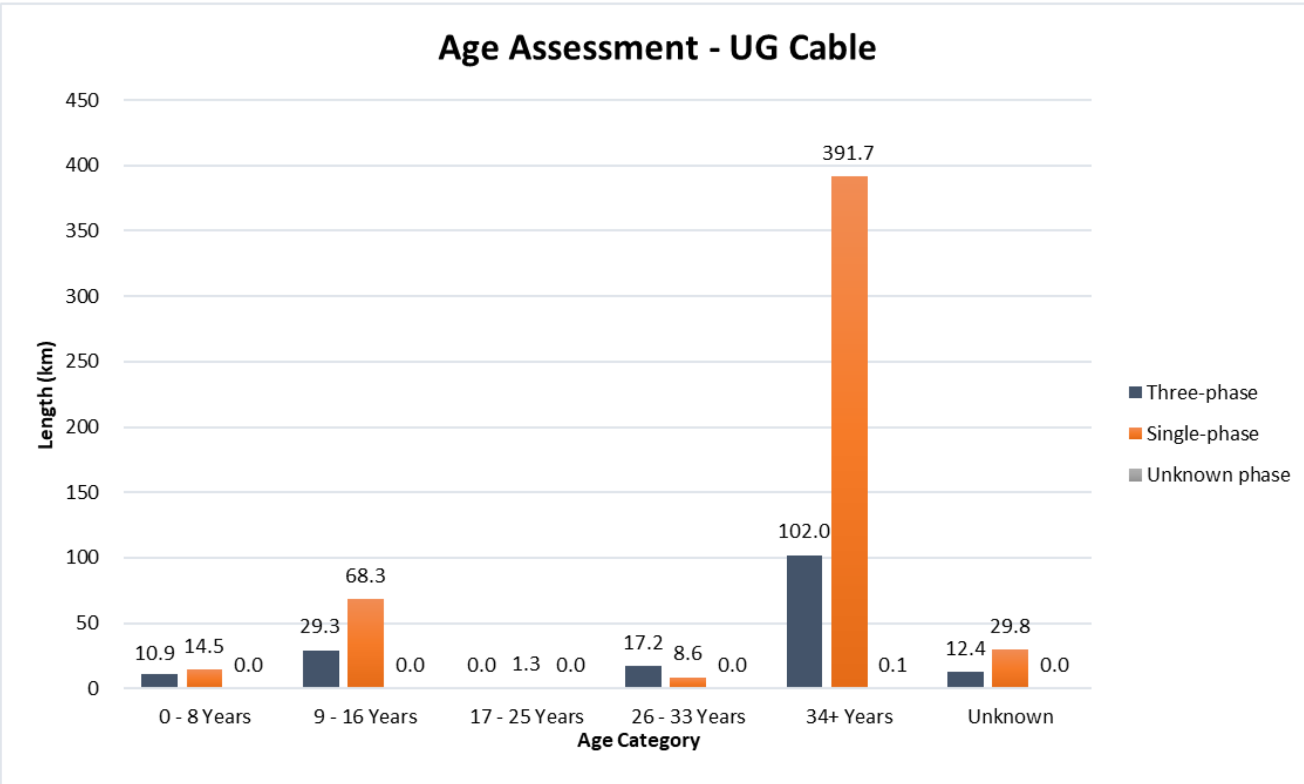
Table 4-9: Underground Cable HI Algorithm

Degradation Factor	Weight	Ranking	Numerical Grade	Max Score
Service Age	1	A,B,C,D,E	4,3,2,1,0	4
Outage Records (6 years)	2	A,B,C,D,E	4,3,2,1,0	8
			Total score	12

Due to the low portion of the underground cable population (approximately 1%) having field testing records, field testing was not incorporated into the asset condition methodology. Instead, cable field testing records should be considered when BHI evaluates underground rebuild and cable replacement projects. These test results can be used to verify and prioritize which cable sections require replacement. Additionally, the relative weights of service age and outage records have been updated since the 2019 ACA study to reflect current industry best practices.

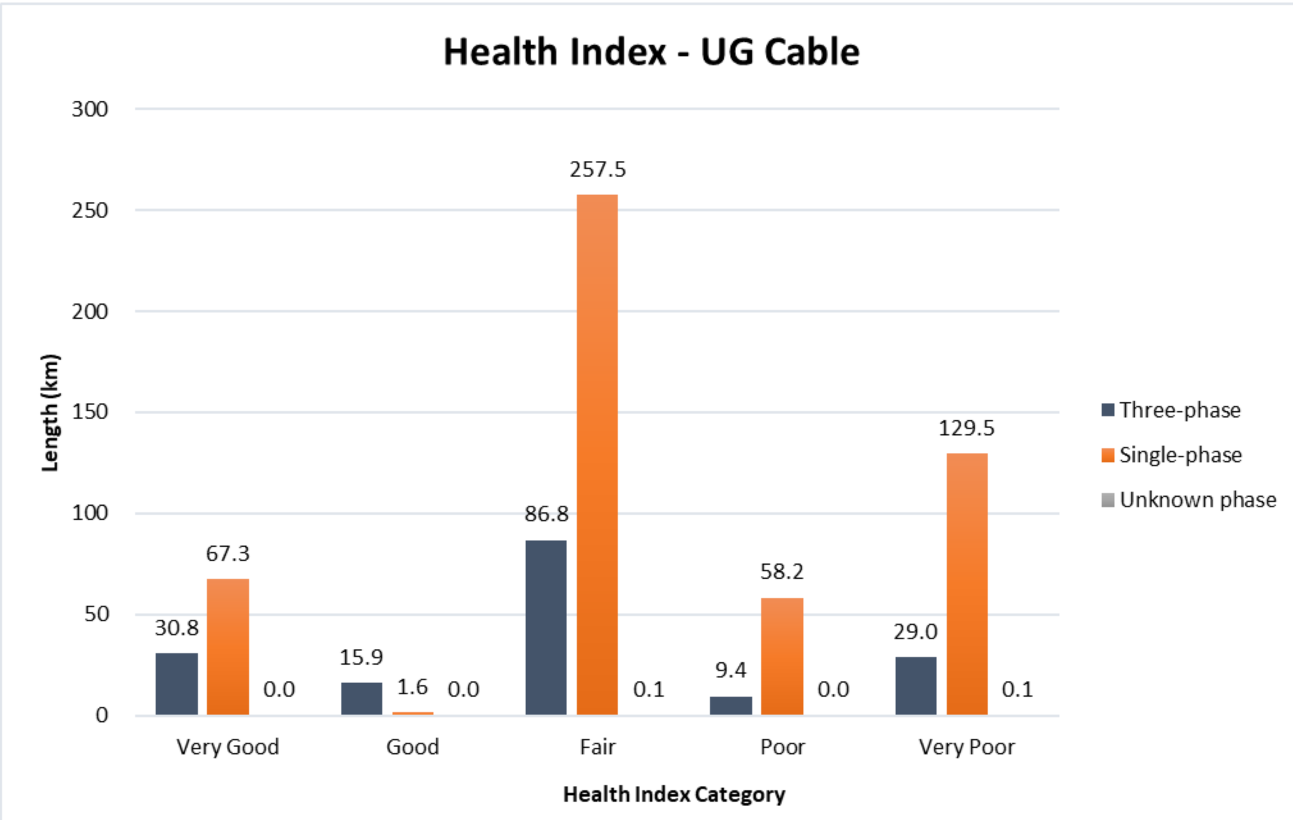
BHI owns approximately 686 km of underground primary cable within its service territory. Where installation date was unknown, the corresponding feeder installation date was used as a proxy. However, age was still unknown for approximately 6% of cables, and was extrapolated by weight onto the asset population with a known age to show an approximate representation of the age distribution. The figure presents the total length of underground primary cables for each age band. Extrapolated age results were not used as part of the HI calculation. Figure 4-9 presents the underground primary cable age demographics.

Figure 4-9: Underground Primary Cable Age Demographics



The overall HI for underground primary cable is illustrated in Figure 4-10. Approximately 33% of the underground primary cables are in Poor or Very Poor condition. These results are largely driven by old service ages of many cables.

Figure 4-10: Underground Primary Cable HI Results



The average DAI for the asset class is 98%. Table 4-10 presents the DAI of individual Degradation Factors used for the underground primary cable HI framework.

Table 4-10: Underground Primary Cable Data Availability

Degradation Factor	% of Assets with Data (cable length)
Service Age	93%
Outage Records (6 years)	100%

4.1.6 Pole-mount Distribution Transformers

Pole-mount distribution transformers are installed on service poles above ground with the primary function to step down distribution voltage to the final secondary voltage for the end-user (customer). The HI for pole-mount transformers is calculated by considering a combination of EOL criteria summarized in Table 4-11. Each Degradation Factor represents a factor critical in determining the asset's condition relative to a potential failure to occur.

Table 4-11: Pole-mount Distribution Transformer HI Algorithm

Degradation Factor	Weight	Ranking	Numerical Grade	Max Score
Service Age	3	A,B,C,D,E	4,3,2,1,0	12
IR Scan	4	A,C,E	4,2,0	16
Peak Loading	3	A,B,C,D,E	4,3,2,1,0	12
Leaking/sweating	4	A,B,C,D,E	4,3,2,1,0	16
			Total score	56

IR scanning results provide an important Degradation Factor for condition assessment of the overhead transformers since they identify hotspots (i.e. high temperatures) on the asset. Transformers operating continuously at high temperatures beyond their normal operating state, can cause accelerated degradation of the insulation oil which may lead to premature failure.

An additional Degradation Factor is the peak loading experienced by the transformer. Load unbalances or peak loading reduces the useful life of a distribution transformer. In general, the useful life of a transformer is determined by its insulation condition which is largely affected by transformer loading, temperature, and presence of oxygen and moisture in the oil. Additionally, visual inspections can identify the presence of oil leaks on overhead transformers, which also factors in the calculation of a Transformer HI.

BHI owns 3,179 pole mount transformers within its service territory. Installation date is unknown for ~0.2% of the asset population. The assets with unknown age were extrapolated by weight onto the asset population with a known age to show an approximate representation of the age distribution. Figure 4-11 presents the age distribution for pole-mount transformers.

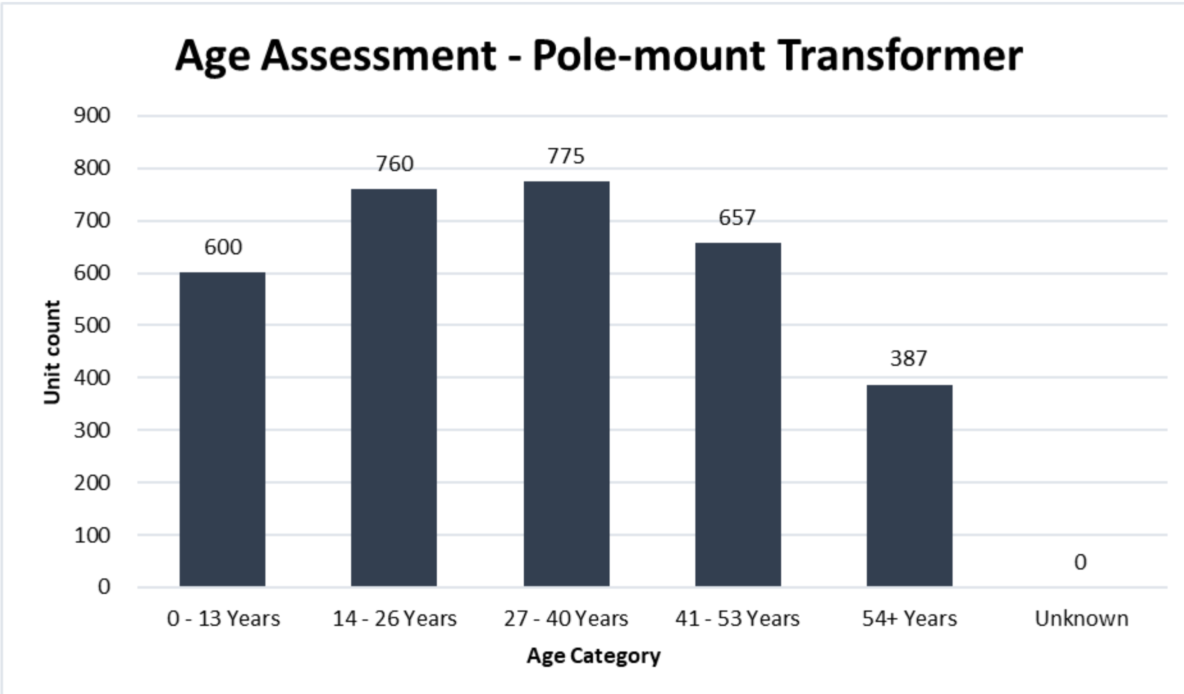
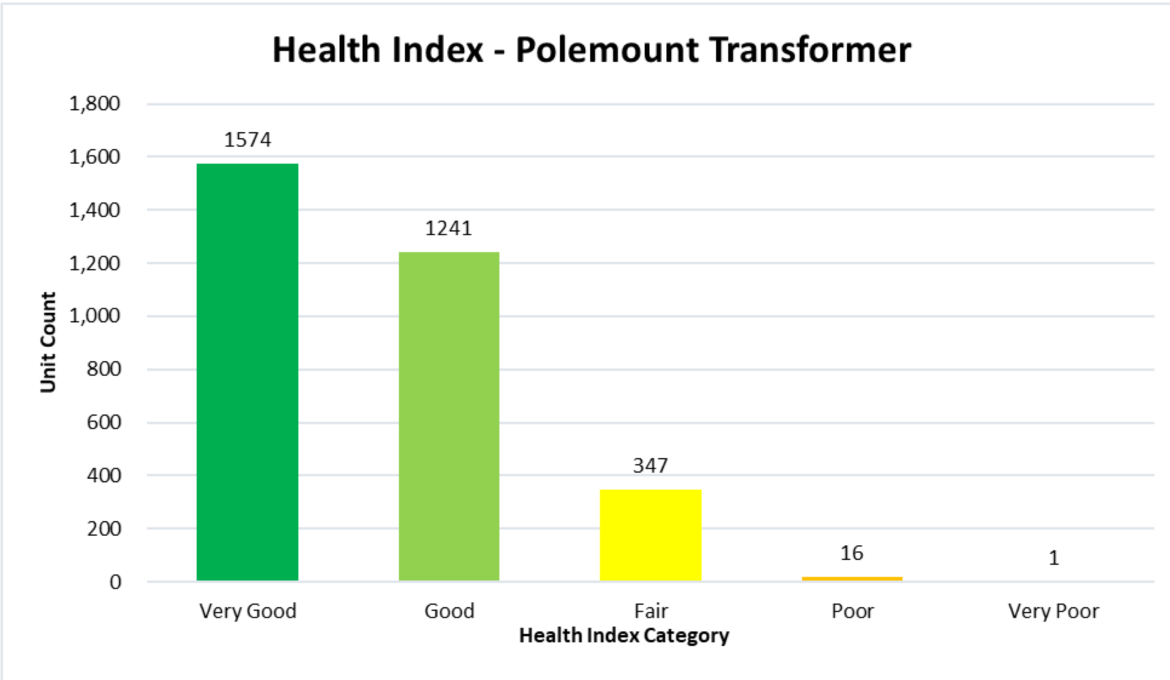


Figure 4-11: Pole-mount Transformer Age Demographics

BHI's transformer maintenance records, nameplate information, and operating loading data were used to calculate the HI based on the criteria provided in Table 4-11. A valid HI was calculated for 99.9% of the overhead transformers. The overall HI distribution is presented in Figure 4-12. Most of the population are in Very Good or Good condition, with 11% in Fair condition, 0.5% in Poor condition and 0.03% in Very Poor condition.

Figure 4-12: Pole-mount Transformer HI Results



The average DAI for the asset class is 98%. Table 4-12 presents the DAI of individual Degradation Factors used for the pole-mount transformer HI framework.

Table 4-12: Pole-mount Transformer Data Availability

Degradation Factor	% of Assets with Data
Service Age	100%
IR Scan	100%
Peak Loading	92%
Leaking/sweating	99%

4.1.7 Underground Distribution Transformers

Underground distribution transformers are utilized for similar functionalities as pole-mount transformers. They step down power from the medium-voltage distribution system to the secondary voltage for the customer. They are located below ground or on the ground level. Three types of underground distribution transformers are assessed within this report:

- Pad-mount transformers;
- Submersible transformers; and
- Vault transformers.

The HI for underground distribution transformers is calculated by considering a combination of EOL criteria summarized in Table 4-13. Each Degradation Factor represents a factor critical in determining the asset's condition relative to a potential failure to occur.

Table 4-13: Pad-mount, Vault, and Submersible Transformer HI Algorithm

Degradation Factor	Weight	Ranking	Numerical Grade	Max Score
Service Age	12	A,B,C,D,E	4,3,2,1,0	48
Peak Loading	10	A,B,C,D,E	4,3,2,1,0	40
Condition of Civil Structure/Pad	5	A,C,E	4,2,0	20
Condition of Enclosure	4	A,B,C,D,E	4,3,2,1,0	16
Oil Leaks	5	A,C,E	4,2,0	20
Overall Condition	4	A,B,C,D,E	4,3,2,1,0	16
IR Scan*	8	A,B,C,D,E	4,3,2,1,0	32
			Total score	160

* IR Scans were used only for Vault Transformers and were not part of the HI Algorithm for Pad-mount and Submersible Transformers.

Visual inspections identify the following defects found on underground transformers:

- Shifted structure or pad;
- Presence of rust;
- Presence of oil leaks;
- Vegetation interference;
- Damage; and
- Lock functionality.

The condition of the pad/structure and enclosure are stand-alone Degradation Factors with their own weight. The condition of the enclosure is important since damage to the enclosure can expose the transformer to severe weather conditions and present serious safety concerns to humans should they come into contact with the contents inside. Hence, an enclosure that is deteriorated should be replaced to maintain safety performance. The condition of the pad is important to maintain the stability of the asset to prevent faults. Pads and transformer can also be replaced independently if it is economically reasonable to do so.

Additionally, the peak loading data is a useful Degradation Factor to use. Load imbalances or peak loading reduces the useful life of a distribution transformer. In general, the useful life of a transformer is determined by its overall condition which is largely affected by transformer loading, temperature, and presence of oxygen and moisture in the oil.

BHI owns 4,066 pad mount transformers, 768 submersible transformers and 66 vault transformers within its service territory. Unknown installation dates account for approximately 0.2% of both pad-mount and submersible transformers. The assets with unknown age were extrapolated by weight onto the asset population with a known age to show an approximate representation of the age distribution.

Figure 4-13 to Figure 4-15 presents the age distribution by transformer types. BHI's transformer maintenance records, nameplate information, and operating data were used to calculate the HI based on the criteria provided in Table 4-13. Approximately 1% of the underground distribution transformers within BHI's service territory are operating above their rated capacity during peak loads, which can have a long-term deteriorating impact on the useful life of the asset.

The overall HI distribution is presented in Figure 4-16 to Figure 4-18 for each transformer type. A valid HI was calculated for ~100%, ~99% and 100% of pad-mount, submersible and vault transformers, respectively. To complete the full analysis, the HI for the remaining population has been extrapolated based on the HI distribution of the asset population with a valid HI score. For pad-mount, submersible, and vault transformers, 2%, 26%, and 17% are in Fair condition respectively. 0.07% of pad-mount transformers are in Poor condition; otherwise, all remaining assets are in Very Good or Good condition.

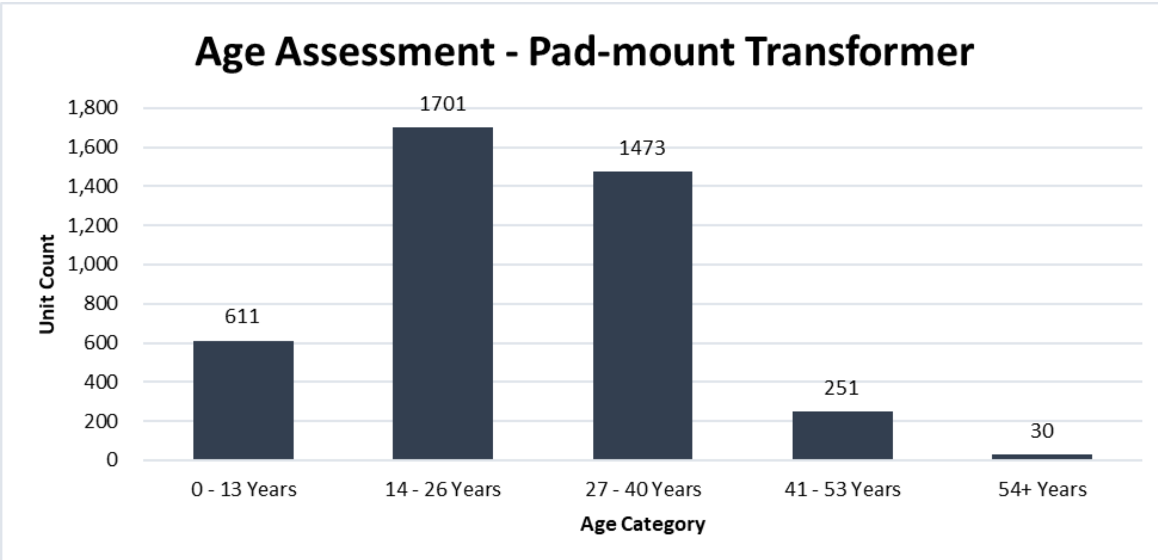


Figure 4-13: Pad-mount Transformer Age Demographics

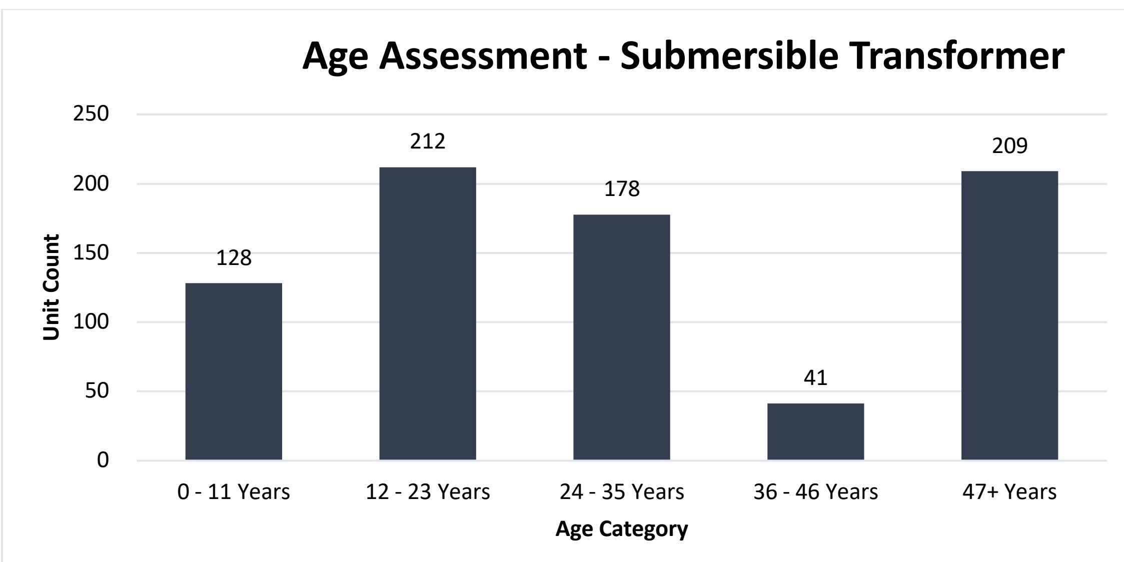


Figure 4-14: Submersible Transformer Age Demographics

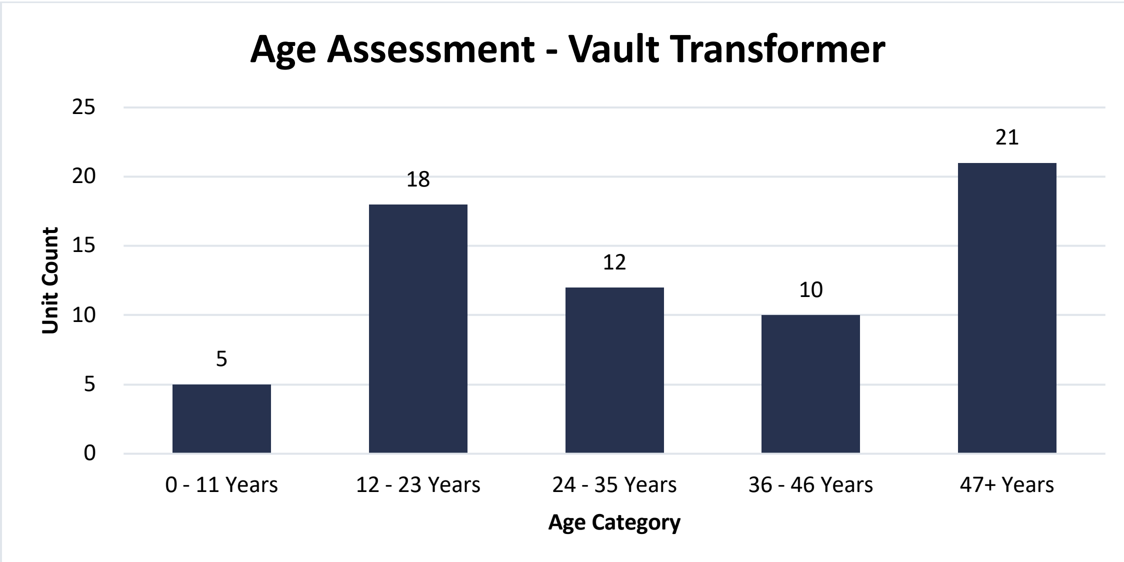


Figure 4-15: Vault Transformer Age Demographics

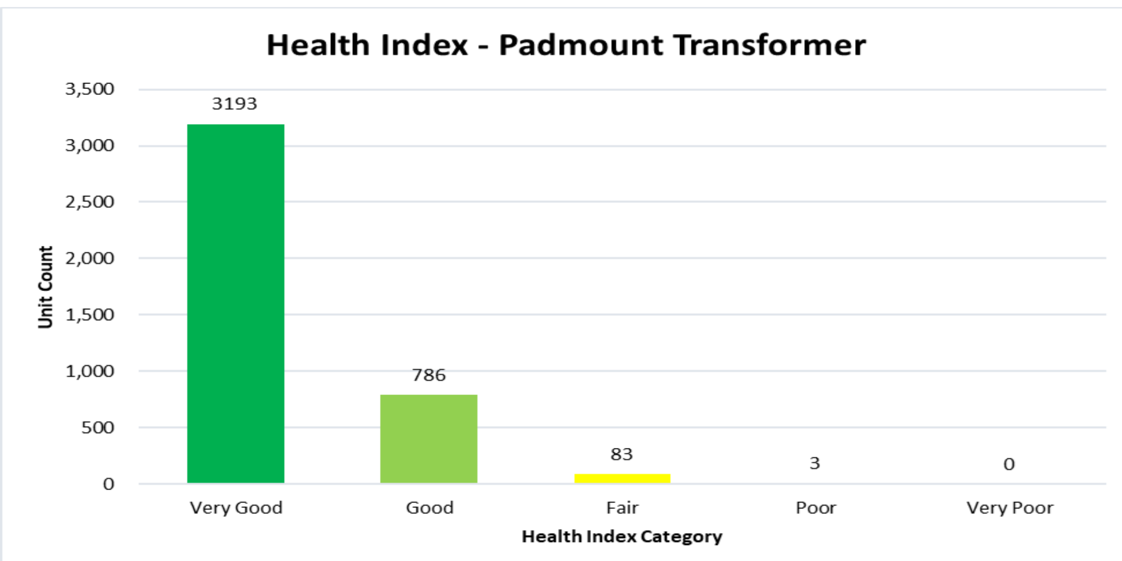


Figure 4-16: Pad-mount Transformer HI Results

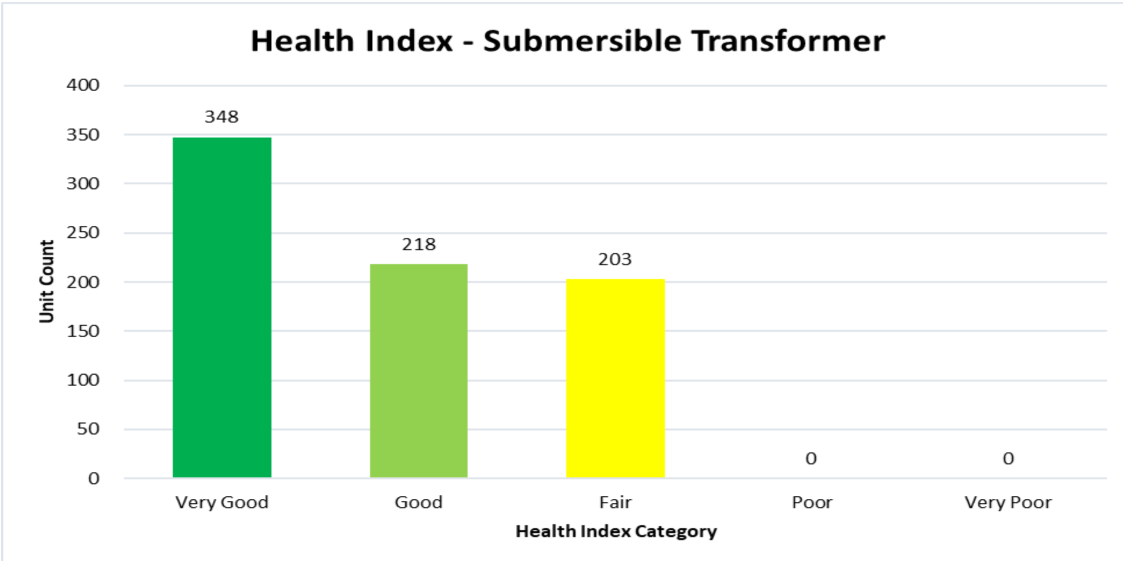


Figure 4-17: Submersible Transformer HI Results

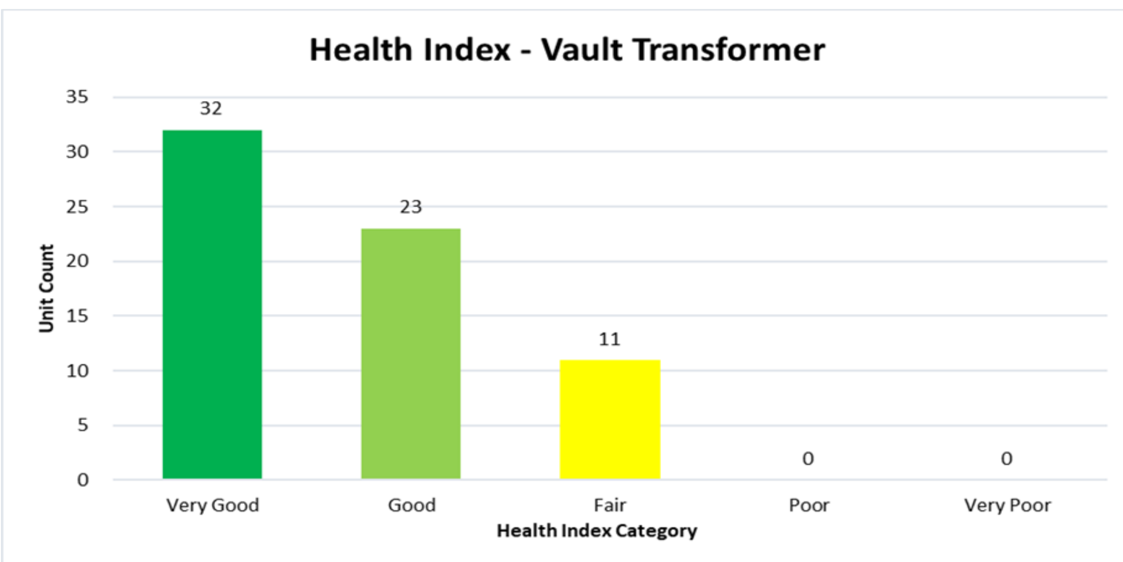


Figure 4-18: Vault Transformer HI Results

Most of the assets have the visual inspection, enclosure condition, age, peak loading information, and IR scans (for Vault Transformers). The class-average DAI for pad-mount, submersible and vault transformer data are ~99%, ~99%, and 100% respectively. Table 4-14 presents the DAI of individual Degradation Factors used for the underground distribution transformers HI framework.

Table 4-14: Underground Distribution Transformer Degradation Factor Data Availability

Degradation Factor	% of Assets with Data		
	Pad-Mount TX	Submersible TX	Vault TX
Service Age	100%	99%	100%
Peak Loading	99%	100%	100%
Condition of Civil Structure/Pad	100%	99%	100%
Condition of Enclosure	100%	99%	100%
Oil Leaks	100%	99%	100%
Overall Condition	100%	99%	100%

4.1.8 Distribution Switchgear

Distribution switchgear are pad-mounted switching /protection devices that provide the necessary operating flexibility to the distribution system. They are employed for controlling, regulating, and isolating the electrical circuit in the distribution system. During a fault, the switchgear can isolate the downstream faulted section, thereby minimizing the impact to the customers. It is also used to de-energize equipment during maintenance and testing. They can manually or automatically transfer load in distribution circuits from a preferred source to an alternate source. The HI for distribution switchgear is calculated by considering a combination of EOL criteria summarized in Table 4-15.

Table 4-15: Distribution Switchgear HI Algorithm

Degradation Factor	Weight	Ranking	Numerical Grade	Max Score
Service Age	5	A,B,C,D,E	4,3,2,1,0	20
IR Scan	8	A,C,E	4,2,0	32
Condition of Enclosure	4	A,B,C,D,E	4,3,2,1,0	16
Condition of Terminations	3	A,B,C,D,E	4,3,2,1,0	12
Condition of Pad	1	A,B,C,D,E	4,3,2,1,0	4

Total score	84

IR scanning results represent an important Degradation Factor for condition assessment of distribution switchgear since they identify hotspots (i.e., high temperatures) on the asset. Assets operating continuously at high temperatures may experience accelerated degradation and/or premature failure.

The condition of the pad and enclosure, which indicate the presence of rust or damage and cracks on the enclosure and the pad, are an important factor in the assessment of overall asset condition. The condition of the enclosure is a stand-alone Degradation Factor with its own weight since damage to the enclosure can expose the transformer to severe weather conditions . Hence, an enclosure that is deteriorated should be replaced to maintain the integrity of the equipment. The condition of the pad (foundation) is important to maintain the stability of the asset . Sometimes pads can be replaced without replacing the whole switchgear.

BHI owns 239 distribution switchgear within its service territory. Age was unknown for 13% of BHI's in-service switchgear. The assets with unknown age were extrapolated by weight onto the asset population with a known age to show an approximate representation of the age distribution. Figure 4-19 presents the age distribution for switchgear.

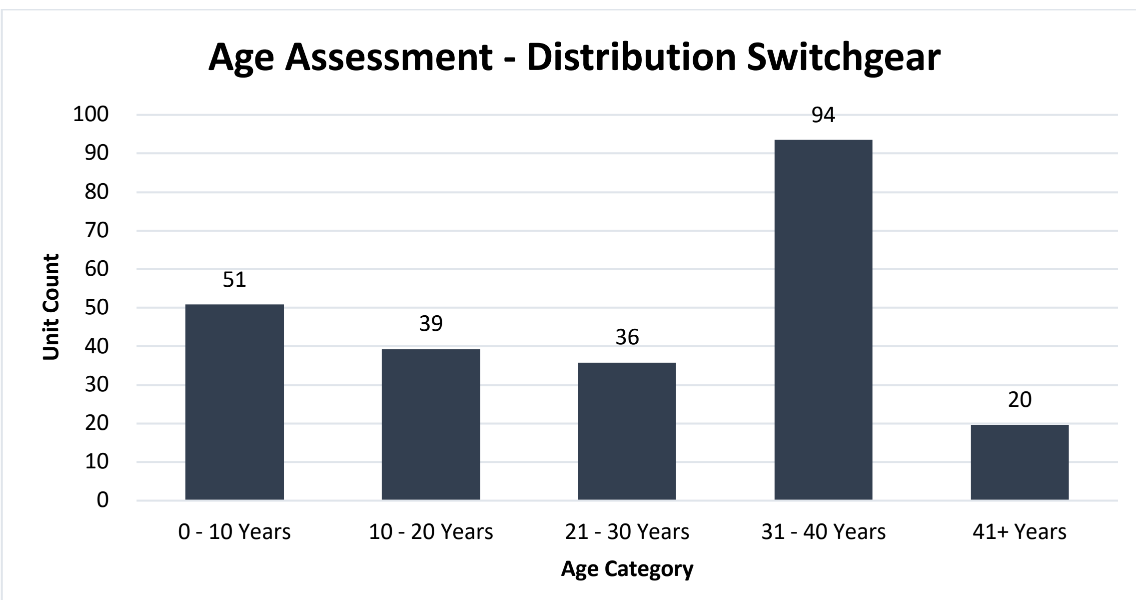


Figure 4-19: Distribution Switchgear Age Demographics

BHI's maintenance records and nameplate information was used to calculate the HI based on the criteria provided in Figure 4-20. A valid HI was calculated for ~77% of the switchgears. To complete the full analysis, the HI for the remaining 23% has been extrapolated based on the HI distribution of the asset population with a valid HI score. The overall HI distribution for the switchgear is presented in Figure 4-20. 2% of assets are in Poor or Very Poor condition, 23% are in Fair condition, and the rest are in Very Good or Good condition.

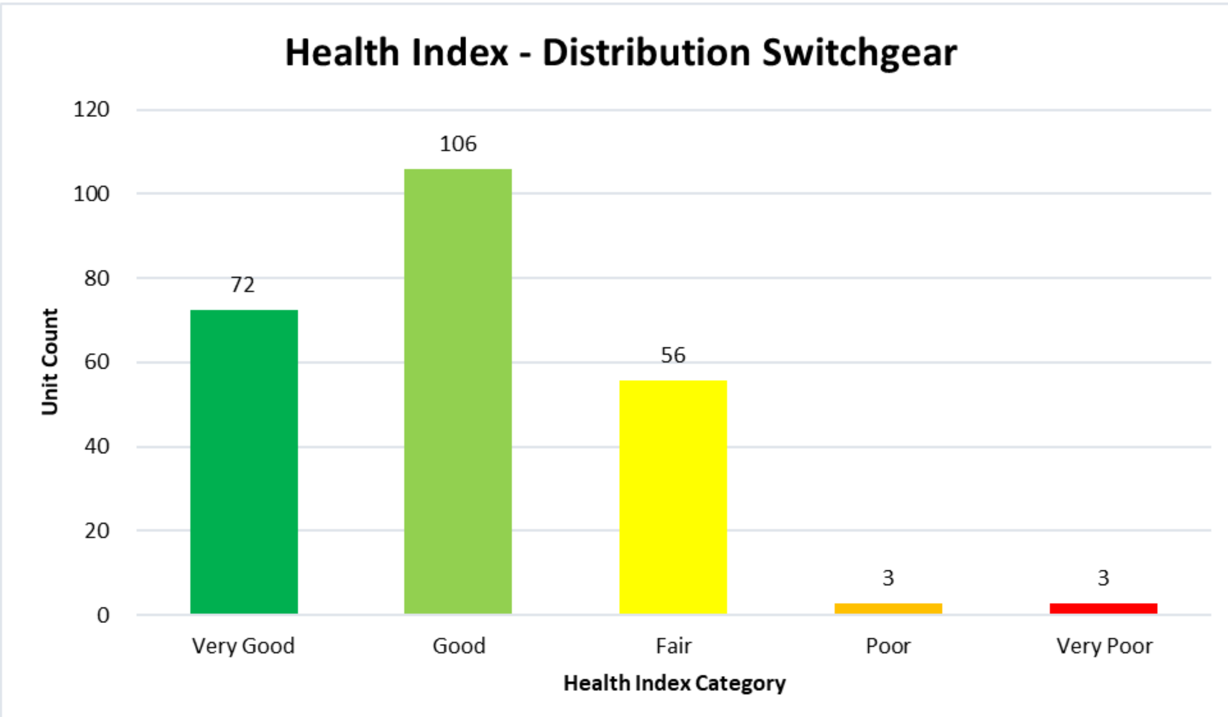


Figure 4-20: Distribution Switchgear HI Results

The average DAI for the asset class is 81%. Table 4-16 presents the DAI of individual Degradation Factors used for the distribution switchgear HI framework.

Table 4-16: Distribution Switchgear Degradation Factor Data Availability

Degradation Factor	% of Assets with Data
Service Age	89%
IR Scan	100%
Condition of Enclosure	76%
Condition of Terminations	27%

Degradation Factor	% of Assets with Data
Condition of Pad	76%

4.1.9 Overhead Switches

BHI's overhead switch types include fused cutouts, load-break, and air-break switches. Load-break and air-break switches are operated to sectionalize the circuit during a restoration procedure by breaking all three phases of load with a single operation. Fused cutout switches are a combination of a switch and a fuse and provide overcurrent protection during overload conditions or short circuits. The HI for switches is calculated by considering a combination of EOL criteria summarized in Table 4-17.

Table 4-17: Overhead Switch HI Algorithm

Degradation Factor	Weight	Ranking	Numerical Grade	Max Score
Service Age	1	A,B,C,D,E	4,3,2,1,0	4
IR Scan	1	A,B,C,D,E	4,3,2,1,0	4
			Total score	8

IR scanning results are an important Degradation Factor for condition assessment of overhead switches since they identify hotspots (i.e. high temperatures) on the asset. Assets operating continuously at high temperatures can cause accelerated degradation of the asset and may experience premature failure.

BHI owns 4,049 overhead switches within its service territory. For assets with unknown installation dates, the assumption made was to use the corresponding feeder age as a proxy. This results in 98% of switches having a known installation date. The applied assumption for service age of assets was used in the HI calculation and was confirmed with BHI. The remaining 2% of the switch population does not have a known installation date. This is due to the fact the switches did not have a feeder tagged to the asset. The 2% of the asset class with an unknown age were extrapolated by weight onto the asset population with a known age. Figure 4-21 presents the age distribution for overhead switches to show an approximate representation of the age distribution. Extrapolated age results were not used as part of the HI calculation.

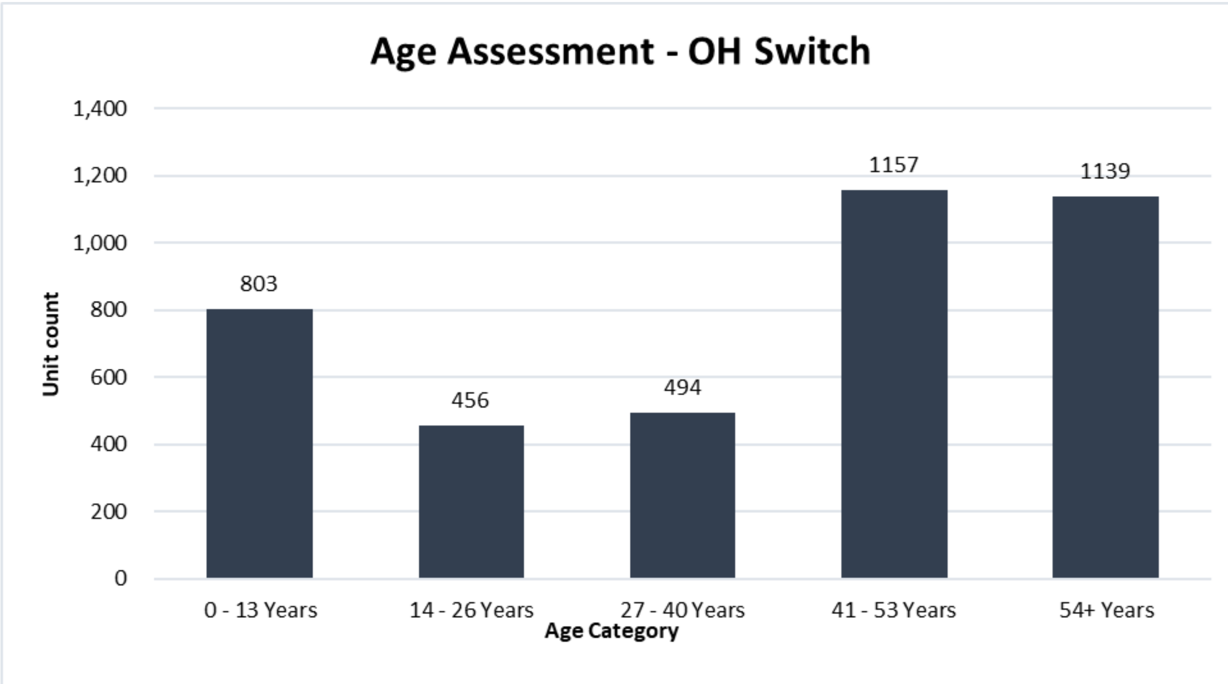


Figure 4-21: Overhead Switch Age Demographics

BHI's maintenance records and nameplate information was used to calculate the HI based on the criteria provided in Table 4-17. Approximately 2% of the population does not have a valid HI score and have been extrapolated to the known valid HI distribution. The overall HI distribution for the overhead switches is presented in Figure 4-22. Less than 1% of overhead switches are in Poor or Very Poor condition, 56% of overhead switches are in Fair condition, and the remaining 42% are in Very Good or Good condition.

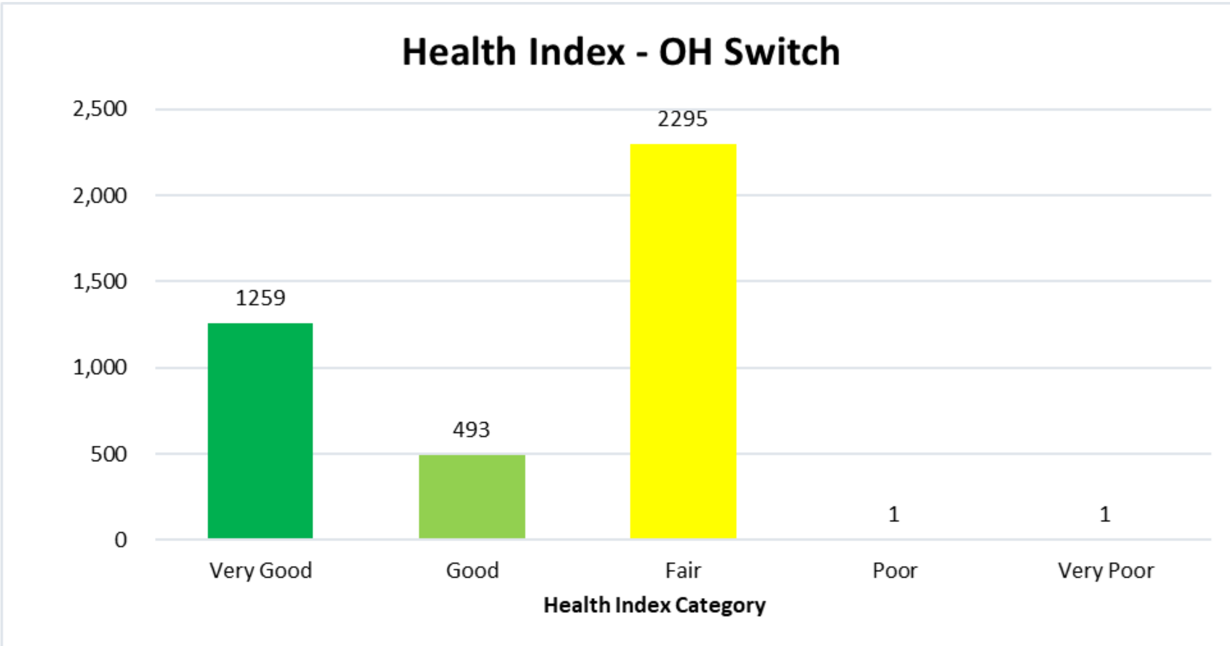


Figure 4-22: Overhead Switch HI Results

The average DAI for the asset class is 99%. Table 4-18 presents the DAI of individual Degradation Factors used for the overhead switch HI framework.

Table 4-18: Overhead Switch Degradation Factor Data Availability

Degradation Factor	% of Assets with Data
Service Age	98%
IR Scan	100%

4.1.10 SCADA Switches

As the name implies, SCADA switches are connected to SCADA and can be operated remotely to sectionalize the circuit during a restoration. The HI for SCADA switches follows that of other overhead switches and is calculated by considering a combination of EOL criteria summarized in Table 4-19.

Table 4-19: SCADA Switch HI Algorithm

Degradation Factor	Weight	Ranking	Numerical Grade	Max Score
Service Age	1	A,B,C,D,E	4,3,2,1,0	4
IR Scan	1	A,B,C,D,E	4,3,2,1,0	4
			Total score	8

IR scanning results are an important Degradation Factor for condition assessment of overhead switches since they identify hotspots (i.e. high temperatures) on the asset. Assets operating continuously at high temperatures can cause accelerated degradation of the asset and may experience premature failure.

BHI owns 71 SCADA switches within its service territory. Service age was known for all assets. Figure 4-23 presents the age distribution for SCADA switches.

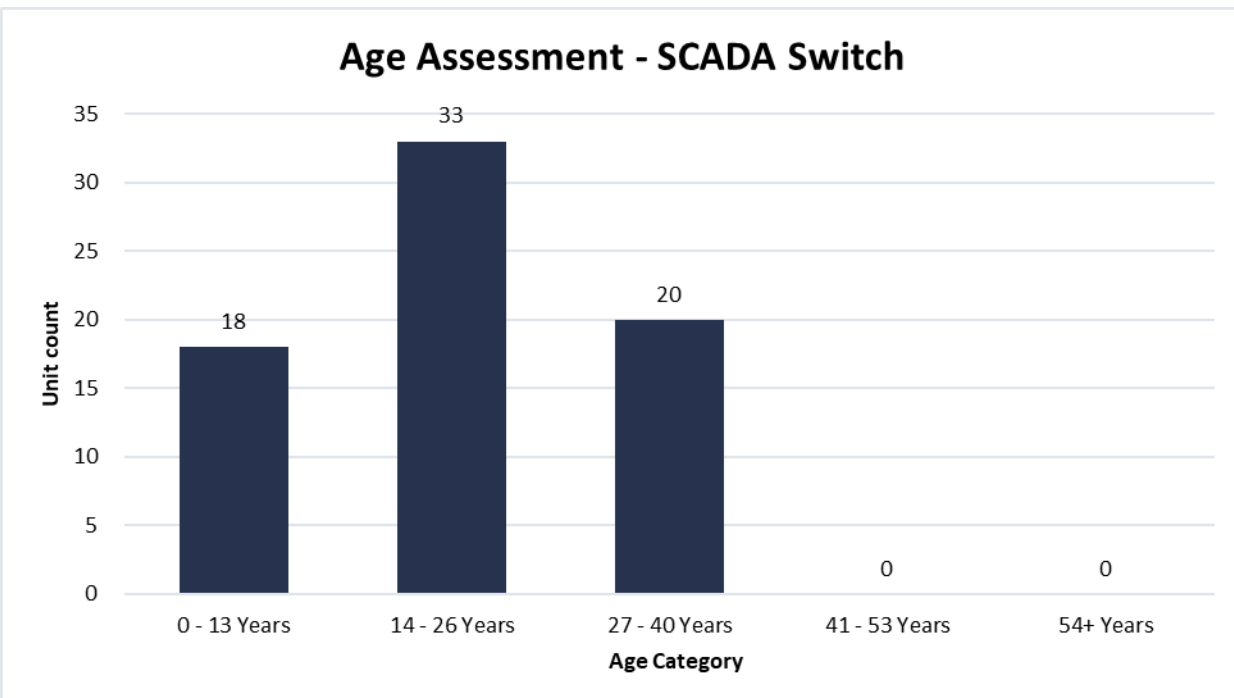
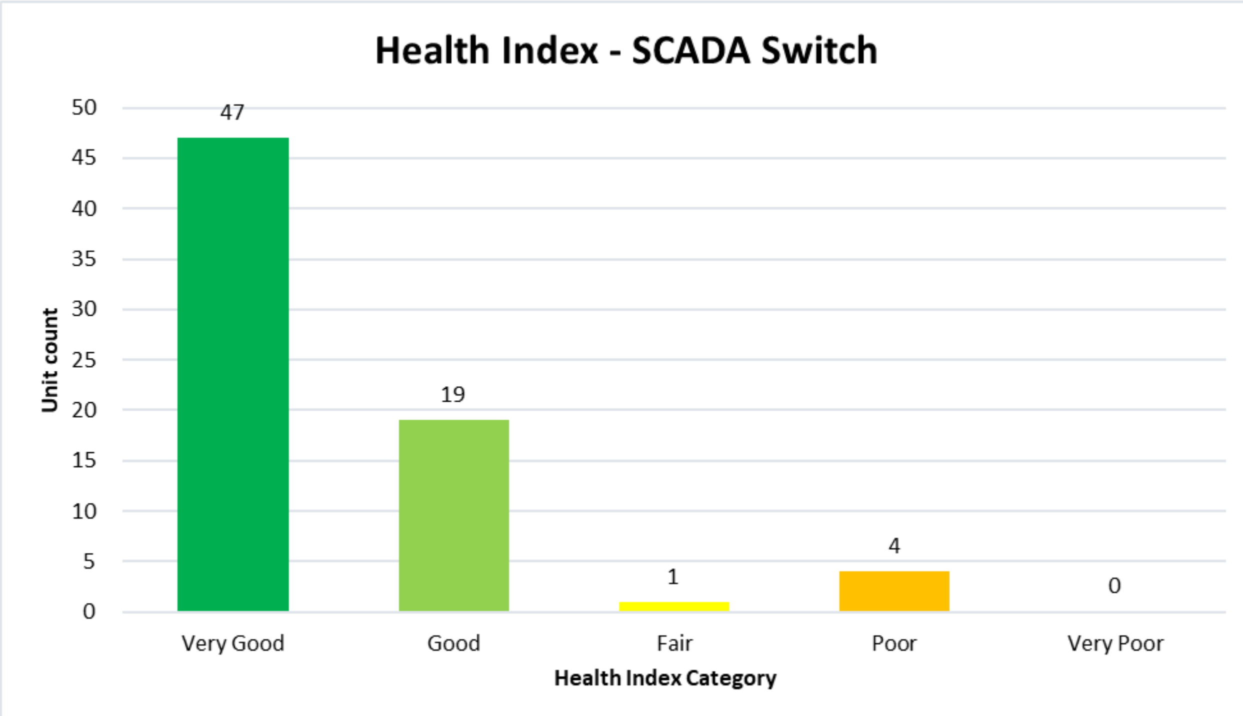


Figure 4-23: SCADA Switch Age Demographics

BHI's maintenance records and nameplate information was used to calculate the HI based on the criteria provided in Table 4-19. All assets had a valid HI score. The overall HI distribution for the SCADA switches is presented in Figure 4-24. 93% of the switches are in Very Good or Good condition WITH 1% in Fair condition and 6% in Poor condition.

Figure 4-24: SCADA Switch HI Results



The DAI for the asset class is 100%. Table 4-20 presents the DAI of individual Degradation Factors used for the SCADA switch HI framework.

Table 4-20: SCADA Switch Degradation Factor Data Availability

Degradation Factor	% of Assets with Data
Service Age	100%
IR Scan	100%

4.1.11 Overhead Line Reclosers

Overhead line reclosers (e.g. IntelliRupter) are installed on the distribution system to interrupt the circuit during a fault and are designed to automatically reclose to attempt to restore the normal operating conditions. Since the majority of the faults on the overhead system are self-clearing/transient, the presence of reclosers improves the reliability of the system significantly as the power is restored within seconds after a fault occurs.

The HI for reclosers is calculated by considering a combination of EOL criteria summarized in Table 4-21.

Table 4-21: Overhead Line Recloser HI Algorithm

Degradation Factor	Weight	Ranking	Numerical Grade	Max Score
Service Age	3	A,B,C,D,E	4,3,2,1,0	12
Counter Reading	3	A,B,C,D,E	4,3,2,1,0	12
			Total score	24

The counter reading criterion provides a reasonable assessment of the operating condition of the reclosers and is determined based on the number of operations of the recloser compared to the rated number of operations of a recloser specified by the manufacturer.[3] Service age provides a reasonably good measure of the remaining life of the asset and is utilized as a Degradation Factor. BHI owns 13 overhead line reclosers; Figure 4-25 presents their age distribution.

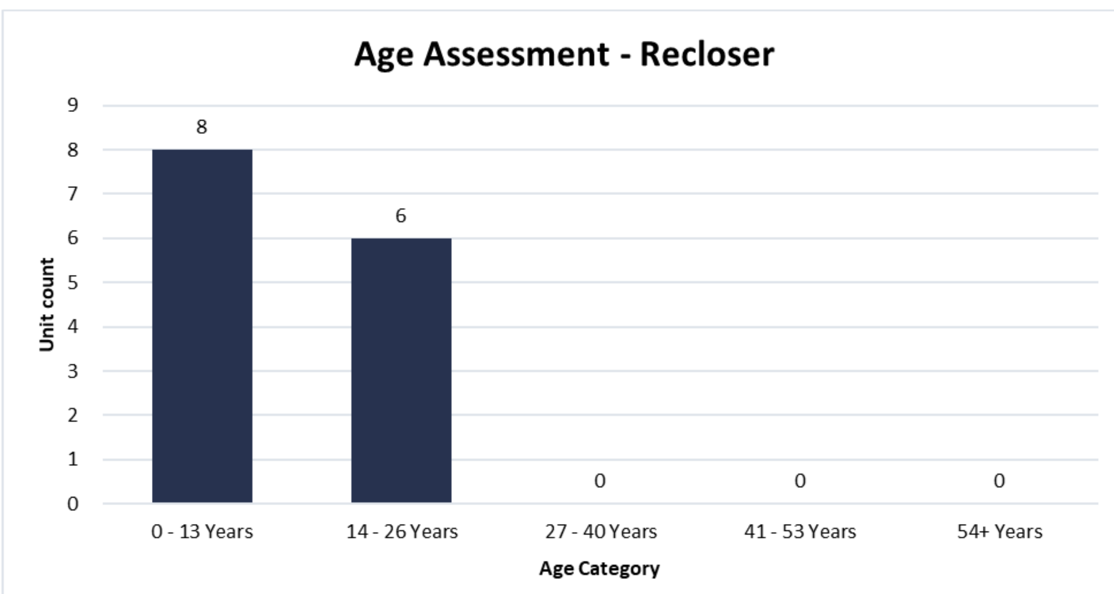


Figure 4-25: Overhead Line Recloser Age Demographics

BHI's maintenance records, nameplate information, and operating parameters were used to calculate the HI based on the criteria provided in Table 4-21. The overall HI distribution for the

[3] S&C IntelliRupter® PulseCloser® Fault Interrupter – Specifications.

reclosers is presented in Figure 4-26. A valid HI could not be calculated for one recloser which is not in service (out for repair); therefore, it was excluded from the HI assessment. All of the remaining reclosers are in Very Good condition.

Figure 4-26: Overhead Line Recloser HI Results

The average DAI for the asset class is 100%. Table 4-22 presents the DAI of individual Degradation Factors used for the recloser HI framework.

Table 4-22: Overhead Line Reclosers Degradation Factors Data Availability

Degradation Factor	% of Assets with Data
Service Age	100%
Counter Readings	100%

4.2 Station Assets

4.2.1 Power Transformers

Power transformers can be considered the most critical asset class. Each transformer can be valued in the range of hundreds of thousands to millions of dollars and can affect tens of thousands of customers. Power transformers in the distribution system are housed within municipal stations. They are used to step down the voltage within the distribution system.

Computing the HI of a transformer requires developing EOL criteria for its various components. Table 4-23 and Table 4-24 summarize the methodology to generate the HI for liquid-filled power transformers and dry-type power transformers respectively. The HI score for a transformer is composed of qualitative visual inspection results and quantitative testing results. These measurements include dissolved gas analysis ("DGA"), insulation power factor, oil quality, insulation resistance, turns ratio, and winding resistance. Each of these parameters represents an aspect of a power transformer with a direct impact on the operational health of the asset. For dry-type power transformers, dissolved gas analysis, insulation power factor and oil quality are not used to calculate the HI Score.

Table 4-23: Liquid-Filled Power Transformer HI Algorithm

Degradation Factor	Weight	Ranking	Numerical Grade	Max Score
Service Age	12	A,B,C,D,E	4,3,2,1,0	48
Load History (%)	12	A,B,C,D,E	4,3,2,1,0	48
Condition of Bushings	5	A,C,E	4,2,0	20
Condition of Main Tank Corrosion	4	A,C,E	4,2,0	16
Condition of Cooling Equipment	4	A,C,E	4,2,0	16
Condition of Conservator	3	A,C,E	4,2,0	12
Condition of Transformer Foundation	1	A,C,E	4,2,0	4
Condition of Transformer Grounding	1	A,C,E	4,2,0	4
Condition of Gaskets and Seals	1	A,C,E	4,2,0	4
Condition of Transformer Connectors	1	A,C,E	4,2,0	4
Oil Leaks	5	A,C,E	4,2,0	20
Oil Level	3	A,C,E	4,2,0	12
DGA	10	A,B,C,D,E	4,3,2,1,0	40

Degradation Factor	Weight	Ranking	Numerical Grade	Max Score
DGA (LTC)	4	A,B,C,D,E	4,3,2,1,0	16
Oil Quality	8	A,C,E	4,2,0	32
Oil Quality (LTC)	4	A,C,E	4,2,0	16
2-Furaldehyde (ppm)	8	A,B,C,D,E	4,3,2,1,0	32
Insulation PF	4	A,B,C,D,E	4,3,2,1,0	16
Insulation Resistance (GΩ @ 20°C)	4	A,B,C,D,E	4,3,2,1,0	16
Turns Ratio Test (DEV %)	5	A,B,C,D,E	4,3,2,1,0	20
Winding Resistance (DEV %)	6	A,B,C,D,E	4,3,2,1,0	24
			Total score	420

Table 4-24: Dry-Type Power Transformer HI Algorithm

Degradation Factor	Weight	Ranking	Numerical Grade	Max Score
Service Age	12	A,B,C,D,E	4,3,2,1,0	48
Load History (%)	12	A,B,C,D,E	4,3,2,1,0	48
Condition of Main Tank Corrosion	4	A,C,E	4,2,0	16
Condition of Cooling Equipment	4	A,C,E	4,2,0	16
Condition of Transformer Foundation	1	A,C,E	4,2,0	4
Condition of Transformer Grounding	1	A,C,E	4,2,0	4
Condition of Gaskets and Seals	1	A,C,E	4,2,0	4
Condition of Transformer Connectors	1	A,C,E	4,2,0	4
Insulation Resistance (GΩ @ 20°C)	12	A,B,C,D,E	4,3,2,1,0	48
Turns Ratio Test (DEV %)	13	A,B,C,D,E	4,3,2,1,0	52
Winding Resistance (DEV %)	14	A,B,C,D,E	4,3,2,1,0	56
			Total score	300

By performing DGA, it is possible to identify the internal faults such as arcing, partial discharge, low-energy sparking, severe overloading, and overheating in the insulating medium. Insulation power factor measurements are an important source of data to monitor transformer and bushing conditions. Lower scores for one or a combination of these Degradation Factors strongly indicate progressed degradation of the asset, hence their larger weights.

Although load history is an operational rather than a maintenance parameter, it holds value as an input for the HI algorithm. The peak loading data from 2019 to 2023 were used for the analysis.

The rate of insulation degradation is related to the operating temperature which is in turn related to transformer loading. The peak loading level of the transformers is expressed in a percentage of the nameplate rating. BHI records and tracks the monthly peak for each substation power transformer.

Oil leaks and overall condition of components are collected by visual inspection and serve as indicators of the total health of the asset. Additionally, service age provides a reasonably good measure of the remaining life of the asset and is employed as a Degradation Factor.

BHI owns 44 power transformers within its service territory, of which 36 are liquid-filled and 8 are dry-type. Installation date is known for all assets. Figure 4-27 presents the age distribution for liquid-filled transformers and Figure 4-28 presents the age distribution of dry-type power transformers.

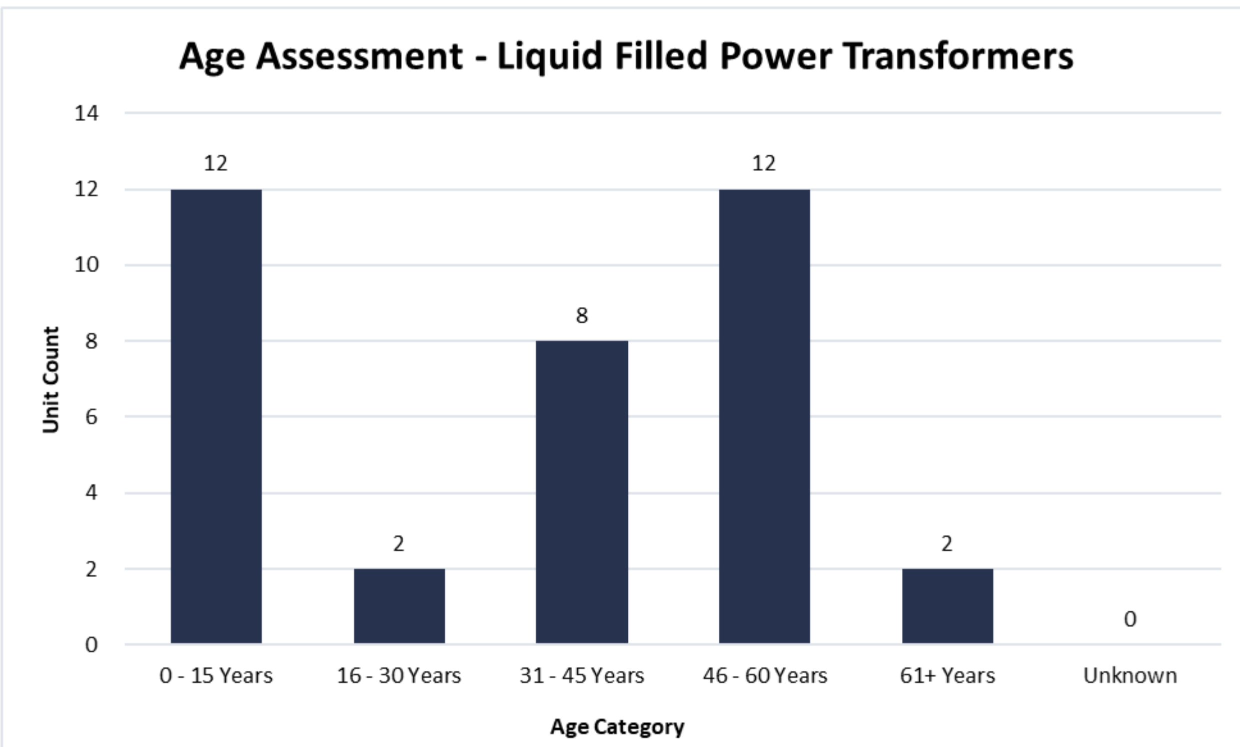


Figure 4-27: Liquid-Filled Power Transformer Age Demographics

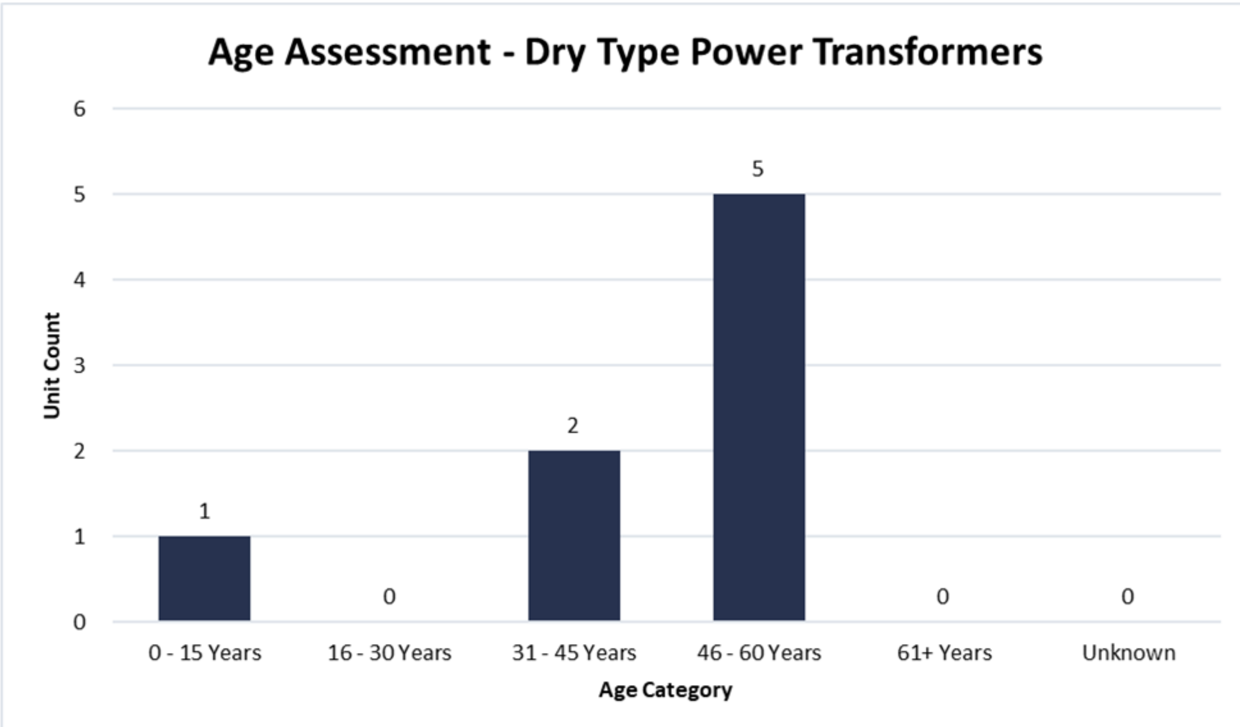


Figure 4-28: Dry-Type Power Transformer Age Demographics

BHI's power transformer inspections, test results, loading history and age demographics were used to calculate the HI based on the criteria provided in Table 4-23 and Table 4-24. A valid HI was calculated for all liquid-filled power transformers and dry-type power transformers. The overall HI distribution for liquid-filled power transformers and dry-type power transformers are presented in Figure 4-29 and Figure 4-30 respectively. Most of the power transformers are in Very Good or Good condition with none being in Poor or Very Poor condition.

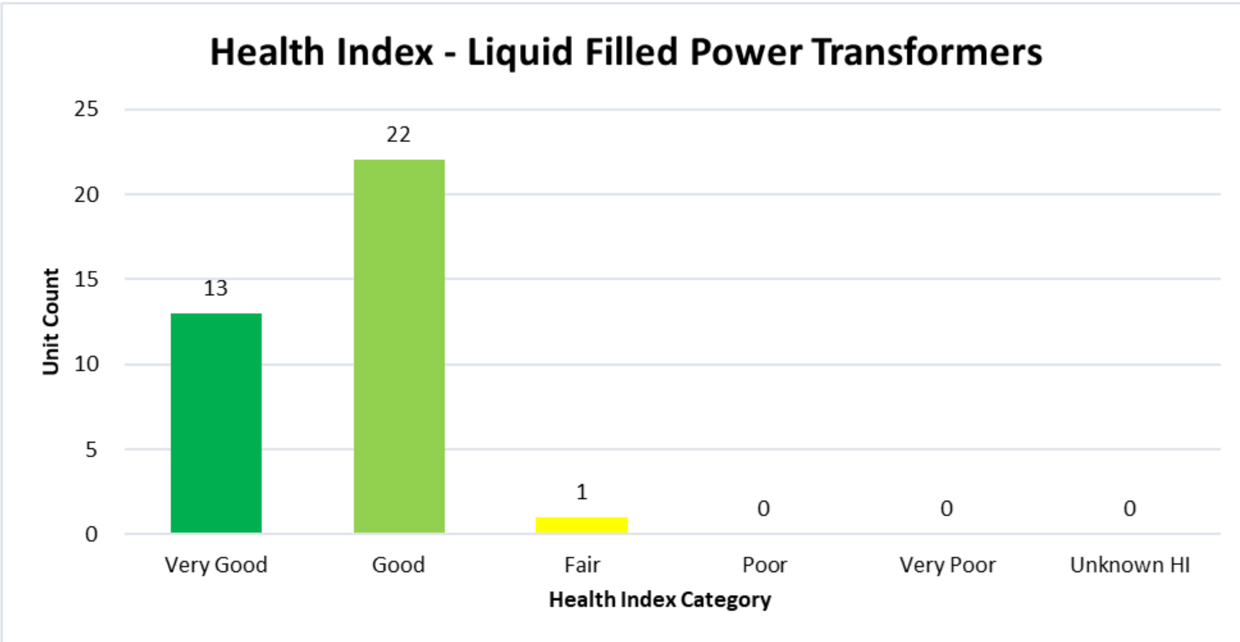


Figure 4-29: Liquid-Filled Power Transformer HI Results

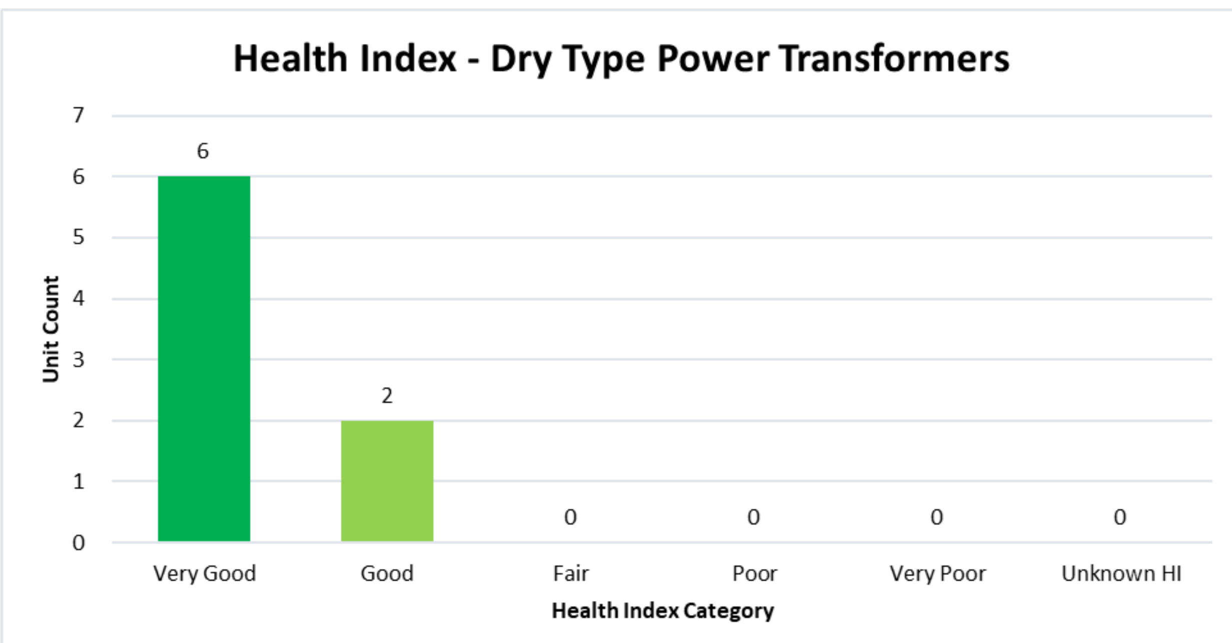


Figure 4-30: Dry-Type Power Transformer HI Results

Figure 4-31 illustrates the DGA analysis results for the power transformers. DGA tests can be a leading indicator as to how the power transformer's internal condition is before experiencing unfavorable results.

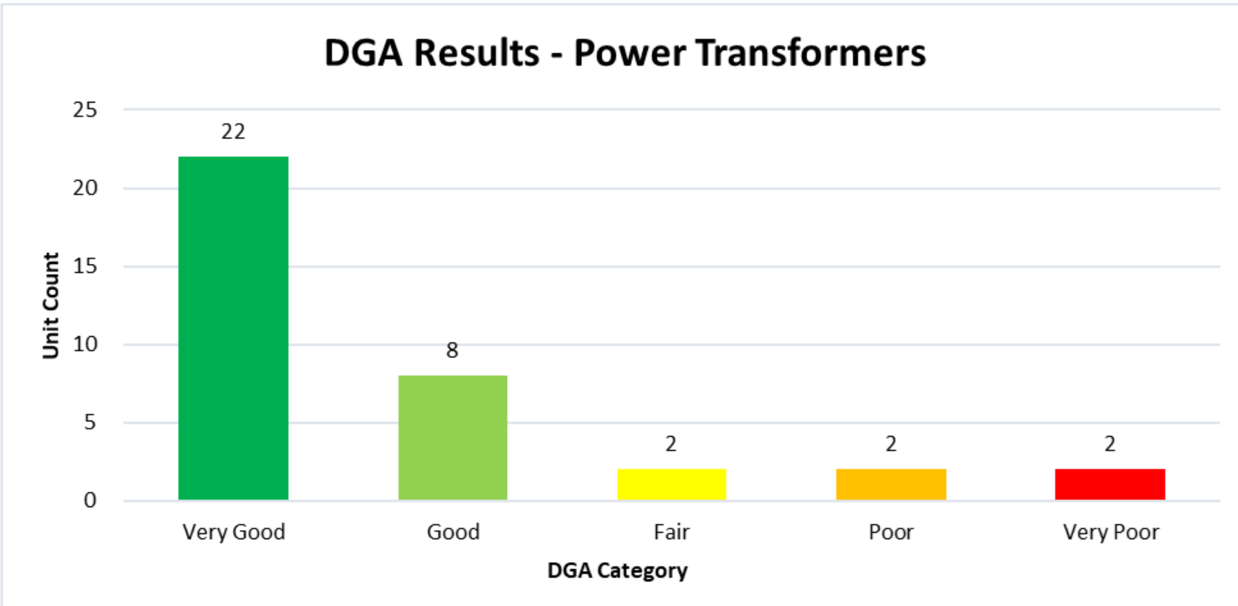


Figure 4-31: Power Transformer DGA Results

The average DAI for liquid-filled power transformers is 100% and for dry-type power transformers is 100%. Table 4-25 and Table 4-26 presents the DAI of individual Degradation Factors used for liquid-filled and dry-type power transformers respectively. The two units with very poor DGA results should be followed up with in accordance with IEEE C57.104.

Table 4-25: Liquid-Filled Power Transformer Degradation Factor Data Availability

Degradation Factor	% of Assets with Data
Service Age	100%
Load History (%)	100%
Condition of Bushings	100%
Condition of Main Tank Corrosion	100%
Condition of Cooling Equipment	100%
Condition of Conservator	100%
Condition of Transformer Foundation	100%

Degradation Factor	% of Assets with Data
Condition of Transformer Grounding	100%
Condition of Gaskets and Seals	100%
Condition of Transformer Connectors	100%
Oil Leaks	100%
Oil Level	100%
DGA	100%
DGA (LTC)	100%
Oil Quality	100%
Oil Quality (LTC)	100%
2-Furaldehyde (ppm)	100%
Insulation PF	100%
Insulation Resistance (GΩ @ 20°C)	100%
Turns Ratio Test (DEV %)	100%
Winding Resistance (DEV %)	100%

Table 4-26: Dry-Type Power Transformer Degradation Factor Data Availability

Degradation Factor	% of Assets with Data
Service Age	100%
Load History (%)	100%
Condition of Main Tank Corrosion	100%
Condition of Cooling Equipment	100%
Condition of Transformer Foundation	100%
Condition of Transformer Grounding	100%
Condition of Gaskets and Seals	100%
Condition of Transformer Connectors	100%
Insulation Resistance (GΩ @ 20°C)	100%
Turns Ratio Test (DEV %)	100%
Winding Resistance (DEV %)	100%

4.2.2 Medium-Voltage Circuit Breakers

Circuit breakers are critical substation assets and are the primary protective devices for maintaining public safety and protecting other station equipment. Breakers work with station relays to open, either in a fault situation, as directed by the operations center, or as part of the automation scheme. Computing the HI of a circuit breaker considers EOL criteria for its various components. Each criterion represents a factor critical in determining the component's condition relative to potential failure. The HI for substation circuit breakers is calculated by considering a combination of test results, number of operations, visual inspections, and obsolescence as summarized in Table 4-27.

Table 4-27: Medium Voltage Circuit Breaker Health Index Algorithm

Degradation Factor	Weight	Ranking	Numerical Grade	Max Score
Service Age	4	A,B,C,D,E	4,3,2,1,0	16
Counter Reading	3	A,B,C,D,E	4,3,2,1,0	12
Visual Inspection	1	A,B,C,D,E	4,3,2,1,0	4
Contact resistance	5	A,B,C,D,E	4,3,2,1,0	20
Insulation Resistance	5	A,B,C,D,E	4,3,2,1,0	20
Obsolescence	6	A,C,E	4,2,0	24
			Total score	96

Testing, including the contact resistance test and insulation resistance test, is weighted the highest because they are the best indicator of the asset's condition and performance. Obsolescence is also weighted relatively high, as it is a strong indicator of the need to replace an asset. Obsolescence considers both technical obsolescence, where the breaker lacks spare parts or manufacturer support, and functional obsolescence, where the breaker lacks modern capabilities. In the grading scheme used, assets that exhibit technical obsolescence would score an "E" and assets that exhibit functional obsolescence would score a "C" for that parameter.

BHI owns 132 circuit breakers within its service territory. Installation date is known for all assets. Figure 4-32 presents the age distribution for circuit breakers.

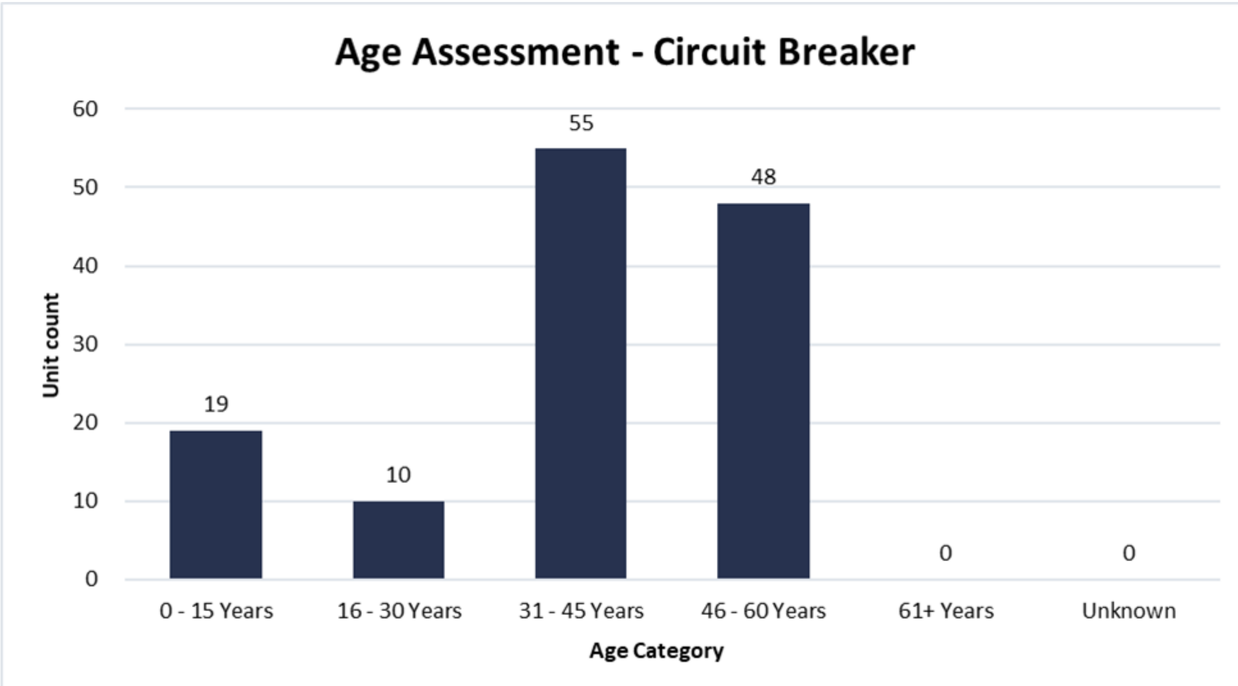


Figure 4-32: Circuit Breaker Age Demographics

BHI's circuit breaker maintenance and nameplate data were used to calculate the HI based on the criteria provided in Table 4-27. A valid HI was calculated for all circuit breakers. The overall HI distribution for the circuit breakers is presented in Figure 4-33. Most of the circuit breakers are in Very Good or Good condition, and 37% are in Fair condition. There are no assets in Poor or Very Poor condition.

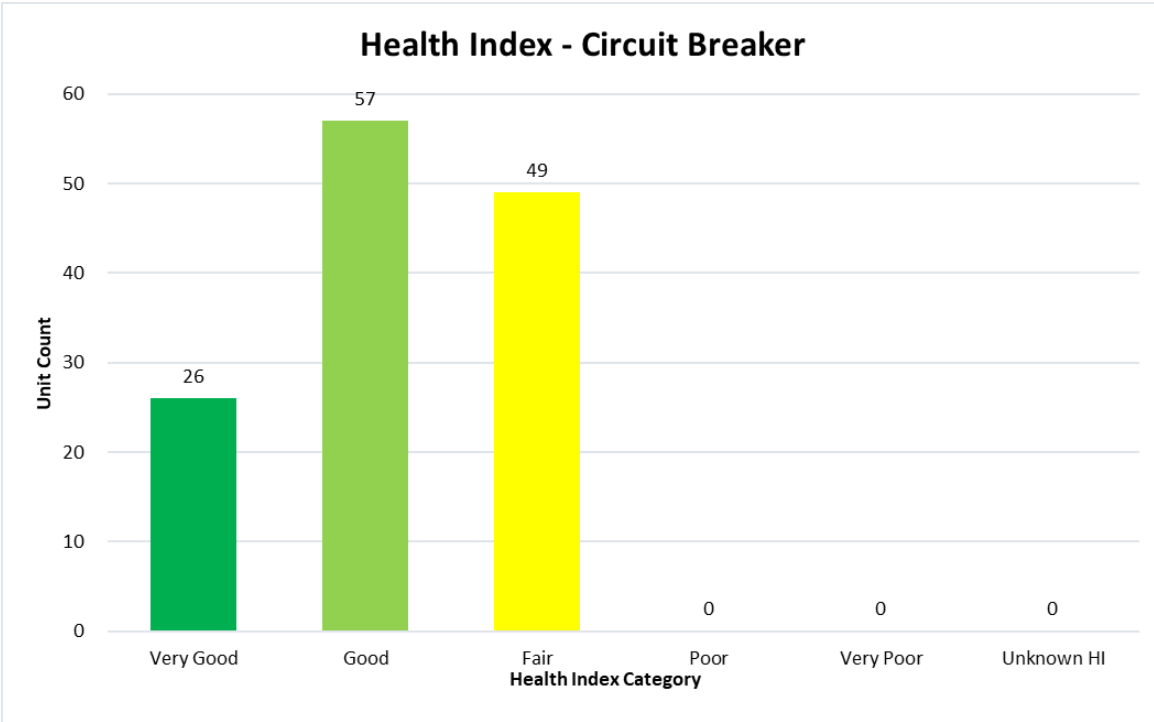


Figure 4-33: Circuit Breaker HI Results

The average DAI for the asset class is 99%. Table 4-28 presents the DAI of individual Degradation Factors used for the circuit breaker HI framework.

Table 4-28: Medium-voltage Circuit Breaker Degradation Factor Data Availability

Degradation Factor	% of Assets with Data
Service Age	100%
Counter Reading	95%
Visual Inspection	98%
Contact resistance	100%
Insulation Resistance	100%
Obsolescence	100%

4.2.3 Station Egress Cables

Station egress cables are the first -sections of cable out of the station (i.e. cables existing stations), before the first riser pole. They carry the entire load of each feeder. Table 4-29 summarizes the methodology to combine the Degradation Factors for station egress cables into an overall HI.

Table 4-29: Egress Cable HI Algorithm

Degradation Factor	Weight	Ranking	Numerical Grade	Max Score
Service Age	5	A,B,C,D,E	4,3,2,1,0	20
Loading History	2	A,B,C,D,E	4,3,2,1,0	8
Outage Records (6 years)	5	A,B,C,D,E	4,3,2,1,0	20
Insulation Resistance	5	A,B,C,D,E	4,3,2,1,0	20
			Total score	68

Service age provides a reasonably good measure of the remaining life of the asset and hence is used as a Degradation Factor in the HI framework. Additionally, the 2019 to 2023 loading history of the cables was also used as a Degradation Factor since overloading these cables can significantly deteriorate their health.

BHI owns 183 egress cables, or 22.65km, within its service territory. Installation date is known for all assets. Figure 4-34 presents the age distribution for egress cables.

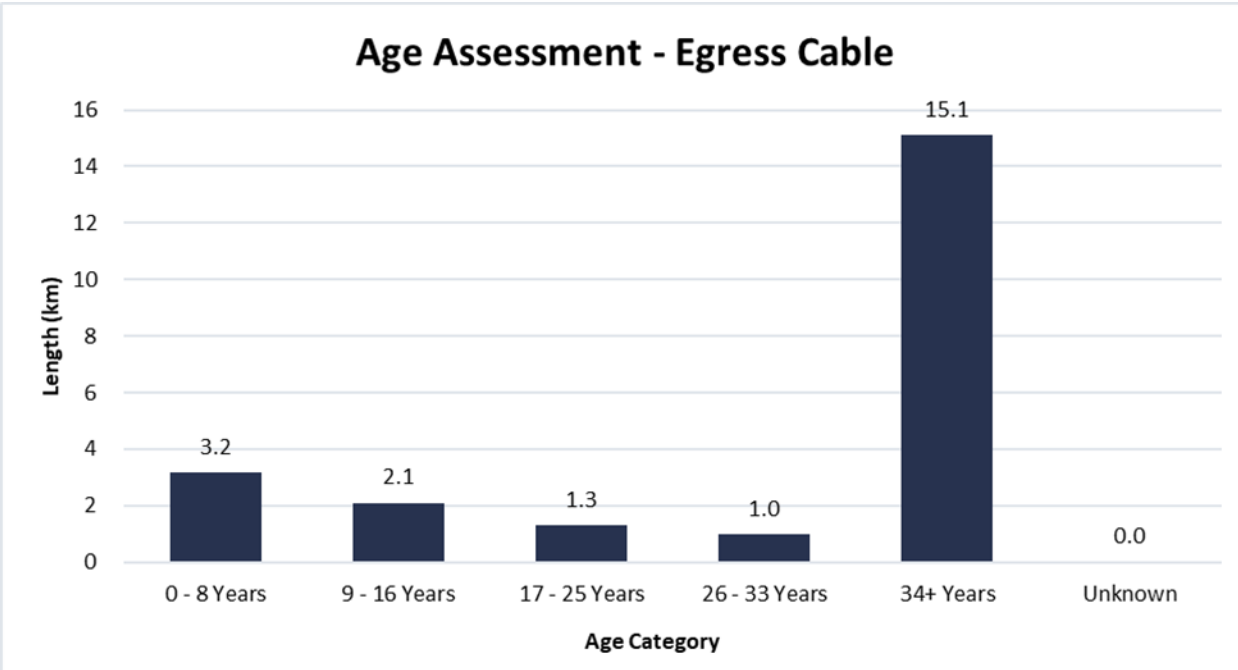


Figure 4-34: Egress Cable Age Demographics

BHI's egress cable loading history, demographic data, and insulation resistance tests were used to calculate the HI based on the criteria provided in Table 4-29. A valid HI was calculated for all egress cables. The overall HI distribution for the egress cables is presented in Figure 4-35. 41% of the egress cables are in Very Good or Good condition, 47% are in Fair condition, and 9% are in Poor condition.

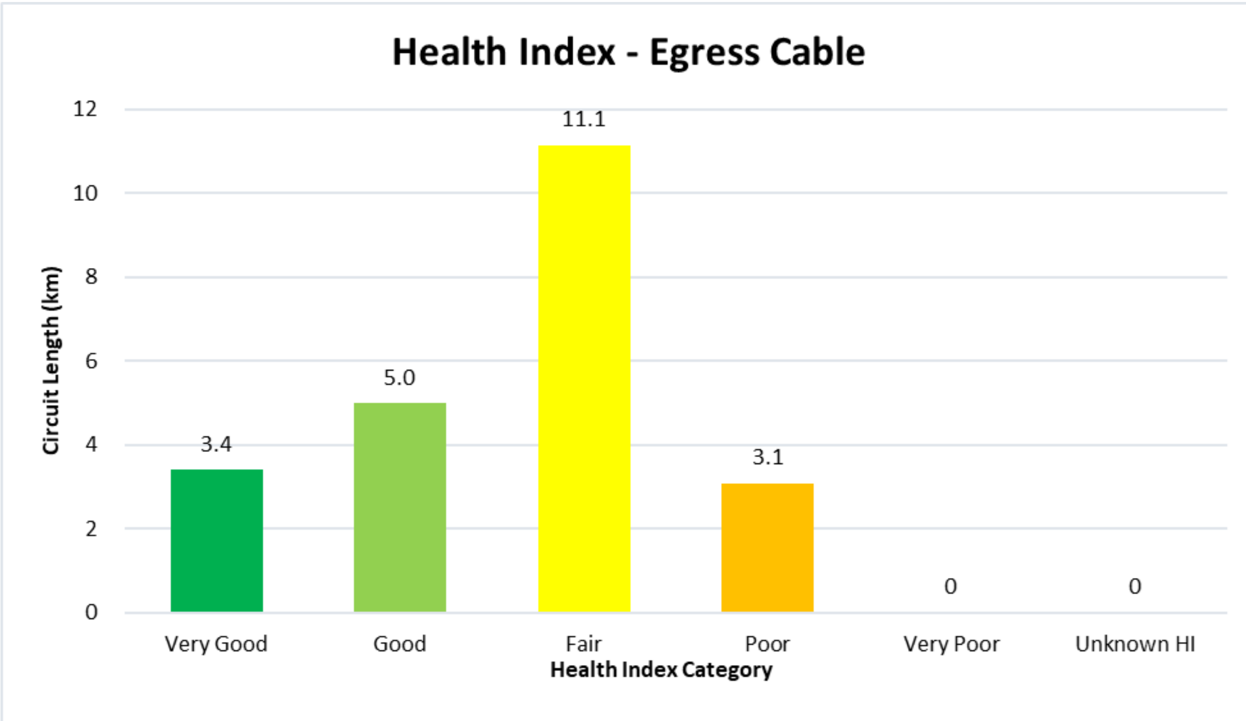


Figure 4-35: Egress Cable HI Results

The average DAI for the asset class is 95%. Table 4-30 presents the DAI of individual Degradation Factors used for the egress cable HI framework.

Table 4-30: Egress Cable Degradation Factor Data Availability

Degradation Factor	% of Assets with Data
Service Age	100%
Loading History	100%
Outage Records (6 years)	100%
Insulation Resistance	83%

4.2.4 Station Battery Banks

The purpose of substation batteries is to provide power for critical control functions such as trip coils of circuit breakers. Batteries are carefully sized to store adequate energy for system operation during an AC power failure. Table 4-31 summarizes the methodology to generate the HI for station battery banks.

Table 4-31: Battery Bank HI Algorithm

Degradation Factor	Weight	Ranking	Numerical Grade	Max Score
Service Age	2	A,B,C,D,E	4,3,2,1,0	8
Capacity Testing	1	A,B,C,D,E	4,3,2,1,0	4
Cell Voltage Deviation Testing	1	A,B,C,D,E	4,3,2,1,0	4
Condition of Compartment	1	A,B,C,D,E	4,3,2,1,0	4
			Total score	20

The battery bank HI score is comprised of several Degradation Factors. The first Degradation Factor is age, which provides insight into the remaining useful life of the asset based on the typical useful lives of DC systems seen across the industry. Batteries also operate based on a determinate chemical process, which has a known lifetime and useful duration. The second parameter is capacity testing (A/H testing) provides detail on individual cell charges, total voltage, and discharge rates as the battery supplies energy over time. Any atypical degradation of a battery bank's performance will be seen with this testing procedure. The third Degradation Factor is cell voltage deviation which provides detail on individual cells deviation from their nominal voltage. Any degradation of individual cells will be seen in this test. The final Degradation Factor is compartment condition. A degradation of the compartment can lead to improper protection of the battery. By building the HI score from these parameters, static and dynamic effects on a battery bank's remaining life can be classified.

Since the 2019 ACA study, the HI formulation for battery banks has been updated to include Cell Voltage Deviation Testing and the Condition of Compartment, which were not part of the previous HI algorithm. Additionally, the weights of various parameters were adjusted to align with industry best practices which has led to a lower reliance on service age compared to 2019. As such, the HI results are not directly comparable between 2019 and 2024.

BHI owns 32 battery banks within its service territory. Installation date is known for all assets. Figure 4-36 presents the age distribution for battery banks.

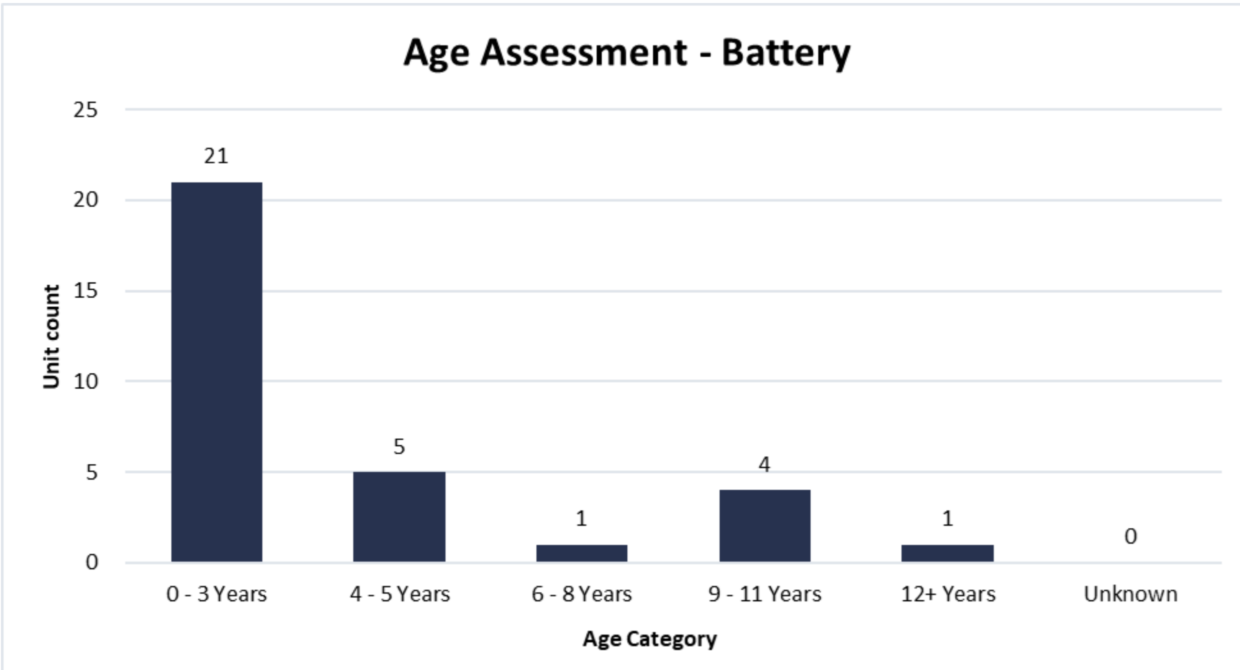


Figure 4-36: Battery Banks Age Demographic

BHI's battery testing, maintenance and nameplate data were used to calculate the HI based on the criteria provided in Table 4-31. A valid HI was calculated for 97% of battery banks. The overall HI distribution for the battery banks is presented in Figure 4-37. Most of the battery banks are in Very Good condition.

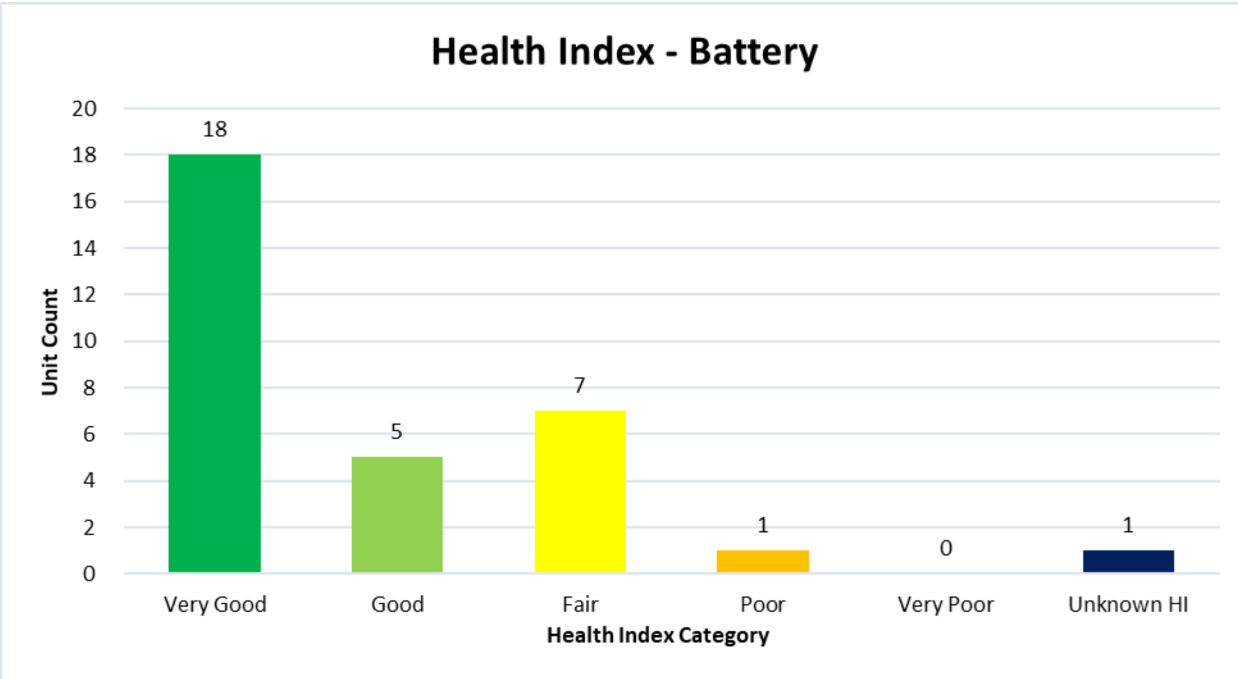


Figure 4-37: Battery Bank HI Results

The average DAI for the asset class is 84%. Table 4-32 presents the DAI of individual Degradation Factors used for the battery bank HI framework.

Table 4-32: Battery Bank Degradation Factor Data Availability

Degradation Factor	% of Assets with Data
Service Age	100%
Capacity Testing	100%
Cell Voltage Deviation Testing	97%
Condition of Compartment	25%

4.2.5 Station Battery Chargers

There is only age data available for BHI's station chargers. Since their age is the only data point, there is no HI formulation for chargers. Figure 4-38 shows the age demographics. There are 32 chargers and 13 of them have exceeded the Typical Useful Life of 20 years.

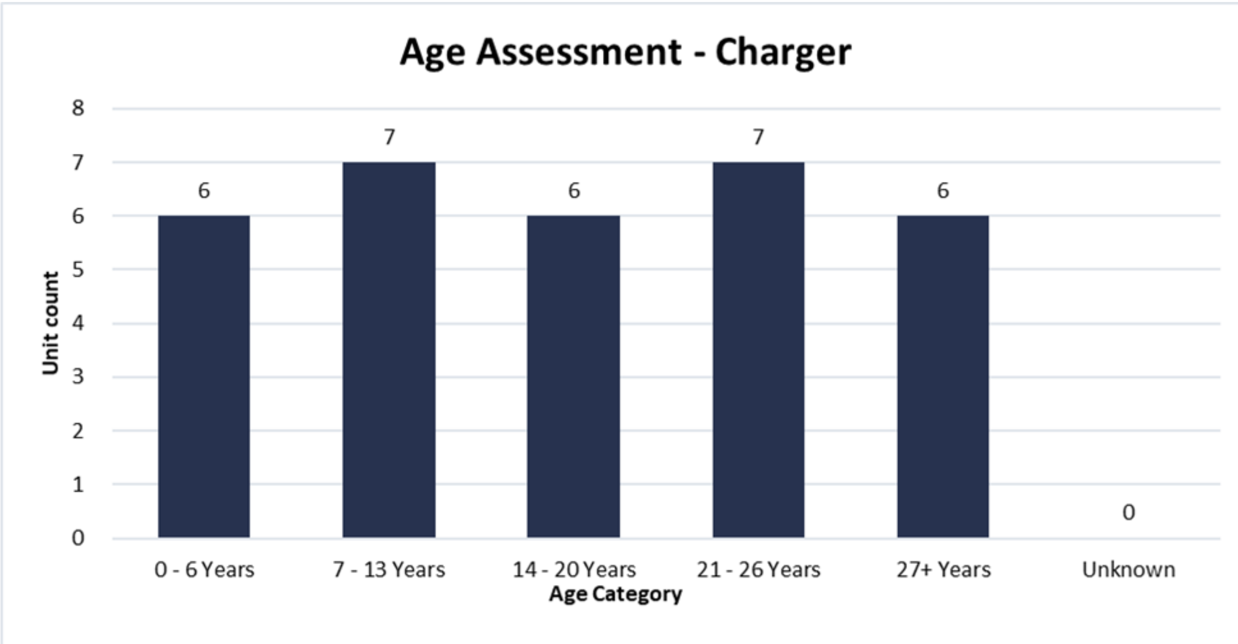


Figure 4-38: Battery Charger Age Demographics

4.2.6 Station Primary Switchgear

Primary station switchgear are a part of the municipal station that controls and regulates the current flowing through the distribution system. They may consist of metal-clad switchgear, overhead reclosers, or pad-mounted switchgear units (e.g., Vista). During a fault, the primary switchgear isolates and clears the faults downstream. It is also used to de-energize equipment during maintenance and testing. BHI has three types of primary station switchgears: Metal-clad, Overhead, and Vista switchgears.

The HI for station primary switchgears is calculated by considering a combination of EOL criteria summarized in Table 4-33.

Table 4-33: Primary Switchgear HI Algorithm

Degradation Factor	Weight	Ranking	Numerical Grade	Max Score
Service Age	3	A,B,C,D,E	4,3,2,1,0	12
Visual Inspection	4	A,B,C,D,E	4,3,2,1,0	16
Electrical Testing	3	A,B,C,D,E	4,3,2,1,0	12
			Total score	42

Service age provides a reasonably good measure of the remaining life of the asset and is utilized as a Degradation Factor. Visual inspection records of the primary switchgear are also used as a Degradation Factor. Electrical testing evaluates the insulation resistance of the primary switchgear recorded through Megger testing.

BHI owns 44 primary switchgears within its service territory. Installation date is known for all assets. Figure 4-39 presents the age distribution for primary switchgear.

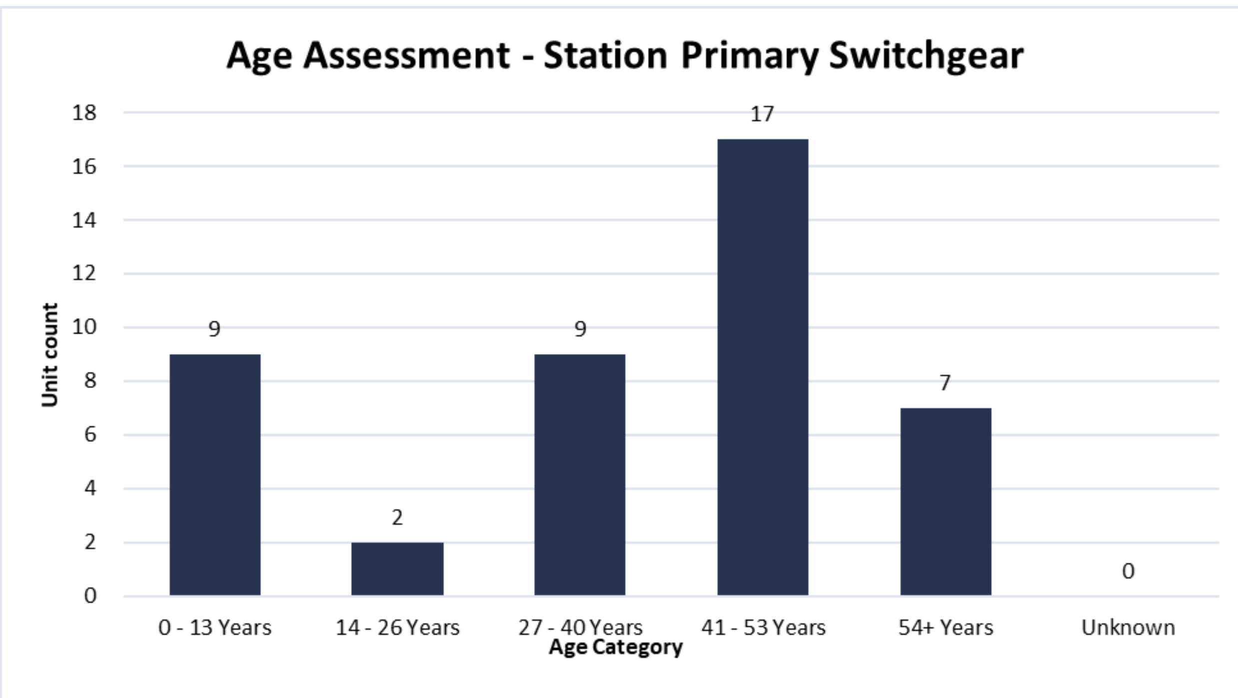


Figure 4-39: Primary Switchgear Age Demographics

BHI's switchgear maintenance and nameplate data were used to calculate the HI based on the criteria provided in Table 4-33. A valid HI was calculated for all switchgear. The overall HI distribution for the switchgear is presented in Figure 4-40. Approximately 45% of the switchgears are in Poor or Very Poor condition, 32% are in Fair condition, and the remaining 23% are in Very Good or Good condition. Table 2-2

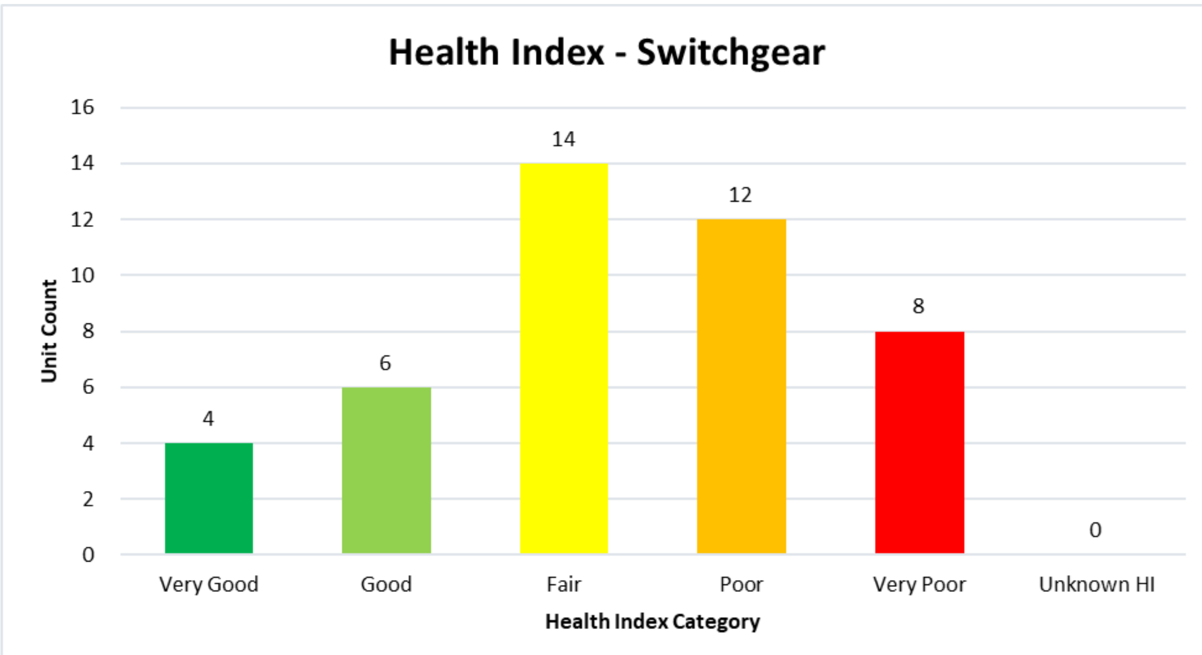


Figure 4-40: Primary Switchgear HI Results

The average DAI for the asset class is 86%. Table 4-34 presents the DAI of individual Degradation Factors used for the switchgear HI framework.

Table 4-34: Primary Switchgear Degradation Factor Data Availability

Degradation Factor	% of Assets with Data
Service Age	100%
Visual Inspection	100%
Electrical Testing	48%

4.2.7 Station Protection Relays

Protection relays are an asset used in substation operations to trip a circuit breaker when a fault is detected. Modern relays are typically microprocessor types and include programmable features and communications. Legacy relays are electromechanical and require regular calibration; however, many electromechanical relays have been replaced with newer models. RTUs are related devices which are used to communicate with the SCADA system.

Protection devices are more likely to become obsolete based on functionality and communication needs rather than physically deteriorating due to environmental conditions. Table 4-35 summarizes the methodology to generate the HI for protection relays. The main inputs considered are service age and test results.

Table 4-35: Protection Relay Health Index Algorithm

Degradation Factor	Weight	Ranking	Numerical Grade	Max Score
Service Age	1	A,B,C,D,E	4,3,2,1,0	4
Testing	1	A,C,E	4,2,0	4
Obsolescence	1	A,E	4,0	4
			Total score	12

BHI owns 127 relays within its service territory. Installation date is known for all assets. Figure 4-41 presents the age distribution for relays.

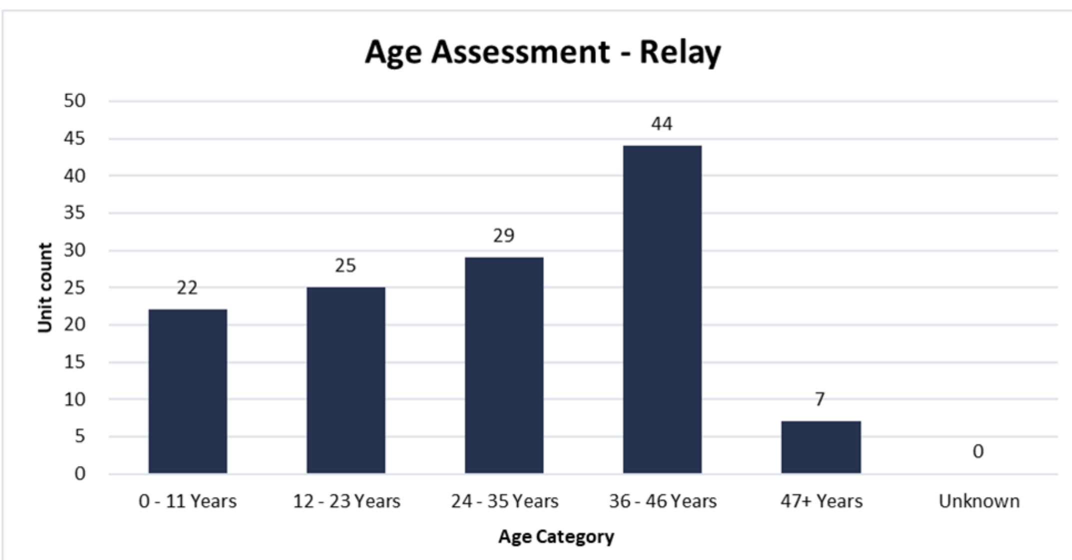


Figure 4-41: Relay Age Demographics

BHI's relay testing and nameplate data were used to calculate the HI based on the criteria provided in Table 4-35. A valid HI was calculated for all relays. The overall HI distribution for the relays is presented in Figure 4-42. Approximately 56% of the relays are in Poor or Very Poor condition, 29% in Fair condition, and the remaining 15% in Very Good condition. The high number of assets in Poor and Very Poor condition is driven by the obsolescence degradation factor. As noted above relays are more likely to need replacement based on obsolescence rather than physical deterioration.

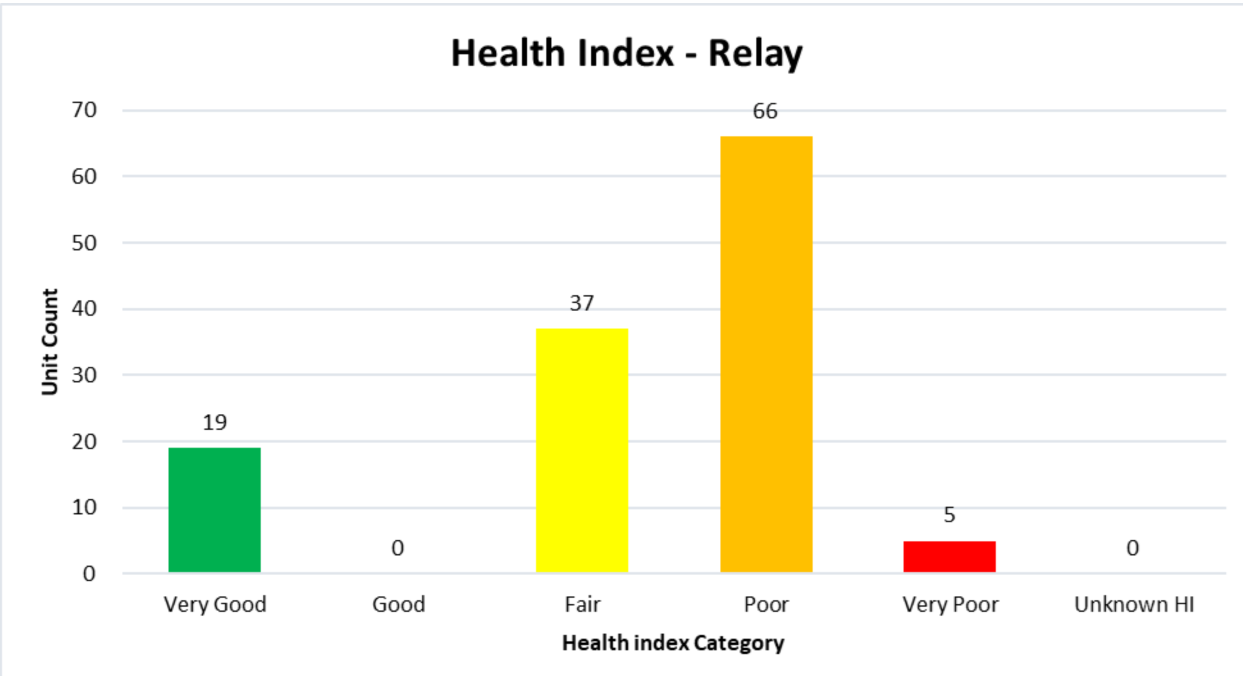


Figure 4-42: Protection Relay HI Results

The average DAI for the asset class is 100%. Table 4-36 presents the DAI of individual Degradation Factors used for the relay HI framework.

Table 4-36: Relays Degradation Factors Data Availability

Degradation Factor	% of Assets with Data
Service Age	100%
Testing	100%
Obsolescence	100%

4.2.8 Station Buildings

Each municipal station has a building where protection and control equipment, battery systems and indoor switchgears are located. The condition of the building is critical as they are the housing unit for storing and operating the in-service assets. Additionally, they serve a protective function for the assets from weather that may impact both the condition and performance of the housed assets. The HI for station buildings is calculated by considering visual inspections of several components of the buildings. Table 4-37 highlights the HI algorithm for buildings.

Table 4-37: Station Building Health Index Algorithm

Degradation Factor	Weight	Ranking	Numerical Grade	Max Score
Service Age	1	A,B,C,D,E	4,3,2,1,0	4
Roof Condition	2	A,B,C,D,E	4,3,2,1,0	8
Wall Condition	2	A,B,C,D,E	4,3,2,1,0	8
Doors/Windows/Louvres Condition	1	A,B,C,D,E	4,3,2,1,0	4
Floors/Foundations Condition	2	A,B,C,D,E	4,3,2,1,0	8
Lighting/Power/HVAC Condition	1	A,B,C,D,E	4,3,2,1,0	4
Overall Building Condition	2	A,B,C,D,E	4,3,2,1,0	8
			Total score	44

BHI owns 32 station buildings within its service territory. Installation date is known for all assets. Figure 4-43 presents the age distribution for station buildings.

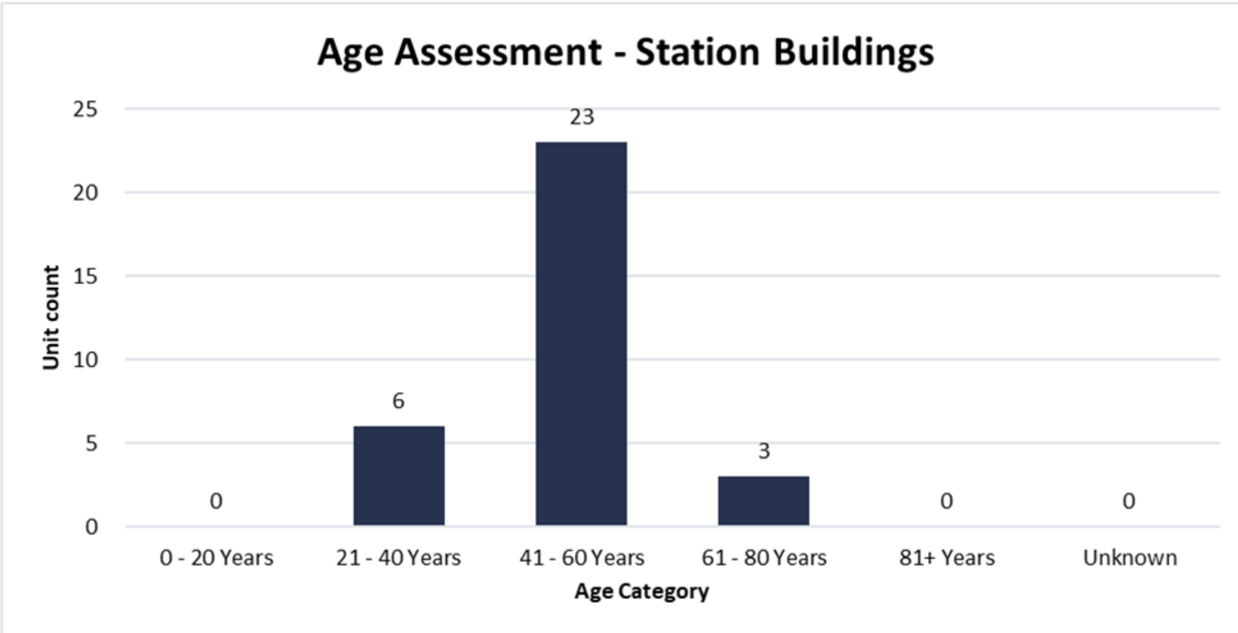


Figure 4-43: Station Building Age Demographics

BHI's building maintenance and demographics data were used to calculate the HI based on the criteria provided in Table 4-37. A valid HI was calculated for all buildings. The overall HI distribution for the buildings is presented in Figure 4-44. Approximately 13% of the buildings are in Poor condition, 38% in Fair condition, and the remaining 50% in Good condition.

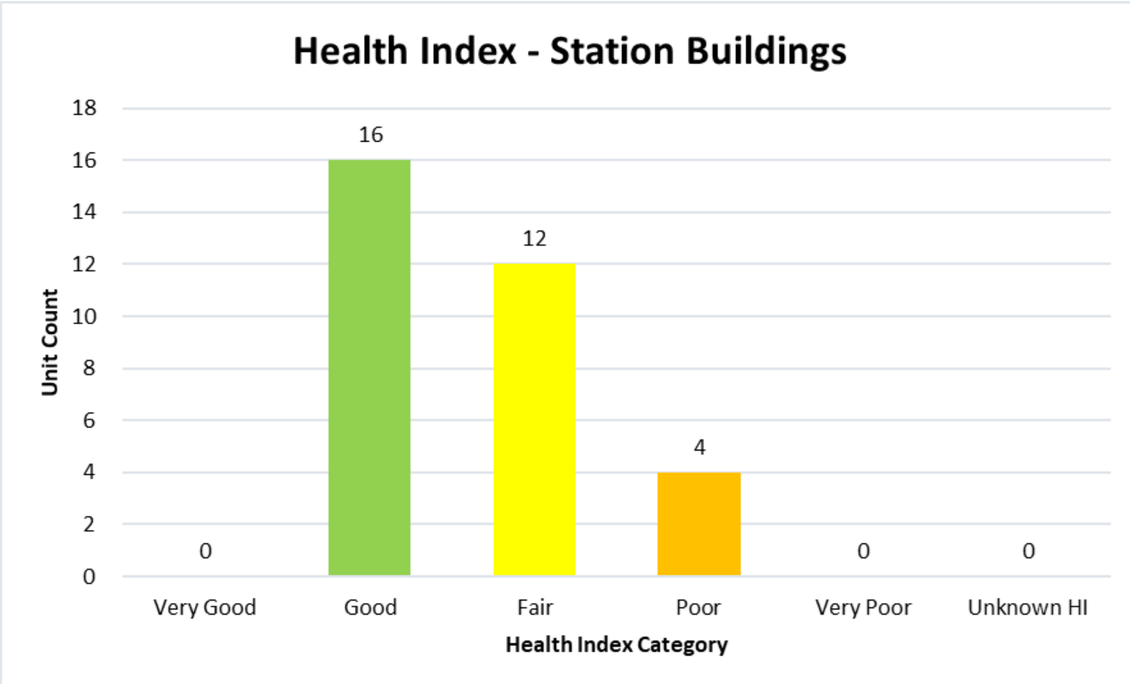


Figure 4-44: Station Building HI Results

The average DAI for the asset class is 100%. Table 4-38 presents the DAI of individual Degradation Factors used for the building HI framework.

Table 4-38: Station Buildings Degradation Factors Data Availability

Degradation Factor	% of Assets with Data
Service Age	100%
Roof Condition	100%
Wall Condition	100%
Doors/Windows/Louvres Condition	100%
Floors/Foundations Condition	100%
Lighting/Power/HVAC Condition	100%
Overall Building Condition	100%

5. Recommendations

A complete ACA framework for BHI represents an integral component of its broader asset management framework, enabling it to proactively manage its distribution assets and ensure that the right actions are taken for the right assets at the right time. This framework leveraged the information captured from maintenance programs and other utility records, creating an essential linkage between the ongoing maintenance activities and the capital investment decision-making process. Leveraging the HI insights allows BHI to make informed investment decisions . There are further opportunities to introduce new data collected, improve on data availability, and continuously improve the ACA framework.

This section breaks down BBA's recommendations into the following categories:

- HI improvement; and
- Data availability improvements.

5.1 Health index improvements

For select asset classes, a recommended HI formulation was used for BHI's ACA framework. The following set of recommendations target additional Degradation Factors that can be incorporated for specific asset classes to improve the HI formulation and provide BHI with additional data to refine its asset condition calculations. The recommendations are based on the "Ideal" ACA framework for assets and should not be interpreted as suggesting that immediate action is warranted. The priority of each recommendation depends on the relative weight of the Degradation Factor that it addresses.

- Primary underground cables
    - Additional cable testing: very-low-frequency tan-delta, partial discharge, and time-domain reflectometry testing
    - Cable post-mortem analysis to identify water trees
    - Cable loading history
- Overhead switches
    - Visual inspection results
- Overhead Line Reclosers

  - Visual inspection results
- Station Power Transformers
  - IR scan results
- Station protection relays
  - Visual inspection results
  - Mean time between failures

5.2 Data availability

Data availability is critical in being able to produce prudent, accurate and justified decision-making outputs. It represents the single most important element that can influence the degree to which the AM decision-making relies on objective factors. Companies understand that it is critical to execute continuous improvement procedures through an AM data lifecycle, such that data gaps and inaccuracies can be addressed and mitigated. In the case of this ACA study, each asset class included a breakdown of data available for each Degradation Factor collected. For Degradation Factors with data availability below 60%, BBA recommends that BHI continue collecting the information related to these data points to reach the 60% data availability threshold.

Additionally, for an asset to have a valid HI, it must meet a minimum 70% of available data across the Degradation Factors used in the HI formulation. As part of future improvement opportunities, it is recommended that BHI continue capturing asset data for Degradation Factors that are currently available for a small proportion of the asset population, such that valid Health Indices can be produced across the population. It is expected that with every passing year, the inspection record database will continue to grow, allowing for Health Indices to be calculated for the remaining population.

BBA noticed that some Degradation Factors recorded by BHI vary in the detail with respect to the grading scheme. Some parameters will have a three-tier grade (e.g., Good, Fair and Poor) and others may have five levels (e.g., from Very Good to Very Poor). BBA recommends for BHI to evaluate options of changing some Degradation Factors recorded to a five-level grade, as doing so can provide more defined segregation between assets that need immediate attention and those that can still be in-service with normal or no maintenance in the short-term. Additionally, BBA noticed that some visual inspection data for distribution assets, such as distribution switchgears, was contained as comments on inspection reports, rather than a tiered grade. In the future, it is recommended that BHI makes visual inspection findings for these assets more explicit to ensure that the HI score accurately reflects the true condition of the asset. Finally, BBA found that the wood pole visual inspection report only had the ability to input one issue in addition to noting if the pole was rotten, the rest of the issues are noted in the comments. It is recommended for future testing that BHI makes it easier to input multiple issues in a standardized manor to ensure that the HI score accurately reflects the true condition of each asset.

This report provides BHI with a broad range of recommendations with respect to specific types of information that it may choose to collect and the metrics it may deploy to enhance it's AM analytics.

Keeping records of asset condition is good practice, as it may assist in planning and assessing the quality of assets being replaced in-service. BBA recommends collecting and keeping condition records consistent for all assets inspected. BBA recommends that BHI tracks all contractor assessments through a central system, such as GIS, as part of their process improvements between Asset Management and GIS. This will help BHI in both standardizing inspection results and quickly identifying and flagging issues within the system. Obtaining and organizing more comprehensive condition data records would establish a stronger baseline of the asset health indices and more robust, multi-parameter, HI formulations can be used that are in-line with standardized practice in the industry.

Finally, it is recommended that BHI moves towards a Risk-Based Framework for investment planning in the future.

This concludes BBA's ACA report for BHI's major distribution and substation assets. We thank BHI's staff and management for the opportunity to participate in this complex study and for their ongoing support throughout its development.

6. Conclusions

As Figure 6-1 and Figure 6-2 indicate, most assets across BHI's asset classes analyzed are in Fair condition or better, with a significant portion of asset populations in Good or Very Good condition. This can indicate BHI has taken the necessary steps to manage its asset health and performance for the benefit of its customers. There are some asset classes that require BHI's attention in the coming years where a material number of assets are in or are approaching Poor or Very Poor condition.

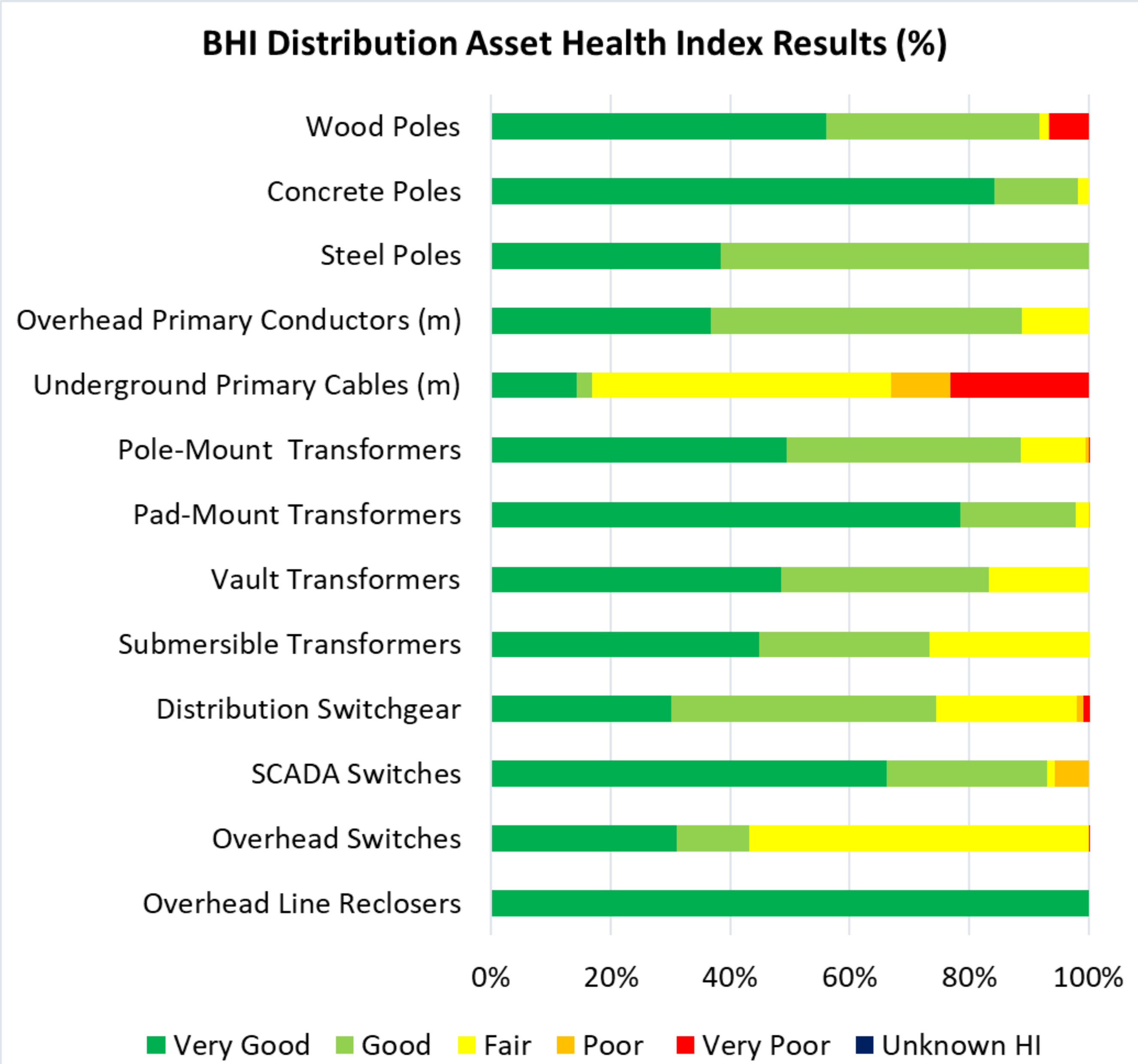


Figure 6-1: Distribution Health Index Results

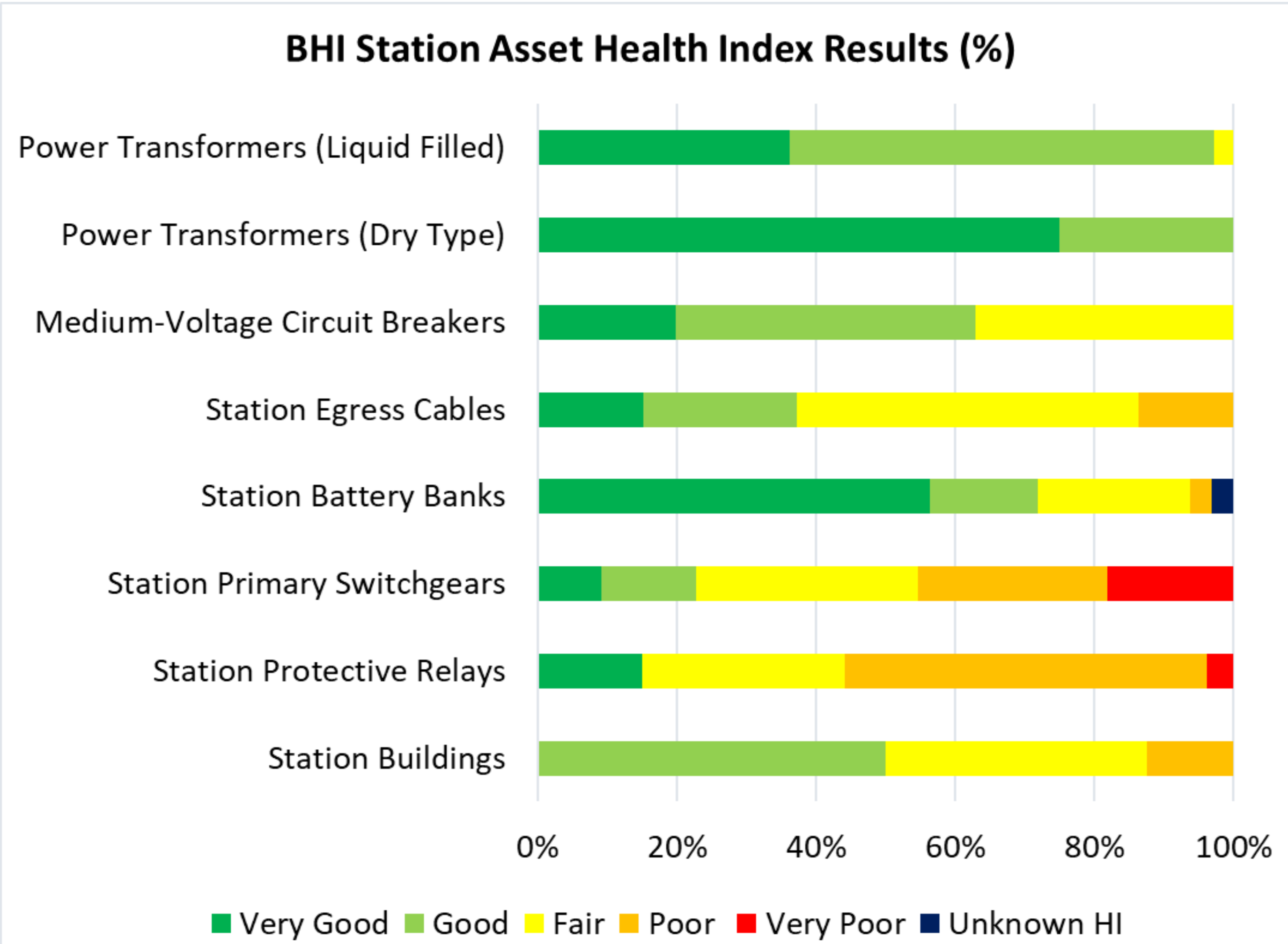


Figure 6-2: Station Health Index Results

BBA recommends that BHI continue their work to mitigate the gaps in the existing data so that more degradation parameters can be assigned actual grades, expanding the sample size of valid HI and capturing all possible degradation of the evaluated assets. As well, BHI should work to expand the types of data captured as to best represent each assets degradation to the greatest accuracy. BHI's testing, inspection, and maintenance programs are well-positioned to continue to capture this information using processes and technologies in place at their facility.

This concludes BBA's report on the condition assessment performed for BHI.

Burlington hydro inc.

Appendix J

2023 Annual System Performance Report

2023

System Performance

Report

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Introduction

The 2023 System Performance Report is intended to provide a comprehensive overview of the performance of the Burlington Hydro distribution system during 2023. It is based on the format established for previous reports and contributes to BHI's Asset Management Strategy by identifying future maintenance and capital budget priorities to enhance the reliability and performance of the distribution system. The following specific attributes are reviewed and addressed:

1) Substation and Feeder performance at 4.16, 13.8 and 27.6 kV primary voltage levels
2) Underground Distribution
3) System demand and critical loading issues
4) System maintenance activities and priorities
5) Reliability statistics and observations
6) Future Capital Budget recommendations

The information contained in the report was supplied by the Burlington Hydro Control Room, System Planning, Asset Management and BHI senior management; it summarizes statistics and incidents that occurred in 2023. Data from previous years was used for comparison purposes and to identify any recurring issues. Recommendations were based on consultations with BHI engineering and operations staff.

1 SUBSTATION AND FEEDER PERFORMANCE

1.1 GENERAL

In 2023, BHI had no major performance issues at any of its 32 substation locations. More specific observations and commentary, on substations, are included in section 1b below.

The following table summarizes the number of feeders at each voltage level.

Primary Voltage	Number of Feeders	Percentage of Total
27.6kV	34	21.11
13.8kV	28	17.39
4.16kV	98	61.49
Total	160	100.00

Table 1- Number of Feeders at each voltage level

The analysis of feeder performance is based on the recording of feeder Auto-Reclosures, of feeder Lock-Outs and a review of causes of interruptions. Appendix A summarizes the performance of each feeder since 2014, as follows:

1. Appendix A1: Auto-Recloses (sorted by total operations, since 2014)
2. Appendix A2: Auto-Recloses (sorted by no. of operations in 2023)
3. Appendix A3: Lock-Outs (sorted by total operations, since 2014)
4. Appendix A4: Lock-Outs (sorted by no. of operations in 2023)

These Appendices also identify the voltages of each feeder, and they are color coded the same as the typical BHI GIS voltage level colors; Blue - 4.16 KV, Red – 13.8 KV and Brown – 27.6 KV.

A review of the actual numbers of Auto-Recloses and Lock-Outs for 2023 and 2022 when compared to the average number since 2014 is also worth note.

Auto-Reclosures	2022	2023	Previous 10-year Average (2014-2023)
27.6kV	67	59	60.3
13.8kV	96	124	123.1
4.16kV	76	67	72.1
Total	239	250	256.1

Table 2- Auto-Recloses comparison between 2022, 2023 and the previous 10-year average (2014-2023)

Lock-Outs	2022	2023	Previous 10-year Average (2014-2023)
27.6kV	19	15	19.5
13.8kV	17	8	20
4.16kV	16	11	23.3
Total	52	34	62.8

Table 3- Lock-Outs comparison between 2022, 2023 and the previous 10-year average (2014-2023)

Conclusions:

It is important to appreciate the difference in loading capacity at each voltage level. A typical 4.16 kV feeder may supply only 500 customers, whereas a 13.8 kV feeder may supply around 1500 and 27.6 kV 4000 customers. Therefore, the exposure of feeders to possible incidents due to the length has a proportional relationship to the number of customers served. Also, it is acknowledged that both the 4.16 and 13.8kV customers experience momentary interruptions and outages when incidents occur on their 27.6kV supply feeder. Therefore Auto-Reclosures and Lock-Outs, at each voltage level, are not at all equal with respect to their impact on customers. With that background the following conclusions can be drawn from the above:

1. The total number of Auto-Reclosures increased in 2023 compared to the previous year, but it is still slightly lower than 10-year average, primarily due to the higher number of Auto-Reclosures at 13.8kV voltage level compared to the previous year.
2. The total number of Lock-Outs significantly decreased in 2023 and is far below 10-year average, primarily due to the decreased number of Lock-Outs at 4.16kV and 13.8 kV voltage level compared to the previous year.

More specific observations and commentary on these items are included in sections 1c, 1d and 1e below.

1.2 SUBSTATIONS

There are no significant changes to the station and feeder loadings in 2023. BHI Control Room Operators are aware of the system capabilities for station and feeder back-ups. At most times of the year these are not an issue, however there are the following potential vulnerabilities, some of which have been previously noted:

1. Brant M.S. and Mount Forest MS should provide back-up to each other, but this can be challenging under heavy load conditions and unplanned outages. To improve the situation BHI did upgrade the 4.16 KV feeder egress cables at Brant MS and the Station Transformer at Mount Forest M.S in the past. However, the upgrade of the 4.16 KV feeder egress cables at Mount Forest MS was deferred to a future date due to major investment required for the feeder riser poles and overhead line upgrade. In addition, feeder phase load balancing and feeder reconfiguration study has been performed and documentation prepared to be issued for implementation. Additional switching devises have been proposed to be installed together with voltage conversion of some radial sections. With proposed system upgrades and additional potential system improvements in the area, the back-up capacity and system reliability between Mount Forest MS and Brant MS will significantly improve.
2. BHI has started the planning process for 13.8KV Fairview MS decommissioning. The process will happen in few stages which will include voltage conversion for couple of feeders (F2 and F3), and load transfer/voltage conversion for the other two feeders (F1 and F4).

BHI expects to operate most of its substations indefinitely, as conversion to a higher voltage can be cost prohibitive. The transformers, switchgears, breakers, relays, and buildings are well maintained, but many of them are over 30 years old and generally supply power to existing and developed neighborhoods. Currently ten (10) Power Transformers are closely monitored based on the results of the Dissolved Gus Analysis (DGA) and quarterly oil test is performed throughout the year. Of the substations, twenty (20) are equipped with a single power transformer and twelve (12) have dual redundant transformation. Twenty-six (26) of the transformers are over 40 years old and therefore present the highest risk of failure. In 2011 an annual replacement program was initiated and since then twelve (12) Power Station Transformers have been replaced with new transformers.

1.3 27.6KV FEEDERS

Appendix B contains the 27.6kV Feeder Outage Reports for all 27.6kV feeders experiencing 5 or more Auto-Reclosures or 2 or more Lock-Outs, during 2023. The following is a commentary on each of these feeders.

Feeder (TS)	No. of 2023 Auto-Reclosures (2022)	No. of 2023 Lock-Outs (2022)	Comments/Cause	
			Auto-Reclosures	Lock-Outs
280M8	10 (1)	2 (0)	Unknown (4) Defective Transformer (3) Animal (1) Defective U/G Primary (1) Defective Switching Cubicle (1)	High Winds (1) Tree/Limb (1)
280M6	1 (5)	2 (1)	Unknown (1)	Defective Switch (2)
280M3	8 (1)	0 (2)	Unknown (6) Animal (1) Defective Transformer (1)	None
13M28	6 (2)	0 (1)	Unknown (6)	None
76M25	2 (2)	2 (0)	High Winds (1) Tree/Limb (1)	High Winds (1) Tree/Limb (1)
76M21	5 (2)	0 (0)	Unknown (1) High Winds/Tree (2) Animal (2)	None

Table 4- 27.6 kV Feeders experiencing 5 or more Auto-Reclosures or 2 or more Lockout.

In total the BHI 27.6kV feeders experienced 15 Lock-Outs and 59 Auto-Reclosures, during 2023 and mainly they were caused by High Winds/T-Storm for the Lock-Outs, and Unknown cause, High Winds/T-Storm, and Wildlife for the Auto-Reclosures. The following table compares the preceding 10 years of Lock-Outs.

YEAR	Number of 27.6 kV Lockouts
2014	20
2015	33
2016	23
2017	14
2018	20
2019	19
2020	22
2021	10
2022	19
2023	15

Table 5- Number of 27.6 kV Lockouts per year

1.4 13.8KV FEEDERS

The performance of certain 13.8kV feeders continues to be monitored closely. Appendix C contains the 13.8kV Feeder Outage Reports for all 13.8kV feeders experiencing 5 or more Auto-Reclosures or 2 or more Lock-Outs, during 2023. The following is a commentary on each of these feeders.

M.S. Feeder	No. of 2023 Auto-Reclosures (2022)	No. of 2023 Lock-Outs (2022)	Comments/Cause	
			Auto-Reclosures	Lock-Outs
LOWVILLE F1	14 (7)	0 (3)	Unknown (5) T-Storm (2) High Winds (1) Tree/Limb (1) Defective Switch (1) Defective Transformer (1) Animal (2) Pole Fire (1)	None
LOWVILLE F4	0 (0)	3 (1)	None	T-Storm/Tree (1) Animal (2)
ORCHARD F1	5 (3)	0 (1)	Unknown (2) High Winds (1) Defective U/G Primary (2)	None

ORCHARD F2	7 (2)	1 (1)	Unknown (1) Defective U/G Primary (2) Animal (2) Tree/Limb (1) Vehicle Accident-Pole Hit (1)	Unknown (1)
PALMER F1	10 (6)	0 (1)	Unknown (6) High Winds/Tree (3) Vehicle Accident-Pole Hit (1)	None
PALMER F2	9 (0)	1 (1)	Unknown (3) High Winds/Tree (4) Defective Switching Cubicle (1) Cold Load (1)	High Winds/Tree (1)
PALMER F3	11 (6)	0 (0)	Unknown (9) Defective U/G Primary (2)	None
PALMER F4	6 (8)	0 (0)	Unknown (1) T-Storm (1) Animal (1) Defective Insulator (1) Defective Transformer (2)	None
RESERVOIR F1	6 (4)	1 (0)	Unknown (2) Animal (1) Defective Connection(1) Defective Transformer (2) Defective U/G Primary (1)	High Winds (1)
TOWERLINE F4	13 (13)	0 (1)	Unknown (10) Animal (2) Defective U/G Primary (1)	None
TYANDAGA F1	5 (2)	0 (0)	Unknown (5)	None
TYANDAGA F3	3 (9)	2 (0)	Unknown (1) Animal (1) Tree/Limb (1)	Tree/Limb (2)
TYANDAGA F4	8 (1)	0 (0)	Cold Load (4) Defective Termination (1) Defective U/G Primary (3)	None

Table 6- 13.8 kV Feeders experiencing 5 or more Auto-Reclosures or, 2 or more Lockout

The 13.8kV feeders had decreased number of Lock-Outs and increase in number of Auto-Reclosures in 2023. A review of the above comments identifies Defective Equipment/Cable, Tree Limbs, and Unknown as main causes for the Lock-Outs; and Unknown, Defective U/G Primary, High Winds/Tree and Wildlife for the Auto-Reclosures. The following table compares the preceding 10 years of Lock-Outs.

YEAR	Number of 13.8 kV Lockouts
2014	21
2015	19
2016	22
2017	36
2018	31
2019	19
2020	11
2021	16
2022	17
2023	8

Table 7- Number of 13.8 kV Lockouts per year

1.5 4.16KV FEEDERS

The 4.16kV feeders performed fairly well, in 2023, Appendix D contains the 4.16kV Feeder Outage Reports for all 4.16kV feeders experiencing 5 or more Auto-Reclosures or 2 or more Lock-Outs, during 2023. The following is a commentary on each of these feeders.

M.S. Feeder	No. of 2023 Auto-Reclosures (2022)	No. of 2023 Lock-Outs (2022)	Comments/Cause	
			Auto-Reclosures	Lock-Outs
SPRUCE F2	6 (2)	1 (2)	Tree/Limb (4) High Winds/Tree (1) T-Storm (2)	Tree/Limb (1)
BRIDGEVIEW F2	6 (3)	0 (0)	High Winds/Tree (4) T-Storm (1) Vehicle Accident-Pole Hit (1)	None
PARTRIDGE F3	3 (2)	2 (0)	High Winds/Tree (3)	High Winds/Tree (2)

Table 8- 4.16 kV Feeders experiencing 5 or more Auto-Reclosures or, 2 or more Lock-Outs.

The 4.16kV feeders had decreased number of Lock-Outs and Auto-Reclosures in 2023. A review of the above comments identifies typical causes from Defective U/G Primary, High Winds, T-Storm and Tree Limbs for both Lock-Outs and Auto-Reclosures.

The need for feeder protection coordination and phase balance improvements has previously been identified as a need for improvement, on several 4.16kV feeders. This should receive increased attention to improving the operational efficiency of the system. Ref. Section 6c for recommendations.

2 UNDERGROUND DISTRIBUTION

A very large percentage of BHI's residential distribution system has been constructed underground, particularly in the newer neighborhoods, north of the QEW. Underground construction has been standard utility practice for over 30 years. These systems contain direct buried high voltage cables that are in contact with the ground and as such exposed to changes in that environment resulting in a higher rate of deterioration of the cable insulation as well as a higher failure rate of underground splices. BHI tracks the incidents of failure at these cables on an individual feeder and geographic location basis and uses this information to inform our capital investment program and capital budgets, for timely replacements and/or repairs. Appendix **C** is a high-level annual record of primary cable failures within the distribution system.

The planned replacement of primary cables is a very significant element within BHI's Asset Management Plan and represents a significant portion of the capital budget. The timing of cable replacements within specific neighborhoods requires a careful balance considering the condition of the cable insulation and the historical reliability performance.

Specific recommendations for future cable replacements, current maintenance and future recommendations for pad-mounted transformers and switching cubicles are included in Appendix D - "System Maintenance Activities & Priorities"

3 SYSTEM DEMAND AND CRITICAL LOADING ISSUES

3.2 OVERALL DEMAND/LOAD GROWTH

The following table shows BHI's System **coincident** measured peak demand and percentage growth for the last 15 years.

Year	Measured Peak Demand (MW)	Month	% Increase/decrease
2008	346.36	June	5.7
2009	350.43	August	1.18
2010	367.59	July	4.90
2011	379.69	July	3.29
2012	373.21	July	-1.71
2013	376.30	July	0.83
2014	325.55	August	-13.49
2015	340.35	July	4.55
2016	360.23	September	5.84
2017	321.21	September	-10.83
2018	351.44	July	9.41
2019	323.41	July	-7.97
2020	350.36	July	8.33
2021	344.66	August	-1.63
2022	344.05	June	-0.18
2023	337.02	September	-2.04

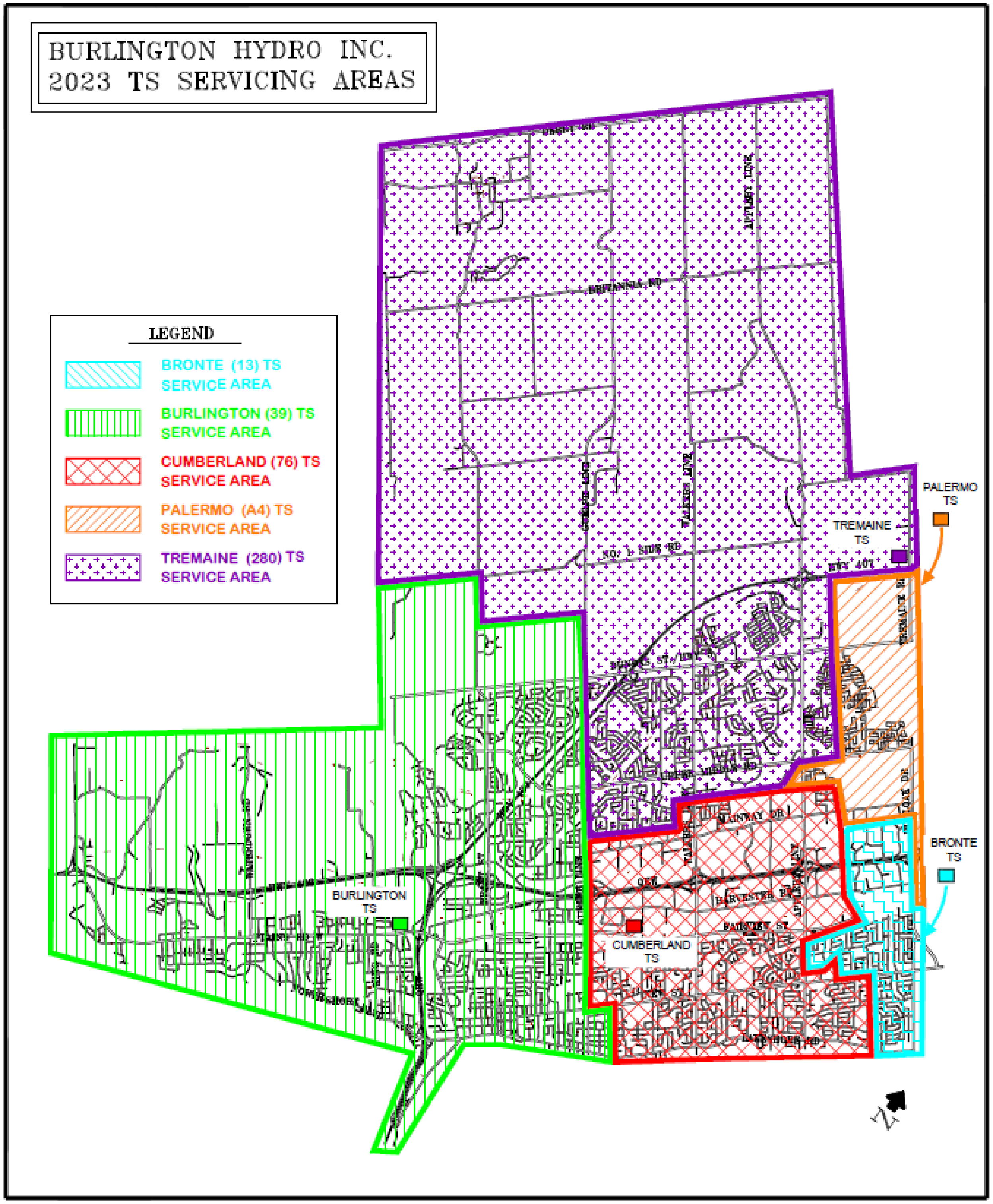
Table 9- Coincident peak demand and percentage growth

The 2023 coincident peak demand was lower than 2022 and lower than the 10 years average. Each year there are many variables that contribute to this number, such as customer growth, the local economy, summer heat and the impact of conservation initiatives.

3.3 27.6 FEEDER LOADS AND TRANSFORMER STATION CAPACITY

The map below indicates the five (5) Transformer Stations' (TS) servicing boundaries, where feeders from each station are servicing the customers in the respective service areas. Feeders are interconnected and configured so the loading is optimized based on available Station capacity and customer demand in these service areas. However, further system enhancements as well as continuation with the Tremaine TS feeders' egress/expansions are required to optimize the use of the TS's allocated capacity and create optimal loading on 27.6 KV feeders at each TS. In the absence of these additional feeders from Tremaine TS, there are limitations to load transfer capability with other TS's which could potentially create inefficiency into the BHI distribution system operation and may expose customers to less-than-optimum reliability.

Critical areas that need immediate attention regarding the feeder loading and available capacity are around the City of Burlington Mobility Hubs, which include the downtown and the three GO Stations, where the loading capacity of the feeders supplying these parts of the City have reached their optimal limit. The City of Burlington's long-term vision for downtown Burlington, GO Corridor and Major Transit Stations Areas (MTSA) is expected to accelerate the growth.
Since the City of Burlington has established the boundaries of the MTSA's (Main Transit Station Areas) we have seen an increased number of development applications for new mid/high rise buildings in these areas that represent large, concentrated demand, which will require expansion of existing feeders as well as bringing in new feeders to meet the needs of the new developments. BHI is constantly monitoring the System and feeders' capacity and performing regular system planning studies to balance load and allow efficient system operation and reliability for our customers. This may entail reconfiguration of existing open points (switching) and construction of new feeders to proactively mitigate any capacity constraints (at the feeder level)



BURLINGTON HYDRO INC.
2023 TS SERVICING AREAS
LEGEND
BRONTE (13) TS SERVICE AREA
BURLINGTON (39) TS SERVICE AREA
CUMBERLAND (76) TS SERVICE AREA
PALERMO (A4) TS SERVICE AREA
TREMAINE (280) TS SERVICE AREA
PALERMO TS
TREMAINE TS
BURLINGTON TS
CUMBERLAND TS
BRONTE TS
BRITANNIA RD
APPLEBY LINE
WALKERS LINE
NO. 1 SIDE RD
HWY 407
DUNDAS ST
UPPER MIDDLE RD
MAINWAY DR
HARVESTER RD
FAIRVIEW ST
LAKESHORE RD
N

BHI's 27.6kV feeder interconnections are well integrated and back-up arrangements have been further enhanced by the addition of remotely operated switches, however further system optimization analysis needs to be performed and more remotely operated switches to be installed at the intersection of existing and proposed feeders as well as for facilitating load transfers.

Most of the 27.6 KV feeders have reasonable loading. This is optimized at the planning capacity of approximately 300A, as is the preferred feeder loading to allow for emergency load transfers and back-up capability. There are some exceptions in maintaining this standard across the board, mainly due to Tremaine TS Feeder egress challenges, load growth in certain areas, and the increase in residential load and decrease in industrial/commercial load. The feeders loading is monitored regularly and if required a load transfer is performed where needed to off-load some of the heavy-loaded feeders. To improve this situation BHI has come up with a short and long-term plan to modify the feeder's configuration, interconnection, and load balancing. However, the permanent solution will ultimately depend on the continuation of the Tremaine TS feeder's expansion projects that are part of the BHI short-term and long-term capital investment strategy. Once implemented, this will provide an opportunity for loads to be easily transferred among the feeders and Transformer Stations, improve system flexibility and reliability, and reduce system losses.

Based on the latest performed study results a new instruction has been prepared and ready to be executed for reconfiguration of the Cumberland TS feeders (76M25 and 76M26) servicing downtown area so they can offload some of the Burlington TS feeders (39M5 and 39M35) servicing Burlington downtown and creating more capacity for connection of the new load. Proposed system enhancement will further improve the performance of the existing intelligent self-healing system located downtown, which approximately take less than a minute to isolate faulted section and restore the power to the rest of the system.

Additional load transfers and feeder's reconfiguration are required at both Burlington TS and Cumberland TS feeders to create capacity for future developments.

4 SYSTEM MAINTENANCE ACTIVITIES AND PRIORITIES

BHI aims to meet or exceed the system maintenance and inspection requirements of Section 4.4 of the Ontario Energy Board's Distribution System Code (DSC). Routine maintenance programs are consistent with good utility practices and are applied annually across all major assets within the BHI distribution system. A detailed maintenance report including future maintenance and operations recommendations can be found in Appendix **D** - "System Maintenance Activities & Priorities".

5 RELIABILITY STATISTICS AND OBSERVATIONS

In accordance with the Electricity Distribution System Reliability Measures and Expectations Report EB-2014-0189 completed by the Ontario Energy Board's (OEB's), BHI records and reports annually the following Service Reliability Indices:

SAIDI = System Average Interruption Duration Index

$$= \frac{\text{Total Customer-Hours of Interruptions}}{\text{Total Customers Served}}$$

SAIFI = System Average Interruption Frequency Index

$$= \frac{\text{Total Customer Interruptions}}{\text{Total Customers Served}}$$

CAIDI = Customer Average Interruption Duration Index

$$= \frac{\text{Total Customer-Hours of Interruptions}}{\text{Total Customer Interruptions}}$$

In addition, BHI also records:

SAARI = System Average Automatic Reclosure Index

$$= \frac{\text{Total Customer Automatic Reclosures}}{\text{Total Customers Served}}$$

These indices provide BHI with an annual measure of its service performance for internal benchmarking and for comparisons with other distribution companies as part of OEB's Performance Based Regulations. The following graphs demonstrate the individual performance measures over the last 8 years (excluding Lost of Supply and Major Events). The graphs below show an increasing but consistent level of performance compared with previous years.

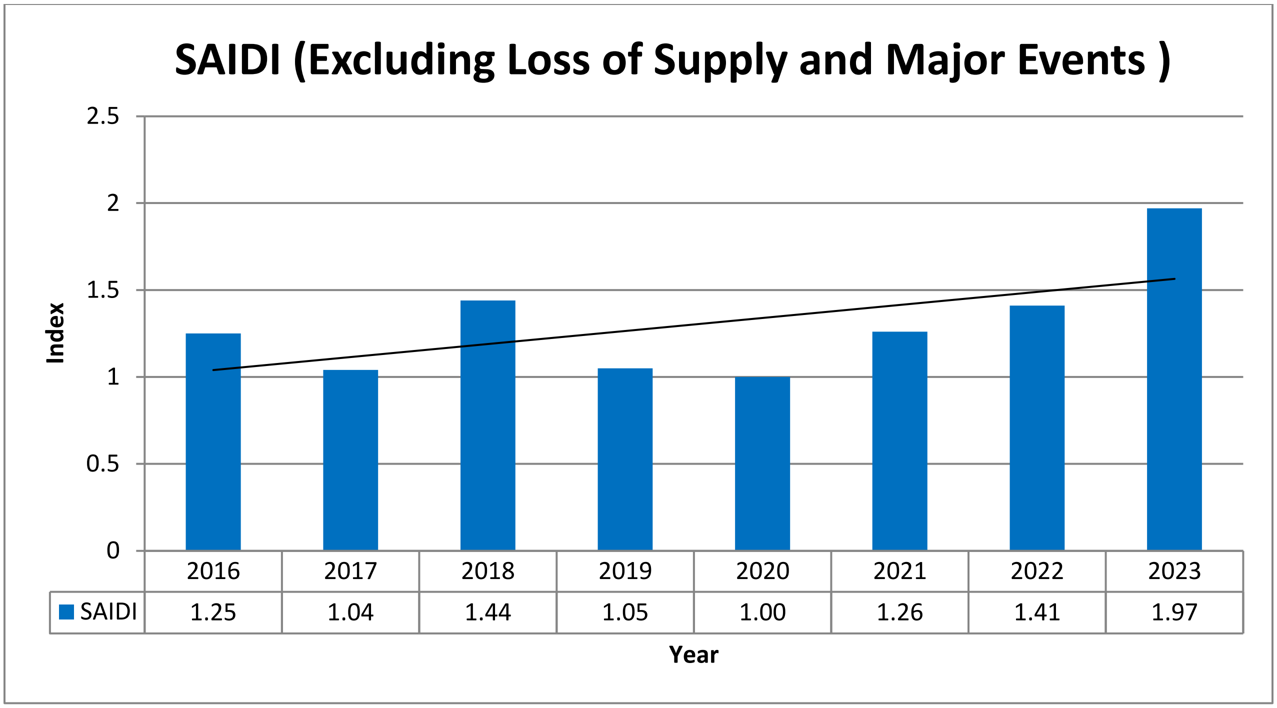


Figure 1- SAIDI from 2016 to 2023

8 Years Average – 1.30

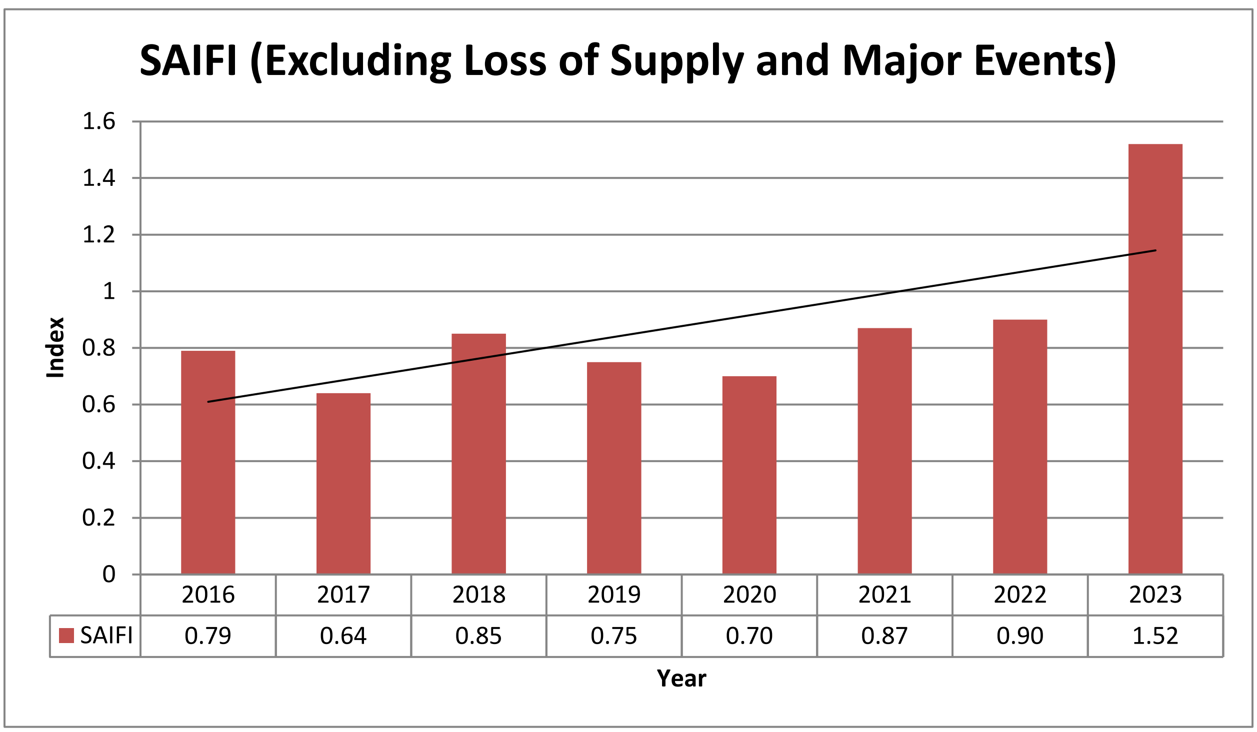
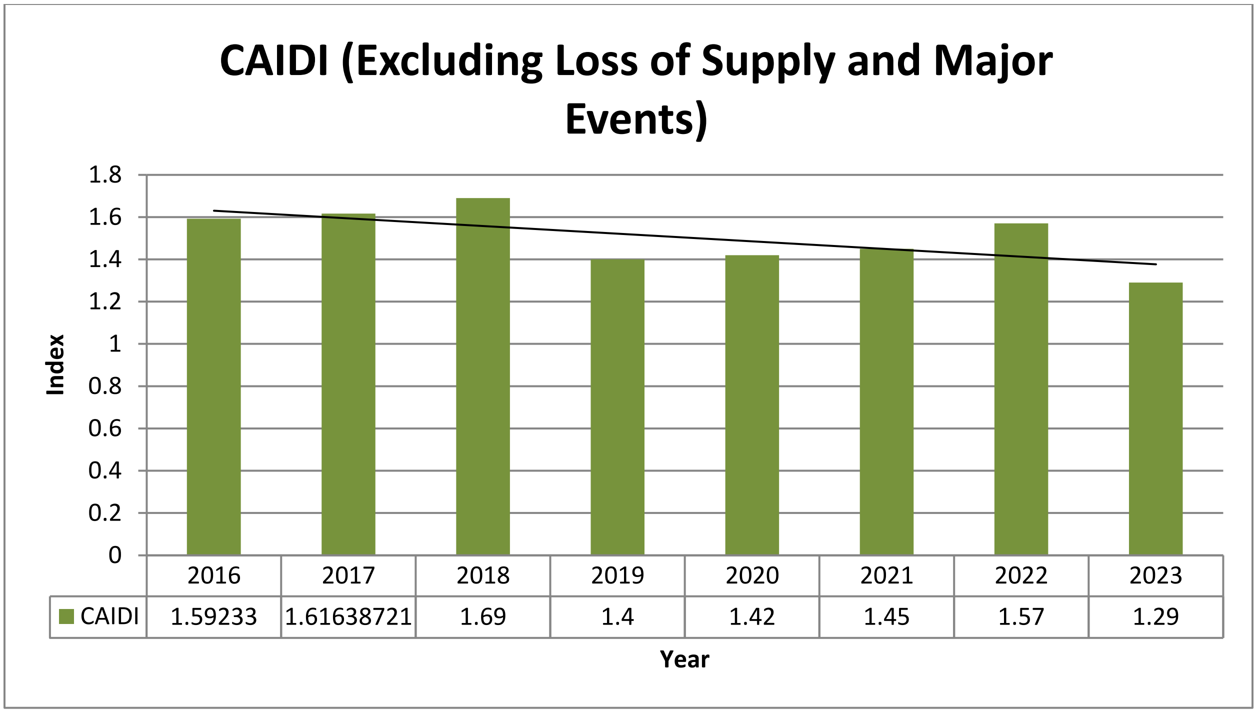


Figure 2- SAIFI from 2016 to 2023

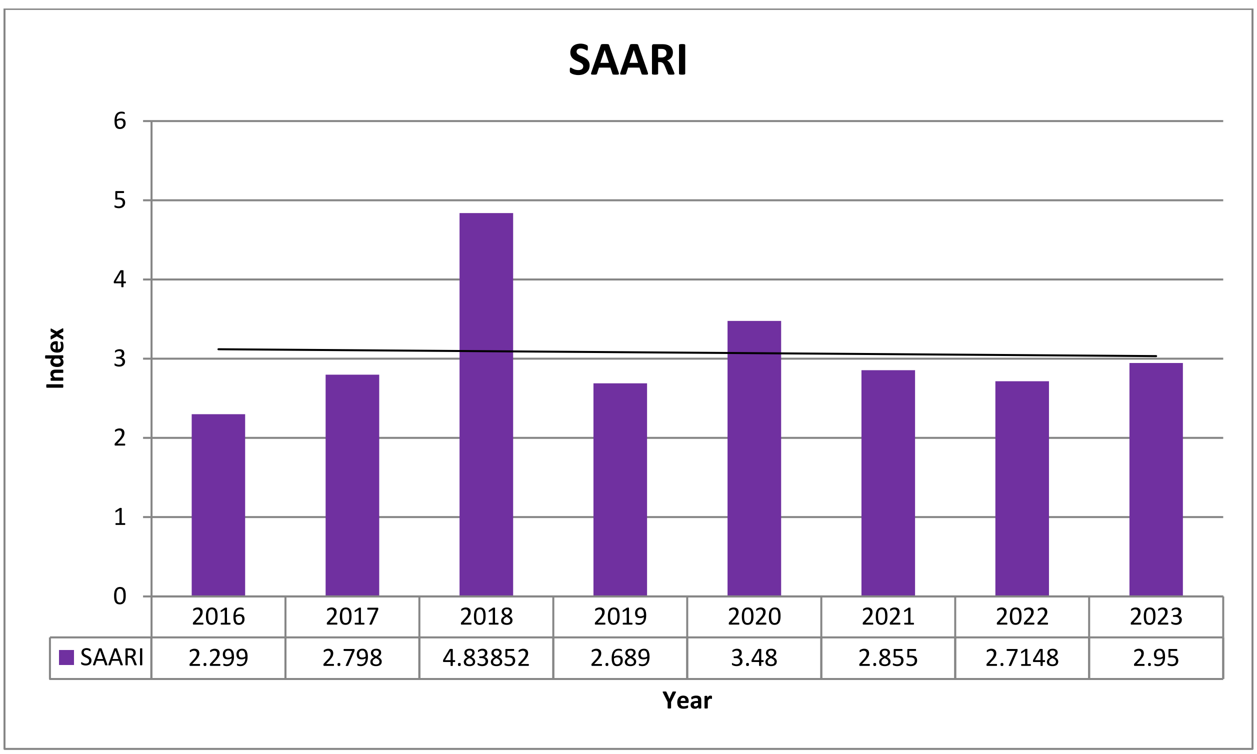
8 Years Average – 0.88



	2016	2017	2018	2019	2020	2021	2022	2023
CAIDI	1.59233	1.61638721	1.69	1.4	1.42	1.45	1.57	1.29

Figure 3- CAIDI from 2016 to 2023

8 Years Average – 1.50



	2016	2017	2018	2019	2020	2021	2022	2023
SAARI	2.299	2.798	4.83852	2.689	3.48	2.855	2.7148	2.95

Figure 4- SAARI from 2016 to 2023

8 Year Average – 3.08

6 FUTURE CAPITAL BUDGET RECOMMENDATIONS

6.1 SUBSTATION EQUIPMENT

With approximately twenty-five (25) of its substation power transformers over 40 years old and twelve (12), having elevated dissolved gases, these units require close monitoring and testing. BHI will aim to replace 1 unit every year or every other year and is looking into alternatives to mitigate risks (critical spares, potential station conversion, refurbishments, etc.). Additional programs for the station primary switchgears, feeder circuit breakers and relay upgrades, at least one station per year, have been introduced and recommended for continuance.

6.2 27.6 KV FEEDERS

The following are the proposed major capital projects as a part of the Tremaine TS 27.6KV feeder's and Burlington TS feeders' expansion, required to be constructed in the next few years as new developments materialize.

Expansion of the existing circuit 27.6 kV O/H line between Appleby Ln and Guelph Ln along Dundas Rd

Expansion of the existing circuit 27.6 kV O/H line between Dundas Rd and Reservoir MS along Guelph Ln

Expansion of two existing circuits 27.6 kV O/H line between Tremaine TS and Dundas Rd along Tremaine Rd

Expansion of three circuits 27.6 kV O/H line from Dundas Rd to UMR along Bronte Creek

Expansion of the existing circuit 27.6 kV O/H line between Skyview Dr and south of Watertown Rd along NSR

Expansion of the existing 27.6 KV U/G line between Burlington GO Station and Guelph Ln along Fairview St

Expansion of the existing 27.6 KV U/G line between Grahams Ln and Pine St along Brant St

6.3 13.8 KV AND 4.16 KV FEEDERS

The following feeders with primary cable failures have been identified and should be reviewed as part of the Asset Management plan and prioritized for capital budget consideration.

- Palmer MS F3
- Towerline MS F4
- Tyandaga MS F4
- Reservoir MS F1 and Orchard MS F1, F2

In addition to the cable replacement program BHI has started a formal program for MS feeder egress cables replacement, considering the cables that are already past their useful life and are showing signs of insulation deterioration during the regular preventive maintenance inspection and testing.

In the past BHI installed new reclosing automation technologies, three phase recloser (IntelliRupter) and single phase reclosers (Tripsaver) on several 13.8 kV feeders. BHI should continue to install these or similar automation technologies and integrate them into the operation of the control room, to improve the reliability for the customers supplied by these feeders. In addition to the Overhead Switches, BHI is planning to upgrade the existing pad mounted switching cubicles at some key locations with remotely controlled switching devices. BHI has plans to expand these applications throughout its system as part of future energy transition and grid modernization requirements, to improve the system performance. Appendix **C** shows the underground primary cables faults and cables rebuild areas from 2002 to 2023.

6.4 SYSTEM PLANNING

BHI has focused on long-term system planning and has identified several projects for investments in its distribution system to meet the needs of anticipated demand at the city established mobility Hub’s (Downtown, MTSA’s) as well as enhance the performance of the distribution system for its customers. These are prioritized in advance of the required update to the Distribution System Plan.

APPENDIX A1

Feeder Auto-Reclosures Summary

(Sorted by Total)

FEEDER	VOLTAGE	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	TOTALS (2014-2023)
TOWERLINE F4	13.8	13	8	4	10	14	7	6	9	13	13	97
LOWVILLE F1	13.8	6	8	11	4	12	9	5	17	7	14	93
INTERCHANGE F1	13.8	5	1	10	7	9	5	8	12	15	4	76
RESERVOIR F1	13.8	6	10	10	15	10	7	2	4	4	6	74
TYANDAGA F2	13.8	10	5	4	13	12	10	10	9	1	0	74
PALMER F1	13.8	4	8	7	5	9	4	7	10	6	10	70
PALMER F3	13.8	5	1	5	9	12	1	8	10	6	11	68
TYANDAGA F3	13.8	7	9	8	6	3	7	6	9	9	3	67
LOWVILLE F3	13.8	2	4	1	6	11	2	5	29	0	4	64
FAIRVIEW F3	13.8	1	10	11	10	10	1	6	3	1	3	56
PALMER F4	13.8	5	7	3	1	10	5	9	1	8	6	55
TOWERLINE F2	13.8	5	10	5	4	8	5	4	5	3	2	51
76M21	27.6	13	3	7	0	1	6	4	4	2	5	45
TOWERLINE F1	13.8	19	1	2	5	1	3	7	1	0	4	43
TYANDAGA F4	13.8	4	4	7	5	3	3	5	2	1	8	42
ORCHARD F2	13.8	5	4	9	1	6	1	3	1	2	7	39
TYANDAGA F1	13.8	5	4	3	5	3	2	4	6	2	5	39
13M27	27.6	8	4	3	1	6	6	4	4	2	1	39
ORCHARD F1	13.8	2	1	10	4	2	1	0	7	3	5	35
PT NELSON F2	4.1	5	2	5	1	5	2	7	7	0	1	35
PALMER F2	13.8	5	0	2	3	8	3	1	2	0	9	33
FAIRVIEW F2	13.8	3	4	2	2	2	4	8	2	4	2	33
INTERCHANGE F2	13.8	4	0	3	3	5	1	2	6	3	4	31
76M30	27.6	2	2	1	1	6	3	6	3	5	1	30
LOWVILLE F2	13.8	1	2	1	3	5	1	3	6	4	3	29
A4M6	27.6	8	4	3	2	6	1	3	0	2	0	29
39M36	27.6	2	3	1	1	4	4	0	6	4	3	28
76M24	27.6	0	0	3	3	10	1	1	2	5	3	28
280M3	27.6	0	0	4	5	1	3	1	3	1	8	26
FAIRWOOD F6	4.1	0	1	2	2	6	7	4	2	1	1	26
76M23	27.6	4	4	2	2	3	1	2	1	4	2	25
EASTERBROOK F3	4.1	1	1	4	2	1	0	2	4	8	1	24
SPRUCE F2	4.1	4	0	4	4	1	1	1	0	2	6	23
76M27	27.6	0	2	0	3	1	2	3	3	3	4	21
39M31	27.6	5	0	2	2	1	1	1	2	5	2	21
39M32	27.6	2	2	0	3	0	4	4	1	3	2	21
280M6	27.6	1	3	2	0	2	3	2	2	5	1	21
39M35	27.6	1	1	4	2	4	0	6	2	1	0	21

FEEDER	VOLTAGE	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	TOTALS (2014-2023)
13M28	27.6	3	1	1	2	1	1	0	3	2	6	20
76M25	27.6	0	2	0	3	6	2	2	1	2	2	20
76M28	27.6	2	1	2	4	0	5	4	1	0	1	20
76M26	27.6	0	1	2	5	6	2	3	0	1	0	20
MARLEY F3	4.1	1	3	1	1	3	2	4	1	2	1	19
WALKERS F1	4.1	0	4	0	5	7	0	0	2	1	0	19
PINEDALE F1	4.1	1	0	1	2	3	6	2	2	0	1	18
WALKERS F4	4.1	0	2	1	1	6	0	2	2	3	1	18
TOWERLINE F3	13.8	0	0	2	0	2	5	2	5	2	0	18
280M8	27.6	0	0	0	0	1	0	1	4	1	10	17
39M5	27.6	0	0	2	5	3	0	4	1	1	1	17
76M22	27.6	1	0	4	1	2	1	1	2	4	1	17
FAIRWOOD F4	4.1	0	1	2	3	3	0	1	1	6	0	17
76M29	27.6	1	1	1	0	2	0	5	1	4	1	16
39M1	27.6	0	4	3	0	2	3	1	2	1	0	16
39M2	27.6	8	2	2	0	2	1	1	0	0	0	16
PINECOVE F3	4.1	2	2	2	1	8	1	0	0	0	0	16
BRIDGEVIEW F2	4.1	0	2	0	0	2	0	0	2	3	6	15
HAMPTON F1	4.1	3	0	0	3	5	2	0	0	0	1	14
FAIRWOOD F2	4.1	0	3	0	0	3	3	0	0	1	3	13
HOWARD F3	4.1	3	1	3	0	0	2	1	1	0	2	13
PINEDALE F2	4.1	0	1	5	1	1	0	0	1	2	2	13
FAIRLEIGH F2	4.1	1	1	0	3	2	0	1	3	1	1	13
SPRUCE F3	4.1	1	2	0	2	2	1	1	2	1	1	13
MAPLE F6	4.1	0	0	0	0	3	6	1	0	3	0	13
PINECOVE F1	4.1	0	0	0	0	7	2	2	1	1	0	13
WALKERS F2	4.1	0	0	2	3	1	1	1	1	0	3	12
39M4	27.6	5	1	0	0	1	0	1	1	2	1	12
MARTHA F1	4.1	1	0	1	1	5	0	3	0	0	1	12
WOODWARD F5	4.1	5	0	2	0	3	0	0	1	0	1	12
PT NELSON F1	4.1	1	0	1	1	0	2	6	0	1	0	12
APPLEBY F1	4.1	0	1	0	4	2	0	3	1	0	0	11
MT FOREST F2	4.1	0	0	2	0	0	1	1	2	5	0	11
13M26	27.6	1	0	0	0	3	0	1	1	2	2	10
LOWVILLE F4	13.8	1	1	0	4	1	0	1	2	0	0	10
RESERVOIR F3	13.8	3	0	3	0	1	1	0	1	1	0	10
MAPLE F5	4.1	0	1	1	1	1	0	0	0	6	0	10
MAPLE F8	4.1	1	2	3	0	1	0	0	1	2	0	10
WOODWARD F2	4.1	3	1	2	0	2	0	0	2	0	0	10

FEEDER	VOLTAGE	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	TOTALS (2014-2023)
ELGIN F1	4.1	1	0	0	1	2	1	2	0	0	2	9
MARTHA F6	4.1	4	0	1	0	0	0	1	2	0	1	9
SPRUCE F1	4.1	2	1	0	0	4	1	0	0	0	1	9
280M4	27.6	0	2	0	3	2	1	0	0	1	0	9
RESERVOIR F4	13.8	4	1	0	0	1	1	0	1	1	0	9
ELIZ GARDENS F3	4.1	2	0	1	4	1	1	0	0	0	0	9
MARTHA F7	4.1	1	2	1	1	0	0	1	3	0	0	9
PARTRIDGE F3	4.1	0	1	0	1	0	0	0	1	2	3	8
APPLEBY F4	4.1	0	0	0	1	2	1	0	1	1	2	8
PARTRIDGE F1	4.1	2	1	0	0	0	0	2	1	1	1	8
PINECOVE F2	4.1	0	0	1	2	2	1	0	0	1	1	8
A4M5	27.6	0	0	0	0	0	3	2	2	1	0	8
HARVESTER F1	4.1	0	0	1	1	3	0	0	1	2	0	8
EASTERBROOK F1	4.1	1	0	1	0	0	0	0	1	1	3	7
ELGIN F4	4.1	0	0	2	1	0	0	1	0	0	3	7
MARLEY F1	4.1	0	0	0	1	1	0	1	1	0	3	7
MARLEY F2	4.1	2	0	0	0	1	0	0	1	1	2	7
RESERVOIR F2	13.8	1	0	2	2	1	0	0	0	0	1	7
39M34	27.6	3	0	0	0	0	1	1	2	0	0	7
EASTERBROOK F2	4.1	0	0	0	2	1	2	2	0	0	0	7
BRANT F2	4.1	3	2	0	0	1	1	0	0	0	0	7
BRIDGEVIEW F1	4.1	2	0	0	2	0	1	0	1	1	0	7
DRURY F1	4.1	5	0	0	0	2	0	0	0	0	0	7
WOODWARD F6	4.1	0	1	0	0	3	1	0	1	1	0	7
APPLEBY F2	4.1	0	1	0	1	0	1	0	0	1	2	6
HARVESTER F3	4.1	1	0	0	0	1	0	0	1	1	2	6
13M25	27.6	2	1	0	0	0	0	1	1	0	1	6
39M6	27.6	0	2	0	1	1	0	0	0	1	1	6
APPLEBY F6	4.1	2	0	1	0	0	1	0	0	1	1	6
MARTHA F2	4.1	0	0	1	0	2	0	0	0	2	1	6
MT FOREST F1	4.1	0	1	1	0	1	1	0	1	0	1	6
280M5	27.6	0	0	0	0	2	2	0	2	0	0	6
39M33	27.6	1	2	0	0	1	0	0	1	1	0	6
ELIZ GARDENS F1	4.1	0	0	0	4	2	0	0	0	0	0	6
GRAHAMS F4	4.1	0	4	1	0	0	0	0	1	0	0	6
PT NELSON F3	4.1	0	0	1	0	1	1	2	1	0	0	6
PARTRIDGE F2	4.1	1	1	2	0	0	0	0	0	0	1	5
FAIRVIEW F1	13.8	0	1	0	1	3	0	0	0	0	0	5

FEEDER	VOLTAGE	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	TOTALS (2014-2023)
FAIRLEIGH F1	4.1	0	0	1	1	1	0	0	1	1	0	5
GRAHAMS F2	4.1	1	1	0	0	0	0	0	1	2	0	5
HAMPTON F6	4.1	1	0	0	3	0	0	0	1	0	0	5
MAPLE F1	4.1	0	0	0	1	2	0	1	1	0	0	5
WOODWARD F3	4.1	1	0	0	0	0	0	1	0	3	0	5
APPLEBY F5	4.1	0	1	1	0	0	0	0	0	1	1	4
BRANT F3	4.1	0	0	0	0	1	2	0	0	0	1	4
DRURY F4	4.1	0	0	1	0	1	1	1	0	0	0	4
ELGIN F2	4.1	1	0	0	0	1	0	2	0	0	0	4
ELIZ GARDENS F2	4.1	0	0	2	0	0	0	0	2	0	0	4
FAIRWOOD F5	4.1	2	0	0	0	1	0	0	1	0	0	4
WOODWARD F4	4.1	0	0	0	2	0	0	0	0	0	1	3
280M7	27.6	0	0	0	0	0	0	2	0	1	0	3
FAIRVIEW F4	13.8	0	0	0	0	3	0	0	0	0	0	3
HAMPTON F2	4.1	0	0	1	0	1	0	0	1	0	0	3
HOWARD F2	4.1	0	0	0	0	1	0	0	2	0	0	3
MAPLE F2	4.1	0	1	1	0	0	0	0	1	0	0	3
MARTHA F8	4.1	2	0	0	1	0	0	0	0	0	0	3
SPRUCE F4	4.1	1	0	0	1	0	0	0	0	1	0	3
MARTHA F3	4.1	0	0	0	1	0	0	0	0	0	1	2
39M3	27.6	0	0	0	1	0	0	1	0	0	0	2
ELGIN F3	4.1	0	1	0	0	0	0	0	0	1	0	2
HAMPTON F3	4.1	0	0	0	0	0	0	0	0	2	0	2
HARVESTER F2	4.1	0	0	0	1	0	1	0	0	0	0	2
FAIRLEIGH F3	4.1	0	0	0	0	1	0	0	0	0	0	1
FAIRWOOD F1	4.1	0	0	0	0	0	0	1	0	0	0	1
FAIRWOOD F3	4.1	0	1	0	0	0	0	0	0	0	0	1
HAMPTON F4	4.1	0	0	1	0	0	0	0	0	0	0	1
HAMPTON F5	4.1	1	0	0	0	0	0	0	0	0	0	1
HOWARD F1	4.1	0	0	0	1	0	0	0	0	0	0	1
MAPLE F3	4.1	0	0	0	0	1	0	0	0	0	0	1
MARTHA F5	4.1	0	0	0	0	0	0	1	0	0	0	1
MT FOREST F3	4.1	0	0	0	0	0	1	0	0	0	0	1
WOODWARD F1	4.1	0	0	0	0	1	0	0	0	0	0	1
APPLEBY F3	4.1	0	0	0	0	0	0	0	0	0	0	0
BRANT F1	4.1	0	0	0	0	0	0	0	0	0	0	0
DRURY F2	4.1	0	0	0	0	0	0	0	0	0	0	0
DRURY F3	4.1	0	0	0	0	0	0	0	0	0	0	0
GRAHAMS F1	4.1	0	0	0	0	0	0	0	0	0	0	0

FEEDER	VOLTAGE	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	TOTALS (2014-2023)
GRAHAMS F3	4.1	0	0	0	0	0	0	0	0	0	0	0
MAPLE F4	4.1	0	0	0	0	0	0	0	0	0	0	0
MAPLE F7	4.1	0	0	0	0	0	0	0	0	0	0	0
MARTHA F4	4.1	0	0	0	0	0	0	0	0	0	0	0
PINEDALE F3	4.1	0	0	0	0	0	0	0	0	0	0	0
PT NELSON F4	4.1	0	0	0	0	0	0	0	0	0	0	0
WALKERS F3	4.1	0	0	0	0	0	0	0	0	0	0	0

APPENDIX A2

Feeder Auto-Reclosures Summary

(Sorted by 2023)

FEEDER	VOLTAGE	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	TOTALS (2014-2023)
LOWVILLE F1	13.8	6	8	11	4	12	9	5	17	7	14	93
TOWERLINE F4	13.8	13	8	4	10	14	7	6	9	13	13	97
PALMER F3	13.8	5	1	5	9	12	1	8	10	6	11	68
PALMER F1	13.8	4	8	7	5	9	4	7	10	6	10	70
280M8	27.6	0	0	0	0	1	0	1	4	1	10	17
PALMER F2	13.8	5	0	2	3	8	3	1	2	0	9	33
TYANDAGA F4	13.8	4	4	7	5	3	3	5	2	1	8	42
280M3	27.6	0	0	4	5	1	3	1	3	1	8	26
ORCHARD F2	13.8	5	4	9	1	6	1	3	1	2	7	39
RESERVOIR F1	13.8	6	10	10	15	10	7	2	4	4	6	74
PALMER F4	13.8	5	7	3	1	10	5	9	1	8	6	55
SPRUCE F2	4.1	4	0	4	4	1	1	1	0	2	6	23
13M28	27.6	3	1	1	2	1	1	0	3	2	6	20
BRIDGEVIEW F2	4.1	0	2	0	0	2	0	0	2	3	6	15
76M21	27.6	13	3	7	0	1	6	4	4	2	5	45
TYANDAGA F1	13.8	5	4	3	5	3	2	4	6	2	5	39
ORCHARD F1	13.8	2	1	10	4	2	1	0	7	3	5	35
INTERCHANGE F1	13.8	5	1	10	7	9	5	8	12	15	4	76
LOWVILLE F3	13.8	2	4	1	6	11	2	5	29	0	4	64
TOWERLINE F1	13.8	19	1	2	5	1	3	7	1	0	4	43
INTERCHANGE F2	13.8	4	0	3	3	5	1	2	6	3	4	31
76M27	27.6	0	2	0	3	1	2	3	3	3	4	21
TYANDAGA F3	13.8	7	9	8	6	3	7	6	9	9	3	67
FAIRVIEW F3	13.8	1	10	11	10	10	1	6	3	1	3	56
LOWVILLE F2	13.8	1	2	1	3	5	1	3	6	4	3	29
39M36	27.6	2	3	1	1	4	4	0	6	4	3	28
76M24	27.6	0	0	3	3	10	1	1	2	5	3	28
FAIRWOOD F2	4.1	0	3	0	0	3	3	0	0	1	3	13
WALKERS F2	4.1	0	0	2	3	1	1	1	1	0	3	12
PARTRIDGE F3	4.1	0	1	0	1	0	0	0	1	2	3	8
EASTERBROOK F1	4.1	1	0	1	0	0	0	0	1	1	3	7
ELGIN F4	4.1	0	0	2	1	0	0	1	0	0	3	7
MARLEY F1	4.1	0	0	0	1	1	0	1	1	0	3	7
TOWERLINE F2	13.8	5	10	5	4	8	5	4	5	3	2	51
FAIRVIEW F2	13.8	3	4	2	2	2	4	8	2	4	2	33
76M23	27.6	4	4	2	2	3	1	2	1	4	2	25
39M31	27.6	5	0	2	2	1	1	1	2	5	2	21
39M32	27.6	2	2	0	3	0	4	4	1	3	2	21

FEEDER	VOLTAGE	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	TOTALS (2014-2023)
HOWARD F3	4.1	3	1	3	0	0	2	1	1	0	2	13
PINEDALE F2	4.1	0	1	5	1	1	0	0	1	2	2	13
13M26	27.6	1	0	0	0	3	0	1	1	2	2	10
ELGIN F1	4.1	1	0	0	1	2	1	2	0	0	2	9
APPLEBY F4	4.1	0	0	0	1	2	1	0	1	1	2	8
MARLEY F2	4.1	2	0	0	0	1	0	0	1	1	2	7
APPLEBY F2	4.1	0	1	0	1	0	1	0	0	1	2	6
HARVESTER F3	4.1	1	0	0	0	1	0	0	1	1	2	6
13M27	27.6	8	4	3	1	6	6	4	4	2	1	39
PT NELSON F2	4.1	5	2	5	1	5	2	7	7	0	1	35
76M30	27.6	2	2	1	1	6	3	6	3	5	1	30
FAIRWOOD F6	4.1	0	1	2	2	6	7	4	2	1	1	26
EASTERBROOK F3	4.1	1	1	4	2	1	0	2	4	8	1	24
280M6	27.6	1	3	2	0	2	3	2	2	5	1	21
76M28	27.6	2	1	2	4	0	5	4	1	0	1	20
MARLEY F3	4.1	1	3	1	1	3	2	4	1	2	1	19
PINEDALE F1	4.1	1	0	1	2	3	6	2	2	0	1	18
WALKERS F4	4.1	0	2	1	1	6	0	2	2	3	1	18
39M5	27.6	0	0	2	5	3	0	4	1	1	1	17
76M22	27.6	1	0	4	1	2	1	1	2	4	1	17
76M29	27.6	1	1	1	0	2	0	5	1	4	1	16
HAMPTON F1	4.1	3	0	0	3	5	2	0	0	0	1	14
FAIRLEIGH F2	4.1	1	1	0	3	2	0	1	3	1	1	13
SPRUCE F3	4.1	1	2	0	2	2	1	1	2	1	1	13
39M4	27.6	5	1	0	0	1	0	1	1	2	1	12
MARTHA F1	4.1	1	0	1	1	5	0	3	0	0	1	12
WOODWARD F5	4.1	5	0	2	0	3	0	0	1	0	1	12
MARTHA F6	4.1	4	0	1	0	0	0	1	2	0	1	9
SPRUCE F1	4.1	2	1	0	0	4	1	0	0	0	1	9
PARTRIDGE F1	4.1	2	1	0	0	0	0	2	1	1	1	8
PINECOVE F2	4.1	0	0	1	2	2	1	0	0	1	1	8
RESERVOIR F2	13.8	1	0	2	2	1	0	0	0	0	1	7
13M25	27.6	2	1	0	0	0	0	1	1	0	1	6
39M6	27.6	0	2	0	1	1	0	0	0	1	1	6
APPLEBY F6	4.1	2	0	1	0	0	1	0	0	1	1	6
MARTHA F2	4.1	0	0	1	0	2	0	0	0	2	1	6
MT FOREST F1	4.1	0	1	1	0	1	1	0	1	0	1	6
PARTRIDGE F2	4.1	1	1	2	0	0	0	0	0	0	1	5
APPLEBY F5	4.1	0	1	1	0	0	0	0	0	1	1	4

FEEDER	VOLTAGE	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	TOTALS (2014-2023)
APPLEBY F5	4.1	0	1	1	0	0	0	0	0	1	1	4
BRANT F3	4.1	0	0	0	0	1	2	0	0	0	1	4
WOODWARD F4	4.1	0	0	0	2	0	0	0	0	0	1	3
MARTHA F3	4.1	0	0	0	1	0	0	0	0	0	1	2
TYANDAGA F2	13.8	10	5	4	13	12	10	10	9	1	0	74
A4M6	27.6	8	4	3	2	6	1	3	0	2	0	29
39M35	27.6	1	1	4	2	4	0	6	2	1	0	21
76M26	27.6	0	1	2	5	6	2	3	0	1	0	20
WALKERS F1	4.1	0	4	0	5	7	0	0	2	1	0	19
TOWERLINE F3	13.8	0	0	2	0	2	5	2	5	2	0	18
FAIRWOOD F4	4.1	0	1	2	3	3	0	1	1	6	0	17
39M1	27.6	0	4	3	0	2	3	1	2	1	0	16
39M2	27.6	8	2	2	0	2	1	1	0	0	0	16
PINECOVE F3	4.1	2	2	2	1	8	1	0	0	0	0	16
MAPLE F6	4.1	0	0	0	0	3	6	1	0	3	0	13
PINECOVE F1	4.1	0	0	0	0	7	2	2	1	1	0	13
PT NELSON F1	4.1	1	0	1	1	0	2	6	0	1	0	12
APPLEBY F1	4.1	0	1	0	4	2	0	3	1	0	0	11
MT FOREST F2	4.1	0	0	2	0	0	1	1	2	5	0	11
LOWVILLE F4	13.8	1	1	0	4	1	0	1	2	0	0	10
RESERVOIR F3	13.8	3	0	3	0	1	1	0	1	1	0	10
MAPLE F5	4.1	0	1	1	1	1	0	0	0	6	0	10
MAPLE F8	4.1	1	2	3	0	1	0	0	1	2	0	10
WOODWARD F2	4.1	3	1	2	0	2	0	0	2	0	0	10
280M4	27.6	0	2	0	3	2	1	0	0	1	0	9
RESERVOIR F4	13.8	4	1	0	0	1	1	0	1	1	0	9
ELIZ GARDENS F3	4.1	2	0	1	4	1	1	0	0	0	0	9
MARTHA F7	4.1	1	2	1	1	0	0	1	3	0	0	9
A4M5	27.6	0	0	0	0	0	3	2	2	1	0	8
HARVESTER F1	4.1	0	0	1	1	3	0	0	1	2	0	8
39M34	27.6	3	0	0	0	0	1	1	2	0	0	7
EASTERBROOK F2	4.1	0	0	0	2	1	2	2	0	0	0	7
BRANT F2	4.1	3	2	0	0	1	1	0	0	0	0	7
BRIDGEVIEW F1	4.1	2	0	0	2	0	1	0	1	1	0	7
DRURY F1	4.1	5	0	0	0	2	0	0	0	0	0	7
WOODWARD F6	4.1	0	1	0	0	3	1	0	1	1	0	7
280M5	27.6	0	0	0	0	2	2	0	2	0	0	6
39M33	27.6	1	2	0	0	1	0	0	1	1	0	6
ELIZ GARDENS F1	4.1	0	0	0	4	2	0	0	0	0	0	6

FEEDER	VOLTAGE	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	TOTALS (2014-2023)
GRAHAMS F4	4.1	0	4	1	0	0	0	0	1	0	0	6
PT NELSON F3	4.1	0	0	1	0	1	1	2	1	0	0	6
FAIRVIEW F1	13.8	0	1	0	1	3	0	0	0	0	0	5
FAIRLEIGH F1	4.1	0	0	1	1	1	0	0	1	1	0	5
GRAHAMS F2	4.1	1	1	0	0	0	0	0	1	2	0	5
HAMPTON F6	4.1	1	0	0	3	0	0	0	1	0	0	5
MAPLE F1	4.1	0	0	0	1	2	0	1	1	0	0	5
WOODWARD F3	4.1	1	0	0	0	0	0	1	0	3	0	5
DRURY F4	4.1	0	0	1	0	1	1	1	0	0	0	4
ELGIN F2	4.1	1	0	0	0	1	0	2	0	0	0	4
ELIZ GARDENS F2	4.1	0	0	2	0	0	0	0	2	0	0	4
FAIRWOOD F5	4.1	2	0	0	0	1	0	0	1	0	0	4
280M7	27.6	0	0	0	0	0	0	2	0	1	0	3
FAIRVIEW F4	13.8	0	0	0	0	3	0	0	0	0	0	3
HAMPTON F2	4.1	0	0	1	0	1	0	0	1	0	0	3
HOWARD F2	4.1	0	0	0	0	1	0	0	2	0	0	3
MAPLE F2	4.1	0	1	1	0	0	0	0	1	0	0	3
MARTHA F8	4.1	2	0	0	1	0	0	0	0	0	0	3
SPRUCE F4	4.1	1	0	0	1	0	0	0	0	1	0	3
39M3	27.6	0	0	0	1	0	0	1	0	0	0	2
ELGIN F3	4.1	0	1	0	0	0	0	0	0	1	0	2
HAMPTON F3	4.1	0	0	0	0	0	0	0	0	2	0	2
HARVESTER F2	4.1	0	0	0	1	0	1	0	0	0	0	2
FAIRLEIGH F3	4.1	0	0	0	0	1	0	0	0	0	0	1
FAIRWOOD F1	4.1	0	0	0	0	0	0	1	0	0	0	1
FAIRWOOD F3	4.1	0	1	0	0	0	0	0	0	0	0	1
HAMPTON F4	4.1	0	0	1	0	0	0	0	0	0	0	1
HAMPTON F5	4.1	1	0	0	0	0	0	0	0	0	0	1
HOWARD F1	4.1	0	0	0	1	0	0	0	0	0	0	1
MAPLE F3	4.1	0	0	0	0	1	0	0	0	0	0	1
MARTHA F5	4.1	0	0	0	0	0	0	1	0	0	0	1
MT FOREST F3	4.1	0	0	0	0	0	1	0	0	0	0	1
WOODWARD F1	4.1	0	0	0	0	1	0	0	0	0	0	1
APPLEBY F3	4.1	0	0	0	0	0	0	0	0	0	0	0
BRANT F1	4.1	0	0	0	0	0	0	0	0	0	0	0
DRURY F2	4.1	0	0	0	0	0	0	0	0	0	0	0
DRURY F3	4.1	0	0	0	0	0	0	0	0	0	0	0
GRAHAMS F1	4.1	0	0	0	0	0	0	0	0	0	0	0
GRAHAMS F3	4.1	0	0	0	0	0	0	0	0	0	0	0

FEEDER	VOLTAGE	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	TOTALS (2014-2023)
MAPLE F4	4.1	0	0	0	0	0	0	0	0	0	0	0
MAPLE F7	4.1	0	0	0	0	0	0	0	0	0	0	0
MARTHA F4	4.1	0	0	0	0	0	0	0	0	0	0	0
PINEDALE F3	4.1	0	0	0	0	0	0	0	0	0	0	0
PT NELSON F4	4.1	0	0	0	0	0	0	0	0	0	0	0
WALKERS F3	4.1	0	0	0	0	0	0	0	0	0	0	0

APPENDIX A3

Feeder Lock-Outs Summary

(Sorted by Total)

FEEDER	KV	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	TOTALS (2014-2023)
LOWVILLE F4	13.8	8	4	10	1	6	2	0	1	1	3	36
LOWVILLE F3	13.8	4	3	3	3	8	2	0	2	3	0	28
76M26	27.6	1	0	1	2	2	3	2	1	4	1	17
TOWERLINE F2	13.8	2	1	0	8	1	1	0	3	0	0	16
39M2	27.6	3	4	0	0	1	1	1	2	1	1	14
39M31	27.6	0	8	0	2	0	0	1	1	0	1	13
PALMER F1	13.8	1	2	1	7	0	1	0	0	1	0	13
39M5	27.6	0	2	2	1	2	2	1	0	2	0	12
A4M6	27.6	0	3	0	1	6	2	0	0	0	0	12
PT NELSON F2	4.1	1	1	0	2	2	0	3	2	1	0	12
SPRUCE F1	4.1	0	7	3	1	0	0	1	0	0	0	12
SPRUCE F3	4.1	0	4	1	1	1	1	1	2	1	0	12
39M1	27.6	0	5	3	0	1	0	0	0	2	0	11
TYANDAGA F3	13.8	0	2	0	0	1	1	2	2	0	2	10
ORCHARD F2	13.8	1	0	1	4	1	0	0	1	1	1	10
PINEDALE F2	4.1	1	0	2	2	2	0	0	1	1	1	10
LOWVILLE F2	13.8	0	2	0	0	2	2	1	3	0	0	10
280M6	27.6	0	1	1	0	0	0	3	1	1	2	9
76M23	27.6	2	1	2	0	0	1	1	1	0	1	9
PALMER F2	13.8	0	0	0	2	3	1	1	0	1	1	9
76M21	27.6	3	1	0	0	2	1	1	1	0	0	9
FAIRVIEW F2	13.8	1	3	0	4	0	1	0	0	0	0	9
INTERCHANGE F1	13.8	1	1	0	0	1	0	0	3	3	0	9
LOWVILLE F1	13.8	0	0	1	1	0	2	1	0	3	0	8
ORCHARD F1	13.8	0	1	1	0	2	1	2	0	1	0	8
DRURY F4	4.1	1	2	1	3	0	1	0	0	0	0	8
FAIRLEIGH F2	4.1	0	0	1	4	1	0	0	2	0	0	8
HARVESTER F1	4.1	3	0	1	1	0	0	1	0	2	0	8
39M35	27.6	1	0	0	2	1	1	0	1	0	1	7
SPRUCE F2	4.1	1	0	1	1	0	0	0	1	2	1	7
WALKERS F1	4.1	1	2	1	1	1	0	0	0	0	1	7
39M3	27.6	0	2	3	0	0	1	0	0	1	0	7
DRURY F1	4.1	5	0	1	0	0	1	0	0	0	0	7
MT FOREST F1	4.1	0	0	0	0	0	4	3	0	0	0	7
76M25	27.6	0	0	3	0	0	1	0	0	0	2	6
PARTRIDGE F3	4.1	1	2	0	0	0	1	0	0	0	2	6
280M4	27.6	1	0	0	2	0	0	2	0	0	1	6
76M24	27.6	2	1	0	2	0	0	0	0	0	1	6
HOWARD F3	4.1	3	0	0	0	0	2	0	0	0	1	6

FEEDER	KV	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	TOTALS (2014-2023)
280M3	27.6	0	0	2	0	1	0	1	0	2	0	6
PINEDALE F1	4.1	3	0	0	1	0	1	0	1	0	0	6
280M8	27.6	0	0	0	0	0	0	2	1	0	2	5
PINECOVE F3	4.1	0	0	0	1	2	1	0	0	0	1	5
13M27	27.6	1	0	0	1	0	0	1	0	2	0	5
39M36	27.6	1	1	0	0	0	2	1	0	0	0	5
FAIRVIEW F3	13.8	1	0	0	0	2	1	1	0	0	0	5
FAIRWOOD F6	4.1	0	1	0	0	0	4	0	0	0	0	5
MAPLE F6	4.1	0	2	0	1	0	0	1	1	0	0	5
MARLEY F2	4.1	5	0	0	0	0	0	0	0	0	0	5
MARLEY F3	4.1	1	2	0	0	1	1	0	0	0	0	5
76M27	27.6	0	0	0	0	0	0	1	1	1	1	4
RESERVOIR F1	13.8	0	0	1	2	0	0	0	0	0	1	4
13M25	27.6	0	0	4	0	0	0	0	0	0	0	4
39M4	27.6	0	0	0	0	2	1	1	0	0	0	4
INTERCHANGE F2	13.8	0	0	0	1	1	1	0	0	1	0	4
RESERVOIR F3	13.8	0	0	3	0	0	1	0	0	0	0	4
TOWERLINE F4	13.8	1	0	0	0	0	1	0	1	1	0	4
TYANDAGA F1	13.8	0	0	0	0	2	1	1	0	0	0	4
HAMPTON F6	4.1	1	0	1	2	0	0	0	0	0	0	4
PARTRIDGE F1	4.1	2	0	2	0	0	0	0	0	0	0	4
PINECOVE F2	4.1	2	0	0	1	0	0	0	0	1	0	4
76M30	27.6	0	0	0	0	1	0	0	0	1	1	3
APPLEBY F4	4.1	0	0	1	0	0	0	1	0	0	1	3
GRAHAMS F4	4.1	0	2	0	0	0	0	0	0	0	1	3
39M32	27.6	0	1	0	0	0	2	0	0	0	0	3
39M34	27.6	1	1	0	0	0	1	0	0	0	0	3
39M6	27.6	1	1	0	0	0	0	0	0	1	0	3
RESERVOIR F2	13.8	0	0	1	0	0	0	2	0	0	0	3
BRANT F2	4.1	0	0	0	0	0	0	1	2	0	0	3
ELGIN F1	4.1	1	0	0	0	2	0	0	0	0	0	3
FAIRLEIGH F1	4.1	0	0	0	1	2	0	0	0	0	0	3
FAIRWOOD F4	4.1	0	0	2	0	1	0	0	0	0	0	3
HAMPTON F1	4.1	2	0	0	0	0	0	0	0	1	0	3
HARVESTER F3	4.1	0	0	0	0	1	2	0	0	0	0	3
PARTRIDGE F2	4.1	1	0	1	0	1	0	0	0	0	0	3
SPRUCE F4	4.1	0	0	1	1	0	0	1	0	0	0	3
WALKERS F3	4.1	0	1	1	0	1	0	0	0	0	0	3
WOODWARD F5	4.1	1	0	0	0	1	0	0	1	0	0	3

FEEDER	KV	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	TOTALS (2014-2023)
13M26	27.6	1	0	1	0	0	0	0	0	0	0	2
280M5	27.6	0	0	1	0	0	0	1	0	0	0	2
76M29	27.6	0	0	0	0	1	0	1	0	0	0	2
A4M5	27.6	0	1	0	1	0	0	0	0	0	0	2
APPLEBY F1	4.1	0	1	0	1	0	0	0	0	0	0	2
EASTERBROOK F1	4.1	1	0	0	0	0	0	1	0	0	0	2
EASTERBROOK F3	4.1	1	0	0	0	0	0	0	1	0	0	2
ELIZ GARDENS F2	4.1	0	0	0	0	0	1	0	0	1	0	2
FAIRWOOD F5	4.1	0	0	0	0	0	0	0	1	1	0	2
HAMPTON F2	4.1	0	0	0	0	2	0	0	0	0	0	2
MAPLE F1	4.1	0	0	0	0	0	0	1	0	1	0	2
MAPLE F8	4.1	0	0	0	0	0	0	2	0	0	0	2
PT NELSON F4	4.1	0	0	0	1	0	0	0	1	0	0	2
WALKERS F2	4.1	0	1	0	0	0	0	0	0	1	0	2
EASTERBROOK F2	4.1	0	0	0	0	0	0	0	0	0	1	1
HAMPTON F4	4.1	0	0	0	0	0	0	0	0	0	1	1
13M28	27.6	0	0	0	0	0	0	0	0	1	0	1
280M7	27.6	0	0	0	0	0	0	1	0	0	0	1
39M33	27.6	1	0	0	0	0	0	0	0	0	0	1
76M22	27.6	1	0	0	0	0	0	0	0	0	0	1
FAIRVIEW F4	13.8	0	0	0	1	0	0	0	0	0	0	1
PALMER F3	13.8	0	0	0	1	0	0	0	0	0	0	1
PALMER F4	13.8	0	0	0	0	1	0	0	0	0	0	1
TOWERLINE F3	13.8	1	0	0	0	0	0	0	0	0	0	1
TYANDAGA F2	13.8	0	0	0	0	0	0	0	0	1	0	1
TYANDAGA F4	13.8	0	0	0	1	0	0	0	0	0	0	1
BRANT F1	4.1	0	0	0	0	0	1	0	0	0	0	1
BRIDGEVIEW F1	4.1	0	0	0	0	0	0	0	0	1	0	1
ELGIN F2	4.1	0	0	1	0	0	0	0	0	0	0	1
ELIZ GARDENS F1	4.1	0	1	0	0	0	0	0	0	0	0	1
FAIRLEIGH F3	4.1	0	0	0	0	1	0	0	0	0	0	1
GRAHAMS F1	4.1	1	0	0	0	0	0	0	0	0	0	1
GRAHAMS F3	4.1	0	0	0	0	0	1	0	0	0	0	1
HARVESTER F2	4.1	0	0	0	1	0	0	0	0	0	0	1
HOWARD F1	4.1	0	0	0	0	1	0	0	0	0	0	1
MAPLE F2	4.1	0	0	0	0	0	0	1	0	0	0	1
MARLEY F1	4.1	0	0	0	0	0	0	0	1	0	0	1
MARTHA F1	4.1	0	0	0	0	0	1	0	0	0	0	1
MARTHA F2	4.1	0	0	0	0	1	0	0	0	0	0	1
MARTHA F5	4.1	0	0	0	0	0	0	0	0	1	0	1

FEEDER	KV	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	TOTALS (2014-2023)
MARTHA F7	4.1	0	0	1	0	0	0	0	0	0	0	1
MT FOREST F3	4.1	0	0	0	0	0	0	0	0	1	0	1
PINECOVE F1	4.1	0	0	0	0	1	0	0	0	0	0	1
PT NELSON F1	4.1	0	0	1	0	0	0	0	0	0	0	1
PT NELSON F3	4.1	0	0	1	0	0	0	0	0	0	0	1
WOODWARD F2	4.1	1	0	0	0	0	0	0	0	0	0	1
WOODWARD F3	4.1	0	0	0	1	0	0	0	0	0	0	1
WOODWARD F4	4.1	0	0	1	0	0	0	0	0	0	0	1
76M28	27.6	0	0	0	0	0	0	0	0	0	0	0
FAIRVIEW F1	13.8	0	0	0	0	0	0	0	0	0	0	0
RESERVOIR F4	13.8	0	0	0	0	0	0	0	0	0	0	0
TOWERLINE F1	13.8	0	0	0	0	0	0	0	0	0	0	0
APPLEBY F2	4.1	0	0	0	0	0	0	0	0	0	0	0
APPLEBY F3	4.1	0	0	0	0	0	0	0	0	0	0	0
APPLEBY F5	4.1	0	0	0	0	0	0	0	0	0	0	0
APPLEBY F6	4.1	0	0	0	0	0	0	0	0	0	0	0
BRANT F3	4.1	0	0	0	0	0	0	0	0	0	0	0
BRIDGEVIEW F2	4.1	0	0	0	0	0	0	0	0	0	0	0
DRURY F2	4.1	0	0	0	0	0	0	0	0	0	0	0
DRURY F3	4.1	0	0	0	0	0	0	0	0	0	0	0
ELGIN F3	4.1	0	0	0	0	0	0	0	0	0	0	0
ELGIN F4	4.1	0	0	0	0	0	0	0	0	0	0	0
ELIZ GARDENS F3	4.1	0	0	0	0	0	0	0	0	0	0	0
FAIRWOOD F1	4.1	0	0	0	0	0	0	0	0	0	0	0
FAIRWOOD F2	4.1	0	0	0	0	0	0	0	0	0	0	0
FAIRWOOD F3	4.1	0	0	0	0	0	0	0	0	0	0	0
GRAHAMS F2	4.1	0	0	0	0	0	0	0	0	0	0	0
HAMPTON F3	4.1	0	0	0	0	0	0	0	0	0	0	0
HAMPTON F5	4.1	0	0	0	0	0	0	0	0	0	0	0
HOWARD F2	4.1	0	0	0	0	0	0	0	0	0	0	0
MAPLE F3	4.1	0	0	0	0	0	0	0	0	0	0	0
MAPLE F4	4.1	0	0	0	0	0	0	0	0	0	0	0
MAPLE F5	4.1	0	0	0	0	0	0	0	0	0	0	0
MAPLE F7	4.1	0	0	0	0	0	0	0	0	0	0	0
MARTHA F3	4.1	0	0	0	0	0	0	0	0	0	0	0
MARTHA F4	4.1	0	0	0	0	0	0	0	0	0	0	0
MARTHA F6	4.1	0	0	0	0	0	0	0	0	0	0	0
MARTHA F8	4.1	0	0	0	0	0	0	0	0	0	0	0
MT FOREST F2	4.1	0	0	0	0	0	0	0	0	0	0	0
PINEDALE F3	4.1	0	0	0	0	0	0	0	0	0	0	0

FEEDER	KV	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	TOTALS (2014-2023)
WALKERS F4	4.1	0	0	0	0	0	0	0	0	0	0	0
WOODWARD F1	4.1	0	0	0	0	0	0	0	0	0	0	0
WOODWARD F6	4.1	0	0	0	0	0	0	0	0	0	0	0

APPENDIX A4

Feeder Lock-Out Summary

(Sorted by 2023)

FEEDER	KV	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	TOTALS (2014-2023)
LOWVILLE F4	13.8	8	4	10	1	6	2	0	1	1	3	36
280M6	27.6	0	1	1	0	0	0	3	1	1	2	9
76M25	27.6	0	0	3	0	0	1	0	0	0	2	6
280M8	27.6	0	0	0	0	0	0	2	1	0	2	5
TYANDAGA F3	13.8	0	2	0	0	1	1	2	2	0	2	10
PARTRIDGE F3	4.1	1	2	0	0	0	1	0	0	0	2	6
76M26	27.6	1	0	1	2	2	3	2	1	4	1	17
39M2	27.6	3	4	0	0	1	1	1	2	1	1	14
39M31	27.6	0	8	0	2	0	0	1	1	0	1	13
76M23	27.6	2	1	2	0	0	1	1	1	0	1	9
39M35	27.6	1	0	0	2	1	1	0	1	0	1	7
280M4	27.6	1	0	0	2	0	0	2	0	0	1	6
76M24	27.6	2	1	0	2	0	0	0	0	0	1	6
76M27	27.6	0	0	0	0	0	0	1	1	1	1	4
76M30	27.6	0	0	0	0	1	0	0	0	1	1	3
ORCHARD F2	13.8	1	0	1	4	1	0	0	1	1	1	10
PALMER F2	13.8	0	0	0	2	3	1	1	0	1	1	9
RESERVOIR F1	13.8	0	0	1	2	0	0	0	0	0	1	4
PINEDALE F2	4.1	1	0	2	2	2	0	0	1	1	1	10
SPRUCE F2	4.1	1	0	1	1	0	0	0	1	2	1	7
WALKERS F1	4.1	1	2	1	1	1	0	0	0	0	1	7
HOWARD F3	4.1	3	0	0	0	0	2	0	0	0	1	6
PINECOVE F3	4.1	0	0	0	1	2	1	0	0	0	1	5
APPLEBY F4	4.1	0	0	1	0	0	0	1	0	0	1	3
GRAHAMS F4	4.1	0	2	0	0	0	0	0	0	0	1	3
EASTERBROOK F2	4.1	0	0	0	0	0	0	0	0	0	1	1
HAMPTON F4	4.1	0	0	0	0	0	0	0	0	0	1	1
39M5	27.6	0	2	2	1	2	2	1	0	2	0	12
A4M6	27.6	0	3	0	1	6	2	0	0	0	0	12
39M1	27.6	0	5	3	0	1	0	0	0	2	0	11
76M21	27.6	3	1	0	0	2	1	1	1	0	0	9
39M3	27.6	0	2	3	0	0	1	0	0	1	0	7
280M3	27.6	0	0	2	0	1	0	1	0	2	0	6
13M27	27.6	1	0	0	1	0	0	1	0	2	0	5
39M36	27.6	1	1	0	0	0	2	1	0	0	0	5
13M25	27.6	0	0	4	0	0	0	0	0	0	0	4
39M4	27.6	0	0	0	0	2	1	1	0	0	0	4
39M32	27.6	0	1	0	0	0	2	0	0	0	0	3
39M34	27.6	1	1	0	0	0	1	0	0	0	0	3

FEEDER	KV	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	TOTALS (2014-2023)
39M6	27.6	1	1	0	0	0	0	0	0	1	0	3
13M26	27.6	1	0	1	0	0	0	0	0	0	0	2
280M5	27.6	0	0	1	0	0	0	1	0	0	0	2
76M29	27.6	0	0	0	0	1	0	1	0	0	0	2
A4M5	27.6	0	1	0	1	0	0	0	0	0	0	2
13M28	27.6	0	0	0	0	0	0	0	0	1	0	1
280M7	27.6	0	0	0	0	0	0	1	0	0	0	1
39M33	27.6	1	0	0	0	0	0	0	0	0	0	1
76M22	27.6	1	0	0	0	0	0	0	0	0	0	1
76M28	27.6	0	0	0	0	0	0	0	0	0	0	0
LOWVILLE F3	13.8	4	3	3	3	8	2	0	2	3	0	28
TOWERLINE F2	13.8	2	1	0	8	1	1	0	3	0	0	16
PALMER F1	13.8	1	2	1	7	0	1	0	0	1	0	13
LOWVILLE F2	13.8	0	2	0	0	2	2	1	3	0	0	10
FAIRVIEW F2	13.8	1	3	0	4	0	1	0	0	0	0	9
INTERCHANGE F1	13.8	1	1	0	0	1	0	0	3	3	0	9
LOWVILLE F1	13.8	0	0	1	1	0	2	1	0	3	0	8
ORCHARD F1	13.8	0	1	1	0	2	1	2	0	1	0	8
FAIRVIEW F3	13.8	1	0	0	0	2	1	1	0	0	0	5
INTERCHANGE F2	13.8	0	0	0	1	1	1	0	0	1	0	4
RESERVOIR F3	13.8	0	0	3	0	0	1	0	0	0	0	4
TOWERLINE F4	13.8	1	0	0	0	0	1	0	1	1	0	4
TYANDAGA F1	13.8	0	0	0	0	2	1	1	0	0	0	4
RESERVOIR F2	13.8	0	0	1	0	0	0	2	0	0	0	3
FAIRVIEW F4	13.8	0	0	0	1	0	0	0	0	0	0	1
PALMER F3	13.8	0	0	0	1	0	0	0	0	0	0	1
PALMER F4	13.8	0	0	0	0	1	0	0	0	0	0	1
TOWERLINE F3	13.8	1	0	0	0	0	0	0	0	0	0	1
TYANDAGA F2	13.8	0	0	0	0	0	0	0	0	1	0	1
TYANDAGA F4	13.8	0	0	0	1	0	0	0	0	0	0	1
FAIRVIEW F1	13.8	0	0	0	0	0	0	0	0	0	0	0
RESERVOIR F4	13.8	0	0	0	0	0	0	0	0	0	0	0
TOWERLINE F1	13.8	0	0	0	0	0	0	0	0	0	0	0
PT NELSON F2	4.1	1	1	0	2	2	0	3	2	1	0	12
SPRUCE F1	4.1	0	7	3	1	0	0	1	0	0	0	12
SPRUCE F3	4.1	0	4	1	1	1	1	1	2	1	0	12
DRURY F4	4.1	1	2	1	3	0	1	0	0	0	0	8
FAIRLEIGH F2	4.1	0	0	1	4	1	0	0	2	0	0	8
HARVESTER F1	4.1	3	0	1	1	0	0	1	0	2	0	8

FEEDER	KV	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	TOTALS (2014-2023)
DRURY F1	4.1	5	0	1	0	0	1	0	0	0	0	7
MT FOREST F1	4.1	0	0	0	0	0	4	3	0	0	0	7
PINEDALE F1	4.1	3	0	0	1	0	1	0	1	0	0	6
FAIRWOOD F6	4.1	0	1	0	0	0	4	0	0	0	0	5
MAPLE F6	4.1	0	2	0	1	0	0	1	1	0	0	5
MARLEY F2	4.1	5	0	0	0	0	0	0	0	0	0	5
MARLEY F3	4.1	1	2	0	0	1	1	0	0	0	0	5
HAMPTON F6	4.1	1	0	1	2	0	0	0	0	0	0	4
PARTRIDGE F1	4.1	2	0	2	0	0	0	0	0	0	0	4
PINECOVE F2	4.1	2	0	0	1	0	0	0	0	1	0	4
BRANT F2	4.1	0	0	0	0	0	0	1	2	0	0	3
ELGIN F1	4.1	1	0	0	0	2	0	0	0	0	0	3
FAIRLEIGH F1	4.1	0	0	0	1	2	0	0	0	0	0	3
FAIRWOOD F4	4.1	0	0	2	0	1	0	0	0	0	0	3
HAMPTON F1	4.1	2	0	0	0	0	0	0	0	1	0	3
HARVESTER F3	4.1	0	0	0	0	1	2	0	0	0	0	3
PARTRIDGE F2	4.1	1	0	1	0	1	0	0	0	0	0	3
SPRUCE F4	4.1	0	0	1	1	0	0	1	0	0	0	3
WALKERS F3	4.1	0	1	1	0	1	0	0	0	0	0	3
WOODWARD F5	4.1	1	0	0	0	1	0	0	1	0	0	3
APPLEBY F1	4.1	0	1	0	1	0	0	0	0	0	0	2
EASTERBROOK F1	4.1	1	0	0	0	0	0	1	0	0	0	2
EASTERBROOK F3	4.1	1	0	0	0	0	0	0	1	0	0	2
ELIZ GARDENS F2	4.1	0	0	0	0	0	1	0	0	1	0	2
FAIRWOOD F5	4.1	0	0	0	0	0	0	0	1	1	0	2
HAMPTON F2	4.1	0	0	0	0	2	0	0	0	0	0	2
MAPLE F1	4.1	0	0	0	0	0	0	1	0	1	0	2
MAPLE F8	4.1	0	0	0	0	0	0	2	0	0	0	2
PT NELSON F4	4.1	0	0	0	1	0	0	0	1	0	0	2
WALKERS F2	4.1	0	1	0	0	0	0	0	0	1	0	2
BRANT F1	4.1	0	0	0	0	0	1	0	0	0	0	1
BRIDGEVIEW F1	4.1	0	0	0	0	0	0	0	0	1	0	1
ELGIN F2	4.1	0	0	1	0	0	0	0	0	0	0	1
ELIZ GARDENS F1	4.1	0	1	0	0	0	0	0	0	0	0	1
FAIRLEIGH F3	4.1	0	0	0	0	1	0	0	0	0	0	1
GRAHAMS F1	4.1	1	0	0	0	0	0	0	0	0	0	1
GRAHAMS F3	4.1	0	0	0	0	0	1	0	0	0	0	1
HARVESTER F2	4.1	0	0	0	1	0	0	0	0	0	0	1
HOWARD F1	4.1	0	0	0	0	1	0	0	0	0	0	1
MAPLE F2	4.1	0	0	0	0	0	0	1	0	0	0	1

FEEDER	KV	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	TOTALS (2014-2023)
MARLEY F1	4.1	0	0	0	0	0	0	0	1	0	0	1
MARTHA F1	4.1	0	0	0	0	0	1	0	0	0	0	1
MARTHA F2	4.1	0	0	0	0	1	0	0	0	0	0	1
MARTHA F5	4.1	0	0	0	0	0	0	0	0	1	0	1
MARTHA F7	4.1	0	0	1	0	0	0	0	0	0	0	1
MT FOREST F3	4.1	0	0	0	0	0	0	0	0	1	0	1
PINECOVE F1	4.1	0	0	0	0	1	0	0	0	0	0	1
PT NELSON F1	4.1	0	0	1	0	0	0	0	0	0	0	1
PT NELSON F3	4.1	0	0	1	0	0	0	0	0	0	0	1
WOODWARD F2	4.1	1	0	0	0	0	0	0	0	0	0	1
WOODWARD F3	4.1	0	0	0	1	0	0	0	0	0	0	1
WOODWARD F4	4.1	0	0	1	0	0	0	0	0	0	0	1
APPLEBY F2	4.1	0	0	0	0	0	0	0	0	0	0	0
APPLEBY F3	4.1	0	0	0	0	0	0	0	0	0	0	0
APPLEBY F5	4.1	0	0	0	0	0	0	0	0	0	0	0
APPLEBY F6	4.1	0	0	0	0	0	0	0	0	0	0	0
BRANT F3	4.1	0	0	0	0	0	0	0	0	0	0	0
BRIDGEVIEW F2	4.1	0	0	0	0	0	0	0	0	0	0	0
DRURY F2	4.1	0	0	0	0	0	0	0	0	0	0	0
DRURY F3	4.1	0	0	0	0	0	0	0	0	0	0	0
ELGIN F3	4.1	0	0	0	0	0	0	0	0	0	0	0
ELGIN F4	4.1	0	0	0	0	0	0	0	0	0	0	0
ELIZ GARDENS F3	4.1	0	0	0	0	0	0	0	0	0	0	0
FAIRWOOD F1	4.1	0	0	0	0	0	0	0	0	0	0	0
FAIRWOOD F2	4.1	0	0	0	0	0	0	0	0	0	0	0
FAIRWOOD F3	4.1	0	0	0	0	0	0	0	0	0	0	0
GRAHAMS F2	4.1	0	0	0	0	0	0	0	0	0	0	0
HAMPTON F3	4.1	0	0	0	0	0	0	0	0	0	0	0
HAMPTON F5	4.1	0	0	0	0	0	0	0	0	0	0	0
HOWARD F2	4.1	0	0	0	0	0	0	0	0	0	0	0
MAPLE F3	4.1	0	0	0	0	0	0	0	0	0	0	0
MAPLE F4	4.1	0	0	0	0	0	0	0	0	0	0	0
MAPLE F5	4.1	0	0	0	0	0	0	0	0	0	0	0
MAPLE F7	4.1	0	0	0	0	0	0	0	0	0	0	0
MARTHA F3	4.1	0	0	0	0	0	0	0	0	0	0	0
MARTHA F4	4.1	0	0	0	0	0	0	0	0	0	0	0
MARTHA F6	4.1	0	0	0	0	0	0	0	0	0	0	0
MARTHA F8	4.1	0	0	0	0	0	0	0	0	0	0	0
MT FOREST F2	4.1	0	0	0	0	0	0	0	0	0	0	0
PINEDALE F3	4.1	0	0	0	0	0	0	0	0	0	0	0

FEEDER	KV	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	TOTALS (2014-2023)
WALKERS F4	4.1	0	0	0	0	0	0	0	0	0	0	0
WOODWARD F1	4.1	0	0	0	0	0	0	0	0	0	0	0
WOODWARD F6	4.1	0	0	0	0	0	0	0	0	0	0	0

Table 10- Feeder Lock-Outs Summary (Sorted by 2023)

APPENDIX B1

Feeder Outage Report

(27.6 kV Feeders)

Feeder Outage Report 280M8

Dates: January 01, 2023 through December 31, 2023

DATE OUT	TIME OUT	DATE IN	TIME IN	OPERATION	CAUSE	LOCATION/REMARKS	NO. OF CUSTOMERS	COUNT
09-Mar-23	09:05	09-Mar-23	09:05	AUTO-RECLOSURE	SQUIRREL	SQUIRREL CONTACT AT 5415 NORTH SERVICE RD.	673	1
01-Apr-23	02:28	01-Apr-23	02:28	AUTO-RECLOSURE	DEFECTIVE TRANSFORMER	TX P98 AT 5151 PORTER ST WAS DEFECTIVE AND HAD TO BE REPLACED	673	1
01-Apr-23	07:22	01-Apr-23	07:22	AUTO-RECLOSURE	DEFECTIVE TRANSFORMER	TX P98 AT 5151 PORTER ST WAS DEFECTIVE AND HAD TO BE REPLACED	673	1
01-Apr-23	08:21	01-Apr-23	08:21	AUTO-RECLOSURE	DEFECTIVE TRANSFORMER	TX P98 AT 5151 PORTER ST WAS DEFECTIVE AND HAD TO BE REPLACED	673	1
28-May-23	19:46	28-May-23	19:46	AUTO-RECLOSURE	UNKNOWN	SUSPECTED SYMPATHY TRIP DUE TO 280M4 LOCKOUT.	673	1
03-Jun-23	09:44	03-Jun-23	09:44	AUTO-RECLOSURE	UNKNOWN		673	1
27-Jun-23	17:53	27-Jun-23	17:53	AUTO-RECLOSURE	UNKNOWN		673	1
02-Aug-23	20:55	02-Aug-23	20:55	AUTO-RECLOSURE	UNKNOWN		673	1
12-Dec-23	10:28	12-Dec-23	10:28	AUTO-RECLOSURE	DEFECTIVE U/G PRIMARY	BAD RED CABLE BET TX Q479 AND F3798	673	1
17-Dec-23	11:15	17-Dec-23	11:15	AUTO-RECLOSURE	DEFECTIVE SWITCHING CUBICLE	SC234 TRACKING AT 1940 IRONSTONE	673	1

Feeder Outage Report 280M6

Dates: January 01, 2023 through December 31, 2023

DATE OUT	TIME OUT	DATE IN	TIME IN	OPERATION	CAUSE	LOCATION/REMARKS	NO. OF CUSTOMERS	COUNT
02-May-23	23:39	02-May-23	23:39	AUTO-RECLOSURE	UNKNOWN		5716	1
18-Jul-23	21:29	18-Jul-23	23:24	Lockout	DEFECTIVE SWITCH		9637	1
19-Jul-23	2:20	20-Jul-23	3:32	Lockout	DEFECTIVE SWITCH		4	1

Feeder Outage Report 280M3

Dates: January 01, 2023 through December 31, 2023

DATE OUT	TIME OUT	DATE IN	TIME IN	OPERATION	CAUSE	LOCATION/REMARKS	NO. OF CUSTOMERS	COUNT
29-Sep-23	07:39	29-Sep-23	07:39	AUTO-RECLOSURE	BIRD	BIRD FOUND @ 3505 UPPERMIDDLE	1968	1
13-Oct-23	07:44	13-Oct-23	07:44	AUTO-RECLOSURE	DEFECTIVE TRANSFORMER	TX Q534 DEFECTIVE. 4040 UPPER MIDDLE ROAD.	1968	1
26-Oct-23	08:47	26-Oct-23	08:47	AUTO-RECLOSURE	UNKNOWN		1968	1
30-Oct-23	00:14	30-Oct-23	00:14	AUTO-RECLOSURE	UNKNOWN		1968	1
06-Dec-23	09:28	06-Dec-23	09:28	AUTO-RECLOSURE	UNKNOWN	S4625 WB, S4196 WB, S4195 WB	1968	1
10-Dec-23	22:27	10-Dec-23	22:27	AUTO-RECLOSURE	UNKNOWN		1968	1
23-Dec-23	20:11	23-Dec-23	20:11	AUTO-RECLOSURE	UNKNOWN		1968	1
27-Dec-23	20:54	27-Dec-23	20:54	AUTO-RECLOSURE	UNKNOWN		1968	1

Feeder Outage Report 13M28

Dates: January 01, 2023 through December 31, 2023

DATE OUT	TIME OUT	DATE IN	TIME IN	OPERATION	CAUSE	LOCATION/REMARKS	NO. OF CUSTOMERS	COUNT
14-May-23	08:47	14-May-23	08:47	AUTO-RECLOSURE	UNKNOWN		736	1
23-Dec-23	11:09	23-Dec-23	11:09	AUTO-RECLOSURE	UNKNOWN		736	1
23-Dec-23	11:09	23-Dec-23	11:09	AUTO-RECLOSURE	UNKNOWN		736	1
23-Dec-23	17:53	23-Dec-23	17:53	AUTO-RECLOSURE	UNKNOWN		736	1
23-Dec-23	17:53	23-Dec-23	17:53	AUTO-RECLOSURE	UNKNOWN		736	1
24-Dec-23	17:53	24-Dec-23	17:53	AUTO-RECLOSURE	UNKNOWN		736	1

Feeder Outage Report 76M25

Dates: January 01, 2023 through December 31, 2023

DATE OUT	TIME OUT	DATE IN	TIME IN	OPERATION	CAUSE	LOCATION/REMARKS	NO. OF CUSTOMERS	COUNT
24-Aug-23	21:33	24-Aug-23	21:33	AUTO-RECLOSURE	T-STORM		4181	1
06-Oct-23	16:18	06-Oct-23	16:18	AUTO-RECLOSURE	TREE/LIMB	WILLOW TREE AT DYNES AND NEW	4181	1
27-Jul-23	9:42	28-Jul-23	15:17	Lockout	T-STORM/TREE		9140	1
06-Oct-23	16:45	06-Oct-23	23:19	Lockout	TREE/LIMB		5123	1

Feeder Outage Report 76M21

Dates: January 01, 2023 through December 31, 2023

DATE OUT	TIME OUT	DATE IN	TIME IN	OPERATION	CAUSE	LOCATION/REMARKS	NO. OF CUSTOMERS	COUNT
03-Mar-23	19:59	03-Mar-23	19:59	AUTO-RECLOSURE	HIGH WINDS/TREE-LINE DOWN		59	1
03-Mar-23	20:42	03-Mar-23	20:42	AUTO-RECLOSURE	HIGH WINDS/TREE-LINE DOWN		59	1
09-Jun-23	18:26	09-Jun-23	18:26	AUTO-RECLOSURE	SQUIRREL	4041-1 NORTH SERVICE RD. 76M21 AUTO AT 1826. #24 REPORTS FOUND DEAD SQUIRREL AT FUSE F4283. WHITE PHASE B #24 DID NOT HAVE 120K FUSE. REFUSED F4283 WITH 200K, CLOSED AND HOLDING.	59	1
25-Nov-23	10:49	25-Nov-23	10:49	AUTO-RECLOSURE	SQUIRREL	1211 HERITAGE SQUIRREL BLEW FUSE	59	1
24-Dec-23	16:09	24-Dec-23	16:09	AUTO-RECLOSURE	UNKNOWN		59	1

APPENDIX **B2**

Feeder Outage Report

(13.8 kV Feeders)

Feeder Outage Report Lowville F1

Dates: January 01, 2023 through December 31, 2023

DATE OUT	TIME OUT	DATE IN	TIME IN	OPERATION	CAUSE	LOCATION/REMARKS	NO. OF CUSTOMERS	COUNT
05-Apr-23	03:30	05-Apr-23	03:30	AUTO-RECLOSURE	T-STORM		200	1
05-Apr-23	11:27	05-Apr-23	11:27	AUTO-RECLOSURE	HIGH WINDS		200	1
17-Apr-23	22:05	17-Apr-23	22:05	AUTO-RECLOSURE	POLE FIRE	4301 #2 SIDE RD POLE FIRE	200	1
23-May-23	10:41	23-May-23	10:41	AUTO-RECLOSURE	TREE/LIMB	TX AL2 FOUND BLOWN DUE TO VINES/TREE LIMBS	200	1
01-Jun-23	11:54	01-Jun-23	11:54	AUTO-RECLOSURE	DEFECTIVE SWITCH	SWITCH ON TX AK12 FOUND BROKEN ON MOUNT NEMO CRES.	200	1
04-Jun-23	07:23	04-Jun-23	07:23	AUTO-RECLOSURE	UNKNOWN		200	1
21-Jun-23	11:31	21-Jun-23	11:31	AUTO-RECLOSURE	SQUIRREL	TX AC30 FUSE BLEW AT 4245 CEDAR SPRINGS RD.	200	1
26-Jun-23	09:10	26-Jun-23	09:10	AUTO-RECLOSURE	UNKNOWN		200	1
10-Jul-23	02:27	10-Jul-23	02:27	AUTO-RECLOSURE	T-STORM		200	1
26-Jul-23	23:38	26-Jul-23	23:38	AUTO-RECLOSURE	UNKNOWN		200	1
12-Aug-23	09:59	12-Aug-23	09:59	AUTO-RECLOSURE	DEFECTIVE TRANSFORMER	TX AD15 GONE BAD AT 4490 WALKERS LINE	200	1
12-Oct-23	17:30	12-Oct-23	17:30	AUTO-RECLOSURE	UNKNOWN		200	1
28-Oct-23	08:25	28-Oct-23	08:25	AUTO-RECLOSURE	UNKNOWN		200	1
26-Nov-23	07:45	26-Nov-23	07:45	AUTO-RECLOSURE	SQUIRREL	SQUIRREL AT AD6	200	1

Feeder Outage Report Lowville F4

Dates: January 01, 2023 through December 31, 2023

DATE OUT	TIME OUT	DATE IN	TIME IN	OPERATION	CAUSE	LOCATION/REMARKS	NO. OF CUSTOMERS	COUNT
15-Feb-23	12:02	15-Feb-23	12:41	Lockout	T-STORM/TREE	No	179	1
06-Oct-23	14:23	06-Oct-23	15:39	Lockout	TREE/LIMB	neighbors are out as well, just went out	303	1
23-Oct-23	10:35	23-Oct-23	10:36	Lockout	SQUIRREL	Lowville f4 lockout at 1035	303	1

Feeder Outage Report Orchard F1

Dates: January 01, 2023 through December 31, 2023

DATE OUT	TIME OUT	DATE IN	TIME IN	OPERATION	CAUSE	LOCATION/REMARKS	NO. OF CUSTOMERS	COUNT
18-Jan-23	11:13	18-Jan-23	11:13	AUTO-RECLOSURE	DEFECTIVE U/G PRIMARY	U/G CABLE FAULT BETWEEN TX L34 TO L42	854	1
05-Apr-23	11:27	05-Apr-23	11:27	AUTO-RECLOSURE	HIGH WINDS		854	1
29-Apr-23	20:30	29-Apr-23	20:30	AUTO-RECLOSURE	DEFECTIVE U/G PRIMARY	CABLE FAULT AT F1882 X TX T75 ON GREENBANK AND BRANT ST	854	1
12-Jun-23	09:25	12-Jun-23	09:25	AUTO-RECLOSURE	UNKNOWN		854	1
22-Jun-23	16:53	22-Jun-23	16:53	AUTO-RECLOSURE	UNKNOWN		854	1

Feeder Outage Report Orchard F2

Dates: January 01, 2023 through December 31, 2023

DATE OUT	TIME OUT	DATE IN	TIME IN	OPERATION	CAUSE	LOCATION/REMARKS	NO. OF CUSTOMERS	COUNT
27-Apr-23	12:42	27-Apr-23	12:42	AUTO-RECLOSURE	VEHICLE ACCIDENT-POLE HIT	CAR HIT POLE AT 1231 NO 1 SIDE RD..	618	1
08-Jul-23	07:27	08-Jul-23	07:27	AUTO-RECLOSURE	UNKNOWN		618	1
09-Aug-23	07:18	09-Aug-23	07:18	AUTO-RECLOSURE	SQUIRREL	TX L221 FUSE BLOWN. REFUSED WITH A 10	618	1
19-Aug-23	22:50	19-Aug-23	22:50	AUTO-RECLOSURE	DEFECTIVE U/G PRIMARY	@ 1422 TYANDAGA PARK DR	618	1
20-Aug-23	14:48	20-Aug-23	14:48	AUTO-RECLOSURE	DEFECTIVE U/G PRIMARY	WHITE PHASE CABLE FAULT FEEDING TX L232 ON TYANDAGA PARK DR.	618	1
11-Oct-23	18:15	11-Oct-23	18:15	AUTO-RECLOSURE	TREE/LIMB		618	1
09-Nov-23	15:30	09-Nov-23	15:34	LOCK-OUT	UNKNOWN	LOCKOUT OF ORCHARD F2. WAITED 4 MINUTES FOR ANY CALLS AND FEEDER WAS CLOSED AND HELD. 1 auto reclose. S2979 B&W O/C ON CLOSE.	618	1
09-Dec-23	11:12	09-Dec-23	11:12	AUTO-RECLOSURE	BIRD	BIRD AT TX L224	618	1

Feeder Outage Report Palmer F1

Dates: January 01, 2023 through December 31, 2023

DATE OUT	TIME OUT	DATE IN	TIME IN	OPERATION	CAUSE	LOCATION/REMARKS	NO. OF CUSTOMERS	COUNT
03-Mar-23	20:08	03-Mar-23	20:08	AUTO-RECLOSURE	HIGH WINDS/TREE-LINE DOWN		220	1
03-Mar-23	20:24	03-Mar-23	20:24	AUTO-RECLOSURE	HIGH WINDS/TREE-LINE DOWN		220	1
17-Mar-23	20:05	17-Mar-23	20:05	AUTO-RECLOSURE	UNKNOWN		220	1
05-Apr-23	11:10	05-Apr-23	11:10	AUTO-RECLOSURE	HIGH WINDS		220	1
22-Apr-23	15:22	22-Apr-23	15:22	AUTO-RECLOSURE	UNKNOWN	WHITE PH	220	1
30-Apr-23	06:31	30-Apr-23	06:31	AUTO-RECLOSURE	UNKNOWN		220	1
15-Jun-23	19:42	15-Jun-23	19:42	AUTO-RECLOSURE	VEHICLE ACCIDENT-POLE HIT		220	1
02-Aug-23	08:25	02-Aug-23	08:25	AUTO-RECLOSURE	UNKNOWN		220	1
26-Nov-23	09:06	26-Nov-23	09:06	AUTO-RECLOSURE	UNKNOWN		220	1
23-Dec-23	20:11	23-Dec-23	20:11	AUTO-RECLOSURE	UNKNOWN		220	1

Feeder Outage Report Palmer F2

Dates: January 01, 2023 through December 31, 2023

DATE OUT	TIME OUT	DATE IN	TIME IN	OPERATION	CAUSE	LOCATION/REMARKS	NO. OF CUSTOMERS	COUNT
03-Mar-23	19:49	03-Mar-23	19:49	AUTO-RECLOSURE	HIGH WINDS/TREE-LINE DOWN		945	1
03-Mar-23	19:57	03-Mar-23	19:57	AUTO-RECLOSURE	HIGH WINDS/TREE-LINE DOWN		945	1
03-Mar-23	20:21	03-Mar-23	20:21	AUTO-RECLOSURE	HIGH WINDS/TREE-LINE DOWN		945	1
04-Mar-23	13:41	04-Mar-23	13:41	AUTO-RECLOSURE	HIGH WINDS		945	1
04-Mar-23	17:43	04-Mar-23	17:43	AUTO-RECLOSURE	UNKNOWN		945	1
03-Mar-23	21:13	04-Mar-23	10:10	PALMER F2	HIGH WINDS		971	1
06-Mar-23	13:49	06-Mar-23	13:49	AUTO-RECLOSURE	DEFECTIVE SWITCHING CUBICLE	CLOSE ATTEMPT ON FN355 IN SC17 FAILED.	945	1
20-Aug-23	06:56	20-Aug-23	06:56	AUTO-RECLOSURE	UNKNOWN		945	1
26-Aug-23	17:20	26-Aug-23	17:20	AUTO-RECLOSURE	COLD LOAD	CLOD LOAD PICK UP AT S4001 OTO 23-628	945	1
23-Dec-23	20:11	23-Dec-23	20:11	AUTO-RECLOSURE	UNKNOWN		945	1

Feeder Outage Report Palmer F3

Dates: January 01, 2023 through December 31, 2023

DATE OUT	TIME OUT	DATE IN	TIME IN	OPERATION	CAUSE	LOCATION/REMARKS	NO. OF CUSTOMERS	COUNT
25-Jan-23	10:11	25-Jan-23	10:11	AUTO-RECLOSURE	UNKNOWN		2053	1
25-Jan-23	19:32	25-Jan-23	19:32	AUTO-RECLOSURE	UNKNOWN		2053	1
01-Feb-23	00:52	01-Feb-23	00:52	AUTO-RECLOSURE	UNKNOWN		2053	1
06-Feb-23	05:47	06-Feb-23	05:47	AUTO-RECLOSURE	UNKNOWN		2053	1
14-Feb-23	12:04	14-Feb-23	12:04	AUTO-RECLOSURE	UNKNOWN		2053	1
21-Feb-23	10:50	21-Feb-23	10:50	AUTO-RECLOSURE	UNKNOWN		2053	1
26-Feb-23	02:02	26-Feb-23	02:02	AUTO-RECLOSURE	UNKNOWN	NO FAULT INDICATOR FLASHING	2053	1
03-Apr-23	06:41	03-Apr-23	06:41	AUTO-RECLOSURE	DEFECTIVE SPLICE U/G PRIMARY	CABLE FAULT BETWEEN F1296 AND TX V144 ON ATKINSON DR.	2053	1
03-Apr-23	06:42	03-Apr-23	06:42	AUTO-RECLOSURE	DEFECTIVE SPLICE U/G PRIMARY	CABLE FAULT BETWEEN F1296 AND TX V144 ON ATKINSON DR.	2053	1
27-May-23	07:20	27-May-23	07:20	AUTO-RECLOSURE	UNKNOWN		2053	1
08-Sep-23	09:39	08-Sep-23	09:39	AUTO-RECLOSURE	UNKNOWN		2053	1

Feeder Outage Report Palmer F4

Dates: January 01, 2023 through December 31, 2023

DATE OUT	TIME OUT	DATE IN	TIME IN	OPERATION	CAUSE	LOCATION/REMARKS	NO. OF CUSTOMER S	COUNT
20-Jul-23	23:5 3	20-Jul-23	23:5 3	AUTO-RECLOSURE	T-STORM		906	1
19-Aug-23	23:0 4	19-Aug-23	23:0 4	AUTO-RECLOSURE	DEFECTIVE TRANSFORMER	DEFECTIVE TX N52 FOUND	906	1
21-Aug-23	22:5 9	21-Aug-23	22:5 9	AUTO-RECLOSURE	DEFECTIVE TRANSFORMER	TX N52 FOUND DEFECTIVE	906	1
27-Sep-23	09:1 5	27-Sep-23	09:1 5	AUTO-RECLOSURE	UNKNOWN		906	1
09-Oct-23	21:0 8	09-Oct-23	21:0 8	AUTO-RECLOSURE	RACCOON	DEAD POSSUM IN SC18 AT 1450 HEADON RD	906	1
21-Oct-23	03:5 5	21-Oct-23	03:5 5	AUTO-RECLOSURE	DEFECTIVE INSULATOR	INSULATOR TRACKING AT SC18	906	1

Feeder Outage Report Reservoir F1

Dates: January 01, 2023 through December 31, 2023

DATE OUT	TIME OUT	DATE IN	TIME IN	OPERATION	CAUSE	LOCATION/REMARKS	NO. OF CUSTOMERS	COUNT
11-Apr-23	14:36	11-Apr-23	14:37	Lockout	HIGH WINDS		2216	1
20-Jul-23	23:53	20-Jul-23	23:53	AUTO-RECLOSURE	T-STORM		906	1
19-Aug-23	23:04	19-Aug-23	23:04	AUTO-RECLOSURE	DEFECTIVE TRANSFORMER	DEFECTIVE TX N52 FOUND	906	1
21-Aug-23	22:59	21-Aug-23	22:59	AUTO-RECLOSURE	DEFECTIVE TRANSFORMER	TX N52 FOUND DEFECTIVE	906	1
27-Sep-23	09:15	27-Sep-23	09:15	AUTO-RECLOSURE	UNKNOWN		906	1
09-Oct-23	21:08	09-Oct-23	21:08	AUTO-RECLOSURE	RACCOON	DEAD POSSUM IN SC18 AT 1450 HEADON RD	906	1
21-Oct-23	03:55	21-Oct-23	03:55	AUTO-RECLOSURE	DEFECTIVE INSULATOR	INSULATOR TRACKING AT SC18	906	1

Feeder Outage Report Towerline F4

Dates: January 01, 2023 through December 31, 2023

DATE OUT	TIME OUT	DATE IN	TIME IN	OPERATION	CAUSE	LOCATION/REMARKS	NO. OF CUSTOMERS	COUNT
22-Jan-23	09:01	22-Jan-23	09:01	AUTO-RECLOSURE	UNKNOWN		190	1
28-Jan-23	07:32	28-Jan-23	07:32	AUTO-RECLOSURE	SQUIRREL	SQUIRREL FOUND ON SEC BUSHING TX G123 AT 5026 SOUTH SERVICE RD	190	1
24-Jun-23	07:49	24-Jun-23	07:49	AUTO-RECLOSURE	UNKNOWN		190	1
02-Jul-23	06:17	02-Jul-23	06:17	AUTO-RECLOSURE	UNKNOWN		190	1
09-Jul-23	08:57	09-Jul-23	08:57	AUTO-RECLOSURE	UNKNOWN		190	1
13-Jul-23	18:22	13-Jul-23	18:22	AUTO-RECLOSURE	UNKNOWN		190	1
13-Jul-23	18:22	13-Jul-23	18:22	AUTO-RECLOSURE	UNKNOWN		190	1
14-Jul-23	19:25	14-Jul-23	19:25	AUTO-RECLOSURE	UNKNOWN		190	1
20-Aug-23	06:46	20-Aug-23	06:46	AUTO-RECLOSURE	UNKNOWN		190	1

21-Aug-23	20:21	21-Aug-23	20:21	AUTO-RECLOSURE	DEFECTIVE U/G PRIMARY	DEFECTIVE U/G PRIMARY AT TX F256 X FF256 AT 686 APPLEBY LINE	190	1
04-Sep-23	16:17	04-Sep-23	16:17	AUTO-RECLOSURE	UNKNOWN		190	1
11-Sep-23	08:33	11-Sep-23	08:33	AUTO-RECLOSURE	UNKNOWN		190	1
30-Sep-23	08:53	30-Sep-23	08:53	AUTO-RECLOSURE	BIRD	DEAD BIRD FOUND IN THE FUSES AT FF478.	190	1

Feeder Outage Report Tyandaga F1

Dates: January 01, 2023 through December 31, 2023

DATE OUT	TIME OUT	DATE IN	TIME IN	OPERATION	CAUSE	LOCATION/REMARKS	NO. OF CUSTOMERS	COUNT
01-Mar-23	12:56	01-Mar-23	12:56	AUTO-RECLOSURE	UNKNOWN	01-Mar-23	1144	1
13-Aug-23	10:36	13-Aug-23	10:36	AUTO-RECLOSURE	UNKNOWN	13-Aug-23	1144	1
18-Nov-23	08:23	18-Nov-23	08:23	AUTO-RECLOSURE	UNKNOWN	18-Nov-23	1144	1
20-Nov-23	09:45	20-Nov-23	09:45	AUTO-RECLOSURE	UNKNOWN	20-Nov-23	1144	1
06-Dec-23	09:28	06-Dec-23	09:28	AUTO-RECLOSURE	UNKNOWN	06-Dec-23	1144	1

Feeder Outage Report Tyandaga F3

Dates: January 01, 2023 through December 31, 2023

DATE OUT	TIME OUT	DATE IN	TIME IN	OPERATION	CAUSE	LOCATION/REMARKS	NO. OF CUSTOMERS	COUNT
03-Mar-23	19:55	03-Mar-23	19:55	AUTO-RECLOSURE	HIGH WINDS/TREE-LINE DOWN		669	1
14-May-23	06:40	14-May-23	06:40	AUTO-RECLOSURE	SQUIRREL	1374 MAJESTIC DR. TYANDAGA F3 AUTO AT 0640. CUSTOMER REPORTS HEARD LOUD BANG AND POWER WENT OUT. #33 RO REPORTS FOUND FUSE BLOWN AT TX N341. FOUND SQUIRREL CONTACT.	669	1
19-Jun-23	15:08	19-Jun-23	15:08	AUTO-RECLOSURE	UNKNOWN		669	1
02-Jan-23	9:24	02-Jan-23	9:47	Lockout	TREE/LIMB	No	694	1
17-Aug-23	23:22	18-Aug-23	0:39	Lockout	TREE/LIMB		675	1

Feeder Outage Report Tyandaga F4

Dates: January 01, 2023 through December 31, 2023

DATE OUT	TIME OUT	DATE IN	TIME IN	OPERATION	CAUSE	LOCATION/REMARKS	NO. OF CUSTOMERS	COUNT
30-Jan-23	17:59	30-Jan-23	17:59	AUTO-RECLOSURE	DEFECTIVE TERMINATION	S1177 DEFECTIVE TERMY. SWITCH ON TYAN F2 BUT F4 AUTO'D	1183	1
30-Jan-23	19:29	30-Jan-23	19:29	AUTO-RECLOSURE	COLD LOAD		1183	1
23-Jun-23	18:42	23-Jun-23	18:42	AUTO-RECLOSURE	DEFECTIVE U/G PRIMARY	1319 HAZELTON BLVD. HEARD A LOUD BANG FROM BRANT ST AND NOW HAS NO POWER. CABLE FAULT BETWEEN TX L314 AND F91, BOTH ENDS OPEN AND TAGGED CAUTION. NOTE: T	1183	1
27-Jul-23	07:23	27-Jul-23	07:23	AUTO-RECLOSURE	COLD LOAD		1183	1
27-Jul-23	07:23	27-Jul-23	07:23	AUTO-RECLOSURE	COLD LOAD		1183	1
27-Jul-23	07:24	27-Jul-23	07:24	AUTO-RECLOSURE	COLD LOAD		1183	1
26-Sep-23	02:38	26-Sep-23	02:38	AUTO-RECLOSURE	DEFECTIVE U/G PRIMARY	CABLE BETWEEN F2291 AND TX L60 FAULTED ON FAIRCHILD.	1183	1
26-Nov-23	07:41	26-Nov-23	07:41	AUTO-RECLOSURE	DEFECTIVE U/G PRIMARY	TX L90 X TX L91 @ MONMOUTH DR	1183	1

APPENDIX B3

Feeder Outage Report
(4.16 kV Feeders)

Feeder Outage Report Spruce F2

Dates: January 01, 2023 through December 31, 2023

DATE OUT	TIME OUT	DATE IN	TIME IN	OPERATION	CAUSE	LOCATION/REMARKS	NO. OF CUSTOMERS	COUNT
04-Mar-23	04:42	04-Mar-23	04:42	AUTO-RECLOSURE	HIGH WINDS/TREE-LINE DOWN		403	1
25-Mar-23	19:18	25-Mar-23	19:18	AUTO-RECLOSURE	TREE/LIMB	TREE DOWN AT 4058 SPRUCE AVE	403	1
20-Jul-23	21:19	20-Jul-23	21:19	AUTO-RECLOSURE	T-STORM/TREE	TREE DOWN AT 357 BLYTHEWOOD RD	403	1
20-Jul-23	21:21	20-Jul-23	21:21	AUTO-RECLOSURE	T-STORM/TREE	TREE DOWN AT 357 BLYTHEWOOD RD	403	1
25-Jul-23	07:45	25-Jul-23	07:45	AUTO-RECLOSURE	TREE/LIMB	TREE PAST SOLID TAP S3818	403	1
25-Jul-23	07:45	25-Jul-23	07:45	AUTO-RECLOSURE	TREE/LIMB	TREE PAST SOLID TAP S3818	403	1
25-Jul-23	07:45	25-Jul-23	08:25	LOCK-OUT	TREE/LIMB	TREE PAST SOLID TAP S3818	403	1

Feeder Outage Report Bridgeview F2

Dates: January 01, 2023 through December 31, 2023

DATE OUT	TIME OUT	DATE IN	TIME IN	OPERATION	CAUSE	LOCATION/REMARKS	NO. OF CUSTOMERS	COUNT
03-Mar-23	19:00	03-Mar-23	19:00	AUTO-RECLOSURE	HIGH WINDS/TREE-LINE DOWN		200	1
03-Mar-23	20:19	03-Mar-23	20:19	AUTO-RECLOSURE	HIGH WINDS/TREE-LINE DOWN		200	1
03-Mar-23	21:24	03-Mar-23	21:24	AUTO-RECLOSURE	HIGH WINDS/TREE-LINE DOWN		200	1
04-Mar-23	02:40	04-Mar-23	02:40	AUTO-RECLOSURE	HIGH WINDS/T-STORM		200	1
05-Mar-23	02:40	05-Mar-23	02:40	AUTO-RECLOSURE	HIGH WINDS/TREE-LINE DOWN		200	1
28-Apr-23	00:34	28-Apr-23	00:34	AUTO-RECLOSURE	VEHICLE ACCIDENT-POLE HIT	1525 SNAKE RD POLE SPLIT IN HALF FROM MVA	200	1

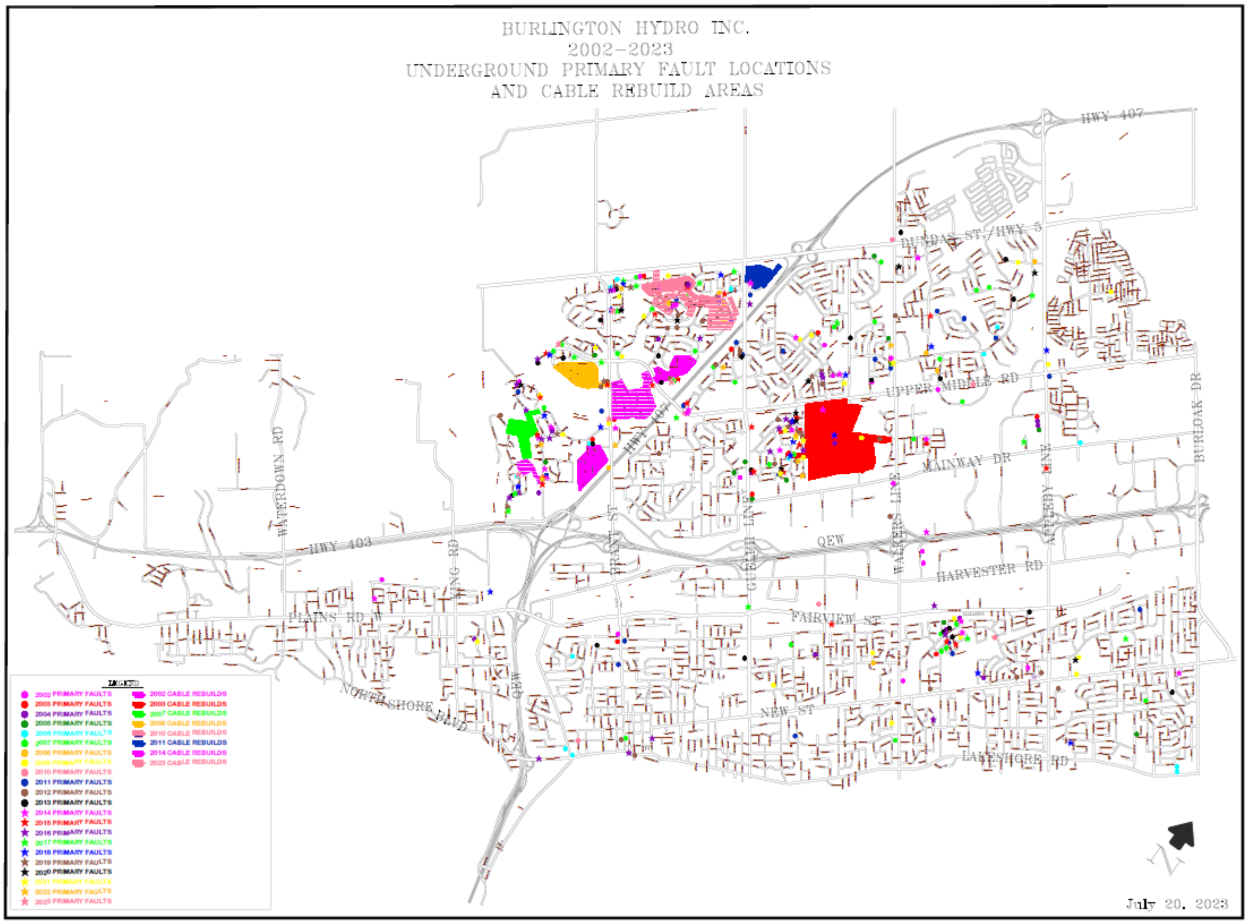
Feeder Outage Report Partridge F3

Dates: January 01, 2023 through December 31, 2023

DATE OUT	TIME OUT	DATE IN	TIME IN	OPERATION	CAUSE	LOCATION/REMARKS	NO. OF CUSTOMERS	COUNT
03-Mar-23	21:37	03-Mar-23	21:37	AUTO-RECLOSURE	HIGH WINDS/TREE-LINE DOWN		358	1
03-Mar-23	21:38	03-Mar-23	21:38	AUTO-RECLOSURE	HIGH WINDS/TREE-LINE DOWN		358	1
03-Mar-23	21:42	03-Mar-23	21:42	AUTO-RECLOSURE	HIGH WINDS/TREE-LINE DOWN		358	1
03-Mar-23	21:38	04-Mar-23	17:09	LOCK-OUT	HIGH WINDS/TREE		358	1
04-Aug-23	07:15	04-Aug-23	07:39	LOCK-OUT	TREE/LIMB		358	1

APPENDIX C

Underground Primary Fault Locations and Cable Rebuild Area


BURLINGTON HYDRO INC.
2002–2023
UNDERGROUND PRIMARY FAULT LOCATIONS
AND CABLE REBUILD AREAS
HWY 407
DUNDAS ST./HWY 5
UPPER MIDDLE RD
MAINWAY DR
BURLOAK DR
APPLEBY LINE
WALKERS LINE
GUELPH LINE
BRANT ST
HWY 403
WATERDOWN RD
KING RD
QEW
HARVESTER RD
PLAINS RD W
FAIRVIEW ST
NORTH SHORE BLVD
NEW ST
LAKESHORE RD
LEGEND
2002 PRIMARY FAULTS
2003 PRIMARY FAULTS
2004 PRIMARY FAULTS
2005 PRIMARY FAULTS
2006 PRIMARY FAULTS
2007 PRIMARY FAULTS
2008 PRIMARY FAULTS
2009 PRIMARY FAULTS
2010 PRIMARY FAULTS
2011 PRIMARY FAULTS
2012 PRIMARY FAULTS
2013 PRIMARY FAULTS
2014 PRIMARY FAULTS
2015 PRIMARY FAULTS
2016 PRIMARY FAULTS
2017 PRIMARY FAULTS
2018 PRIMARY FAULTS
2019 PRIMARY FAULTS
2020 PRIMARY FAULTS
2021 PRIMARY FAULTS
2022 PRIMARY FAULTS
2023 PRIMARY FAULTS
2002 CABLE REBUILDS
2003 CABLE REBUILDS
2007 CABLE REBUILDS
2008 CABLE REBUILDS
2010 CABLE REBUILDS
2011 CABLE REBUILDS
2014 CABLE REBUILDS
2023 CABLE REBUILDS
N
July 20, 2023

APPENDIX D

System Maintenance Activities & Priorities

4.0 - SYSTEM MAINTENANCE ACTIVITIES & PRIORITIES

Asset Management

ABSTRACT

BHI aims to meet or exceed the system maintenance and inspection requirements of Section 4.4 and Appendix C of the Ontario Energy Board Distribution System Code (DSC) – latest revision. The following routine maintenance programs are consistent with good utility practices and are applied annually over a 3-year patrolled inspection period within the BHI distribution system territory.

June 21, 2023

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4.1.0 SYSTEM MAINTENANCE ACTIVITIES – OVERHEAD SYSTEM

4.1.1 WOOD POLE INSPECTION AND REPLACEMENT

The OEB – Distribution System Code requires BHI inspect each asset within a 3-year cycle. BHI has gone above and beyond that requirement by taking a proactive approach to the annual inspection, testing, and replacement of hydro poles.

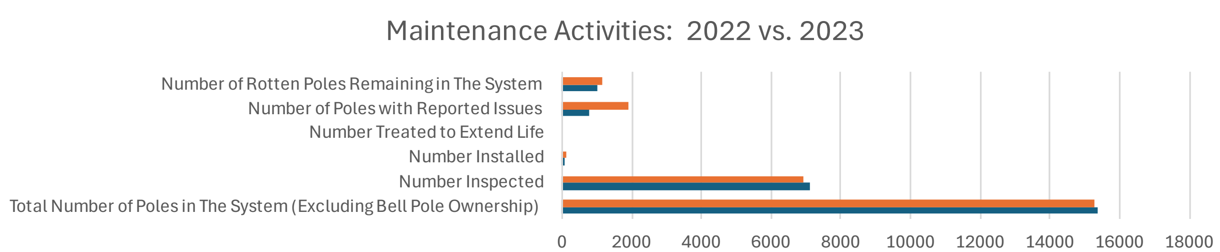
The inspection and tests are performed by a contracted pole testing company (Under Pressure Inc.) using a few outlined methods and considerations:

- **Asset Age**
  - Assets within the BHI system have a typical useful life; based on the 'Asset Depreciation Study for the OEB', wood poles have a TUL of 45 years with a maximum of 75. Wood poles determined to be installed within 10-years are typically in good condition, poles >21-years to end-of-life are predominantly of focus and flagged for testing beyond visual inspection and hammer testing.
- **Visual Inspection**
  - The visual inspection asses the visible surface condition of the pole; if there are defects found such as integrity issues (woodpecker holes, pest infestation, cracks, leaning etc.), rotten pole tops, loose hardware/attachments, rotten crossarms, porcelain insulators, and attached equipment issues.
- **Hammer Test**
  - Pole integrity is verified by sound when the pole is tapped by a hammer or mallet in various locations starting from the base of the pole to determine if the pole is producing a clear and sharp rebound when struck.
- **Resistograph Test Drill – Wood Poles**
  - Predominant on poles >21-years of installation, a measurement is taken using a thin precisely calibrated drill for remaining pole fiber strength. The drill measures pole rot and decay just below the base to a remaining strength level of which >70% is a pass, and <70% but >60% is a marginal pass; anything less is considered a failure, consistent with clause 8.3.1.3 of CSA 22.3 No-1 latest version.

Poles are categorized for remediation dependent on inspection results. Areas of focus are then grouped in clusters of the worst degradation criteria poles for potential capital rebuild. A high priority is placed on 3-phase poles with primary feeder circuits, equipment such as transformers, switching devices, underground dips, and line dead-end or major line angles over 15° which pose a higher risk due to the impact of failure. The following is a summary comparison of the pole testing and replacement program from 2022 to 2023:

Maintenance Activities: Wood Hydro Poles	2022	2023	Trend
Total Number of Poles in The System (Excluding Bell Pole Ownership)	15362	15294	↓
Number Inspected	7127	6930	↓
Number Installed	87	99	↑
Number Treated to Extend Life	0	0	→
Number of Poles with Reported Visible Issues	776	1880	↑
Number of Rotten Poles Remaining in The System	994	1164	↑

Figure 2: Table 1 – Wood Pole Testing & Replacement



	Total Number of Poles in The System (Excluding Bell Pole Ownership)	Number Inspected	Number Installed	Number Treated to Extend Life	Number of Poles with Reported Issues	Number of Rotten Poles Remaining in The System
2023	15294	6930	99	0	1880	1164
2022	15362	7127	87	0	776	994

Figure 3: Chart 1 – Wood Pole Testing & Replacement 2022 vs 2023

The figures above indicate that BHI is maintaining its commitment to improving its 'System Renewal' program through the inspection cycle periods, maintenance, and remediation replacements. The pole installations for 2023 include replacements due to end-of-life conditions, vehicle accidents, and storm damage.

Throughout the fiscal year, 6930 poles were inspected, beginning a new 3-year overhead inspectional cycle for BHI from 2023. Comparing 2023 to 2022, 170 additional poles were identified as rotten, again no poles were treated, and 99 poles were replaced with an additional 12 replacements comparative to year-over-year. Additionally, 1104 poles were reported to have some issue compared to the year before stemming from the visual inspection criteria mentioned previously. The increase in rotten poles is attributable to the changes in the inspection process, resulting in a higher number of failed poles during this initial cycle due to updated drill test criteria. Due to the 3-year overhead inspection cycle under a new inspection contractor, it is expected that rotten pole count will continue to increase at this pace throughout this inspector's second cycle due to age, environmental, and location degradation factors.

Overhead Inspections	
Pole Issue Type	# of Issues
Loose Hardware	286
Vegetation	198
Anchor Issue	260
Riser Issue	122
Leaking Tx	127
Rotten Crossarm	76
Rotten Pole Top	188
Sweating Tx	269
Infered	277
Minor Leaning	30
Major Leaning	47
Rotten Pole	1164
Total	**3044**

Figure 4: Table 2 - Overhead System Inspections – Hydro Poles 2023

Part of ongoing process review and improvements, review of data gaps have been added to the inspection requirements. Pole leaning severity, lightning arrester connection verification, and porcelain insulator identification have been added and inspected with ongoing efforts for pole remaining strength percent to be an ease of access for BHI personnel. Pole issues are remediated throughout the year as needed dependent on priority and condition category. With the 2023 fiscal year end, the BHI 3-year inspection cycle has ended and 2023 will begin a new cycle; see 'Appendix A' for the inspection cycle map.

4.1.2 CONCRETE POLE INSPECTION & REPLACEMENT

Concrete poles undergo a visual inspection, completed by the same contractor as wood poles. Based on the same OEB study, concrete poles have a typical useful life of 60 years with a maximum of 80. In 2023, 24 concrete poles were visually inspected for any mechanical defects and/or leaning issues. Throughout the cycle year, no poles were identified with visible condition issues. BHI continues to monitor these assets through inspections to ensure current issues are not expanding and creating integral strength issues. Through these continued efforts, process reviews with our inspection contractor, Under Pressure, are essential in ensuring all required data is collected. Lightning arrester connections, pole rust/corrosion conditions, visual leaning concerns, and porcelain insulator identification were all inspected throughout cycle year. See ‘Appendix A’ for the inspection cycle map.

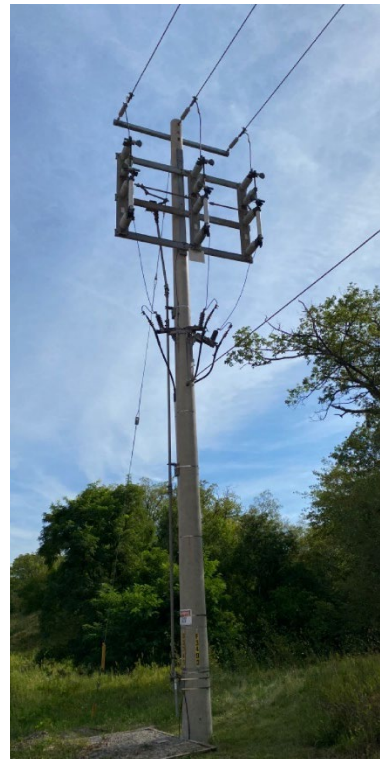


Figure 5: BHI Concrete Pole

4.1.3 INSULATOR WASHING – PORCELAIN INSULATORS

Insulator washing is an important preventative measure to minimize flashovers and pole fires. The insulator washing program is primarily carried out after the Winter months to ensure all salt exposure is removed from the insulators by a certified dedicated crew (K-Line), contracted by BHI. Frequency of the washing is dependent on the amount of de-icing salt mixture used throughout that year. BHI's focus is main arterial roads and high traffic areas throughout the service area. Particular attention is given to the 27.6kV system including any areas where there are underbuilt circuits and areas with potential for high salt contamination such as areas adjacent to highways. In the course of this work in 2023, no equipment was identified for replacement and remediated. Note, specific areas with polymer insulators are not washed as the skirt surface area is not of concern for flashover, for this reason, only porcelain insulators are targeted within those areas. See 'Appendix B' for the completed insulator washing map, 2023.

Figure 6: Burlington Hydro's Contractor Performing Insulator Washing

4.1.4 TREE TRIMMING & VEGETATION CONTROL

Tree trimming tackles a few safety and reliability aspects by mitigating safety issues, asset damage, maintenance, and service interruption (minimizing BHI's SAIDI, SAIFI scores). Significant effort is maintained to reduce impact temporary and potential long-duration outage impacts for customers. During storms, fallen branches and limbs can cause downed power lines, damaging equipment such as switches & transformers and potential pole fires that are an endangerment to the public. Additionally, as the tree branches and limbs grow throughout the year, with wind as a factor, the continuous rubbing can damage power line conductors causing other safety and reliability concerns. Tree trimming was successfully carried out in 2023, by 2 certified contractors (Davey Tree and Kodiak Tree Services – formerly by OLC) throughout the 'Tree Trimming Zones' identified for the year. In accordance with BHI's established 3-year inspection cycle; this is a normal utility practice. 'Tree Trimming Zones' 3, 8, & 12 were completed as outstanding from 2022 and 2, 6, & 9 were fully completed as part of the 2023 schedule. See 'Appendix C' for tree trimming zone maps.

Figure 7: Example of Tree Trimming Performed by Burlington Hydro's Contractor

Vegetation surrounding BHI assets are of concern primarily due to emergency access that can create delays in emergency repairs and replacements. These vegetation related issues are remediated throughout the year, see 'Appendix A' for inspection zones through the patrolled 3-year inspection cycle.

Figure 8: Reported Overgrown Vegetation on a Burlington Hydro Wooded Hydro Pole

4.1.5 INFRARED THERMOGRAPHY – OVERHEAD SYSTEM & STATIONS

Annual inspection and scanning of the overhead system and municipal stations are an important and worthwhile part of a good preventative maintenance program. This approach ensures areas with high risk for failure do not result in safety concerns for the public and interruption losses for BHI customers. The infrared inspections were completed in 2023 by an engineering contractor (DDP). A total of 27 hot spots were identified resulting in 3 intermediate rated issues and 3 receiving a rating of serious. All locations rated serious were remediated with no areas of concern regarding types of equipment, locations or patterns of serious concern requiring targeted focus. See 'Appendix D' for the infrared main circuit maps, 27.6kV, and 13.8kV & 4.16kV.

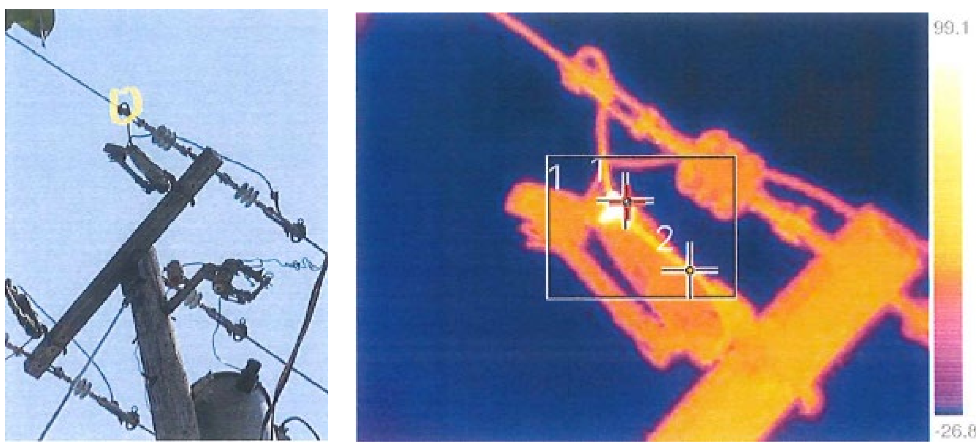


Figure 9: Infrared Photos Provided by Burlington Hydro's Contractor's Report

Measurements	°C
Spot 1	150>
Spot 2	48
Area 1 Max.	150>
Rating	Serious
Recmmendation	Replace or Tighten

Figure 10: Table 3 – IR Measurements & Recommendation

4.1.6 AIR BREAK SWITCH MAINTENANCE

Maintenance programs are crucial during yearly inspection cycles in ensuring the overhead system safety and reliability is maintained to the highest degree. Air break switches (ABS) are an essential part of the overhead system as they provide a live operating break on the circuit for safe work practices while BHI crews perform switching and isolating operations. The ABS is typically a manually operated switch by a mechanical open, operated by a handle secured to the hydro pole close to ground level. Crews are required to be electrically bonded by being elevated on a grounding mat to ensure an equipotential work zone for the operator. Through the maintenance program, BHI crews inspect correct operation of equipment, ensuring the mechanical handle is operating as intended without defect, the switches open as intended, grounding connections are correctly connected, no arc flash burns are present, as well as ensuring contacts are cleaned and lubricated. Through the patrolled inspections, the 2023 inspection area had 16 ABS inspected. Out of all inspected and serviced ABS, only 1 defect was found with a broken operating handle which was remediated along with routine maintenance and lubrication on all ABS. No additional maintenance program recommendations required at this time. See 'Appendix A' inspection cycle map for areas of focus for each year.

Figure 11: Broken Operating Handle from a Burlington Hydro Air Break Switch Location

4.1.7 POLE MOUNTED TRANSFORMERS

Along with the hydro pole inspection, attached equipment throughout the patrolled inspection cycle year is inspected as well at the same time. Inspection criteria is verified to ensure that there are no minor or catastrophic failures resulting in service interruptions to customers in the future.

The following are criteria typically reviewed for pole mounted transformers:

- **Asset Age**
  - BHI assets have a general useful as well as a financial book value. The 'Asset Depreciation Study for the Ontario Energy Board' lists overhead transformers as having a typical useful life of 40 years with a maximum of 60 years. Book value is based over 40 years before the asset is considered a fully depreciated asset.
- **Visual Damage**
  - Any visual defects that can be seen are noted dependent on the determined severity of damage, determines repair or replacement recommendations.
- **Oil Leakage**
  - Due to insufficient seals, metallic rust, and/or overheating, an overhead pole mounted transformer can experience oil leakage. This can typically be noticed by as oil stains on the outside of the transformer and/or ground contamination. Soil clean-up and remediation is completed as needed. Oil PCBs were remediated to meet Canadian Environmental Protection Act – PCB Regulations since 2011 throughout BHI's service territory.
- **Animal Nesting**
  - Small animals are known to create nests on overhead assets. This can result in faults causing service interruptions and impact BHI SAIDI & SAIFI scores. These issues are remediated as necessary.
- **Load Reporting**
  - A useful tool used in transformer replacement metrics is load reporting recently introduced in 2022 through our GIS. BHI can determine if the transformer is under or overutilized based on coincidental and non-coincidental peak loads.

Pole mounted transformers are remediated as required. Current economic situations have resulted in greater than normal logistical delays for manufacturers as well as a combined labour shortage. This has resulted in replacement inventory delays and in-depth review of asset conditions and replacement criteria.

Maintenance Activities: Pole Mounted Transformers	2022	2023	Trend
Total Number of Overhead Transformers in The System	3176	3178	↑
Number of Polemount Transformer Installations	30	32	↑
Number of Three Phase Bank Installations	3	5	↑

Figure 12: Table 4 – Pole Mounted Transformers

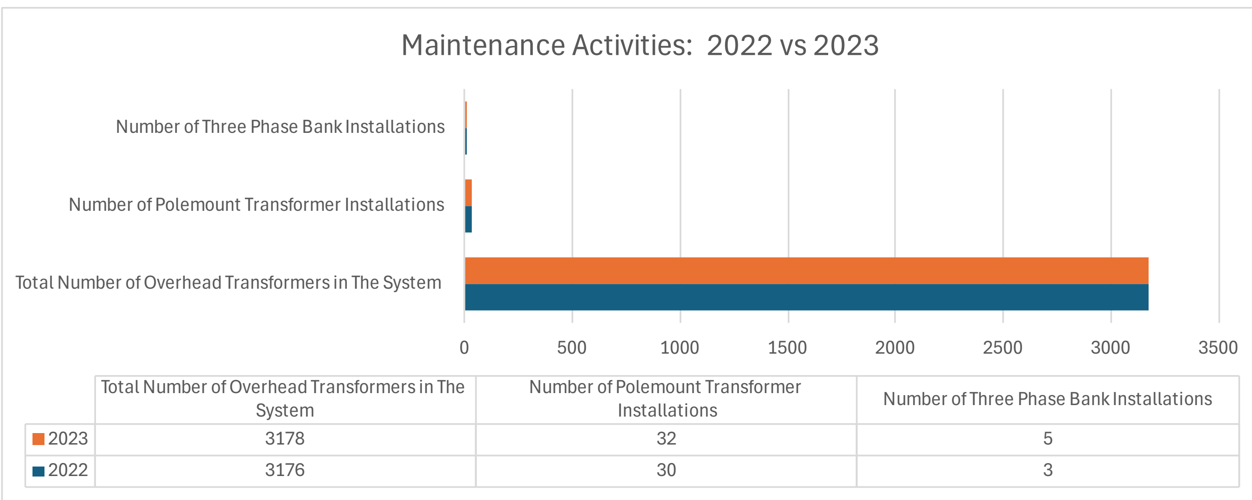


Figure 13: Chart 2 – Pole Mounted Transformers 2022 vs 2023

As the trend lines show, there was an increase in overhead transformer activity from 2022 to 2023. This trend is a minimal increase but ensures optimized loading on available transformers to minimize system losses as well as BHI underground system expansions through replacement efforts as well as new installations. See 'Appendix A' for inspection cycle year area.

4.2.0 SYSTEM MAINTENANCE ACTIVITIES – UNDERGROUND SYSTEM

4.2.1 PAD-MOUNTED TRANSFORMERS

Through the BHI 3-year inspection cycle, the same areas are targeted for pad-mounted transformers in accordance with the minimum inspection requirements of the Distribution System Code. The following are typical criteria of inspection patrols:

- **Asset Age**
    - BHI assets have a general useful as well as a financial book value. The 'Asset Depreciation Study for the Ontario Energy Board' lists underground pad-mounted transformers as having a typical useful life of 40 years with a maximum of 45 years. Book value is based over 40 years before the asset is considered a fully depreciated asset.
- **Visual Defects – Damage, Rust, Graffiti, & Discolouration**
    - Any visual defects that can be seen are noted dependent on the determined severity of damage such as internal equipment, external rust, snowplows, pedestrians, and vehicle accidents, determines the replacement or repair recommendation. As per city by-law 49-2022 – Section 6.12 graffiti is remediated as reported including discolouration from UV and environmental exposure such as street de-icing.
- **Oil Leakage**
    - Due to insufficient seals, metallic rust, and/or overheating, an underground pad-mounted transformer can experience oil leakage. This can typically be noticed by visual inspection of oil leaking on the outside of the transformer, dark discolouration saturation on the concrete pad, and/or ground contamination. Soil clean-up and restoration is completed as needed.
- **Load Reporting**
    - A useful tool used in transformer replacement metrics is load reporting recently introduced in 2022 through our GIS. BHI can determine if the transformer is under or overutilized based on coincidental and non-coincidental peak loads.

Maintenance Activities: Pad-Mounted Transformers	2022	2023	Trend
Total Number of Three Phase Pad Mounted Transformers	974	980	↑
Total Number of Single Phase Pad Mounted Transformers	3146	3153	↑
Number of Three Phase Installations	12	8	↓
Number of Single Phase Installations	15	15	→

Figure 14: Table 5 – Pad-Mounted Transformers

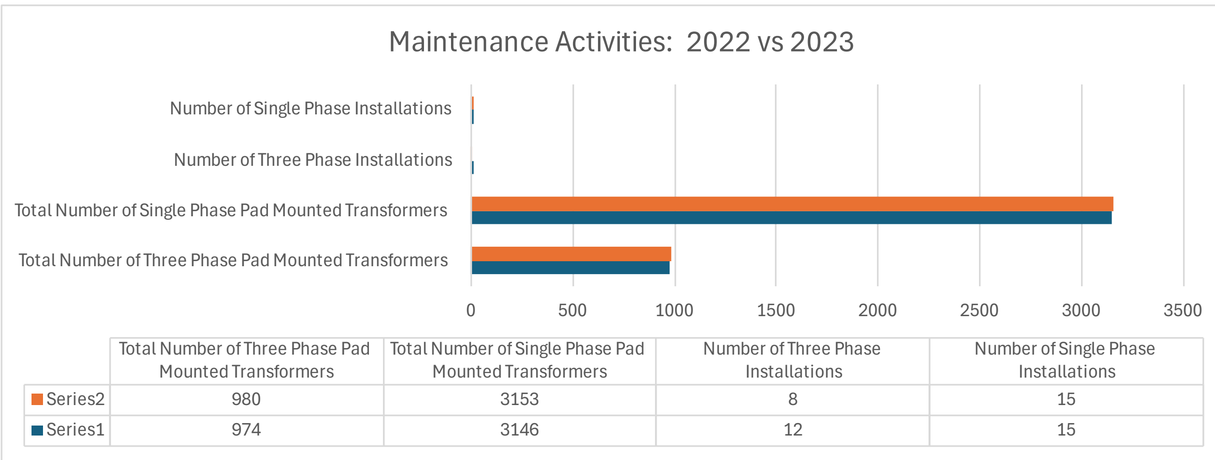


Figure 15: Chart 3 – Pad-Mounted Transformers 2022 vs 2023

Throughout the year there were a total of 8 leaking transformers replaced out of a list of 14 reported. An ongoing list of leaking transformers is being kept up to date and transformers are ordered and replaced as permitted by current stock levels. We have seen a minimal downward trend in pad-mount transformer installations at -4 for the 2023 cycle year but BHI continues to mitigate procurement delays by ensuring top priority assets are replaced as required. See 'Appendix A' for inspection cycle year area.

Underground Inspections	
Issue Type	# of Issues
Oil Leak	101
Sweating	112
Graffiti	249
Rusted	69
Grading	78
Lock	30
Paint	137
Vegetation	495
Shifted	31
Total	**1302**

Figure 16: Table 6 – Underground System Inspections 2023

4.2.2 SUBMERSIBLE TRANSFORMERS

Submersible transformers are inspected as part of the annual transformer visual inspection process by ensuring no damage is present on the outer lid with potential for a tripping hazard or worse for the public. There were 2 replacements of submersible transformers in 2023. There was a previous recommendation to introduce a formal program for the washing of underground vaults; this program has not been initiated yet. See 'Appendix A' for inspection cycle year as well as 4.3.2 for future recommendations.

4.2.3 CLEANING OF SWITCHING CUBICLES

BHI has 240 pad mounted switching cubicles within its distribution system which is an increase of 4 units from the previous year: 1 PMH unit and 3 Vista units. There were 65 switching cubicles inspected through the cycle year by DDP for internal inspection and Under Pressure Inc for exterior inspection. Through the inspection cycle, 8 units had shown signs of hot spots through IR scanning as well as 7 having ultrasound detection. A specialized maintenance technique, using "dry ice", is employed, to clean the selected number of the switching cubicles. This work can be safely completed with the equipment energized, therefore reducing the time and cost for switching activities. No remediation was completed in 2023, all required maintenance will be pushed through the 2024 budget year, as required. See 'Appendix E' for inspection cycle year area.

4.2.4 SUBSTATION INSPECTION AND PREVENTIVE MAINTENANCE

Visual patrolled inspections of the stations and the equipment is performed monthly. Any issues found are reported, prioritized, and rectified as necessary. In addition to the visual inspection, preventive maintenance is performed at each station every 5 years. In 2023 the following stations were maintained:

- Drury, Maple, Port Nelson & Tyandaga

For 2024, the following stations are targeted for maintenance:

- Fairleigh, Howard, Pinecove, Spruce, Towerline, Interchage, & Reservior

4.2.5 CABLE FAULTS

A total of 35 primary cable faults were remediated throughout the 2023 year. Primary cable faults result in significant service interruption times and require reactive emergency repairs if service cannot be restored promptly. This affects BHI SAIDI & SAIFI metrics with increases in both metrics. SAIDI had increased from 1.41 in 2022 to 1.97 in 2023 while SAIFI had increased from 0.90 in 2022 to 1.52 in 2023. Overall, 2023 reliability metrics are above the OEB target for BHI.

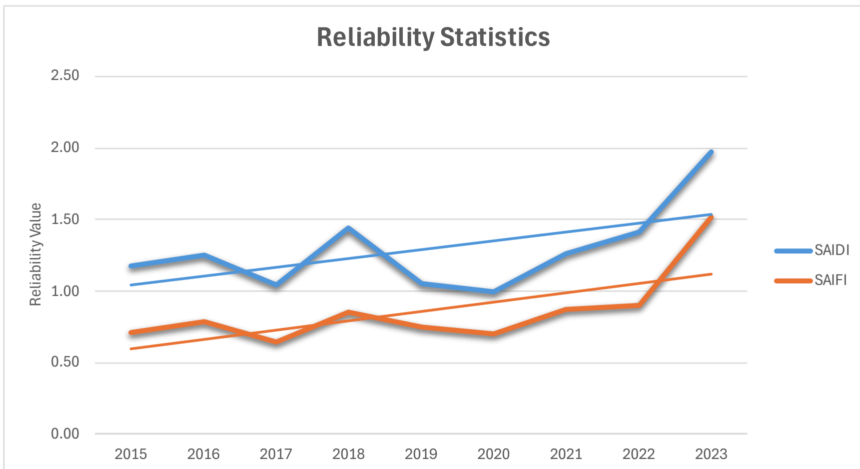


Figure 17: Chart 4 – Reliability Statistics for Yearly SAIDI & SAIFI Metrics

	2015	2016	2017	2018	2019	2020	2021	2022	2023	Target
SAIDI	1.18	1.25	1.04	1.44	1.05	1.00	1.26	1.41	1.97	1.19
SAIFI	0.71	0.79	0.64	0.85	0.75	0.70	0.87	0.90	1.52	0.75

Figure 18: Table 7 - Reliability Statistics for SAIDI & SAIFI Metrics (Excluding Loss of Supply & Major Events)

Metrics	Year	YTD	Trend
Number of Customers	2022	68,850	
	2023	69,057	↑
Customer Hours of Interruption - Defective U/G Primary	2022	14,973	
	2023	14,115	↓
SAIDI - Defective U/G Primary	2022	0.22	
	2023	0.20	↓
Number of Customer Interruptions - Defective U/G Primai	2022	5,191	
	2023	6,517	↑
SAIFI - Defective U/G Primary	2022	0.08	
	2023	0.09	↑

Figure 19: Table 8 – Underground Primary Cable SAIDI & SAIFI Metrics for 2022 vs 2023

4.2.6 SCADAMATE INSPECTION AND MAINTENANCE

S&C ScadaMate switches are intelligent circuit-breaking switching devices used in distribution automation systems to enhance grid reliability and performance. Proper maintenance ensures their optimal operation, reduces unplanned outages, and extends the switch's lifespan. There is a total of 71 ScadaMate installed within the Burlington Hydro service territory.

Figure 20: Existing ScadaMate Installation

Due to multiple switch failures, a maintenance program was established for 2023. Inspection of components such as the insulation and sensors, disconnection of live parts, control cabinet and control cable, as well as verifying the condition of lightening arresters with proper grounding connections. Cleaning and lubrication are performed on the insulators to remove dirt and contaminants and the current carrying contacts are wiped down to remove grease and dirt buildup as to allow for the application of a light coating of non-sulfur containing contact lubricant. A total of 69 units were maintained throughout the 2023 year. The 2 units that were not maintained were due to an access issue as well as a critical customer load that could not be isolated during the time of maintenance. Both units will be maintained at a later date in 2024. See 'Appendix F' for the ScadaMate location map.

4.2.7 SUBMERSIBLE TO PAD-MOUNTED TRANSFORMER CONVERSION

With climate change and climate change related risks becoming a larger topic of consideration, CSA has made changes to their existing CSA 22.3 No. 7 – Underground Systems standards. Where practicable, pad-mounted installations above ground should be selected over submersible installations in subsurface chambers. Burlington Hydro has a commitment to the Burlington 'Climate Action Plan' and a recommended pilot has been introduced to convert end-of-life submersible transformers to pad-mounted transformers. The lifecycle cost of pad mounted units is less than submersible units, allowing Burlington Hydro to achieve more with replacement budgets and provide overall better service to the community. The initial pilot conversion was completed on transformer T186 with a custom concrete lid designed to be used with existing submersible transformer foundations in the conversion to pad-mounted units. A future program which will be finalized after the unit has been replaced with an anticipated 2024 program start.

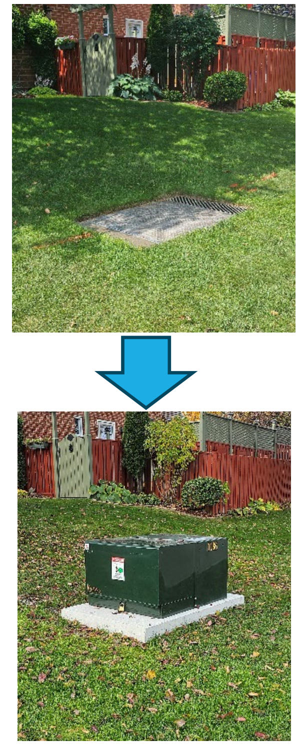


Figure 21: Transformer T186 Pilot Conversion

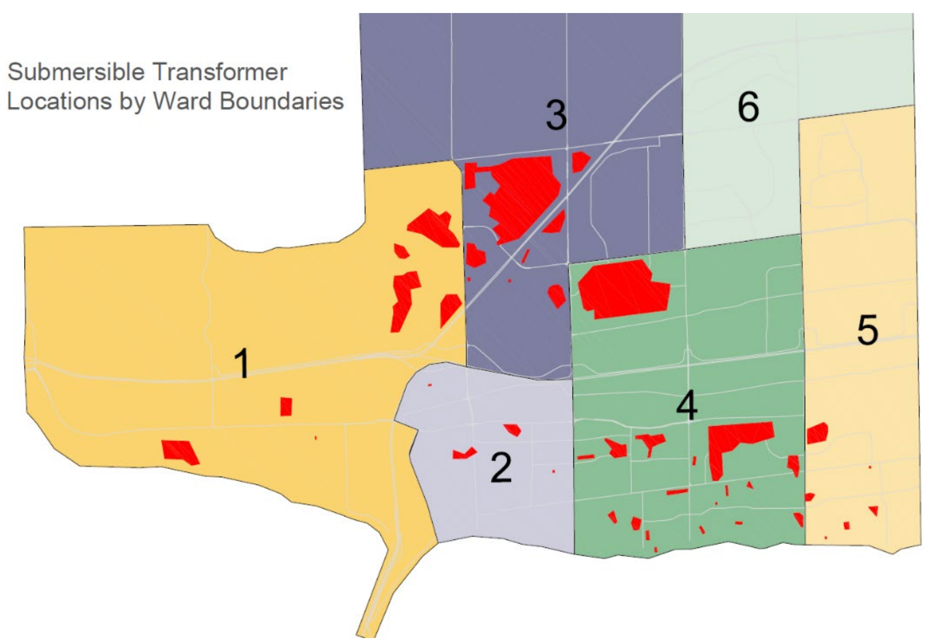


Figure 221: Submersible Transformer Locations by Ward boundaries

4.3.0 FUTURE MAINTENANCE & OPERATION RECOMMENDATIONS

4.3.1 WOOD POLE REPLACEMENTS

With the conclusion of the 2020 to 2022 3-year patrolled inspection cycle, a great amount of detailed data is available for the next BHI Asset Condition Assessment Report in 2024. Due to current Cost of Service budget allocations and a continued increase in equipment costs and delays due to ever changing economic situations, a continued effort will be put towards pole replacements and any changes required to replacement frequency due to the influx of rotten poles will be evaluated in advance of the next cost of service application. The current pole replacement program may require acceleration with currently 1,164 identified rotten poles requiring replacement due to failed integral strength conditions. With current pole replacement costs, a general goal of 110 rotten pole replacements is targeted while only 60-80 are able to be met due to increased inventory & labour costs.

4.3.2 VAULT CLEANING/WASHING

Currently, there is not a submersible vault washing program for the BHI underground system. A review of the patrolled inspection reports for all underground system vaulted equipment should be considered for future budgets and dependent on reported conditions, consideration should be given to a more concentrated vault cleaning/washing program for equipment that does not currently have one. Dirt buildup could result in electrical tracking under certain conditions.

4.3.3 LEAKING TRANSFORMER REPLACEMENTS

With continued procurement issues, all reported leaking transformers are inspected on condition and equipment is ordered unless emergency repairs are required. Additional stock is recommended to be ordered to ensure replacements can be performed in a timely manner in the event that the leaking transformer fails, or immediate replacement is triggered through ESA/customer complaint. An ongoing leaking transformer list is kept between Asset Management & Lines with transformers ordered accordingly. Additional repair methods are being investigated such as leak sealer from Polywater and ONTech Coatings services.

4.3.4 TRANSFORMER LOAD UTILIZATION REPLACEMENTS

As mentioned previously, load reports are now available through the Burlington Hydro GIS. Coincidental peaks should be assessed on transformers that are above 100% and below 25%-50% utilization. There is a large quantity of pad mounted transformers within our service territory. A focused effort in replacements should be targeted with an appropriate budget to reduce system strain and losses. An 'Annual Transformer Utilization by Transformer Type' report was created for 2023 and will be utilized in these efforts.

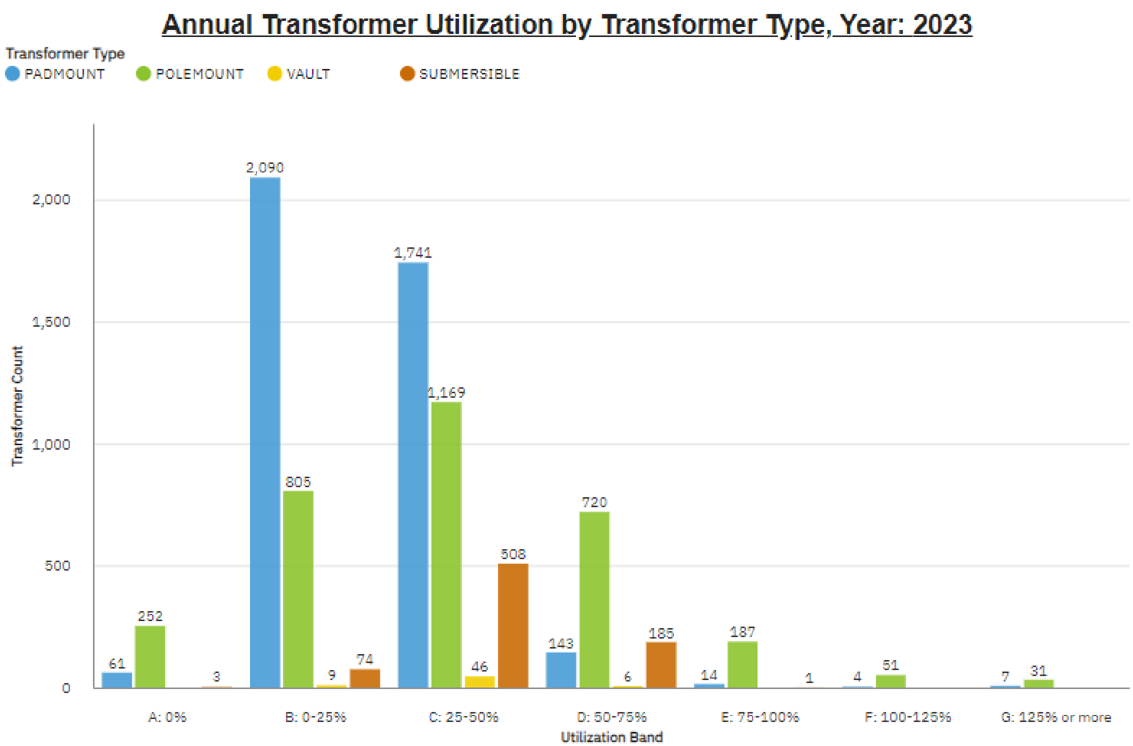


Figure 23: Chart 6 – Annual Transformer Utilization by Transformer Type – 2023

4.3.6 CABLE TESTING – PALMER AND NORTH TYANDAGA SUBDIVISIONS

As previous successes with the Brant Hills cable testing program, a continued effort needs to be maintained to gather more data on subdivisions susceptible to continued cable faults. Palmer & North Tyandaga subdivisions have already been targeted as the next best candidates for testing. The same approach will need to be taken with cable testing, equipment maintenance where required. Palmer cable testing is going to be completed in conjunction with N.Tyandaga cable testing in 2024. Cable testing has been delayed due to ongoing inventory procurement delays from manufacturers and vendors. With the implementation of test point mounted fault indicators, certain older style elbows cannot make proper contact resulting in some FCI not working as intended. As cables reach end of life, the FCI will be transferred to the new elbows at each location.

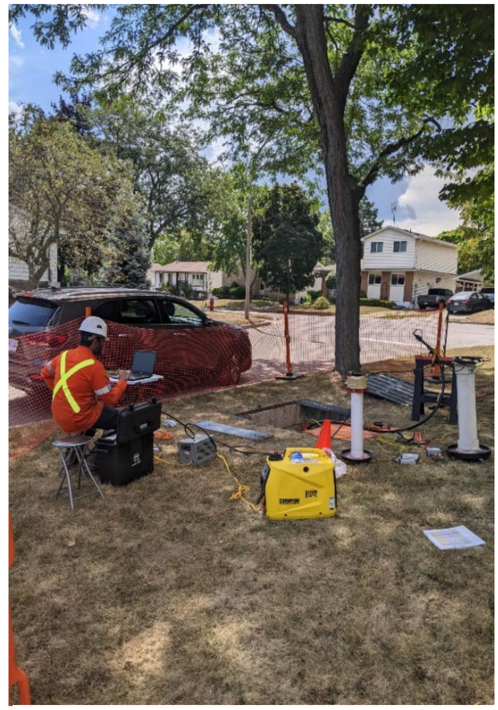


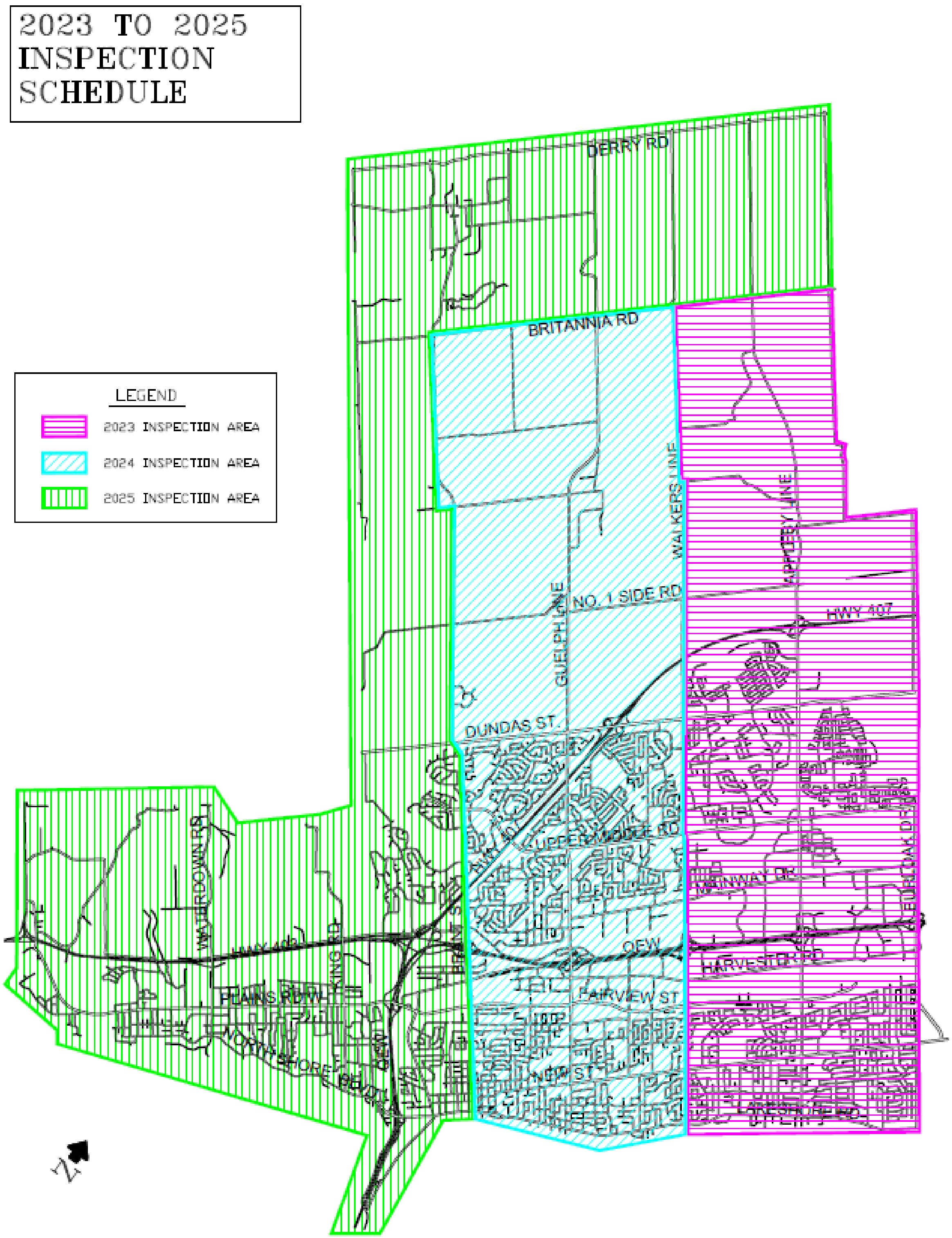
Figure 24: Burlington Hydro's Contractor Performing Cable Testing at a Submersible Transformer

4.3.7 CABLE REJUVENATION PROGRAM

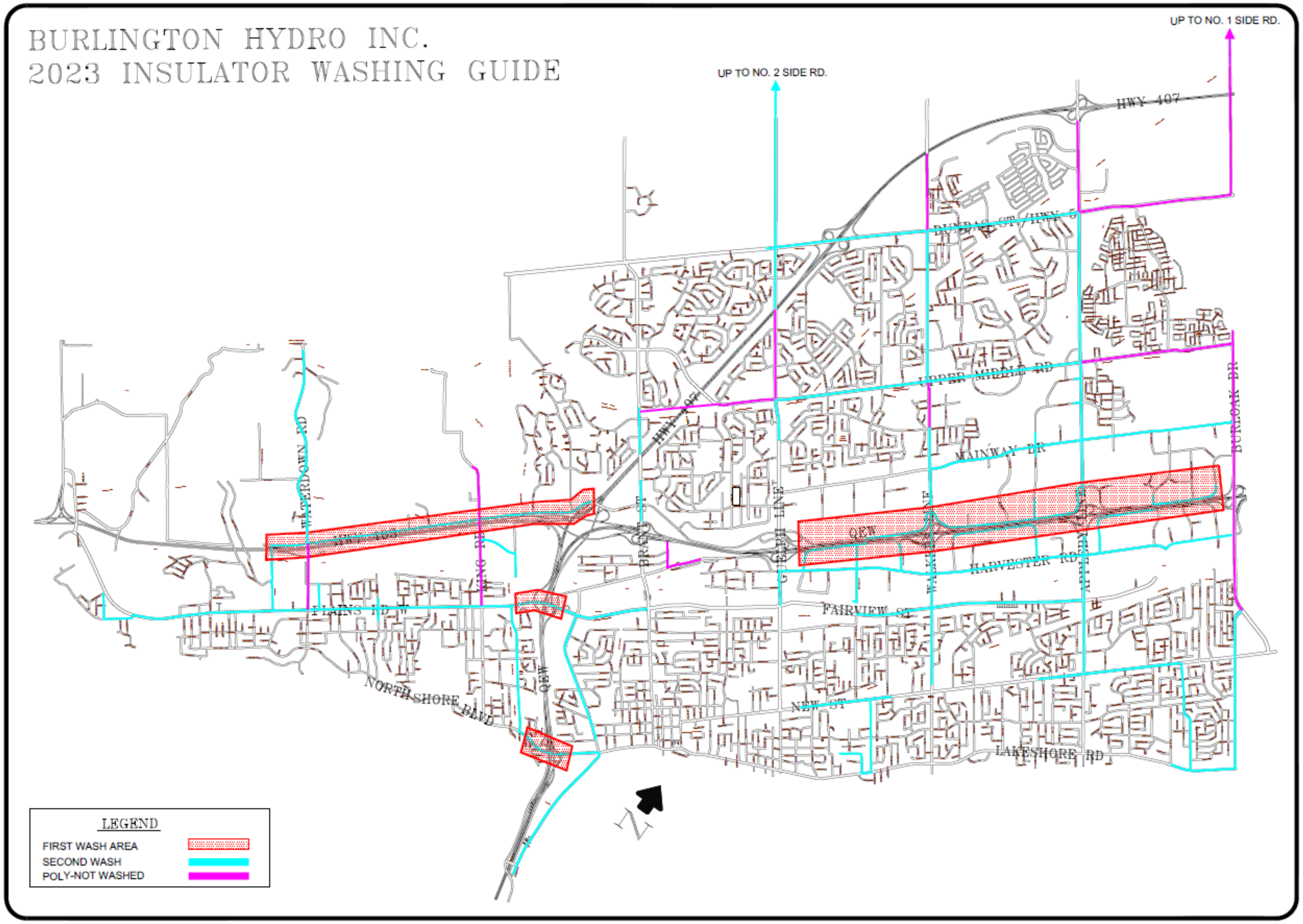
Continued efforts with cable testing have shown suboptimal results for cable conditions in Brant Hills. Novinium is a Southwire company that is currently the only cable rejuvenation provider in North America. As test result data is compiled, areas need to be assessed for potential use of cable injection. Cable injection primarily focuses on voids, defects, and water trees within cable insulation to fill the gaps and reduce the chance of cable faults while extending the asset life of cables. This is a much cheaper alternative to cable replacement and can be capitalized as it extends and improves asset life. A coordinated cable rejuvenation effort may be required to ensure not only cable injection but attached cable accessories are replaced as well to mitigate the risks of potential failures or issues from aged equipment. Meetings with Novinium, Kinectrics and other industry partners have been held in 2023 to start determining how cable rejuvenation might play a part in BHI’s asset management strategy leading into 2024.

APPENDIX

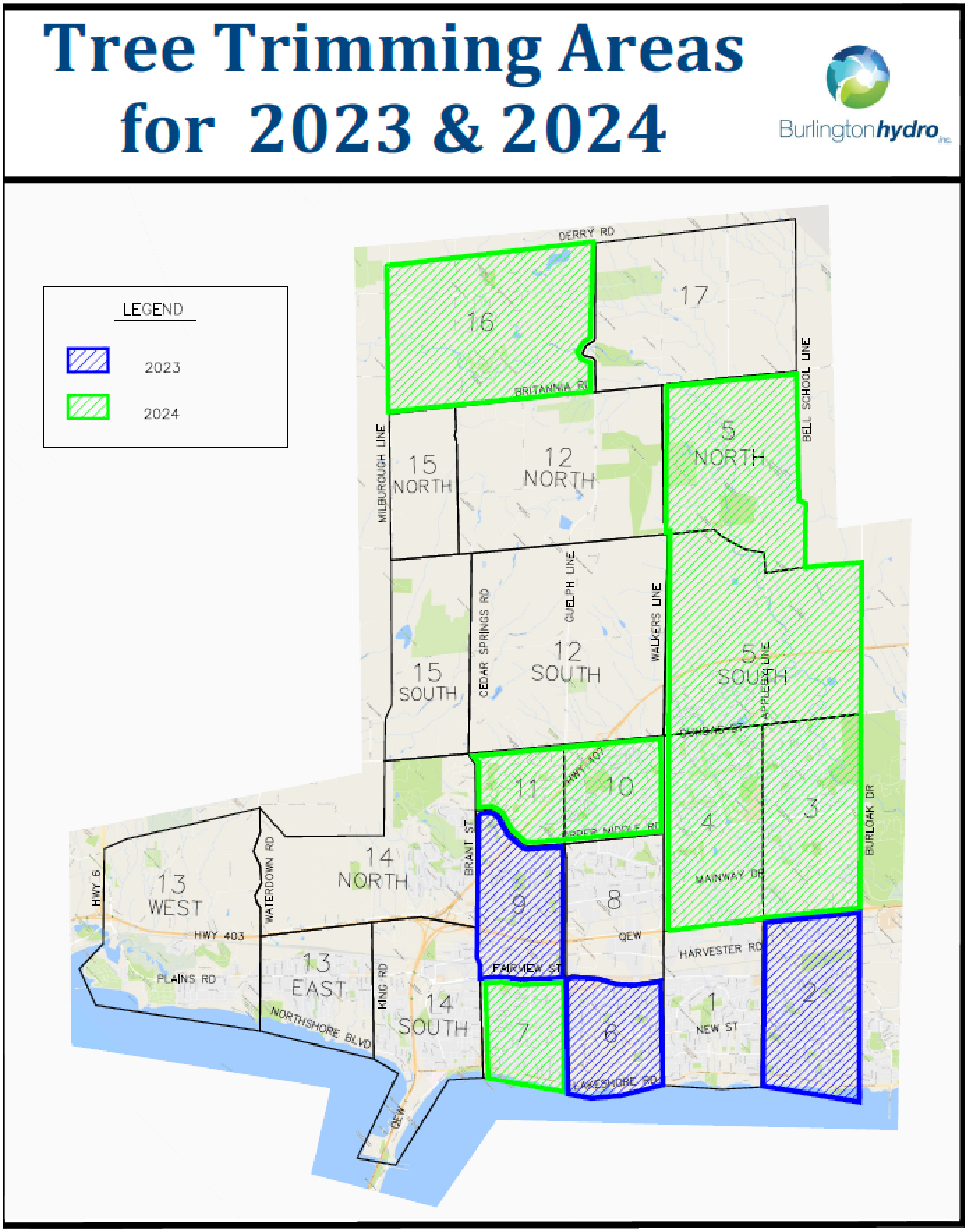
APPENDIX A – INSPECTION CYCLE 2023-2025



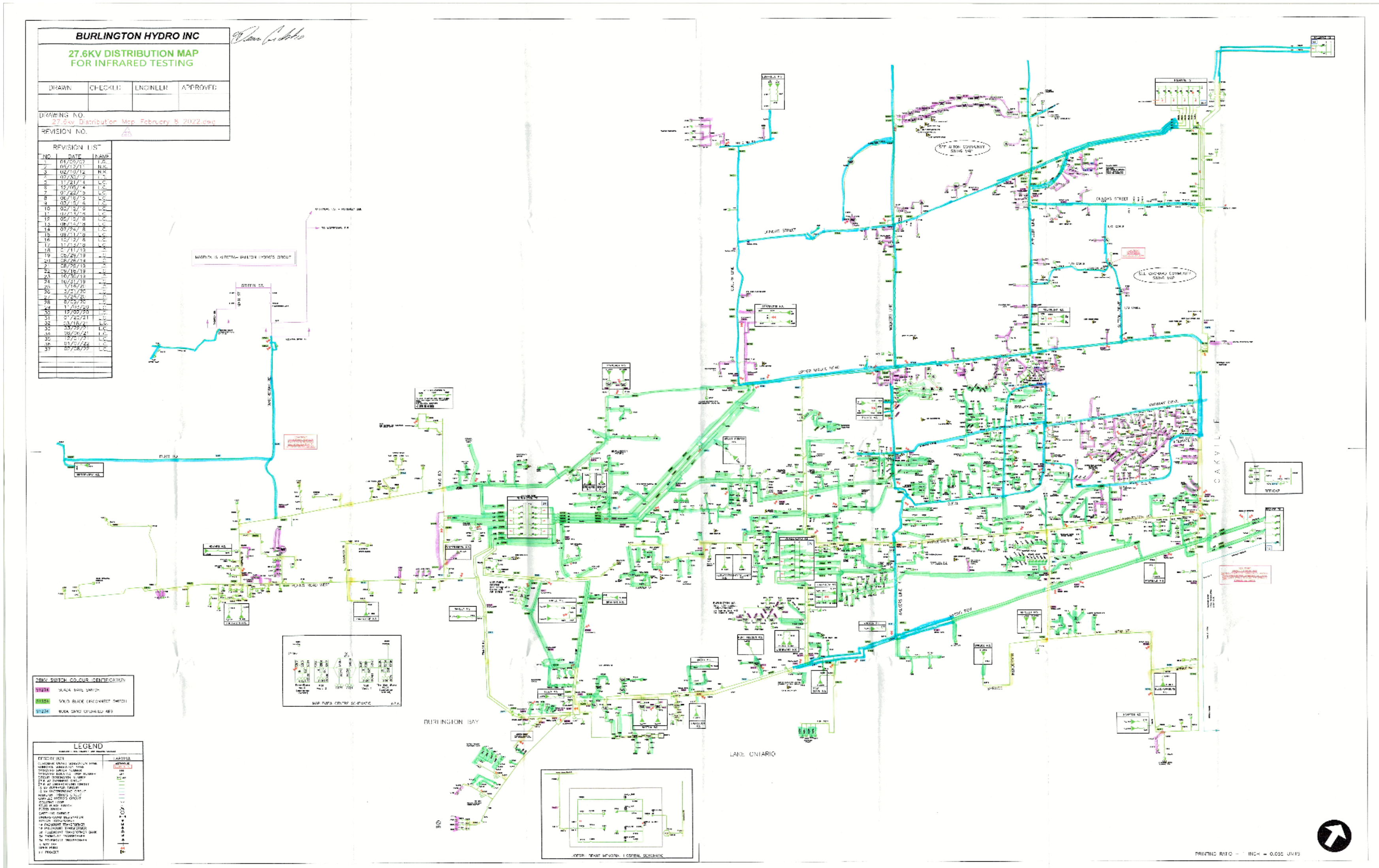
APPENDIX B – INSULATOR WASHING CYCLE 2023

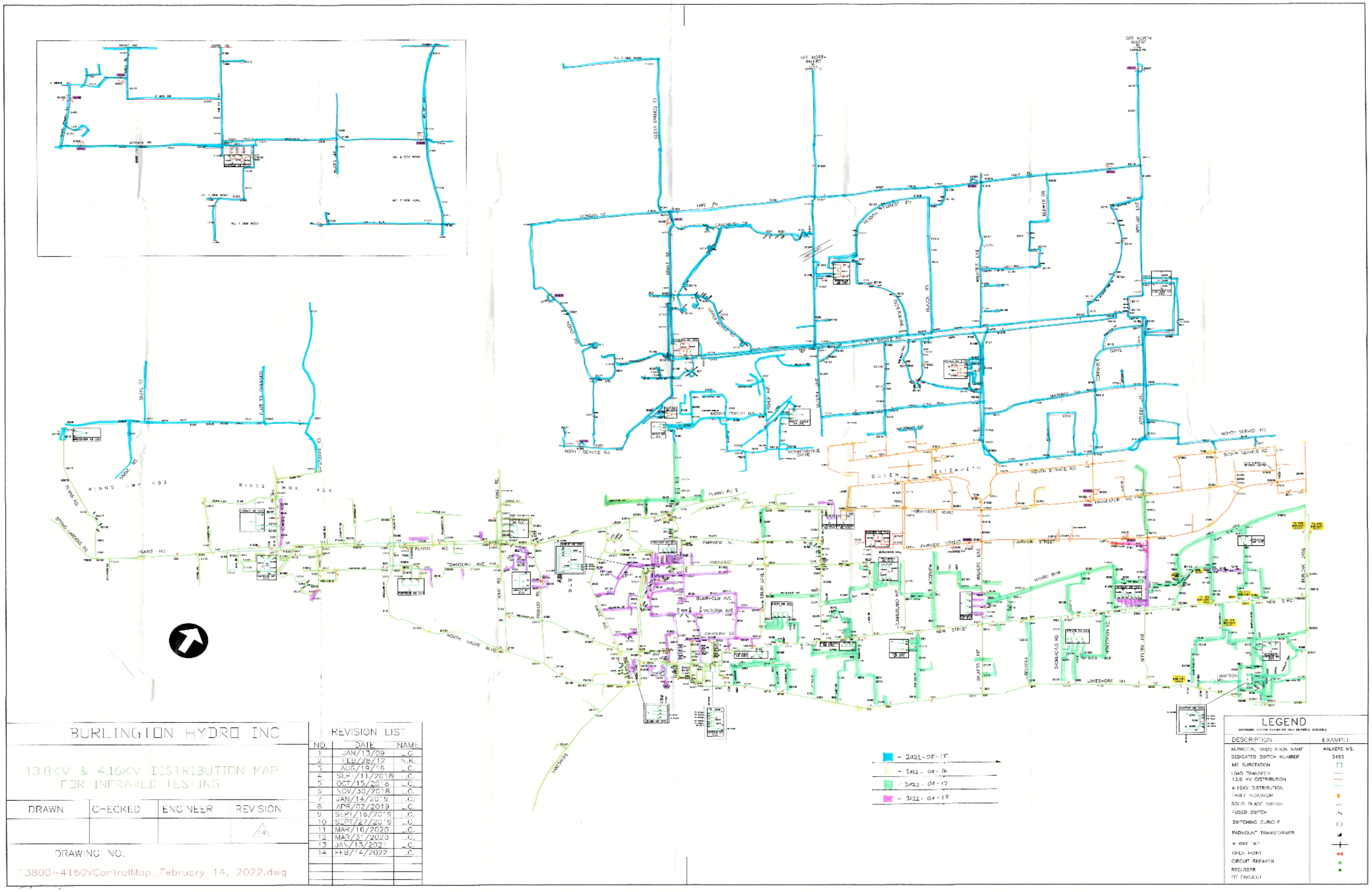


APPENDIX C – TREE TRIMMING ZONES 2020-2022

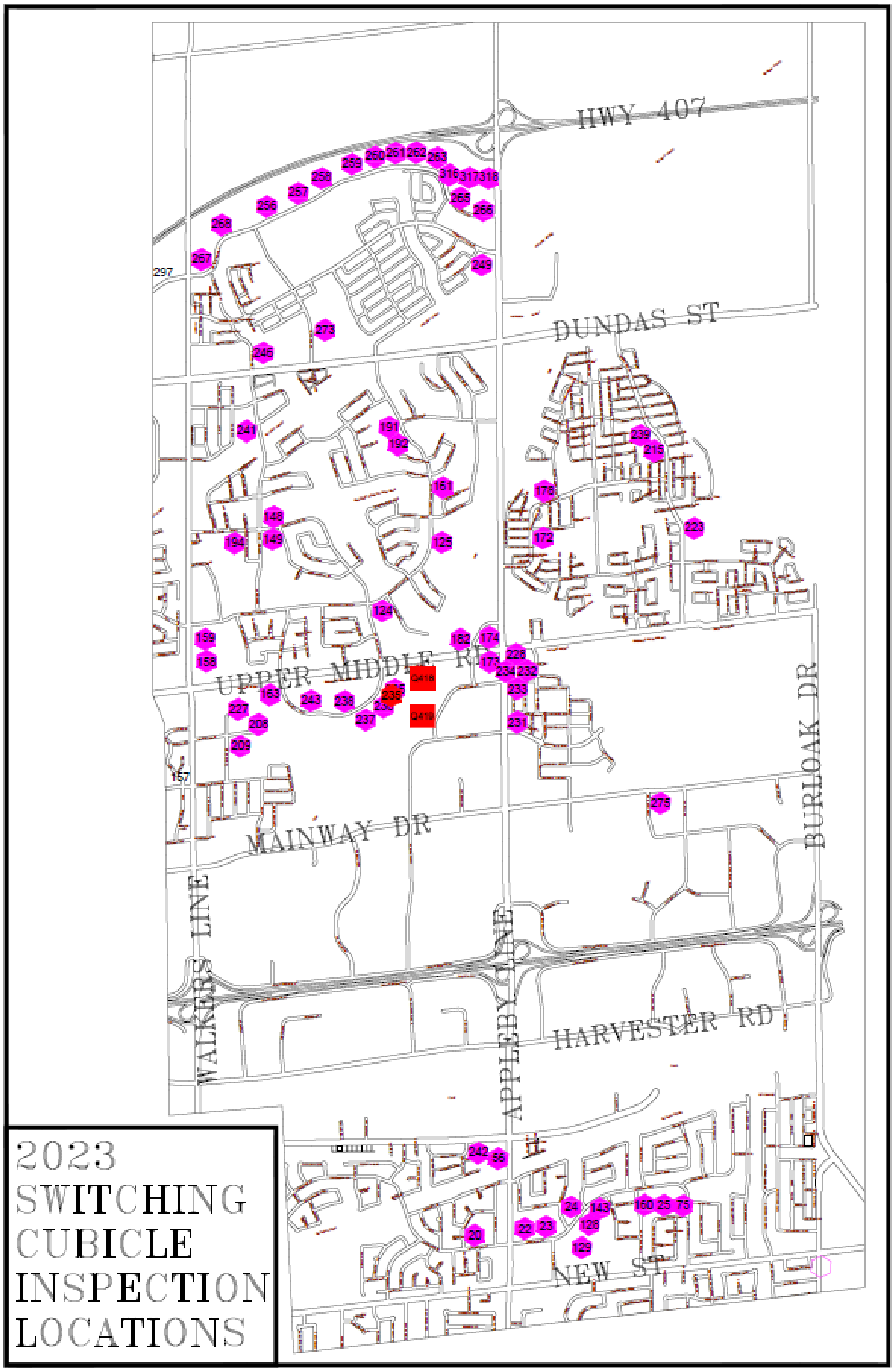


APPENDIX D – INFRARED THERMOGRAPHY MAPS – 27.6KV MAP AND 13.8KV & 4.16KV MAP

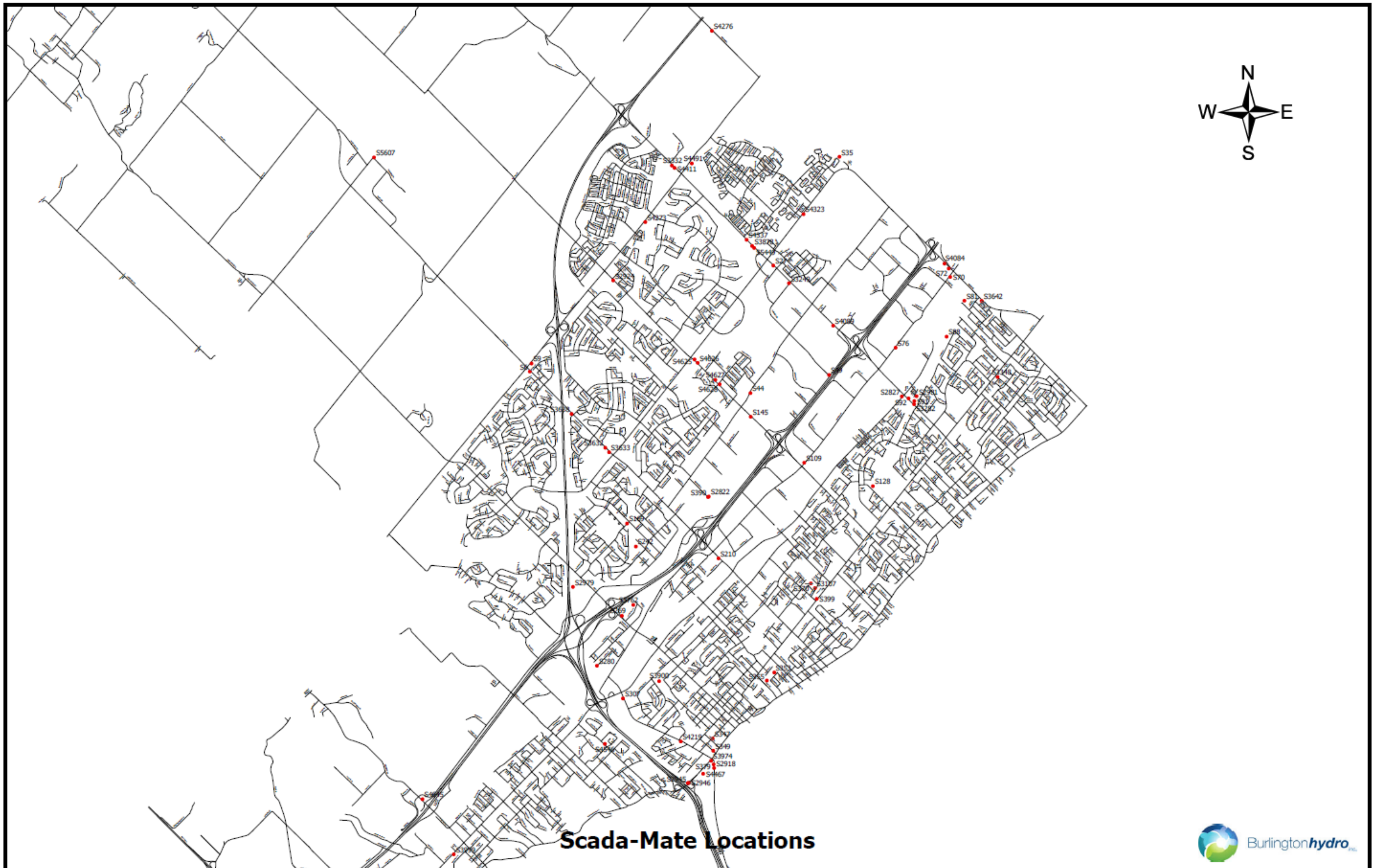



BURLINGTON HYDRO INC
13.8KV & 4.16KV DISTRIBUTION MAP
FOR INFRARED TESTING
DRAWN
CHECKED
ENGINEER
REVISION
14
DRAWING NO.
13800-4160VControlMap_February 14, 2022.dwg
REVISION LIST
NO. DATE NAME
1 JAN/13/09 L.C.
2 FEB/28/12 N.K.
3 AUG/19/16 L.C.
4 SEPT/11/2018 L.C.
5 OCT/15/2018 L.C.
6 NOV/30/2018 L.C.
7 JAN/14/2019 L.C.
8 APR/02/2019 L.C.
9 SEPT/16/2019 L.C.
10 SEPT/27/2019 L.C.
11 MAR/16/2020 L.C.
12 MAR/31/2020 L.C.
13 JAN/13/2021 L.C.
14 FEB/14/2022 L.C.
- 2022-08-15
- 2022-08-16
- 2022-08-17
- 2022-08-18
LEGEND
DESCRIPTION
EXAMPLE
MUNICIPAL SUBSTATION NAME
WALKERS MS.
DEDICATED SWITCH NUMBER
3465
MS. SUBSTATION
LOAD TRANSFER
13.8 KV DISTRIBUTION
4.16KV DISTRIBUTION
FAULT INDICATOR
SOLID BLADE SWITCH
FUSED SWITCH
SWITCHING CUBICLE
PADMOUNT TRANSFORMER
4 WAY TAP
OPEN POINT
CIRCUIT BREAKER
RECLOSER
FIT PROJECT
LAKESHORE RD.
HAMPTON MS.
FAIRVIEW STREET
NORTH SERVICE RD.
SOUTH SERVICE RD.
PLAINS RD.
KINGS HWY. 403

APPENDIX E – SWITCHING CUBICLE INSPECTION LOCATIONS



APPENDIX F – SCADAMATE MAINTENANCE LOCATIONS



Appendix K

Vision 2024 Burlington's Strategic Plan

Vision 2040

Burlington's Strategic Plan 2015 – 2040

Updated
May 2021

burlington.ca/strategicplan

City of Burlington

Welcome to Burlington's 2015 – 2040 Strategic Plan - Update 2021

In 2016, the City of Burlington published it's 2015-2040 Strategic Plan. This visionary plan was the result of more than a year of public engagement that included input from residents, businesses, community groups, City employees and members of Burlington City Council.

The City was facing a number of economic and demographic changes that required a coordinated and strategic response. The city continues to deal with an important transition, of being a municipality that finds itself needing to grow in place. In addition to our core mandate of providing a range of critical City services, the City decided to add a new mandate: to actively "city-build."

City-building means using all of the tools available to City Council, working with community partners to define how we grow, and to actively shape the physical, social, economic and cultural fabric of the city as we grow.

The City of Burlington's 2015-2040 Strategic Plan is fundamentally different from past plans. It is the 25-year blueprint for city-building and will be supported in more detail with the Official Plan, Integrated Mobility Plan, Asset Management Plan, Burlington Economic Development Strategic Plan and Burlington's Plan: From Vison to Focus, Burlington's 4-year work plan. The Strategic Plan takes on the challenging issues of today and tomorrow, seizes current and future opportunities and helps Burlington prepare for the next 25 years.

This plan is a framework for critical decision-making and considers how we manage our resources. Although the plan has a 25-year horizon, there will be four-year work plans, prioritization of the goals and initiatives within the plan and a conversation with the community to address our changing city and new realities. It encourages common goals across Burlington in partnership with our community.

During the engagement process, the City heard what is important to the people of Burlington. Here are the four key strategic directions you will learn more about in this Strategic Plan.

Burlington is:

- A City that Grows
- A City that Moves
- A Healthy and Greener City
- An Engaging City

2021 Strategic Plan reorganization and alignment with other City plans

With this update in 2021, these strategic directions have not changed. We have reorganized our 25-year plan to be the visionary plan it was intended to be: Vision 2040. It is in our 4-year workplans, and associated monitoring of internal and external dashboards, where we will see the specific initiatives to help us progress toward our vision for the future.

Burlington's Strategic Plan and other Corporate Priorities

The City of Burlington's 2015 – 2040 Strategic Plan is the City's guiding document.
Here is how other City plans are aligned.

Long-term policy	City of Burlington's 2015 – 2040 Strategic Plan		
Medium-term policy documents	Burlington's Plan: From Vision to Focus	Official Plan (5 – 10 year renewal)	Related plans: Integrated Mobility Plan, Asset Management Plan, Climate Action Plan, Cultural Action Plan and more
Short-term implementation plans	Annual Vision to Focus Action Plan	City Manager Objectives/Service Work Plans	City's Financial Plan (operating and capital budgets)

Burlington - Partnering for Success

Burlington is pleased to work with other levels of government to provide a suite of services to help us achieve our goals and support the 17 United Nations Sustainable Development Goals* to improve community well-being. We proudly work with other levels of government.

The Government of Canada is responsible for issues that affect Canada as a whole country such as international relations, immigration, criminal law, taxes, national defence, and foreign policy.

The Province of Ontario is responsible for issues that affect the province as a whole such as education, health care, the environment, agriculture, and highways.

Halton Region provides clean drinking water, resilient infrastructure, public health programs, financial assistance, and family supports.

The City of Burlington provides customer relations and resident representation, design and build services, leisure services, maintenance services, public safety services and roads and transportation services.

In addition to government, Burlington is pleased to recognize the support and contributions of the many community organizations, support groups, NGOs, businesses and residents that contribute to making Burlington a top city each and every day.

**For more information on Vision 2040 and the UN SDGs, please visit burlington.ca/strategicplan*

Corporate Alignment and Accountability

Burlington's 2015-2040 Strategic Plan is a long-term vision for the future. It is a framework for critical decision making and guide to how we manage our resources today to position Burlington for the future. Burlington's corporate alignment and accountability is built on Service Management and Results Based Accountability Frameworks.

A Results-Based Accountability Framework* takes into consideration two types of accountability:

- Community Measurement Results
- Performance Measurement Results

**The Fiscal Policy Studies Institute*
www.resultsbasedaccountability.com

Key Strategic Directions and Broad Objectives

A City that Grows

>> The City of Burlington attracts talent, good jobs and economic opportunity while having achieved community responsive growth and balanced, targeted population growth for youth, families, newcomers and seniors.

- Focused and directed population growth to lay the foundation for a larger economy, more jobs, fiscal sustainability, better infrastructure and public transportation
- Higher densities in key areas to build neighbourhoods that are environmentally friendly, infrastructure-efficient, walkable, bikeable and transit-oriented
- A clear and focused economic development vision to help sustain a prosperous and complete city
- Attraction of younger people and newcomers to help sustain the fiscal, social, environmental and cultural fabric of the city

A City that Moves

>> People and goods move throughout the city more efficiently and safely. A variety of convenient, affordable and green forms of transportation that align with regional patterns are the norm. Walkability within new/transitioning neighbourhoods and the downtown are a reality.

- More mobility choice within the city and region through improved public transportation, active transportation and community responsive growth management to allow more residents to get where they need to go efficiently

A Healthy and Greener City

>> The City of Burlington is a leader in the stewardship of the environment while encouraging healthy lifestyles.

- Better environmental outcomes to help combat climate change, improve quality of life and economic competitiveness and foster civic pride
- Better physical and mental health of residents to positively impact resiliency and quality of life

An Engaging City

>> Community members are engaged, empowered, welcomed and well-served by their City through outstanding customer experiences. Residents are involved to enhance sound decision-making supporting good governance. Culture and community activities thrive, creating a positive sense of place, inclusivity and community.

- An engaged community where culture, civic activities, neighbourhood initiatives and recreational activities help to enhance and grow the sense of engagement, community, place and unity
- Accessible municipal programs, buildings, services and public spaces are available and welcoming to people of all abilities

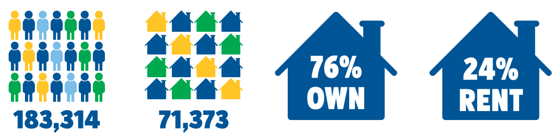
Burlington - Our City

Located on the northwest shore of Lake Ontario, Burlington, with its population of 183,300, is a place where our people, our nature and our businesses thrive. As a community of the Greater Toronto/Hamilton area, Burlington is close to major transportation and the U.S. border. To the south, Burlington is fortunate to have a beautiful and publicly accessible waterfront along the shores of Lake Ontario and in the north, through the cliffs of the Niagara Escarpment, the city has a UNESCO world biosphere reserve.

Burlington boasts great employment opportunities, low crime rates and a community feel. More than half of the city is protected rural space. Burlington is proud of its green city heritage with more than 581 hectares (1,436 acres) of parkland and some of the best hiking in the world on the Bruce Trail and the Niagara Escarpment. The city offers world-class urban amenities, including shopping and dining and is home to some of Ontario's top festivals and events. Attractions include the world-renowned Royal Botanical Gardens and the Burlington Performing Arts Centre.

Household Characteristics (2016)

183,314 Total Population, 71,373 Total Households, 76% Own, 24% Rent



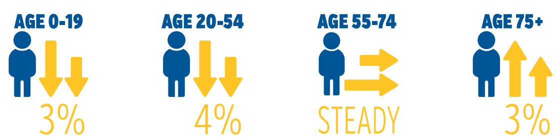
As we move towards 2040, we anticipate:

The percentage of population in the 0-19 age group is forecast to steadily decline from 22% to 19%

The 20-54 age group is also forecast to steadily decline from 46% to 42%

The 55-74 age group is forecast to remain steady at 23%

The percentage of population in the 75+ age group is forecast to rapidly increase from 12% to 15%



Source: City of Burlington Growth Analysis Study (2019) prepared by Dillon Consulting and Watson & Associates to inform Halton Region's Integrated Growth Management Strategy. The forecast population growth by age group to 2041 is based on the Reference Scenario identified in the Growth Analysis Study.

Monitoring, Measuring and Reporting - The Road to Achieving Future Success

With Burlington's 2015-2040 Strategic Plan being a long-term vision for the future, it is a living document that will be monitored and reported on to Burlington Council as progress is reviewed and evaluated. There may be changes along the way, such as: global, regional, and city circumstances changing, events occurring, and other levels of government influencing change. It is the role of leadership to be aware of these changes in circumstance and/or influences.

Progress of desired goals will be measured. As we move towards our vision, part of the monitoring process will include review of resourcing, financial and organizational capacity, reviewing new constraints and new opportunities and shifting plans as needed in an open and transparent way. Council and the public will be made aware of what is needed to help the City meet our goals and targets and see successful outcomes. This means having necessary conversations about our business plans, our projects and our services and determining known and projected barriers and risks. This is all part of the continuous improvement to achieve Vision 2040.

A measured and strategic approach will help with decision-making and adjusting the vision as needed. Vision 2040 is also tied to medium-term policy documents and short-term implementation plans that were created to help the City be more successful in achieving our desired vision for our community.

Our Vision

Where people, nature and business thrive

Our Values

Working together,

1. We are caring, friendly and inclusive community
2. We value innovation and trusted partnerships
3. We demonstrate respect by being fair and ethical

STRATEGIC DIRECTION 1

A City that Grows

>> The City of Burlington attracts talent, good jobs and economic opportunity while having achieved community responsive growth and balanced, targeted population growth for youth, families, newcomers and seniors.

We aspire to have:

- More people who live in Burlington also work in Burlington
- Employment lands connected to the community and region
- Residents close to goods and services
- Innovative, entrepreneurial businesses settled or developed in Burlington
- Burlington's downtown as culturally active, thriving and home to a mix of residents and businesses
- Easy access to amenities, services, recreation and employment areas with more opportunities for walking, cycling and using public transit
- Burlington's rural areas economically and socially active
- Buildings and public spaces where people can live, work or gather
- Burlington as an inclusive and diverse city and employer

The aspirational goals we are moving towards are:

- Overall employment is 106,000 by 2031.
- Overall population is 193,000 by 2031
- Minimum housing targets by 2041 are:
  - Minimum of 50% of new housing units produced annually be in the form of townhouses or multi-story buildings
  - Minimum of 30% of new housing units produced annually be affordable or assisted housing

STRATEGIC DIRECTION 2

A City that Moves

>> People and goods move throughout the city more efficiently and safely. A variety of convenient, affordable and green forms of transportation that align with regional patterns are the norm. Walkability within new/transitioning neighbourhoods and the downtown are a reality.

We aspire to have:

- Walkable neighbourhoods well connected throughout the city
- Transit rider access to regional and provincial transportation network
- Convenient and timely transit connections between municipalities
- People rely less on automobiles
- Burlington's rural areas connected to the city

The aspirational goals we are moving towards are:

- Transit mode share has reached 15% and continues to grow year over year
- Modal split is 70% car, 15% transit, 15% active transportation and the car mode share continues to decline year over year

STRATEGIC DIRECTION 3

A Healthy and Greener City

>> The City of Burlington is a leader in the stewardship of the environment while encouraging healthy lifestyles.

We aspire to have:

- Every Burlington resident live within a 15- to 20-minute walk from parks or green space
- Multi-use parks and green spaces
- Residents grow their own fresh and healthy food
- Burlington's rural area and waterfront easily accessible
- Recreation and sports programs widely available to all residents
- Access to parks and amenities for residents in rural Burlington
- A healthy, natural heritage system
- Burlington's community and City operations net carbon-neutral
- A healthy thriving urban forest and increased tree canopy
- A clean, safe and useable waterfront
- Leadership in storm water management and low impact development

The aspirational goals we are moving towards are:

- City's Operations will be Net Carbon Neutral
- Increase the City's tree canopy to 35%

STRATEGIC DIRECTION 4

An Engaging City

>> Community members are engaged, empowered, welcomed and well-served by their City through outstanding customer experiences. Residents are involved to enhance sound decision-making supporting good governance. Culture and community activities thrive, creating a positive sense of place, inclusivity and community.

We aspire to have:

- A customer centric approach in all City service areas
- Sound decision-making processes
- City information that is always accessible
- Burlington's infrastructure in good condition
- New infrastructure that is paid for by new development
- All residents, especially newcomers, feel welcomed and at home in Burlington

The aspirational goals we are moving towards are:

- 80% of residents consistently feel that meaningful engagement occurs where community input would help shape decisions
- The customer experience is considered 100% of the time in the design and delivery of all services
- 85% of customers using on-line services have an outstanding and customer-focused digital experience
- The City's infrastructure funding gap is eliminated by 2040

City of Burlington | 426 Brant St., Burlington, ON L7R 3Z6 | City of Burlington | @cityburlington | burlington.ca/strategicplan

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