September 17, 2026

BY RESS

Mr. Ritchie Murray, Registrar
Ontario Energy Board
2300 Yonge Street, 26th Floor, P.O. Box 2319
Toronto, ON M4P 1E4

Re: Board File No. EB-2026-0033

Enova Power Corp. - Licence No. ED-2022-0006
Application for Approval of 2027 Electricity Distribution Rates

---

Dear Mr. Murray

Enova Power Corp. ("Enova Power") is writing in connection with its 2027 Electricity Distribution Rate Application, **OEB File No. EB-2026-0033**.

As outlined in the Manager's Summary of the application filed on August 10, 2026, Enova Power was in the process of preparing its Distribution System Plan ("DSP") and anticipated filing the DSP by September 30, 2026. The DSP for the 2027–2031 period is required to support Enova Power's Incremental Capital Module ("ICM") rate application, which seeks approval to fund investments in a new heating, ventilation and air conditioning ("HVAC") system, comprehensive interior renovations, and accessibility improvements to the customer service centre at Enova Power's Victoria Street property. The project is expected to have an in-service date in Q2 2027.

Enova Power has completed the DSP ahead of schedule and is hereby filing the 2027–2031 Distribution System Plan with the Ontario Energy Board as part of the requirements of Enova Power's 2027 ICM rate application.

Enova Power respectfully requests that the OEB accept the DSP and consider it as part of the evidence supporting Enova Power's ICM application.

Contact the undersigned should you require any further information.

Respectfully submitted,

Original Signed By:

Ravi Baichan, CPA, CGA
Director, Regulatory Affairs & Risk Management

Enova Power Corp.

Distribution System Plan



Historical Period: 2020 - 2026

Forecast Period: 2027 - 2031

August 22, 2026

(Page Intentionally left blank)

CONTENTS

CONTENTS ii
LIST OF TABLES vi
LIST OF FIGURES ix
APPENDICES x
GLOSSARY xi
1. INTRODUCTION AND BACKGROUND 1
1.1. Application and Scope 1
1.2. Organization of the Report 2
1.3. Purpose and Timing of this Distribution System Plan 3
1.4. Description of the Utility Company 3
1.4.1. Corporate Structure 3
1.4.2. Enova's Purpose, Vision and Values & Strategic Objectives 4
1.4.3. Risk – Costs, Revenue and Stranded Assets 6
1.4.4. The Distribution System 8
1.4.4.1. Service Area & Customer Demographics 9
1.4.4.2. Climate 15
1.4.4.3. Demand & Energy 16
1.4.4.4. Embedded Generation 17
2. (CHAPTER 5.2) DISTRIBUTION SYSTEM PLANS 19
2.1. (CHAPTER 5.2.1) Distribution System Plan Overview 22
2.1.1. Capital Investment Highlights 23
2.1.2. Objectives of this Distribution System Plan 32
2.1.3. Changes since last Distribution System Plan 33
2.1.3.1. Merger 33
2.1.3.2. COVID-19 Impacts 34
2.1.4. Incremental Capital Module (ICM) Funding 36
2.1.5. Distribution Asset Condition 37
2.1.6. Reliability 38
2.1.7. Innovation 38
2.1.8. Retirement of 8.32 kV Distribution Assets 39
2.1.9. Grid Modernization Technologies 39
2.2. (CHAPTER 5.2.2) Coordinated Planning with Third Parties 41

2.2.1. Customer Engagement on the Distribution System Plan 41
2.2.1.1. Development Community & Municipal Government Workshop 42
2.2.1.2. Mid-Market & Large Business Workshop (July 28, 2026) 45
2.2.2. Consultations Specific to the ICM Application 49
2.2.3. On-Going Consultations and Communications 49
2.2.3.1. Customer Surveys 49
2.2.3.2. Municipal Planning and Development Coordination 52
2.2.3.3. Development Community Consultations 53
2.2.3.4. Independent Electricity System Operator (IESO) 54
2.2.3.5. KWCG Integrated Regional Resources Planning 54
2.2.3.6. Wholesale Meter Services 55
2.2.3.7. Ontario Power System Restoration 55
2.2.3.8. Outage Planning 56
2.2.3.9. Transmitter (HONI) 56
2.2.3.10. Embedded Distributors 57
2.2.3.11. Host Distributors 57
2.2.3.12. (5.2.2.1) Telecommunications Entities 58
2.2.3.13. (5.2.2.2) Renewable Energy Generation (REG) 59
2.2.4. Influence on the Distribution System Plan 60
2.2.4.1. Reliability - Momentary Interruptions 62
2.3. (CHAPTER 5.2.3) Performance Measurement for Continuous Improvement 65
2.3.1. (5.2.3.1) Distribution System Plan 65
2.3.1.1. Objectives for Continuous Improvement 65
2.3.2. (5.2.3.2) Service Quality and Reliability 66
2.3.3. Other Performance Measures 82
2.3.3.1. Momentary Interruptions and MAIFI 82
2.3.3.2. System Losses 83
2.3.4. (5.2.3.3) Distributor Specific Reliability Targets 85
3. (CHAPTER 5.3) ASSET MANAGEMENT PROCESS 86
3.1. (5.3.1) Planning Process 86
3.1.1. Overview of the Planning Process 87
3.1.1.1. Identification of Capital Expenditures 87
3.1.1.2. Selection of Viable Capital Investments 90
3.1.1.3. Prioritization of Capital Expenditures 92

3.1.1.4. Optimization of Capital Investments 94
3.1.1.5. Aligning Investments with Budget Envelope 94
3.1.1.6. Pacing of Forecast Capital Investments 2027-2031 96
3.1.2. Important Changes to Asset Management Processes 100
3.1.3. (5.3.1.1) Process 104
3.1.4. (5.3.1.2) Data 110
3.2. (5.3.2) Overview of Assets Managed 112
3.2.1. Overview of Distribution Service Area 112
3.2.2. Asset Information 112
3.2.3. Transmission Assets Deemed as Distribution 113
3.2.4. Host / Embedded Distributor Arrangements 113
3.3. (5.3.3) Asset Lifecycle Optimization Policies and Practices 115
3.3.1. Overview of Enova's asset lifecycle optimization policies and practices 115
3.3.1.1. Asset Replacement and Refurbishment Policies 116
3.3.1.2. System Renewal Program Spending Optimization 119
3.3.1.3. Balancing customer's need for reliability and capital expenditure costs 121
3.3.1.4. Enova Inspection and Maintenance Programs 124
3.3.1.4.1. Enova Inspection Programs 124
A) Inspection of Overhead Systems 127
B) Inspection of Underground Systems 129
C) Inspection of Stations 131
3.3.1.4.2. Enova Maintenance Programs 134
A) Reactive Maintenance (RM) 134
B) Preventative Maintenance (PM) 134
C) Condition-Based (Predictive) Maintenance (CBM) 134
D) Maintenance of Overhead Systems 135
E) Maintenance of Underground Systems 139
F) Maintenance of Transformer Stations and Distribution Stations 141
3.3.1.5. Impact of System Renewal Investments on Routine O&M 145
3.3.2. Asset life optimization policies, processes, and tools 146
3.4. (5.3.4) System Capability Assessment for Renewable Energy Generation and Distributed Energy Resources 147
3.5. (5.3.5) Non-Wires Solutions (NWS) to Address System Needs 148

3.6. (5.3.6) Climate Vulnerability Assessment and System Hardening 149
4. (5.4) CAPITAL EXPENDITURE PLAN 152
4.1. (5.4.1) Capital Expenditure Summary 153
4.1.1. Historical Capital Expenditures (2020-2026) 160
4.1.1.1. Historical Variance Analysis - Year to Plan (2020) 164
4.1.1.2. Historical Variance Analysis - Year to Plan (2021) 168
4.1.1.3. Historical Variance Analysis - Year to Plan (2022) 172
4.1.1.4. Historical Variance Analysis - Year to Plan (2023) 176
4.1.1.5. Historical Variance Analysis - Year to Plan (2024) 179
4.1.1.6. Historical Variance Analysis - Year to Plan (2025) 182
4.1.1.7. Historical Variance Analysis - Year to Plan (2026 - Bridge Year) 184
4.1.2. Forecast Capital Expenditures, 2027-2031 189
4.1.2.1. Major Drivers in Forecast Capital Expenditures, 2027-2031 190
4.1.2.2. Test Year - 2027 197
4.1.2.3. Forecast Variance Analysis - Year to Year (2027 - Test Year) 200
4.1.2.4. Forecast Variance Analysis - Year to Year (2028) 202
4.1.2.5. Forecast Variance Analysis - Year to Year (2029) 204
4.1.2.6. Forecast Variance Analysis - Year to Year (2030) 206
4.1.2.7. Forecast Variance Analysis - Year to Year (2031) 208
4.1.2.8. Forecast vs Historical Capital Expenditure Analysis 210
4.1.2.9. Important Modifications to Capital Programs Since Last Distribution System Plan 212
4.2. (5.4.2) Justifying Capital Expenditures 216
4.2.1. Overall Plan 216
4.2.2. (5.4.2.1) Material Investments 219
4.3. (5.4.2.2) Benefit-Cost Analysis Framework 222

LIST OF TABLES

Table 1-1: Materiality Thresholds ($000s) 2
Table 1-2: Strategic Objectives 5
Table 1-3: Enova Distribution Asset Summary 9
Table 1-4: Enova Service Area Demographics 10
Table 1-5: Service Area - Rural / Urban Breakdown 13
Table 1-6: Customers - Rural / Urban Breakdown 13
Table 1-7: Enova Population Density 14
Table 1-8a: Historical Customer Growth 14
Table 1-8b: Forecast Customer Growth 15
Table 1-9: Enova Generator Connections by Type 17
Table 1-10: SCL-Constrained Transformer Stations 18
Table 2-1: Financial Data Type 20
Table 2-2a: Data Vintage Table 20
Table 2-2b: Date Vintage Table 21
Table 2-3: Forecast vs Historical Capital Expenditures (%) 24
Table 2-4: Capital Forecast by OEB Category ($000s) 25
Table 2-5: Forecast vs Historical Average Annual Expenditures ($000s) 25
Table 2-6: Total System Renewal Forecast Investments ($000s) 26
Table 2-7: Total System Access Forecast Investments ($000s) 28
Table 2-8: Total General Plant Forecast Investments ($000s) 29
Table 2-9: Total System Service Forecast Investments ($000s) 31
Table 2-10: Host Distributors 57
Table 2-11: Customer Priorities from Engagement 61
Table 2-12: Historical Momentary Interruption Events 63
Table 2-13: Customer Focus Metrics 70
Table 2-14: Operational Effectiveness Metrics 74
Table 2-15: Operational Effectiveness Metrics 75
Table 2-16: Public Responsiveness Metrics 78
Table 2-17: Financial Performance Metrics 80

Table 2-18: Momentary Interruption Events 82
Table 2-19: MAIFI 83
Table 2-20: Annual System Losses 84
Table 3-1: Prioritization Weighting Factors 93
Table 3-2: Capital Plan Composition (gross unless noted, $000s) 97
Table 3-3: Regular Programs — Core and Station Expansion (gross, $000s) 97
Table 3-4: Incremental Components (gross, $000s) 98
Table 3-5: Representative 2027 Projects by Category 99
Table 3-6: Cost/Value Attributes – Customer Survey Results 104
Table 3-7: NWS for material capital investment programs > $2M ($000s) 108
Table 3-8 Enova Asset Data Maturity Assessment 111
Table 3-9: Enova Distribution Asset Summary 112
Table 3-10: Enova Gross Summer Peak Load MW (2024) 114
Table 3-11: Inspections – Overhead and Underground Lines 126
Table 3-12: Inspections – Municipal and Rural Distribution Stations (DS) 126
Table 3-13: Inspections – Transformer Stations (TS) 126
Table 3-14: Typical Overhead Deficiencies 127
Table 3-15: Typical Underground Deficiencies 129
Table 3-16: Typical Station Deficiencies 132
Table 3-17: Enova Maintenance Programs – Overhead Lines 135
Table 3-18: Enova Maintenance Programs – Underground Lines 135
Table 3-19: Enova Maintenance Programs – Stations (TS) 142
Table 3-20: Enova Maintenance Programs – Stations (DS) 142
Table 4-1: Materiality Thresholds ($000s) 152
Table 4-2 Enova Needs-to-Investment-to-Outcomes Alignment 153
Table 4-3: KWH Appendix 2-AB – Capital Expenditure Summary ($000s) 2020-2022 156
Table 4-4: WNH Appendix 2-AB – Capital Expenditure Summary ($000s) 2020-2022 156
Table 4-5: Enova Appendix 2-AB – Capital Expenditure Summary ($000s) Consolidated 2020-2031 157
Table 4-6: Appendix 2-AA – Capital Projects Table ($000s) 158
Table 4-7: Summary of 2020 - 2026 Capital Expenditures by OEB Category ($000s) 161

Table 4-8: 2020 WNH Capital Variance – Year to Plan ($000s) 164
Table 4-9: 2020 KWH Capital Variance – Year to Plan ($000s) 166
Table 4-10: 2021 WNH Capital Variance – Year to Plan ($000s) 168
Table 4-11: 2021 KWH Capital Variance – Year to Plan ($000s) 170
Table 4-12: 2022 WNH Capital Variance – Year to Plan ($000s) 172
Table 4-13: 2022 KWH Capital Variance – Year to Plan ($000s) 174
Table 4-14: 2023 Enova Capital Variance – Year to Plan ($000s) 176
Table 4-15: 2024 Enova Capital Variance – Year to Plan ($000s) 179
Table 4-16: 2025 Enova Capital Variance – Year to Plan ($000s) 182
Table 4-17: 2026 Enova Capital Variance – 2025 to 2026 B ($000s) 184
Table 4-18: Major 2026 Overhead Projects 187
Table 4-19: Major 2026 Underground Projects 187
Table 4-20: Forecast Expenditures (2027-2031) ($000s) 189
Table 4-21: Forecast Overhead Line Renewal Program (2027-2031) ($000s) 193
Table 4-22: Forecast Underground Cable Renewal Program (2027-2031) ($000s) 193
Table 4-23 Innovation Capital Forecast, 2027–2031 (Gross $) ($000s) 195
Table 4-24: Summary of 2027 Investments ($000s) 197
Table 4-25: 2027 System Access Investment Summary 198
Table 4-26: 2027 System Renewal Investment Summary 198
Table 4-27: 2027 System Service Investment Summary 198
Table 4-28: 2027 General Plant Investment Summary 199
Table 4-29: 2027 Y-Y Capital Variances by Investment Category ($000s) 200
Table 4-30: 2028 Y-Y Capital Variances by Investment Category ($000s) 202
Table 4-31: 2029 Y-Y Capital Variances by Investment Category ($000s) 204
Table 4-32: 2030 Y-Y Capital Variances by Investment Category ($000s) 206
Table 4-33: 2031 Y-Y Capital Variances by Investment Category ($000s) 208
Table 4-34: Forecast vs Historical Expenditures ($000s) 210
Table 4-35: Historical and Forecast Expenditures as Percentage of Total Expenditures 215
Table 4-36: Summary of 2027 Material Investments ($000s) 219
Table 4-37: 2027 Material Investments in Rank Order 221
Table 4-38: 2027 NWS Pre-assessment Results 222

LIST OF FIGURES

Figure 1-1: Enova Ownership Structure 4
Figure 1-2: Enova Service Territory 11
Figure 1-3: Enova Service Territory Boundary Adjustments 12
Figure 2-1: Capital - Historical Expenditures and Forecast Investments 23
Figure 2-2: Historical and Forecast Capital Expenditures (%) 24
Figure 2-3: Health Index Distribution 37
Figure 3-1: Enova's Capital Planning Process 87
Figure 3-2: Enova Asset Lifecycle Process 115
Figure 3-3: SAIDI (2020 – 2024) 121
Figure 3-4: SAIFI (2020 – 2024) 121
Figure 3-5: Enova OEB Inspection Areas 125
Figure 3-6: System Renewal vs O&M Expenditures ($000s) 145
Figure 4-1: Actual Capital and O&M Expenditures 2020-2031 160
Figure 4-2: Historical Capital Expenditures ($000s) 162
Figure 4-3: Historical Capital vs O&M Expenditures ($000s) 163
Figure 4-4: Forecast Capex ($000s) 189
Figure 4-5: Material Program / Project Expenditures (2027) 220

APPENDICES

Appendix A - 2027 Material Capital Investments

Appendix B-1 - Asset Condition Assessment (ACA) Report

Appendix B-2 - Asset Management Policy

Appendix C-1 - KWCG Needs Assessment Report (2024)

Appendix C-2 - KWCG IRRP Scoping Assessment Outcome Report (2024)

Appendix C-3 - KWCG IRRP Report & Appendices (2021)

Appendix C-4 - KWCG RIP Report (2021)

Appendix C-5 - KWCG Regional Planning Status Letter

Appendix D-1 - Renewable Energy Generation (REG) Investment Plan

Appendix D-2 - IESO REG Letter of Comment

Appendix E - System Supply and Capacity Study

Appendix F-1 - Distribution System Reliability Report

Appendix F-2 - Appendix 2-G SQI & SQR

Appendix G - Operations Maintenance Report

Appendix H - Information Technology Management Plan

Appendix I - Facilities Management Plan

Appendix J - Fleet Management Plan

Appendix K – NWS Pre-Assessment

Appendix L - This appendix has been intentionally removed and is no longer applicable.

Appendix M - VASH - Climate Vulnerability of Distribution Pole Assets

Appendix N- OEB Appendix 5-A Unit Cost Metrics

Appendix O - OEB Chapter 2 Appendix 2-AA

GLOSSARY

1) ACA – Asset Condition Assessment
2) ACSR – Aluminum Conductor Steel-Reinforced
3) AM – Asset Management
4) AMI – Advanced Metering Infrastructure
5) AMP – Asset Management Process
6) CDM – Conservation and Demand Management
7) CAIDI – Customer Average Interruption Duration Index
8) CI – Customers Interrupted
9) CIP – Capital Investment Plan
10) CIS – Customer Information Systems
11) CHI – Customer Hours Interrupted
12) CMI – Customer Minutes of Interruption
13) CoF - Consequence of Failure
14) CS - Country Squire (formally WNH)
15) CSA – Canadian Standards Association
16) DG – Distributed Generation
17) DGA – Dissolved Gas Analysis
18) DS – Distribution Station
19) DSC – Distribution System Code
20) DSP – Distribution System Plan
21) EA – Environmental Assessment
22) EII - Engineered Intelligence Inc. (formerly METSCO Energy Solutions Inc.)
23) Enova – Enova Power Corporation
24) EOL – End of Life
25) ESA – Electrical Safety Authority
26) FIT – Feed-In-Tariff
27) FLISR – Fault Location, Isolation and Service Restoration
28) GATR – Guelph Area Transmission Reinforcement
29) GIS – Geographic Information System

30) GS – General Service
31) HONI – Hydro One Networks Inc.
32) IESO – Independent Electricity System Operator
33) IRRP – Integrated Regional Resource Planning
34) IT / IST – Information Systems and Technology
35) KPI – Key Performance Indicator
36) kW - kilowatt
37) KWCG – Kitchener – Waterloo – Cambridge – Guelph
38) KWHI – Kitchener-Wilmot Hydro Inc.
39) LDC – Local Distribution Company
40) LDG – Load Displacement Generation
41) LOS – Loss of Supply
42) LRT – Light Rail Transit
43) LTLT – Long Term Load Transfer
44) LTR – Limited Time Rating
45) MADDs - mergers, acquisitions, amalgamations and divestitures
46) MAIFI – Momentary Average Interruption Frequency Index
47) MED – Major Event Day
48) METSCO - METSCO Energy Solutions
49) MTO - Ministry of Transportation of Ontario
50) NWA - Non-wires alternatives
51) O/H or OH - Overhead
52) O&M – Operation & Maintenance
53) OM&A – Operation, Maintenance & Administration
54) ONAN - Oil Natural Air Natural
55) ONAF - Oil Natural Air Forced
56) ODS – Operational Data Store
57) OEB – Ontario Energy Board
58) OMS – Outage Management System
59) OPA – Ontario Power Authority
60) ORTAC – Ontario Resource and Transmission Assessment Criteria

61) OT – Operation Technology
62) PILAR – Power Interruption, Logging and Tracking
63) PLT - Power Line Technician
64) PoF - Probability of Failure
65) PSWHA – Public Service Works on Highways Act, R.S.O. 1990, c. P.49
66) PUCC – Public Utilities Coordinating Committee
67) REG – Renewable Energy Generation
68) RIP – Regional Infrastructure Planning
69) ROE – Return on Equity
70) RRFE – Renewed Regulatory Framework for Electricity Distributors
71) RTU – Remote Terminal Units
72) SAIDI – System Average Interruption Duration Index
73) SAIFI – System Average Interruption Frequency Index
74) SCADA – Supervisory Control and Data Acquisition
75) SEI – Serious Electrical Incidents
76) Summer System Peak Demand - single highest total (coincident) electricity demand (MW) placed on the utility system during the summer months
77) the Board – Ontario Energy Board
78) Region – Region of Waterloo
79) TRXLPE – Tree-Retardant Cross-Linked Polyethylene
80) TUL – Typical Useful Life
81) TS – Transmission Station or Transformer Station
82) U/G or UG – Underground
83) UCC – Utilities Coordinating Committee
84) ULTC – Under-Load Tap Changing
85) URD – Underground Residential Distribution
86) USF – Utilities Standards Forum
87) VS - Victoria Street (formerly KWH)
88) Winter System Peak Demand - single highest total (coincident) electricity demand (MW) placed on the utility system during the winter months
89) WNHI/ WNH – Waterloo North Hydro Inc

90) XFMR – Transformer

91) XLPE – Cross-Linked Polyethylene

1. INTRODUCTION AND BACKGROUND

1.1. Application and Scope

Enova Power Corp. (Enova) Distribution System Plan (DSP) provides a consolidated view of Enova's Asset Management and Capital Investment Plans. The information contained herein is aligned with Enova's Mission, Vision and Strategic Objectives. The DSP informs Enova's senior executive team (Executive) and the development of Enova's business plans. The DSP describes how Enova plans to develop, manage and maintain its major distribution assets to provide a safe, secure, reliable, efficient and cost-effective service to its customers.

This DSP and the activities described herein are also aligned with, and support, the achievement of the four key OEB performance outcomes as established in the Renewed Regulatory Framework for Electricity (RRFE) and the Handbook for Utility Rate Applications (Handbook): namely, Customer Focus, Operational Effectiveness, Public Policy Responsiveness and Financial Performance. This DSP has been prepared in accordance with the Ontario Energy Board's (OEB) Chapter 5 "Filing Requirements for Electricity Distribution Rate Applications - 2026 Edition for 2027 Rate Applications, December 16th, 2025" (Chapter 5).

Enova was formed on September 1, 2022, by the merger of Waterloo North Hydro Holding Corporation (WNHHC) and Kitchener Power Corporation (KPC) and subsequently Waterloo North Hydro Inc. (WNH) with Kitchener-Wilmot Hydro Inc. (KWH). This is Enova's first consolidated DSP. The DSP spans a seven-year historical period covering 2020 to 2026 and a five-year forecast period covering 2027 to 2031. The Bridge Year and Test Year are 2026 and 2027, respectively. The historical period dates back to the Test Years of the legacy LDCs' cost of service applications; 2020 for KWH and 2021 for WNH.

Historical and forecast investment plans are described. For the years 2020 – 2022, financial information is shown both by legacy LDCs and on a consolidated basis. Moving forward from the merger in 2022, all financial information is shown on a consolidated basis. This is to support the effective and efficient planning of capital investments and Enova's efforts to operate as a single entity.

Table 1-1 provides the level of materiality for capital investments for Enova and its legacy LDC's.

Table 1-1: Materiality Thresholds ($000s)

Enova: 2023-2026	$400
KWH: 2020-2022	$200
WNH: 2020-2022	$190

These thresholds inform Enova's description of forecast expenditures, as well as capital variances over the historical period.

1.2. Organization of the Report

ENOVA's DSP has been organized according to the recommended format contained within the OEB's "Chapter 5 - Filing Requirements for Electricity Distribution Rate Applications - 2026 Edition for 2027 Rate Applications" (Chapter 5). Where applicable, cross-references to Chapter 5 are provided in brackets () at all headings/subheadings within this report for ease of reference.

This report is divided into the following four sections:

Section 1- Introduction and Background

Provides additional information to introduce interested stakeholders to Enova and help provide context around the many elements of this DSP.

Section 2 - Aligns with the requirements outlined in **Section 5.2 Distribution Plans**.

Section 3 - Aligns with the requirements outlined in **Section 5.3 Asset Management Process.**

Section 4 - Aligns with the requirements outlined in **Section 5.4 Capital Expenditure Plan.**

Appendices - Enova has also provided **Appendices A through O** immediately following the main body of the report to provide additional information in support of the DSP and to better focus on the key elements of its business.

1.3. Purpose and Timing of this Distribution System Plan

This DSP has been prepared to support Enova's 2027 Incremental Capital Module Application (ICM Application). The ICM Application seeks supplemental funding for the "VS HVAC Replacement and Facility Renovation Project". Details of the ICM and renovation project are outlined in the appendices of the ICM Application.

In Enova's merger approval (MADDs application), Enova stated that if it pursued ICM funding it would file a harmonized DSP with that ICM application. Filing the DSP at this time fulfills that commitment and provides the OEB with the planning context for the VS HVAC Replacement and Facility Renovation Project and Enova's broader five-year investment plans.

There are no other requests for supplemental funding supported by this DSP; however, this DSP is being used to inform the OEB and interested stakeholders of other potential requests for ICM funding that may come forward over the forecast period.

1.4. Description of the Utility Company

1.4.1. Corporate Structure

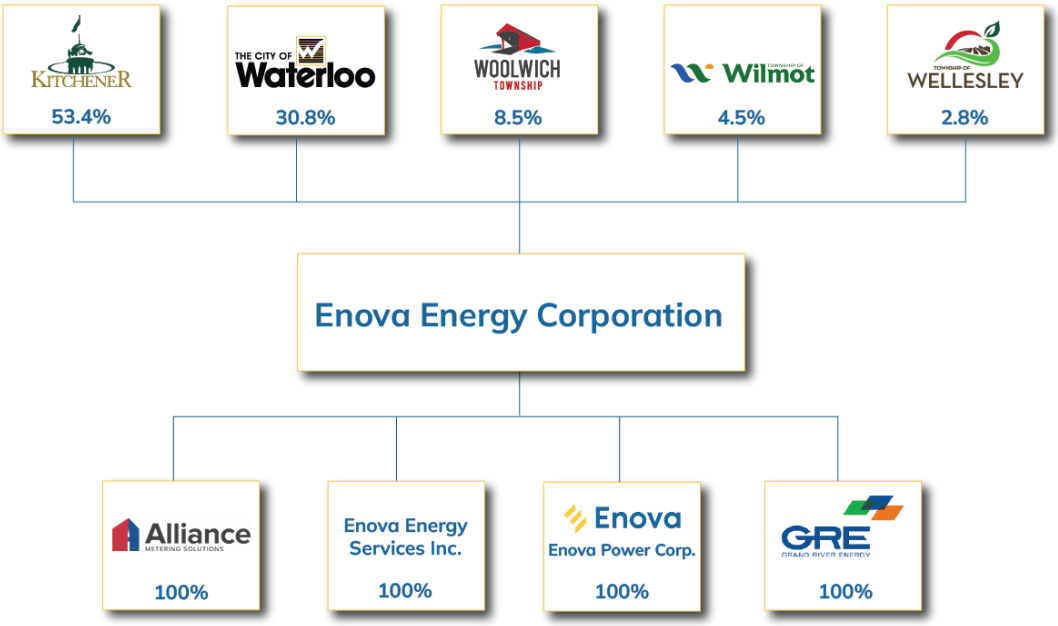
Enova Power Corp. (Enova) is an electrical Local Distribution Company (LDC) licensed by the Ontario Energy Board (OEB) in accordance with its Distribution License ED-2022-0006. Enova was formed on September 1, 2022, by the merger of Waterloo North Hydro Holding Corporation (WNHHC) and Kitchener Power Corporation (KPC) and subsequently Waterloo North Hydro Inc. (WNH) with Kitchener-Wilmot Hydro Inc. (KWH).

Enova is incorporated under the Ontario Business Corporations Act and is a wholly owned subsidiary of Enova Energy Corporation (EEC). Other companies owned by EEC include Alliance Metering Solutions (100%), Enova Energy Services Inc. (100%), and Grand River Energy Solutions Corp. (100%).

The business affairs of EEC and Enova are managed by their Boards of Directors, consisting of thirteen (13) and nine (9) directors respectively. The Shareholders appoint the directors to the EEC board which in turn appoints the directors to the Enova board.

Figure 1-1 depicts Enova's ownership structure.

Figure 1-1: Enova Ownership Structure



1.4.2. Enova's Purpose, Vision and Values & Strategic Objectives

Enova's Purpose, Vision, Values, and Strategic Objectives define the organization, how it operates and provides guidance in its strategic planning.

Purpose

To energize and empower our communities.

Vision

To drive what's next in energy and sustainability for our communities and beyond.

Values

i) Safety and well-being above all.
ii) Everyone has a voice.
iii) Transparent in all we do.
iv) Driven to explore new ideas.
v) Inclusive and empowered.

Strategic Objectives

Enova's Strategic Objectives are listed in **Table 1-2**. Enova's Strategic Objectives are used to inform its investment selection and prioritization process. More about this process is presented in **Section 3** of this DSP.

Table 1-2: Strategic Objectives

#	Strategic Objectives	Asset Management Strategy
1	Health and Safety (Public & Employee)	Prioritize the health and safety of customers and communities. Implement rigorous safety protocols and invest in technologies that enhance safety and emergency response capabilities. Prioritize the health and safety of employees, support employee mental health and ongoing training, and invest in technologies that enhance safety.
2	Supply	Ensure an adequate supply of electricity to meet our customers' needs.
3	Reliability & Cyber Security	Reliability and Cyber Security are core business imperatives that go hand-in-hand to ensure the supply of electricity has the reliability needed to meet our customers' needs. Enova will demonstrate leadership in risk management, grid reliability, attracting security-conscious partners and safeguarding our customer's information.
4	Regulatory Compliance	Meet the regulatory obligations required by OEB and various other government organizations and operate Enova within the rules, regulations and the law.
5	Employee Relations and Development	Continue to attract and develop talented people in our utility. We must also help our employees to be individually successful.
6	Operational Synergy & Financial Performance	Continue to operate the business efficiently and create a culture of excellence and continuous improvement.
7	Customer Centric Services	Deliver on customer expectations and continue to create value and contribute to making our customers more efficient and successful.
8	Flexible Grid Technology	Consider non-wire alternatives, DSO, generation connections, and demand response programs. Be flexible to customer needs.
9	Economic Development	Contribute to regional economic development by investing in infrastructure projects, supporting local suppliers, and creating job opportunities. Collaborate with government and industry partners to contribute to economic growth.
10	Shareholder and Community Relations	Recognize the contributions of the Shareholders and the Community in the success of Enova, and in turn work to make them successful.
11	System Aesthetics	Continue to find ways, where it is feasible, to design and construct our system to improve landscape aesthetics.
12	Environmental Sustainability	Operate the business with minimal impact on the environment and comply with environmental rules and regulations.

1.4.3. Risk – Costs, Revenue and Stranded Assets

Enova believes that a thorough understanding of its customer base is needed in order to make good investment decisions and manage risk. Enova surveys the landscape of the local economy to look for positive and negative trends that may have an impact on its business.

Over the historical period, the Region of Waterloo (ROW) and Enova have faced a number of economic challenges, some of which will carry on into the forecast period.

- COVID-19 disrupted plans envisioned in legacy operations and investment planning. Supply chains for goods and services were disrupted, significantly increasing costs and the delivery of goods and services. As will be mentioned throughout the DSP, post-COVID-19 cost increases have not significantly mitigated and inflation remains stubbornly high. Supply chain challenges still exist in some areas of the business. Cost impacts are expected to carry forward into the forecast period.

- More recently, Immigration & Labor Market Rebalancing caused by federal government policies has had a direct negative impact in the ROW. Following federal caps on study permits, the ROW went from rapid population growth to near stagnation. The net departure of over 9,000 international students has adversely impacted post-secondary institutions, landlords, and retail/service sectors reliant on student spending and workforce availability.

- In December of 2025, the ROW abruptly halted approval for new development applications due to water capacity limits at the Mannheim water treatment plant and local wells. It has been reported that the construction of at least 5,000 new homes has been stalled, 1,500 jobs have been lost and more than $500 million in private investment is at risk while home builders wait. A multi-year plan has since been created on how to restore the water supply to meet anticipated demand.

- U.S. tariffs on Canadian goods are significantly impacting the Region of Waterloo, acting as a major economic drag for its heavy manufacturing and automotive sectors. These trade disruptions have slowed local economic growth and triggered localized job risks.

Enova recognizes that the economic environment remains uncertain. It is too early to determine the extent or duration of the impacts that changes in federal government policies, regional water capacity restrictions, and U.S. tariffs may have on Enova's customer base, electricity demand, or distribution revenues.

Despite these uncertainties, Enova remains confident that the underlying drivers of the local economy remain strong. Enova's customer base is well diversified, consisting primarily of residential, small, and medium-sized business customers, with many of its largest customers being government and institutional organizations. This diversity reduces reliance on any single customer or industry sector and limits the risk of material reductions in distribution revenue or the stranding of significant distribution assets.

Enova continues to monitor economic conditions, growth trends, and emerging risks throughout its service territory. The company makes every effort to understand both the opportunities and challenges associated with its unique service area and incorporates this information into its distribution system planning and investment decisions to ensure the continued provision of safe, reliable, and cost-effective electricity service.

1.4.4. The Distribution System

Enova's distribution system currently supplies approximately 165,000 business and residential customers within a service area of approximately 1,108 km^2. In the Province of Ontario, Enova is ranked 7th by customer base, 6th by total service area and 4th by rural service area size. In 2024, Enova experienced a gross Summer System Peak Demand of approximately 690 MW. At the time of Enova's system peak, total embedded generation supplied approximately 29 MW or 4.2% of the system peak. Enova's winter demand peaked at approximately 543 MW.

Enova's twelve (12), 115 kV and 230 kV grid-connected transformer stations are supplied by 14 Hydro One transmission lines. From these transformer stations, Enova distributes electricity to its customers through its 127 feeders at distribution voltages of 13.8 kV and 27.6 kV. Further distribution occurs at the 8.32 kV level with 10 distribution stations and 28 feeders. The 8.32 kV system is being phased out over time to more efficient 27.6 kV distribution.

Table 1-3 provides a summary of Enova's Distribution assets.

Please refer to the following for more detailed information regarding Enova's distribution System and assets:

- **Appendix B-1: Asset Condition Assessment (ACA) Plan**
- **Appendix E: System Supply and Capacity Report**

Table 1-3: Enova Distribution Asset Summary

Asset Group	Total	Asset Group	Total
STATIONS		**UNDERGROUND ASSETS**	
Grid Connected Transformer Stations	12	Underground Primary Circuits (km)	1,624
> 50 kV Power Transformers	27	Total Underground Primary Cable (km)	3,587
< 50 kV Power Transformers	10	Distribution Transformers - Pad Mount	5,627
HV Switches / Circuit Switches	24	Distribution Transformers - Submersible	4,065
Switchgear	34	Distribution Transformers - Vault Rooms	673
27.6 kV Feeders	15	Distribution Transformers - Network	32
13.8 kV Feeders	112	Electronic Reclosers / Switches	46
Circuit Breakers	224	Manual Load Break Switches / Switch vaults	554
Protective Relays	407	Non-Load Break Switches	543
OVERHEAD ASSETS		**METERING**	
Primary Circuits (km)	2,049	Retail Revenue Meters - Residential	148,043
Poles	45,814	Retail Revenue Meters - Commercial < 50kW	14,360
Distribution Transformers	8,555	Retail Revenue Meters - Commercial > 50kW	1,697
Electronic Reclosers	190	Retail Revenue Meter Installations	4,950
Manual Load Break Switches	880	Wholesale Revenue Meters	91
Non-Load Break Switches	7,102	AMI Communication Towers	11
Capacitor Banks	121		

1.4.4.1. Service Area & Customer Demographics

With a total service area of approximately 1,108 km^2, Enova provides electricity distribution services to approximately 165,000 business and residential customers (500,000+ residents) in the City of Kitchener, the City of Waterloo, the Township of Wellesley, the Township of Wilmot and the Township of Woolwich, all of which are located within the Regional Municipality of Waterloo.

As a result of the OEB's direction to eliminate Long Term Load Transfer Customers, Service Area Amendments were made by Enova's legacy LDCs and adjacent LDCs. This resulted in Enova's service territory increasing by a net 30.7 km^2 (3.4%) to its current 1,108 km^2. The

boundary amendments also added approximately 142 (0.1%) customers which are scattered along the boundaries of Townships of North Dumfries, Blandford-Blenheim, East Zorra-Tavistock, Mapleton, Centre Wellington, Guelph Eramosa and the City of Cambridge.

A breakdown of Enova's service area is shown in **Table 1-4**. For simplicity the municipal service areas are adjusted by the boundary amendments adjacent to the municipality.

Table 1-4: Enova Service Area Demographics

MUNICIPALITY	SERVICE AREA (km^2)	%
City of Kitchener	138.3	12.5%
City of Waterloo	65.3	5.9%
Township of Woolwich	336.0	30.3%
Township of Wellesley	281.6	25.4%
Township of Wilmot	287.0	25.9%
Total	1,108.2	100.0%

The current Enova boundary map is provided in **Figure 1-2.** For greater clarity, the adjustments for the Service Area Amendments are highlighted in **Figure 1-3.**

Figure 1-2: Enova Service Territory

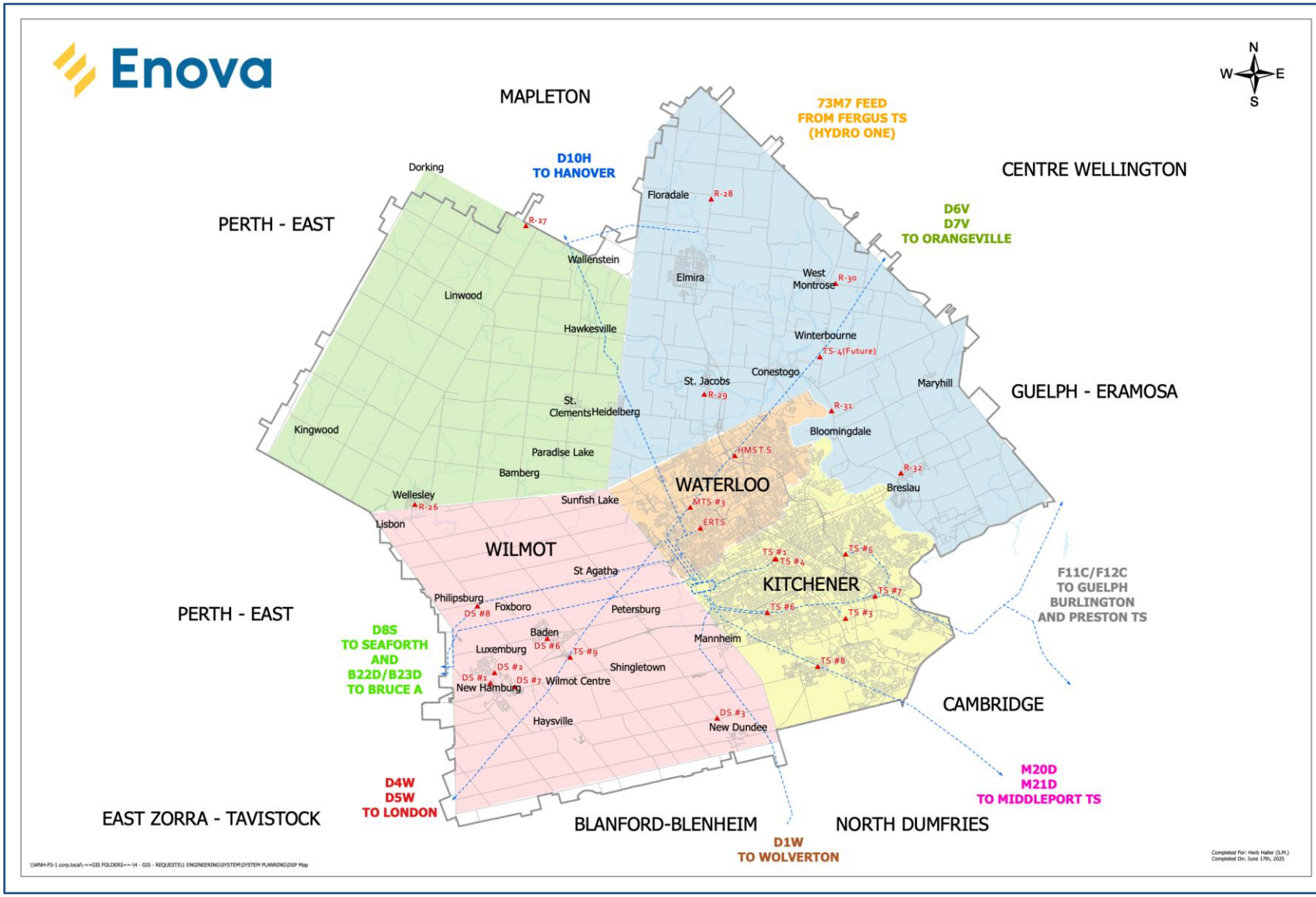
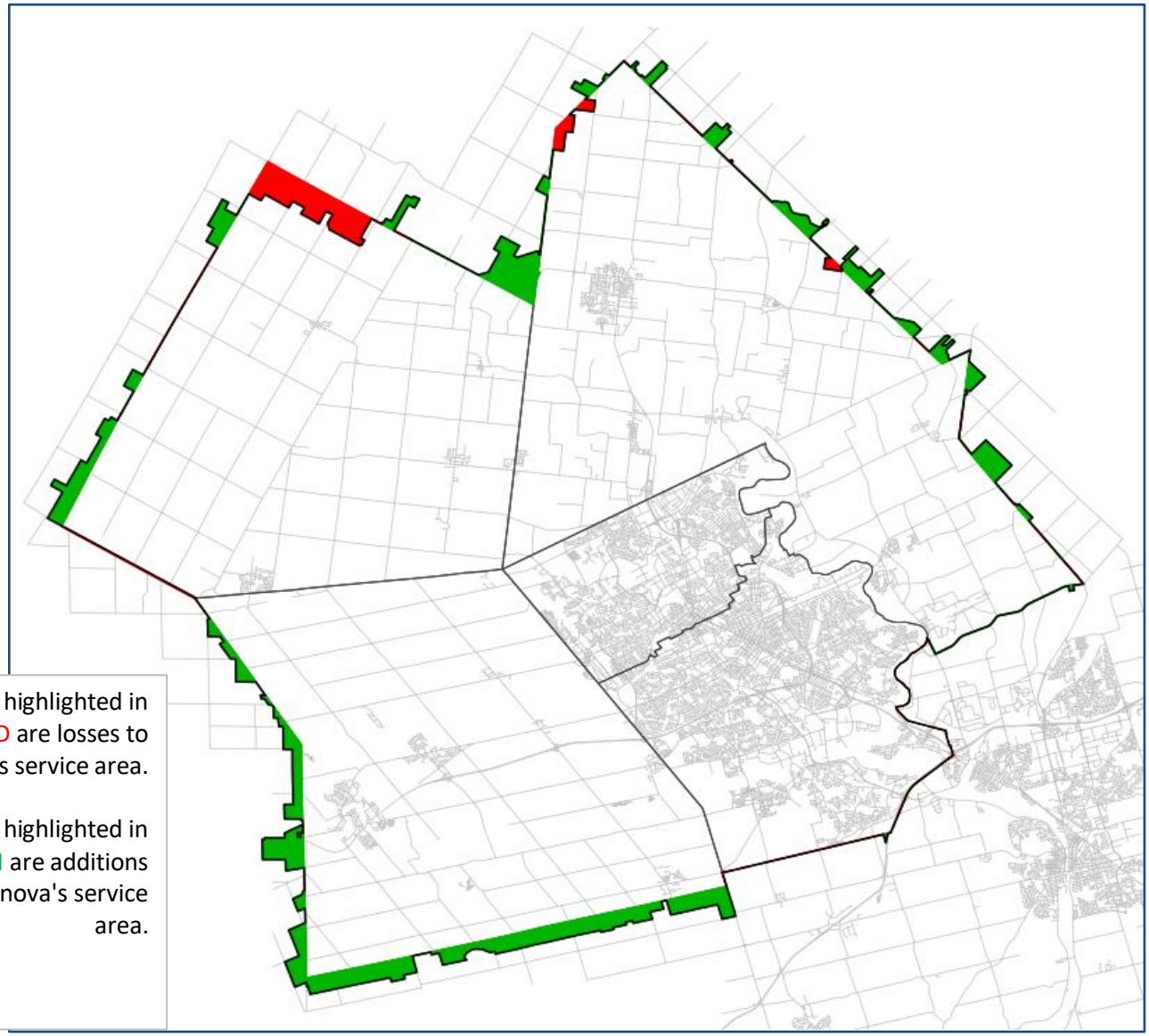


Figure 1-3: Enova Service Territory Boundary Adjustments



The urban and rural breakdown of Enova's service area is illustrated in **Table 1-5**.

Table 1-5: Service Area - Rural / Urban Breakdown

Municipality	Total Urban (km^2)	%	Total Rural (km^2)	%	Total (km^2)
City of Kitchener	138.3	68%			138.3
City of Waterloo	65.3	32%			65.3
Township of Woolwich			329.3	36%	329.3
Township of Wellesley			278.5	31%	278.5
Township of Wilmot			266.1	29%	266.1
Boundary Area Changes (net)			30.7	3%	30.7
Total	203.6	100%	904.7	100%	1108.2
% of Total	18%		82%		

The urban and rural breakdown of Enova's customers is illustrated in **Table 1-6**.

Table 1-6: Customers - Rural / Urban Breakdown

Municipality	Total Customers	% of Total	Urban Customers	% of Total	Rural Customers	% of Total
City of Kitchener	95,372	57.8%	95,372	57.8%		
City of Waterloo	46,080	27.9%	46,080	27.9%		
Township of Woolwich	11,086	6.7%			11,086	6.7%
Township of Wellesley	3,559	2.2%			3,559	2.2%
Township of Wilmot	8,651	5.2%			8,651	5.2%
Boundary Area Changes (net)	142	0.1%			142	0.1%
Total	164,890	100%	141,452	85.8%	23,438	14.2%

Enova's service area is 82% rural, making it the 4th largest rural area in the province; yet this accounts for only 14.2% of its customer base.

The data presented in **Section 3.2 - Overview of Assets Managed** will illustrate the relatively disproportionate number of assets required to service Enova's rural areas vs urban areas. This has a major influence on Enova's cost structure.

In spite of the service area amendments, 98.2% of Enova's Service Area and 99.9% of Enova's customer base remain within the Region of Waterloo municipalities.

Current population and population densities are illustrated in **Tables 1-7**.

Table 1-7: Enova Population Density

Municipality	Population	%	Service Area (km2)	%	Population Density (per km2)	Urban Population	Rural Population
City of Kitchener	292,240	57.3%	138.3	12.8%	2,113	292,240	
City of Waterloo	154,440	30.3%	65.3	6.1%	2,365	154,440	
Township of Woolwich	28,530	5.6%	329.3	30.6%	87		28,530
Township of Wilmot	23,010	4.5%	266.1	24.7%	86		23,010
Township of Wellesley	11,650	2.3%	278.5	25.8%	42		11,650
Total	509,870	100%	1,078	100%	473	446,680	63,190

Since 2020, Enova has experienced an annual customer growth rate of 0.93%. Enova has forecast an overall customer growth rate of 0.86% over the 2027 – 2031 period. **Tables 1-8 (a&b)** illustrates Enova's historical and forecast customer totals and growth in customer base by rate class.

Table 1-8a: Historical Customer Growth

Projected Growth	Historical						
Customer Class	2020	2021	2022	2023	2024	2025	2026 *
Residential	141,747	143,058	144,624	146,023	147,311	149,230	150,718
GS <50	13,997	14,060	14,213	14,339	14,437	14,633	14,685
GS =>50	1,718	1,679	1,648	1,659	1,660	1,707	1,718
Large User	2	2	2	1	1	1	1
Wholesale Market Participant	-	-	-	-	-	-	-
Streetlight	40,222	40,710	41,166	41,578	41,717	41,777	41,929
Embedded Distributor	2	2	2	2	2	2	2
Unmetered Scattered Load	1,450	1,460	1,456	1,481	1,483	1,479	1,483
Total	199,138	200,971	203,111	205,083	206,611	208,829	210,535
% Increase	n/a	0.92%	1.06%	0.97%	0.75%	1.07%	0.82%

Note (*) due to the timing of this DSP, these years are forecast.

Table 1-8b: Forecast Customer Growth

Projected Growth	Forecast				
Customer Class	**2027**	**2028**	**2029**	**2030**	**2031**
Residential	152,220	153,738	155,271	156,820	158,388
GS <50	14,738	14,790	14,843	14,896	14,950
GS =>50	1,729	1,740	1,751	1,762	1,768
Large User	1	1	1	1	1
Wholesale Market Participant	-	-	-	-	-
Streetlight	42,081	42,233	42,387	42,540	42,695
Embedded Distributor	2	2	2	2	2
Unmetered Scattered Load	1,487	1,491	1,495	1,499	1,503
Total	212,258	213,996	215,750	217,521	219,307
% Increase	0.82%	0.82%	0.82%	0.82%	0.82%

Individually, over the forecast period, the average growth rate for residential class is 1.0%, and the GS<50 kW and GS>=50 kW classes have an average growth rate of 0.80% and 0.1%, respectively. Streetlight connections have grown at about 0.7% annually and all other classes have a growth rate of near zero percent.

1.4.4.2. Climate

Enova experiences weather typical of Southwestern Ontario; however, severe weather events do occur. In 2022, Enova experienced a high-impact Derecho; a widespread, fast-moving, and long-lived windstorm associated with a band of severe thunderstorms. During the storm, which affected the Quebec City-Windsor Corridor, wind speeds up to 147 km/hr were measured in Kitchener, making this the largest single power outage event over the historical period. Additionally, Enova's large rural area provides greater exposure to damage from severe wind and ice events than do the urban areas.

A discussion on the impacts of weather-related events on Enova's reliability can be found in **Appendix F-1 - Distribution System Reliability Report**.

1.4.4.3. Demand & Energy

Over the historical period, Enova's annualized Summer System Peak Demand grew at approximately 3.0% while its annualized Winter System Peak Demand grew at approximately 0.9%. On June 19th, 2024, at approximately 17:00 hours EST, Enova experienced a gross Summer System Peak Demand of 689.7 MW.

Coming out of COVID-19, Enova has seen a steady rise in both summer and winter peak loads. From 2026 to 2031, Enova forecasts the annual growth in its customer base to remain in the range of 1%. Enova's annualized Summer System Peak Demand is forecasted to grow at approximately 2.5% while its annualized Winter System Peak Demand is forecasted to grow at approximately 5.2%. The main drivers of the load increase include further adoption of electric vehicles, electric hot water heaters and electric heat pumps, albeit at a slower pace than forecast under previous federal government programs. In addition, developers are proposing that 150 MVA of data centre load be connected within Enova's service area towards the end of the forecast period.

Enova is a summer peaking utility and weather still remains the main factor impacting volatility in Enova's peak demand. More detailed information can be found in **Appendix - E Supply and Capacity Report**.

1.4.4.4. Embedded Generation

As of December 31, 2024, 1,934 generators were connected to the Enova distribution system for a total connected capacity of 71,462 kW. Of these, 1,912 were REG connections totalling 42,832 kW. **Table 1-9** provides a breakdown of the 2024 connections by generation type.

Table 1-9: Enova Generator Connections by Type

Generation Type	microFIT		FIT		Net Metered		Load Displacement		Others		Total Connected	
	Num	(kW)	Num	(kW)	Num	(kW)	Num	(kW)	Num	(kW)	Num	(kW)
Solar	1,375	11,273	80	13,940	445	7,232	5	412			1,905	32,857
CHP							14	12,510			14	12,510
Wind			1	35	3	63	0	0			4	98
Biogas			1	2,852			1	800	1	6,225	3	9,877
Battery							7	14,120	1	2,000	8	16,120
Total	1,375	11,273	82	16,827	448	7,295	27	27,842	2	8,225	1,934	71,462
% of Total	71%	16%	4%	24%	23%	10%	1%	39%	0%	12%	100%	100%
REG	1,375	11,273	82	16,827	448	7,295	6	1,212	1	6,225	1,912	42,832
% REG	72%	26%	4%	39%	23%	17%	0%	3%	0%	15%	100%	100%
NON REG											22	28,630

At the time of Enova's system peak, total embedded generation supplied approximately 28.9 MW or 4.2% of the system peak. This represents 40.5% of installed generation capacity. REGs contributed 14 MW or 2% of the system peak. This represents 32.8% of the total REG installed capacity. The remainder of Enova's peak demand was supplied through IESO wholesale transmission and < 50 kV points of supply.

Table 1-10 lists the three stations that have Short Circuit Limited constraints at this time. These limitations, however, do not prevent microgeneration (< 12 kW) from being connected to these stations as microgeneration contributes negligible short circuit current to the feeder. Short-circuit limitations will be alleviated over time as equipment is replaced through Enova's System Renewal program.

Table 1-10: SCL-Constrained Transformer Stations

Station	Buses	Total Generation Capacity (kW)	Connected Generation (kW)	Remaining Capacity	Connected Customers	Limitation	Primary Constraint
Rush	B1B2	12,350	1,600	0 kW (0%)	11,340	SCL	Circuit breaker / bus short-circuit ratings
Kitchener 1TS	B1B2	5,180	1,583	0 kW (0%)	5,338	SCL	Circuit breaker / bus short-circuit ratings
Kitchener 4TS	B71B81	12,990	380	0 kW (0%)	7,915	SCL	Circuit breaker / bus short-circuit ratings and reverse power limitations
Kitchener 4TS	B72B82	8,450	766	0 kW (0%)	8,944	SCL	Circuit breaker / bus short-circuit ratings and reverse power limitations
Total		38,970	4,329	0 kW (0%)	33,537		

Overall, there is a significant amount of generation capacity available at Enova's transformer stations and feeders. Based on Enova's evaluation of current connections and forecast applications, Enova believes that there is adequate capacity to connect the anticipated generation over the forecast period.

Please refer to **Appendix D-1: Renewable Energy Generation Investment (REGI) Plan** for a more indepth analysis regarding the readiness of Enova's distribution system to accommodate renewable generation.

2. (CHAPTER 5.2) DISTRIBUTION SYSTEM PLANS

Enova's DSP provides a comprehensive and detailed description of the distribution system, condition of current assets operational performance and other supporting information needed to develop its forecasted capital investment plans.

Enova's investment plans are the outcome of extensive information gathering, analysis and planning efforts with internal and external stakeholders.

Internally, all functions of the organization provided their expertise to inform Enova's forecast investment plans. Engineering, operations, finance, information technology, regulatory, fleet, metering, facilities, and customer service have all made significant contributions towards the strategic direction of the plan and the tactical executions to achieve the desired outcomes.

Externally, input from third parties such as customers, municipalities, developers, the transmitter, the IESO and telecoms has also, to various degrees, informed the development of Enova's forecast expenditures.

Enova has aligned its Asset Management and Capital Investment Planning processes, and their intended outcomes, with the needs, priorities and preferences of its customers, Enova's Strategic Objectives and with the principles and expectations of the OEB.

Enova's DSP has been organized according to the recommended format contained within the OEB's "Chapter 5 - Filing Requirements for Electricity Distribution Rate Applications - 2026 Edition for 2027 Rate Applications" (Chapter 5). All Enova capital investments are allocated into one of the four OEB categories.

Cross-references to Chapter 5 are provided in brackets () at all headings/subheadings within this report for ease of reference.

This DSP spans a seven-year historical period covering 2020 to 2026 and a five-year forecast period covering 2027 to 2031. The Bridge Year and Test Year are 2026 and 2027, respectively. The historical period dates back to the test years of the legacy LDCs' cost of service applications; 2020 for KWH and 2021 for WNH.

Historical expenditures and forecast investment plans are described. For the years 2020 – 2022, financial information is shown both by legacy LDCs and on a consolidated basis. Since the 2022 merger, all financial information is presented on a consolidated basis. This is to support the effective and efficient planning of capital investments and Enova's efforts to operate as a single entity.

Table 2-1 identifies the type of financial data presented in the DSP. **Table 2-2 (a&b)** identifies the source and vintage of data used in the DSP.

Table 2-1: Financial Data Type

Years	Information Type
2020-2025	Actual
2026	Budget
2027-2031	Forecast

Table 2-2a: Data Vintage Table

#	Dataset / Analysis	Purpose	Source System	Reporting Period	Data Vintage	Data Owner	Version	Comments
1	Customer Connections	Load forecasting	CIS	Dec. 31, 2025	Jan. 15, 2026	Customer Services	v1.0	Includes all active customers
2	Peak Demand	Capacity planning	SCADA	2020–2025	Feb. 2, 2026	System Operations	v1.1	Weather normalized
3	Energy Consumption	Load forecast	MDM	2020–2025	Jan. 30, 2026	Metering	v1.0	Annual billed consumption
4	Asset Register	Asset condition assessment	GIS	Dec. 31, 2025	Jan. 20, 2026	Asset Management	v2.0	Includes major in-service assets
5	Asset Age & Condition Profile	Replacement prioritization	ACA / ENGIN	Dec. 31, 2025	Jan. 20, 2026	Asset Management	v2.0	Asset management Frameworks
6	Reliability Indices (SAIDI/SAIFI)	Reliability analysis	OMS	2020–2025	Feb. 5, 2026	Operations	v1.0	Excludes Major Event Days and Loss of Supply where applicable
7	Outage History	Failure analysis	OMS	2020–2025	Feb. 5, 2026	Operations	v1.0	Cause codes standardized
8	Vegetation Management	Asset risk assessment	Work Management System	2020–2025	Jan. 25, 2026	Operations	v1.0	Completed cycles only

Table 2-2b: Date Vintage Table

#	Dataset / Analysis	Purpose	Source System	Reporting Period	Data Vintage (Extract Date)	Data Owner	Version	Comments
9	Capital Project History	Historical investment analysis	ERP	2020–2025	Feb. 10, 2026	Finance	v1.2	Final audited values
10	O&M Expenditures	Cost trend analysis	ERP	2020–2025	Feb. 10, 2026	Finance	v1.2	Audited financial statements
11	Distributed Energy Resources	DER hosting capacity	GIS / DER Registry	Dec. 31, 2025	Jan. 28, 2026	Engineering / Planning	v1.0	Includes connected DERs
12	Load Forecast Inputs	Forecast development	Planning Model	2026–2031	Mar. 1, 2026	Engineering / Planning	v3.0	Final planning assumptions
13	Customer Growth Forecast	Demand planning	Corporate Forecast	2026–2031	Feb. 15, 2026	Engineering / Planning	v1.0	Based on municipal growth forecasts
14	Non-Wires Alternatives Screening	NWS assessment	Planning Studies	2026	Mar. 10, 2026	Engineering / Planning	v1.0	Final screening results

2.1. (CHAPTER 5.2.1) Distribution System Plan Overview

This section provides an overview of the key elements of Enova's DSP, including:

- Capital Investment Highlights
- Objectives of this DSP
- Changes Since the Previous DSP
- Incremental Capital Module (ICM) Funding
- Distribution Asset Condition
- Reliability Performance
- Innovation Initiatives
- Retirement of 8.32 kV Distribution Assets
- Grid Modernization Technologies

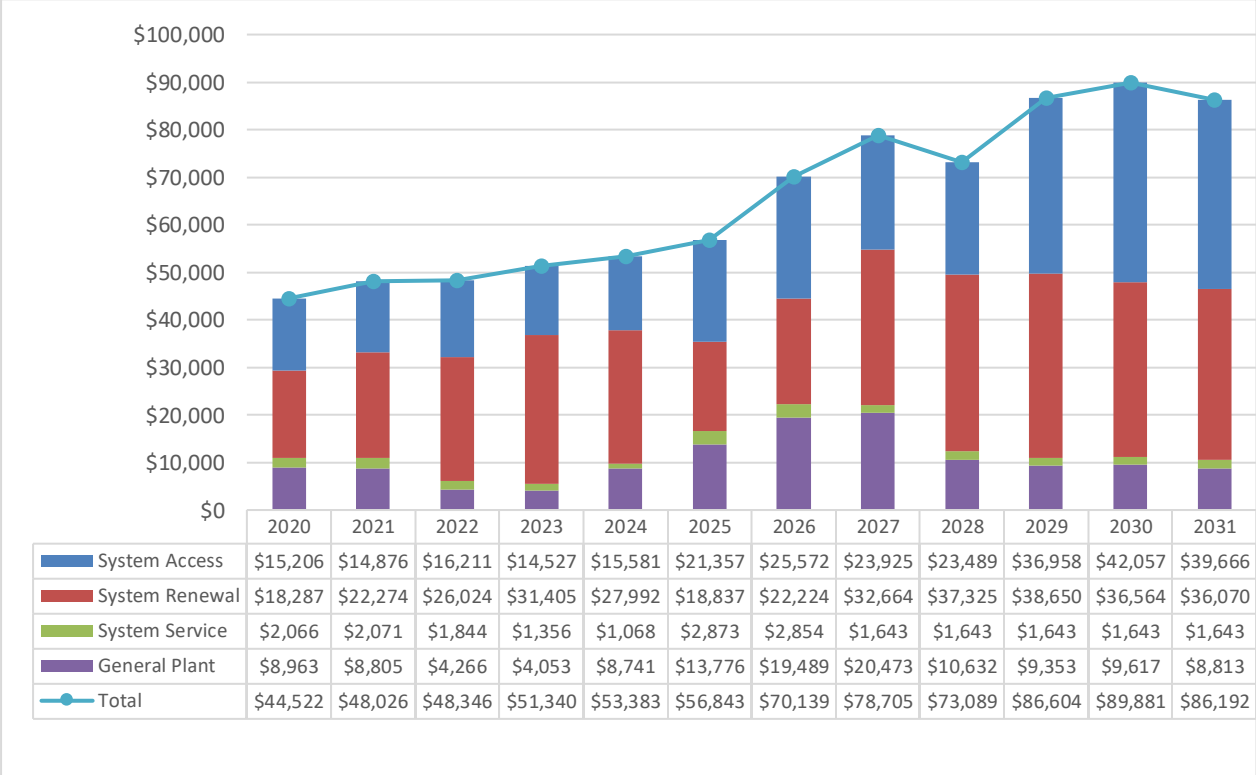
Each subsection provides a high-level summary of the topic, with references to later sections of the DSP where more detailed information, supporting analyses, and justification are presented.

2.1.1. Capital Investment Highlights

A comprehensive treatment of historical and forecast expenditures is provided in **Section 4 Capital Expenditure Plan**. This section provides highlights of that plan.

Figure 2-1 illustrates how Enova's capital requirements have changed over time. The 2020 to 2022 expenditures are consolidated amounts from Enova's legacy LDCs. Figures in this DSP are stated in 2026 dollars with no escalation for inflation applied.

Figure 2-1: Capital - Historical Expenditures and Forecast Investments

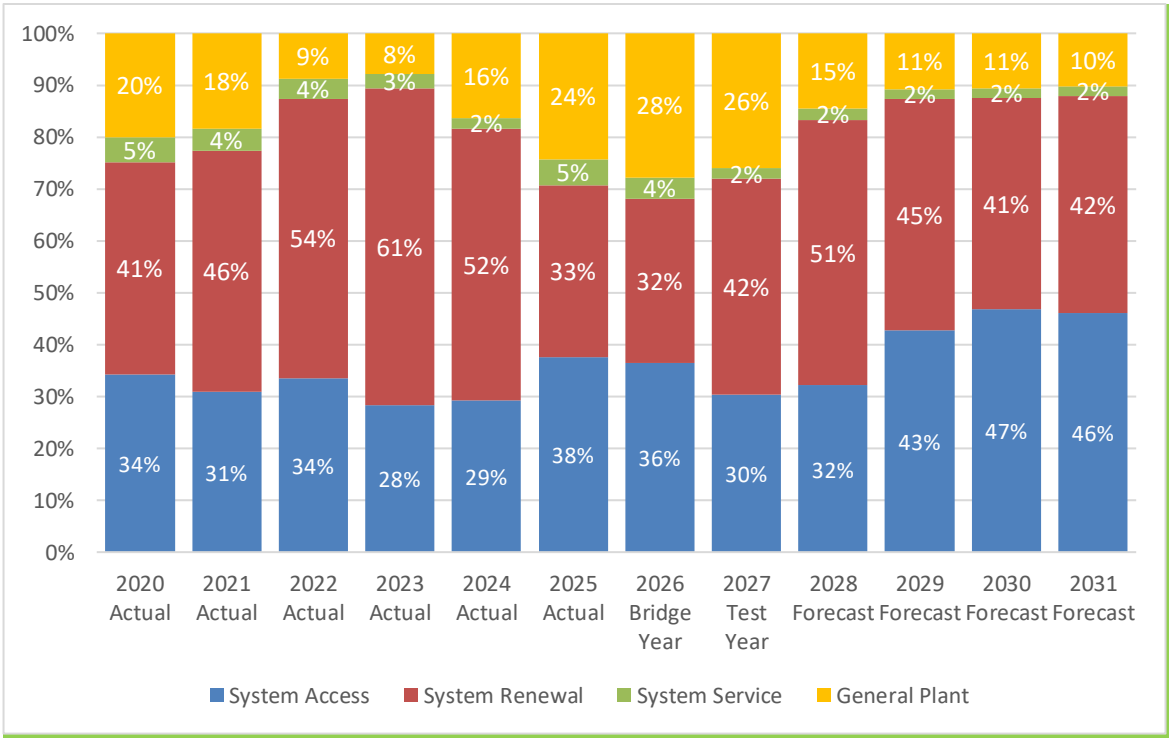


	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
System Access	$15,206	$14,876	$16,211	$14,527	$15,581	$21,357	$25,572	$23,925	$23,489	$36,958	$42,057	$39,666
System Renewal	$18,287	$22,274	$26,024	$31,405	$27,992	$18,837	$22,224	$32,664	$37,325	$38,650	$36,564	$36,070
System Service	$2,066	$2,071	$1,844	$1,356	$1,068	$2,873	$2,854	$1,643	$1,643	$1,643	$1,643	$1,643
General Plant	$8,963	$8,805	$4,266	$4,053	$8,741	$13,776	$19,489	$20,473	$10,632	$9,353	$9,617	$8,813
Total	$44,522	$48,026	$48,346	$51,340	$53,383	$56,843	$70,139	$78,705	$73,089	$86,604	$89,881	$86,192

Figure 2-2 presents a summary of the allocation of annual investments in each investment category as a percentage of total investments, and how those allocations have changed over time.

Table 2-3 presents a comparison between average historical and forecast allocations by investment category.

Figure 2-2: Historical and Forecast Capital Expenditures (%)



SA expenditures' portion of the total investment plan is seen to increase substantially over the forecast period. All other categories see slight declines in their shares.

Table 2-3: Forecast vs Historical Capital Expenditures (%)

OEB Investment Categories	Historical Annual Average	Forecast Annual Average
System Access	33%	40%
System Renewal	46%	44%
System Service	4%	2%
General Plant	18%	14%
Total	100%	100%

Table 2-4 provides a summary of Enova's Capital Investment Plan over the forecast period including capital contributions and O&M.

Table 2-4: Capital Forecast by OEB Category ($000s)

OEB Category	2027	2028	2029	2030	2031	Forecast Total	% of Total Capex
System Access	$23,925	$23,489	$36,958	$42,057	$39,666	$166,095	40%
System Renewal	$32,664	$37,325	$38,650	$36,564	$36,070	$181,273	44%
System Service	$1,643	$1,643	$1,643	$1,643	$1,643	$8,215	2%
General Plant	$20,473	$10,632	$9,353	$9,204	$9,225	$58,887	14%
Gross Capex	$78,705	$73,089	$86,604	$89,468	$86,604	$414,470	100%
Capital Contributions	($7,485)	($7,495)	($7,489)	($6,783)	($8,208)	($37,460)	-9%
Net Capex	$71,219	$65,593	$79,115	$82,685	$78,396	$377,008	91%
O&M	$22,030	$22,130	$22,130	$22,230	$22,230		

(no escalation for inflation included)

The two major areas of investment in Enova's CIP are in the areas of System Renewal and System Access. Over the forecast period these two categories account for 84% of total planned capital investments. Increased capital expenditures are not expected to materially impact O&M costs over the forecast period.

Table 2-5 provides an overview of forecast versus historical expenditures on an annualized basis. System Access shows the largest increase in forecast expenditures.

Table 2-5: Forecast vs Historical Average Annual Expenditures ($000s)

OEB Investment Category	Historical Annual Average	Forecast Annual Average	$ Variance	% Variance
ENOVA	2020-2026	2027-2031	Forecast - Historical	Forecast - Historical
System Access	$ 17,619	$ 33,219	$15,600	88.5%
System Renewal	$ 23,863	$36,255	$12,391	51.9%
System Service	$2,019	$1,643	$(376)	-18.6%
General Plant	$9,727	$11,777	$2,050	21.1%
Gross CAPEX	$53,228	$82,894	$29,666	55.7%
Contributed Capital	$8,271	$7,492	$(779)	-9.4%
Net CAPEX	$44,957	$75,402	$30,445	67.7%
O&M	$19,869	$22,989	$3,120	15.7%
O&M as a % of Gross Capex	37%	28%		

Overall, on an annual basis, Enova's forecast gross capital expenditures are expected to increase 56% and net capital expenditures are expected to increase 68% over the historical period as forecasted contributed capital is expected to decline.

System Renewal (SR) Drivers

Table 2-6 provides a summary of the major drivers of SR Investments. Out of 14 SR programs, these four (4) make up 90% of planned SR investments. SR investments exhibit the second-highest percentage increase (52%) in forecast expenditures over historical. These investments are related to the renewal of Enova's underground distribution, overhead distribution and station assets. SR investments in the plan were informed by Enova's internal asset management processes.

Table 2-6: Total System Renewal Forecast Investments ($000s)

System Renewal – Projects / Programs	Total Forecast Investments	% of Total Expenditure	Historical Average	Forecast Average	Variance	% Variance
UG Line Renewal - Subdivisions	$72,644	40.1%	$4,800	$14,529	$9,729	202.7%
Station Equipment - Renewal	$41,623	23.0%	$3,375	$8,325	$4,949	146.6%
OH Line Renewal - Voltage Upgrade	$29,431	16.2%	$1,665	$5,886	$4,222	253.6%
OH Line Renewal - Routine Projects	$20,536	11.3%	$6,204	$4,107	-$2,097	-33.8%
Subtotal	$164,235	90.6%	$16,044	$32,847	$16,803	569.1%

UG Line Renewal - Subdivisions

The replacement of underground primary subdivision cable is the single largest investment in Enova's forecast SR plan.

Enova's analysis of Asset Condition Assessments has determined that significant investments are required to maintain the safe and reliable operation of its system. Assets in Poor and Very Poor condition have been identified and Enova has set out a plan to prioritize and pace asset replacements over the forecast period.

The cable that has been identified as requiring replacement is direct buried, making it costly and time-consuming to replace. In conjunction with the cable replacements, these projects have integrated the replacement of submersible transformers. This improves the logistics of

the work and eliminates a type of transformer that has been a leading contributor to defective equipment failures and customer hours of interruption.

Station Equipment - Renewal

Station equipment renewal project drivers are condition and personnel safety. Station renewal work includes HMSTS “B” transformer replacement, 6TS, 7TS and HMSTS“B” switchgear and circuit breaker replacements, and 3TS circuit breaker replacements.

OH Line Renewal - Voltage Upgrade

These are overhead line renewal projects where the primary driver is asset condition; however, there is a secondary benefit in that these lines, when rebuilt, will operate at higher voltages, allowing for greater flexibility and connecting customers and generators and more efficient operation of the distribution system.

OH Line Renewal - Routine Projects

These are projects where the primary driver for overhead line replacement is asset condition. These projects can be considered as like-for-like replacements.

Enova has increased its overhead line renewal program based on the results contained in its most recent ACA. Over the historical period, Enova averaged approximately 900 – 1,000 pole replacements per year. This program will increase pole replacements to between 1400 and 1500 annually over the forecast period.

OH Line Renewal - Failing Conductor

These overhead line renewal projects are primarily driven by the deteriorating condition of legacy No. 4 and No. 6 aluminum conductor steel-reinforced (ACSR) conductors. These smaller-gauge conductors are located predominantly in rural areas of Enova’s service territory. Due to their relatively small physical size, these conductors are particularly susceptible to mechanical fatigue and galvanic corrosion. Enova and its legacy LDCs have experienced conductor failures involving these assets, including instances in which conductors have broken and fallen. Such failures create public and worker safety risks, may result in unplanned customer outages, and can require emergency repair work. The renewal

program replaces these deteriorated conductors before failure, thereby reducing safety risk, improving system reliability, and avoiding the higher costs and operational disruption associated with reactive repairs.

System Access (SA) Drivers

Table 2-7 provides a summary of the major drivers of SA Investments. Out of 11 SA programs, these 5 make up 86% of planned SA investments. SA investments exhibit the largest percentage increase (88%) in forecast expenditures over historical. System Access investments accommodate connections, expansions, customer/load-growth related capacity requirements and relocations of the distribution system as well as support Enova's metering program. These are non-discretionary capital investments, mandated by the OEB.

Table 2-7: Total System Access Forecast Investments ($000s)

System Renewal – Projects / Programs	Total Forecast Investments	% of Total Expenditure	Historical Average	Forecast Average	Variance	% Variance
Customer Connections - Loads	$40,247	24.2%	$5,001	$8,049	$3,049	61.0%
Station Equipment - Expansions	$35,818	21.6%	$214	$7,164	$6,949	3242.6%
Meters - Retail	$30,479	18.4%	$955	$6,096	$5,141	538.5%
UG Line Expansions - Subdivisions	$20,827	12.5%	$3,113	$4,165	$1,052	33.8%
Relocations - Special Projects	$15,656	9.4%	$303	$3,131	$2,829	934.9%
Subtotal	$143,027	86.1%	$9,585	$28,605	$19,020	4810.8%

Customer Connections – Loads

This program is driven by the routine requests from load customers, both residential and commercial, for connections to the distribution system. These investments support growth in population, housing, transportation and employment developments in its service area.

Station Equipment – Expansions

The largest single driver of these investments is the planned 11TS station expansion required to provide capacity for a new customer connection. This is the principal driver for the increases in 2029 and 2030.

Meters – Retail

These investments are primarily driven by the staged replacement of Enova's first-generation AMI 1.0 smart meter population. The AMI 2.0 program has been developed and paced to replace approximately 165,000 meters over an eight year period starting in 2029.

UG Line Expansions – Subdivisions

The main drivers for these expenditures are requests for servicing by developers for new subdivisions.

Relocations - Special Projects

These investments are for plant relocations where cost recovery does not follow the model set under the Public Service Works on Highways Act. Project types include overhead-to-underground burials and overhead relocations driven solely by the construction of sidewalks or trails. Over the forecast period, one of many projects will be relocations to facilitate Phase Two of the ION LRT project.

General Plant (GP) Drivers

Table 2-8 provides a summary of the major drivers of GP Investments. Out of 14 GP programs, these 4 make up 85% of planned GP investments. GP investments exhibit the third-largest percentage increase (21%) in forecast expenditures over historical. GP expenditures have multiple drivers: internal needs to support Enova's operations along with construction and maintenance programs including facilities, fleet, tools, information technology, operational technology, GIS/CIS platforms, and hardware/software renewals.

Table 2-8: Total General Plant Forecast Investments ($000s)

General Plant– Projects / Programs	Total Forecast Investments	% of Total Expenditure	Historical Average	Forecast Average	Variance	% Variance
Software - IT	$17,538	29.8%	$2,841	$3,508	$666	23.5%
Fleet	$15,180	25.8%	$1,644	$3,036	$1,392	84.7%
Buildings	$10,140	17.2%	$1,242	$2,028	$786	63.3%
Software - Distribution Support	$7,282	12.4%	$341	$1,456	$1,116	327.2%
Subtotal	$50,140	85.1%	$6,068	$10,028	$3,960	498.6%

Software – IT

These are investments for system software with a typical useful life of 3-5 years or large scale CIS/ERP system software with a typical useful life of 10 years. Drivers for capital replacement or upgrades include, obsolescence and lack of support, enhanced cyber security requirements, enhanced organizational functionality, and enhanced customer-centric requirements.

Forecast capital expenditures in Software - IT are shaped principally by two factors: a one-time application CC&B upgrade ($3.85M) concentrated in 2027, and the scheduling of discrete, project-based system investments that taper over the period. Underlying these is a recurring base of evergreen software maintenance, hardware lifecycle replacement, and cyber security investment.

For more detailed information, please refer to **Appendix H: Information Technology Management Plan.**

Fleet

These are investments for the replacement of large vehicles, small vehicles, trailers and construction equipment.

Enova is proposing an annual expenditure plan of approximately $3.0 million annually over the 2027-2031 timeframe. The drivers for these investments are asset condition and operational needs to complete its capital and maintenance program over the same time period.

For more detailed information, please refer to **Appendix J: Fleet Management Plan**.

Buildings (Facilities)

Facility capital upgrades or replacements normally fall into three main categories: structural/functional improvements, aesthetic upgrades, and efficiency retrofits. The major driver for expenditures in this program is the VS HVAC Replacement and Facility Renovation Project. Year two of the project forecasts expenditures in 2027 of $7.36 million. Capital improvements at the Country Squire facility adds almost another $1.0 million in 2028.

For more detailed information, please refer to **Appendix I: Facilities Management Plan** and the ICM application.

Software - Distribution Support

These are capital expenditures to support and enhance operational software functions. Enova intends to improve data visualization and data-to-insights capabilities to transform data into meaningful, actionable business strategies. These initiatives will enhance Enova's existing Asset Management, Engineering Design, and System Planning capabilities.

System Service (SS) Drivers

Table 2-9 provides a summary of the major drivers of SS Investments. Out of 7 SS programs, these 2 make up 100% of planned SS investments. SS investments were mainly driven by reliability and system operability concerns.

Table 2-9: Total System Service Forecast Investments ($000s)

System Service	Total Forecast Investments	% of Total Investment	Historical Average	Forecast Average	Variance	% Variance
Grid Improvements - Connectivity	$6,643	80.8%	$136	$1,329	$1,192	875.1%
Grid Improvements - Automation	$1,573	19.2%	$704	$315	-$389	-55.3%
Subtotal	$8,216	100.0%	$840	$1,643	$803	819.8%

Grid Improvements – Connectivity

These are planned capital projects designed to increase connectivity between different parts of the distribution system and improve operational flexibility during contingencies such as loss of supply, foreign interference (vehicle accidents), adverse weather equipment damage and equipment failure. Prior to the merger, KWH and WNH distribution systems were almost completely independent of each other, both in capacity and connectivity. These investments will allow greater interoperability between the two systems, increasing resilience and better utilization of existing capacity.

Grid Improvements - Automation

These are planned grid modernization initiatives to improve grid resiliency, flexibility and utilization of technologies (e.g. DERs). Investments include stations and grid intelligence projects that increase the use of SCADA, FLISR, electronic reclosers and sensors.

2.1.2. Objectives of this Distribution System Plan

Enova has identified the following objectives it plans to achieve through this DSP. These objectives will be achieved through targeted and strategic investments across the Enova distribution system.

1) Maintain reliable and safe assets and infrastructure. This will be achieved through the completion of Enova's Asset Replacement Plan as set out in **Appendix B-1 Asset Condition Assessment Report**.

2) Ensure that distribution capacity and physical infrastructure remain sufficient to meet the needs of existing customers and accommodate new customer connections, load growth, electric vehicles, and distributed energy resources. This objective will be supported through effective system planning, ongoing customer and stakeholder consultation, and the timely design and execution of connection and capacity-expansion projects.

3) Meet or exceed OEB system reliability performance targets on a 5-year rolling basis. This objective will be achieved by the completion of Enova's Asset Replacement Plan and continued investments in smart grid technologies.

4) Maintain System Losses in a range of between 2.7% and 3.3%. This will be achieved through the completion of planned voltage conversion work and retirement of 8.32 kV infrastructure.

5) Support Grid Modernization. This will be achieved through the continued adoption of smart grid technologies and exploring non-wires solutions (NWS) to defer traditional infrastructure upgrades.

6) Improve grid resilience and adapt to extreme weather. This will be achieved through incorporating resilience into system planning, engineering and standards, adoption of the OEB Vulnerability Assessment and System Hardening Toolkit and incorporating climate resiliency into asset investment.

2.1.3. Changes since last Distribution System Plan

This is Enova's first DSP since the merger of WNH and KWH to form Enova, and as such, no direct comparison to a previous DSP can be made. At the time of preparing this report, Enova is three years into the harmonization and consolidation of the two legacy LDC's. This section reflects the major changes that have occurred during the 2020 to 2024 period.

2.1.3.1. Merger

The most significant change that impacts this DSP is the merger of Waterloo North Hydro Inc. (WNH) with Kitchener-Wilmot Hydro Inc. (KWH) to form the new Enova Power Corp. on September 1, 2022.

Enova's legacy LDC's last filed their DSPs in 2020 (KWH), and 2021 (WNH) respectively. As such, this DSP spans a 7-year historical period covering 2020 to 2026 instead of the standard 5-year period.

It is still early days in Enova's planned harmonization and consolidation of the two legacy LDC's; however, numerous changes have occurred and are still in progress. Some of the key changes that are setting up Enova to be successful over the forecast period are as follows:

i) Staffing – numerous changes have redeployed talent to be more effective in support of the new organization, its mission, goals and strategic objectives.

ii) Support IT and OT systems – Enova took the opportunity to not only harmonize systems but to enhance capabilities to better support customers, staff and to promote efficiencies in its operations. Key informational and support systems that were upgraded and enhanced include,

- Customer Information System (CIS)

- Geographical Information System (GIS)
- Asset Management Software (ENGIN 2.0)
- Meter Data Management System (MDM)
- Automated Utility Design (AUD)

iii) Asset Management and Supply Planning – Enova has taken a more integrated and focused approach by setting up a unit tasked with achieving better integration and quality control of performance data; more timely and accurate trending analysis; and more timely deliverables that will inform Enova's Asset Management Process and Investment Plan development.

iv) Capital Program Allocations – although not changing the fundamental purpose of legacy programs, Enova took the opportunity during the harmonization process to be more granular in its program specification and approach to allocating costs. This will allow for better tracking and reporting to inform Enova's Asset Management Process and Investment Plan development. Nothing in this work deviated from the legacy LDCs' methodologies of allocating costs to the OEB's four investment categories.

v) Inspection & Maintenance Programs – after a review of both legacy policies and practices, Enova is taking the opportunity, not only to harmonize the programs, but to make enhancements so that the asset condition information collected is more granular, structured, digitized and ubiquitous to multiple information systems.

Although not yet fully developed, these new capabilities will allow Enova to improve upon the quality of its Asset Management Processes and Investment Planning.

2.1.3.2. COVID-19 Impacts

Enova's two legacy LDC's completed their previous plans up to early 2020 when a state of emergency was declared by the Premier of Ontario due to COVID-19. It is important to point out the evolving circumstances caused by the impacts of the COVID-19 pandemic. Reprioritization of projects and adjustments to capital programs were continuous during 2020, 2021 and 2022. Altered customer-driven work demands and disrupted supply chains resulted in extraordinary inflationary effects.

Even though the pandemic officially ended in March of 2022, the disruptive effects of COVID-19 lingered on as inflation hit 8.1% in July of 2022. Work plan adjustments were made into 2023 as customers, developers and municipalities attempted to return to a more normal and stable business climate.

Post COVID-19 inflation has eased somewhat but has not returned to pre-COVID-19 levels. Post COVID-19 cost inputs have remained persistently high, even into 2026. Some costs, such as transformer and vehicle prices, are expected to remain permanently at the elevated levels established during the COVID-19 pandemic.

2.1.4. Incremental Capital Module (ICM) Funding

This DSP has been prepared to support Enova's 2027 Incremental Capital Module Application (ICM Application) for 2027 rates. The ICM Application seeks supplemental funding for the HVAC Replacement and Renovation (Facility Renovation) of Enova's Victoria Street head office location. Details of the ICM and renovation project are outlined in the appendices of the ICM Application. Estimated capital expenditures for the current ICM application can be found in the Appendix A - 2027 Material Capital Investments.

This DSP is also being used to inform interested stakeholders of other potential requests for ICM funding that may come forward over the forecast period. At the time this DSP was prepared, Enova has identified the two projects that may qualify for potential future ICM requests on an information-only basis. Specifically:

1) Underground Distribution Cable Replacement Program ICM - This program is intended to accelerate existing cable replacement programs, with the potential ICM portion representing work above what is already included in core programs and supported by the current rates. The accelerated program is driven by cable condition assessments, failure rates and the quantity of cable in Poor and Very Poor condition.

2) AMI 2.0 Program ICM - The program is a staged replacement of Enova's first-generation smart meter fleet as those assets approach the end of their useful service life.

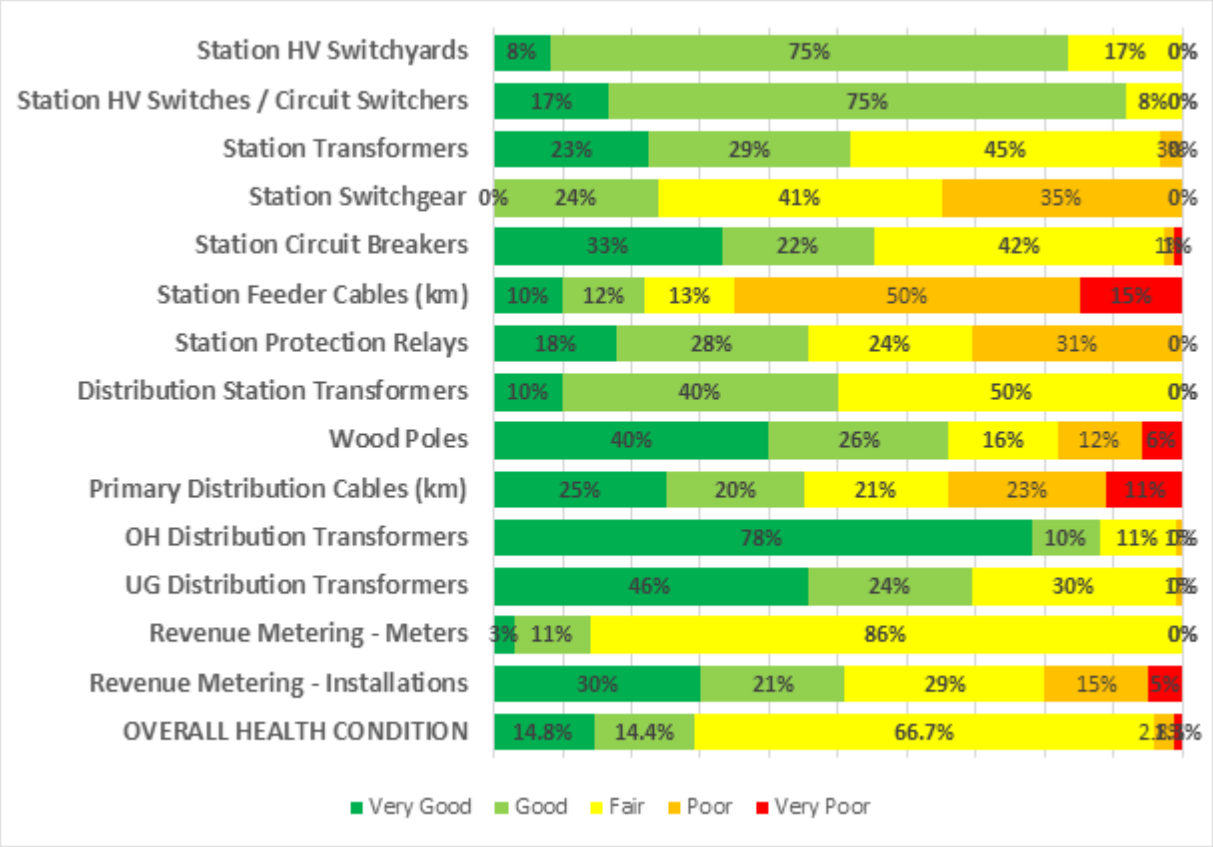
Enova reserves the right to withdraw, modify, or adjust its plans for future Incremental Capital Module (ICM) requests based on changing circumstances, regulatory requirements, or evolving business needs. More information can also be found in **Section 5.4.1 – Capital Expenditure Summary.**

2.1.5. Distribution Asset Condition

A key input to the System Renewal portion of the DSP is Enova's Asset Condition Assessment (ACA). The ACA uses Health Index scoring to categorize major assets as Very Good, Good, Fair, Poor, or Very Poor. Poor and Very Poor assets generally require proactive or reactive renewal planning, while Fair assets require monitoring and may require remedial work or replacement depending on condition, criticality, and rate of deterioration.

Figure 2-3 provides a high-level overview of the condition of Enova's major asset classes. On a weighted average based on asset quantities, the majority of assets fall into the Fair category.

Figure 2-3: Health Index Distribution



Most problematic for Enova are the Very Poor (15%) and Poor (50%) of station feeder cables. These assets cannot be rehabilitated and are costly and time-consuming to replace.

The primary distribution cables Very Poor (11%) and Poor (23%) are also problematic due to the nature of their installation; they are direct buried. Replacement requires greater coordination with municipalities and the work can be disruptive to customers, more so in work-from-home situations. Again, these assets are costly and time-consuming to replace.

More detailed information can be found in **Appendix B-1: Asset Condition Assessment (ACA) Report.**

2.1.6. Reliability

Reliability was also a top concern of customers in the latest customer satisfaction survey. Enova's historical 5-year average reliability performance metrics for SAIDI (0.77) and SAIFI (0.88) are below the OEB's reliability targets of SAIDI (0.84), SAIFI (1.10) set in 2022. Enova's SAIDI and SAIFI are also below the industry average. Even so, defective equipment ranks as the top cause of CHI (30.1%).

Enova's forecast capital plan includes significant investment in the replacement of underground cables, which are a leading contributor to the defective equipment performance metric. The program also includes the replacement of submersible transformers in residential underground distribution systems, as failures of these transformers are another major contributor to the defective equipment metric.

Enova also plans to continue with the implementation of FLISR and electronic reclosers to improve CHI by reducing outage scope and duration.

The objective of these investments is for Enova to maintain its favourable reliability performance at or below OEB targets and also improve customer satisfaction

2.1.7. Innovation

Enova's forecast innovation capital expenditures fund a coordinated set of investments that position the distribution system to integrate distributed energy resources (DERs), enable emerging market functions, and modernize the distribution system. The program is organized into three related streams: a recurring innovation program that includes early-stage DER

deployment; a Market Transaction Platform; and a Distributed Energy Resource Management System (DERMS). The profile reflects a transition from early-stage DER deployments in 2027 to the build-out of distribution-support platforms over 2028–2030, supported by a steady annual innovation program, before declining in 2031 as the principal platform implementations complete and move into ongoing enhancement and optimization. For more detailed information, please refer to **Section 4.1.2.1 Major Drivers in Forecast Capital Expenditures, 2027-2031.**

2.1.8. Retirement of 8.32 kV Distribution Assets

System Renewal investments made between 2020 – 2024, allowed Enova to retire three 8.32 kV rural stations. One more station is planned for retirement by the end of 2026.

Portions of the remaining 8.32 kV lines in the rural areas will continue to be retired over the forecast period through continuing renewal investments. These assets have been replaced with ones that operate at higher voltages and are more efficient.

The construction of new lines is guided by current standards that are more rigorous than those of 50 years ago. New construction generally incorporates higher voltages, larger conductor and increased pole strength. This results in improved resilience; increased distribution capacity, and increased sighting options for the connection of DERs. Generally, the features of new line construction tend to reduce voltage quality issues and system line losses.

Elimination of 8.32 kV lines also reduces inventory needs and avoids further capital renewal investments for the related distribution stations equipment and buildings.

2.1.9. Grid Modernization Technologies

Enova continues to invest in grid modernization technologies to improve the efficiency, reliability, resilience, and operational effectiveness of its distribution system. The deployment of Advanced Metering Infrastructure (AMI), the Outage Management System (OMS), Fault Location, Isolation and Service Restoration (FLISR), electronic line reclosers, intelligent

sensors, and other smart grid technologies has significantly enhanced Enova's ability to detect, diagnose, and respond to distribution system events.

These technologies provide system operators with near real-time visibility of network conditions, enabling faster fault identification, improved system monitoring, and more efficient dispatch of field crews. Enhanced automation and system intelligence support quicker switching and restoration activities, reducing outage duration while improving the coordination and effectiveness of restoration efforts.

Grid modernization investments also provide meaningful benefits to customers by improving service reliability and reducing the frequency and duration of power interruptions. Shorter restoration times help minimize the economic impacts of outages on residential, commercial, and industrial customers, including lost productivity, business disruption, and inconvenience. At the same time, improved outage detection and remote monitoring reduce the need for manual system inspections and unnecessary truck rolls, contributing to more efficient utilization of operating resources and helping moderate long-term growth in operating and maintenance (O&M) costs.

In addition to improving day-to-day operations, these technologies strengthen Enova's ability to manage emergency events through enhanced situational awareness and faster operational decision-making. As Enova continues to expand the deployment of grid modernization technologies throughout the 2027–2031 planning period, it expects to realize further improvements in system reliability, operational efficiency, customer service, and the overall cost-effectiveness of operating and maintaining the distribution system.

2.2. (CHAPTER 5.2.2) Coordinated Planning with Third Parties

Enova recognizes that effective distribution system planning requires ongoing coordination with customers, municipalities, energy sector partners, telecommunications providers, and other infrastructure stakeholders. Coordinated planning enables the Enova to optimize investments, minimize overall community costs, improve project delivery, and ensure that distribution infrastructure supports regional growth and long-term customer needs.

The development of this DSP incorporated information obtained through customer engagement on the DSP, and regular consultation and coordination activities undertaken throughout the planning process. These consultations included discussions with municipal governments, large commercial and industrial customers, subdivision developers, neighbouring electricity distributors (Embedded and Host distributors), Hydro One Networks Inc. (as transmitter), the IESO, telecommunications entities, and other organizations whose infrastructure planning activities influence or are influenced by Enova's distribution system. These consultation activities informed both the identification of system needs and the timing and scope of capital investments included in this DSP.

Through these coordinated planning activities, Enova has developed a capital investment plan that reflects both local customer needs and broader regional infrastructure planning, while seeking to maximize customer value and minimize overall infrastructure costs.

Greater detail on the Enova’s consultation activities is provided in the following sections.

2.2.1. Customer Engagement on the Distribution System Plan

In accordance with the OEB's Chapter 5 Filing Requirements, Enova undertook customer engagement activities to obtain stakeholder feedback on the specific proposals contained in this DSP. The objective of these engagement sessions was to provide customers with a clear understanding of Enova's proposed capital investment plans, operating practices, the drivers supporting those investments, and the customer benefits expected to result from the proposed expenditures.

Enova conducted two dedicated customer engagement workshops representing different customer segments to ensure that feedback reflected the diverse needs and perspectives of its customer base. The sessions were led by Enova's President & Chief Executive Officer and Vice-President, Grid Transformation & Chief Distribution Officer. Senior staff from Finance, Regulatory Affairs, Engineering, and Asset Management also participated to provide detailed responses to customer questions and facilitate discussion.

The presentations outlined the principal drivers underlying Enova's proposed investment plan, including asset renewal, system capacity, reliability improvements, grid modernization initiatives, and customer-driven investments. Particular attention was given to the VS HVAC Replacement and Facility Renovation Project, which forms the basis of Enova's proposed Incremental Capital Module (ICM) request. The presentations also explained how the proposed investments support customer value by maintaining a safe, reliable, resilient, and cost-effective electricity distribution system.

Customers were encouraged to actively participate throughout the engagement process. Written feedback opportunities were provided both before and after each presentation to allow participants sufficient time to consider the information presented. Customers were asked to comment on their service expectations, investment priorities, and whether the proposed investment plan appropriately addressed their current and future electricity needs.

Each workshop concluded with an open question-and-answer session during which Enova's executive leadership and senior subject matter experts responded directly to customer questions and comments. Feedback received during the engagement process was documented and considered in the development and refinement of this DSP. A summary of the engagement activities, customer feedback, and Enova's responses is provided in the following sections.

2.2.1.1. Development Community & Municipal Government Workshop

Enova conducted a dedicated customer engagement workshop for representatives of the development community and local municipal governments on July 27, 2026. The purpose of the workshop was to present the proposed investments contained in the DSP, explain the

underlying investment drivers, and obtain stakeholder feedback on Enova's proposed capital expenditure plans and operating practices.

Invitations were extended to representatives from the development community, communication companies, natural gas distributors, and all municipalities within Enova's service territory. On July 15, 2026, Enova issued 72 invitations, consisting of 15 invitations to members of the development community, 13 invitations to communication companies, 4 invitations to natural gas distributors, and 40 invitations to municipal departments. Reminder invitations were distributed approximately one week later to encourage participation. In total, 9 organizations registered for the workshop, with 5 representatives ultimately attending.

The workshop was attended by representatives from the City of Kitchener (3 participants) and the City of Waterloo (2 participants). While attendance was lower than anticipated, and no representatives from the development community were ultimately able to participate, the workshop nevertheless provided valuable input from municipal stakeholders responsible for planning and coordinating future infrastructure development. The discussion offered important insights into municipal growth plans, infrastructure coordination requirements, and emerging challenges that will influence the future development of Enova's distribution system. This feedback will continue to inform Enova's planning activities and strengthen coordination with municipal partners as development continues to grow.

Customer Feedback – Municipal Customers

Municipal participants focused their comments and questions on Enova's ability to support municipal growth, infrastructure renewal, and the evolving needs of their communities. Overall, participants indicated that the workshop was informative and improved their understanding of Enova's proposed investment plan, the drivers supporting those investments, and the challenges associated with planning and operating the electricity distribution system.

The key themes raised during the discussion included:

- Maintaining sufficient distribution system capacity and infrastructure to accommodate municipal growth, new developments, intensification, and future economic expansion.

- The importance of environmental sustainability and ensuring that future investments support community climate objectives while maintaining a safe, reliable, and affordable electricity system.
- Municipal stakeholders expressed interest in Enova's approach to cybersecurity resilience and how it is responding to evolving cyber threats. They emphasized the importance of protecting critical electricity infrastructure and maintaining reliable service as the distribution system becomes increasingly digitized.
- How Enova coordinates infrastructure planning and construction activities with natural gas utilities, municipalities, and other infrastructure providers as community growth and energy usage patterns continue to evolve.
- The measures Enova is implementing to improve the resilience of the distribution system in response to increasingly frequent and severe weather events.
- Strategies for accommodating new electricity infrastructure within increasingly constrained municipal rights-of-way while minimizing impacts on existing infrastructure, reducing construction conflicts, and preserving flexibility for future municipal projects.
- Enova's use of advanced technologies, including grid modernization initiatives, to improve system reliability, operational efficiency, outage response, and customer service.

Overall, municipal participants expressed support for Enova's long-term planning approach and recognized the importance of continued investment to ensure the distribution system can reliably support future community growth while maintaining safe, resilient, and reliable service.

The discussion also reinforced the importance of continued collaboration between Enova, municipalities, developers, communication companies, natural gas utilities, and other infrastructure providers. Participants encouraged Enova to continue engaging early in the municipal planning process to improve project coordination, minimize construction impacts, optimize the use of constrained municipal rights-of-way, and ensure that electricity infrastructure is delivered efficiently to support the Region's anticipated growth.

The feedback received was consistent with the objectives of Enova's DSP and confirmed that customers place a high value on investments that improve system capacity, reliability, resilience, cybersecurity, coordination with municipal infrastructure projects, and environmental sustainability. Enova will continue to incorporate this feedback into its planning processes as it prioritizes future capital investments and operational initiatives.

2.2.1.2. Mid-Market & Large Business Workshop (July 28, 2026)

Enova conducted a dedicated customer engagement workshop with representatives from its General Service and Large User customer base on July 28, 2026. Similar to the workshop held on July 27, 2026, the purpose of the session was to present the proposed investments contained in the DSP, explain the underlying investment drivers, and obtain customer feedback on Enova's proposed capital expenditure plans and operating practices.

On July 15, 2026, Enova extended invitations to 149 customer contacts representing a broad cross-section of its General Service and Large User customer base. Reminder invitations were distributed approximately one week later to encourage participation. In total, 11 customers registered for the workshop, with 9 representatives ultimately attending.

Although attendance was lower than anticipated, the workshop provided an opportunity for meaningful discussion with customers representing a range of commercial, industrial, institutional, and public sector organizations. Participants provided valuable perspectives on their current and future electricity needs, helping to inform Enova's understanding of customer priorities and expectations.

Customer Feedback – General Service & Large User Customers

Discussion focused on Enova's ability to support future economic growth, maintain a reliable and resilient distribution system, coordinate infrastructure investments to minimize customer impacts, and continue the adoption of advanced grid technologies. Customers also expressed interest in Enova's plans to accommodate increasing electricity demand associated with business expansion, electrification, and changing patterns of energy use while continuing to provide safe, reliable, and cost-effective electricity service.

The key themes identified during the discussion are summarized below.

Reliability and Resilience

Reliability was consistently identified as customers' highest priority. Participants recognized the importance of replacing aging and deteriorating infrastructure to maintain dependable electricity service and reduce the frequency and duration of outages. Customers expressed particular support for investments that strengthen the distribution system against increasingly frequent and severe weather events.

Several large industrial and commercial customers noted that momentary interruptions can be as disruptive to their operations as sustained outages, resulting in production interruptions, equipment resets, and lost productivity. Enova described the measures currently in place to reduce the frequency of momentary interruptions, including asset inspections, vegetation management, animal guarding, and protection system improvements. Enova also committed to further investigate additional initiatives to improve momentary outage performance.

Environmental Sustainability

Customers identified environmental sustainability as a high priority when evaluating Enova's proposed capital investments. Participants expressed support for investments that facilitate electrification, improve energy efficiency, integration of renewable and distributed energy resources, and contribute to broader community climate objectives while maintaining reliable and affordable electricity service.

Affordability

Customers recognized the importance of balancing affordability with the need for continued investment in critical electricity infrastructure. Feedback indicated broad support for prudent investments that improve long-term reliability, resilience, and system capacity, even where such investments may result in modest increases in customer rates. Participants generally viewed proactive infrastructure renewal as preferable to deferring investment, recognizing that postponing necessary asset renewal would increase future reliability risks and potentially

result in higher long-term costs. Consistent with this view, none of the respondents supported deferring renewal projects that could adversely affect system reliability as a means of keeping customer costs low.

Grid Modernization and Emerging Technologies

Customers expressed interest in Enova's continued adoption of advanced technologies to improve reliability, operational efficiency, and customer service. Technologies identified as priorities included:

- Self-healing distribution networks and automated restoration technologies;
- Distributed energy resources, including solar generation and battery energy storage;
- Electric vehicle infrastructure and system readiness for transportation electrification;
- Dynamic electricity pricing and other technologies that provide customers with greater flexibility in managing their energy usage.

Supporting Future Growth

Customers sought assurance that Enova's investment plans would provide sufficient capacity to accommodate continued business expansion, population growth, and increasing electrification. Discussion focused on Enova's plans to:

- Increase system capacity to support new commercial and industrial development;
- Accommodate increased electricity demand from electric vehicles and electric heating technologies;
- Facilitate the connection of renewable generation and distributed energy resources;
- Support regional economic development through timely infrastructure expansion; and
- Maintain a secure and resilient electricity system, including continued attention to cybersecurity.

Customer Communication

Participants encouraged Enova to continue improving customer communications before, during, and after planned and unplanned outages. Suggestions included increasing access

to live customer service representatives, expanding online self-service capabilities, and providing more timely and detailed outage communications.

Customers expressed interest in having greater clarity regarding the availability of distribution system capacity for new distributed energy resource (DER) and generation connections. Enova discussed opportunities to improve the customer connection experience by streamlining internal processes and enhancing coordination between planning, engineering, and customer service functions. As part of its ongoing continuous improvement initiatives, Enova will work to make it easier for customers to access information on available generation capacity, understand planned system upgrades that may affect connection opportunities, and engage with the appropriate staff early in the connection process. These improvements are intended to increase transparency, improve customer experience, and support the timely integration of new generation resources into the distribution system.

Overall, participants expressed strong support for Enova's long-term planning approach and recognized the importance of continued investment to ensure the electricity distribution system remains safe, reliable, resilient, and capable of supporting future economic growth and electrification. Customers generally agreed that balancing reliability, resilience, affordability, and environmental sustainability should remain central objectives of Enova's investment strategy.

The feedback received during the workshop was consistent with the objectives of Enova's DSP and confirmed that customers place significant value on investments that improve reliability, increase system capacity, strengthen resilience to extreme weather, support environmental sustainability, and enable the adoption of advanced technologies. Enova will continue to incorporate this feedback into its planning and investment decision-making processes.

2.2.2. Consultations Specific to the ICM Application

The results of consultations specific to Enova's 2027 Incremental Capital Module Application (Application) are outlined in the appendices of the Application.

2.2.3. On-Going Consultations and Communications

2.2.3.1. Customer Surveys

Every two years, Enova conducts an Electric Utility Customer Satisfaction Survey to inform its capital and operating investment planning process. The most recent survey was conducted by UtilityPulse between November 17 and November 23, 2025. The survey gathered customer feedback on service quality, reliability, customer priorities, and future investment preferences to support Enova's long-term planning activities. UtilityPulse subsequently issued a report summarizing the survey findings in January 2026, and the results have been incorporated into the development of this DSP.

Overall, Enova Scores are high and Enova scored better than the provincial and national averages across the survey. Survey respondents generally gave Enova excellent operational and representative scores. In terms of core responsibilities, the survey revealed the following.

- Provides consistent, reliable energy (93%).
- Quickly handles outages and restores power. (90%)
- Has accurate billing (90%).
- Has a standard of reliability that meets expectations (91%).
- Operates a cost-effective electricity system (75%).
- Provides info/tools to help manage electricity consumption (82%).

Enova Power's UtilityPULSE Report Card®

UtilityPULSE's Report Card® is based on tens of thousands of customer interviews gathered over many years. The purpose of the UtilityPULSE Report Card® is to provide electric utilities with a snapshot of performance – on the things customers deem to be important. Research has identified over 20 attributes, sorted into six topic categories (drivers), that customers have used to describe their utility when they have been satisfied or very satisfied with their utility. These attributes form the nucleus, or base, from which "scores" are assigned. Customer satisfaction and loyalty also play a major role in the calculations.

Category: Customer Care *(Overall A rating)*

Drivers and rating: Price and Value (B+); Customer Service (A)

Category: Company Image *(Overall A rating)*

Drivers and rating: Company Leadership (A); Corporate Stewardship (A)

Category: Management Operation *(Overall A rating)*

Drivers and rating: Operational Effectiveness (A); Power Quality and Reliability (A+)

Enova received a high rating in the survey, but that does not mean there isn't room for improvement. The survey pointed out:

- customers expect excellent customer service, reduced outages, and reliable electricity.
- The biggest challenges facing Enova are outages and this is an area where customers primarily want to see improvements. Many even perceive outages to be increasing in frequency.
- When asked, customers responded with the one or two most important things Enova could do to improve service to its customers. The top five are listed below.
  1) Better prices/lower prices (23%)
  2) Good/like it/satisfied/keep up the good work (8%)
  3) Change/extend the hours of off peak rates (3%)
  4) Get involved with green energy (e.g. wind, solar, etc.) (3%)
  5) Better power reliability/less power outages (2%)

By a wide margin, the cost of electricity is the most important factor for customers.

Ongoing customer consultations at Enova take on many forms.

i) Enova meets with individual customers, builders and consultants to facilitate customer connections. Initiated by either party, the number and location of the meetings vary. Enova produces estimates, layout drawings, or even detailed design drawings depending on the nature of the project. Often, the municipality and other utilities (i.e., gas, water, telecom) are participants in a coordinated planning process. These consultations enhance Enova's overall infrastructure planning and execution and support the RRFE outcomes of Operational Effectiveness and Customer Focus. One notable impact on this DSP is the inclusion of System Access investments for the planned 11TS station expansion required to provide capacity for a new customer connection. A total of $36.6 million was included over the forecast period.

ii) Enova initiates face-to-face customer consultations specifically to solicit information on major renewal projects. Customers are invited to meet with Enova staff to review and discuss proposed project plans. The feedback provided informs and helps shape, not only that specific project's final design, but also future projects. These consultations enhance Enova's overall infrastructure planning and execution and support the RRFE outcomes of Operational Effectiveness and Customer Focus.

iii) The cost of electricity is a top concern amongst Enova customers responding in the survey. Enova's Key Accounts staff help customers with cost savings, energy and demand reduction. They play a large role in assisting Enova customers with energy efficiency, energy planning, general customer communication and education. Initiated by either party, the number and location of the meetings vary. These consultations support the RRFE outcomes of Operational Effectiveness and Customer Focus.

2.2.3.2. Municipal Planning and Development Coordination

Enova regularly consults with local municipal planning and economic development staff from the City of Waterloo, City of Kitchener, Township of Woolwich, Township of Wellesley, Township of Wilmot and the Region of Waterloo. The purpose of the consultations is to share planning and development information that will aid in the timely, coordinated and cost-effective delivery of services for both Enova and the municipalities. This is an ongoing process of information exchange that informs Enova's current design and construction decisions or longer-term system planning decisions. These consultations can be initiated by either party and vary in format and timing. Deliverables are usually in the form of informal meeting notes. The larger municipalities (cities and the Region) create their own Long Term Corridor Management Capital Plan documents which Enova references in its planning.

As a result of these consultations, Enova increased its annual forecast expenditures for municipal road relocations from $2.825 million to $4.258 million, representing an increase of approximately 51%. This adjustment reflects the anticipated level of municipal infrastructure activity over the forecast period and demonstrates how stakeholder consultation has directly informed Enova's capital expenditure plan.

Some examples of these consultations are as follows;

a) On a weekly basis, Enova interacts with municipal planning departments and receives information on proposed development and municipal work impacting Enova's distribution system. A portion of these transmittals requires Enova to respond with comment or action. Some develop into further discussions and meetings. These consultations have their greatest impact on current and future year investment plans and support the RRFE outcome of Operational Effectiveness.

b) On a monthly basis, Enova participates in Utilities Coordinating Committee meetings. This is a standing committee that meets to discuss local development and includes other stakeholders such as the municipalities, Region of Waterloo, Bell, Rogers, Kitchener Utilities and Enbridge Gas. These consultations have their greatest impact on current year investment plans and support the RRFE outcome of Operational Effectiveness.

c) Both the municipalities and Enova initiate ad hoc consultations normally regarding larger and longer-term commercial and residential developments or relocations due to road alterations. These consultations can be as brief as one meeting or can last months to several years depending on the timing and scale of development. There may also be other participants such as customers, developers, and other agencies.

Without these ongoing consultations, Enova would always be in a reactive state which would lead to inefficiencies and poor customer satisfaction. Consultations with municipalities allow for greater coordination with all stakeholders and the efficient use of Enova resources. Longer-term, they help shape Enova's System Access investment planning and support the RRFE outcome of Operational Effectiveness.

2.2.3.3. Development Community Consultations

a) On a quarterly basis, Enova participates in Home Builders Association meetings. Information on the direction of near and long-term development and growth trends is shared.

b) On an ad hoc basis during the normal course of business, Enova engineering staff consult with builders, developers and real estate companies. Enova uses these opportunities to gather information on the timing of near-term developments and longer-term trends. These consultations can be initiated by either party as needed.

c) On an annual basis Enova solicits information from the development community to feed into Enova's annual budget, long-term load forecast and 5-year capital forecast. These consultations have an impact on near-term investment plans.

Similar to the consultations with municipalities, there are no final deliverables; this is an ongoing process of information exchange that informs Enova's short-term and long-term System Access investment plans and ensures adequate resources are scheduled. Without them, Enova would always be in a reactive state which would lead to inefficiencies and poor customer satisfaction. Consultations with developers have helped shape System Access investments involving residential subdivisions and multi-unit apartment/condominium

projects in this DSP. These consultations also support the RRFE outcome of Customer Focus and Operational Effectiveness.

2.2.3.4. Independent Electricity System Operator (IESO)

Enova has been engaged in long term consultations with the IESO in four key areas:

- KWCG Integrated Regional Resources Planning
- Wholesale Meter Services
- Ontario Power System Restoration
- Outage Planning

2.2.3.5. KWCG Integrated Regional Resources Planning

Enova is a full and active member of the Kitchener-Waterloo-Cambridge-Guelph (KWCG) Regional Planning Technical Working Group. Enova works with the organizations listed below to develop Integrated Regional Resources Plans (IRRP) and the Regional Infrastructure Plans (RIP) for the KWCG region.

- GrandBridge Energy Inc. (Cambridge area)
- Alectra Utilities Corporation (Guelph area)
- Hydro One Distribution (HONI Dx),
- Hydro One Transmission, (HONI Tx)
- Independent Electricity System Operator (IESO)

The second cycle of the Regional Planning process for the KWCG region was completed in December 2021. The last IRRP for the KWCG region, dated May 6, 2021, is provided in **Appendix C-3** and the last RIP for the KWCG region, dated Dec 10, 2021, is provided in **Appendix C-4** of this DSP.

The third regional planning cycle is currently underway for the KWCG region. Enova has participated in the planning meetings and consulted with all of the aforementioned stakeholders. The KWCG Needs Assessment was completed in April 2024 (**Appendix C-1**). The Needs Assessment concluded that further regional coordination was required. As a

result, the IESO completed a Scoping Assessment in June 2024 (**Appendix C-2**). The IESO also initiated the KWCG IRRP process, which was scheduled for completion in Q2 of 2026.

The IESO has since adjusted the timing of the KWCG IRRP regional planning study to allow for the completion of the IESO's South Central Bulk Planning Study (SCBPS). The IESO recognizes that, with the forecasted load growth, an additional 500 kV transmission may be needed in the KWCG area. The SCBPS has developed several options; however, at the time of this report, the preferred option has not yet been selected. The final selection and engagement stages for the proposed options are scheduled for Q3 of 2026.

The final phase of the regional planning process, the Regional Infrastructure Plan (RIP) phase, will follow the completion of the IRRP.

Hydro One's Regional Planning Status letter can be found in **Appendix C-5**.

2.2.3.6. Wholesale Meter Services

All of Enova's points of supply with HONI transmission, HONI distribution, and GrandBridge Energy are registered with the IESO in the wholesale market. Enova is also registered with the IESO as a Wholesale Meter Service Provider. This results in various and frequent consultations with the IESO on matters of meter operations, maintenance and settlement in order to maintain wholesale meter operation and remain compliant with the IESO Wholesale Market Rules. These are ongoing consultations; there are no final deliverables.

2.2.3.7. Ontario Power System Restoration

As a registered Market Participant, Enova works with the IESO and all other market participants to maintain a viable Ontario Power System Restoration Plan (OPSRP). The OPSRP provides a framework to ensure that the IESO and market participants can collectively recover Ontario's integrated power system and re-establish interconnected operation. Coordinated by the IESO, Enova participates along with all market participants in annual OPSRP reviews, updates, training and mock exercises to practice their roles and responsibilities. The IESO delivers an annual updated OPSRP report. These consultations also support the RRFE outcome of Operational Effectiveness.

2.2.3.8. Outage Planning

On a daily basis, Enova and IESO operating staff work together to coordinate planned outages on transmission facilities. All grid-connected LDC's and transmitters are required to isolate grid or grid-connected equipment for maintenance or repair. At times Enova is the requesting party and at other times it is HONI or other grid connected LDC's. All parties work with the IESO to coordinate activities so that work can proceed in a safe and efficient manner at minimal risk to the transmission system. These are ongoing consultations; there are no final deliverables. These consultations also support the RRFE outcome of Operational Effectiveness.

2.2.3.9. Transmitter (HONI)

Enova owns and operates grid-connected transformer stations supplied by Hydro One Networks (HONI) 115 kV and 230 kV transmission lines. HONI is Enova's only transmitter. Enova regularly consults with HONI to share planning and operational information that will aid in the timely, coordinated and cost-effective delivery of services for both parties. The value of the information may be immediate and considered in current design, construction or operational decisions or longer term to be used in system planning. These consultations can be initiated by either party and vary in format and timing.

Some examples of consultations with HONI are;

a) On a regular basis, Enova operations and stations staff and their HONI counterparts communicate and coordinate over daily operations, planned and emergency maintenance. These communications can be initiated by either party, have their greatest impact on O&M and resulting actions are coordinated as much as possible to minimize equipment outage requirements. These are ongoing consultations; there are no final deliverables.

b) On an as-needed basis, Enova senior engineering and operations staff initiate consultations with more senior HONI staff, mainly over supply point reliability concerns. Transmission reliability has been and will continue to be a concern over the forecast period. Deliverables from these consultations come in the form of raising

HONI's awareness over transmission supply and reliability concerns and encouraging HONI to prioritize reliability centric investments.

c) Enova consults with HONI as part of the KWCG Regional Planning Technical Working Group. See **Section 2.2.3.5 KWCG Integrated Regional Resources Planning** for more information.

These consultations also support the RRFE outcome of Operational Effectiveness.

2.2.3.10. Embedded Distributors

Hydro One Networks (HONI) is registered as an Embedded Distributor to Enova on the Elmira TS 33M2 feeder. Enova consults with HONI regarding any forecast impacts by load or Renewable Energy Generation connections on the 33M2 feeder from Elmira TS. Hydro One responds to each connection request which will be assessed individually as per the established process between the two parties. Enova does not foresee any impacts from the Embedded Distributor on this DSP. No investments to support this Embedded Distributor have been included in the forecast expenditures.

2.2.3.11. Host Distributors

Enova is Embedded Distributor to two Host Distributors at <50 kV at two points of supply listed in **Table 2-10**.

Table 2-10: Host Distributors

Host LDC	Feeder	Feeder Voltage (kV)
HONI Dx	73M7	44
GrandBridge Energy	21M25	27.6

On an ad hoc basis, Enova consults with Hydro One Distribution (HONI Dx), and GrandBridge Energy on issues such as supply point reliability and capacity. These communications can be initiated by either party and their value is derived from sharing planning and development information that will aid in the timely, coordinated and cost-

effective delivery of services for both Enova and the Host Distributor. The value of the information may be immediate and considered in current design and construction decisions or longer term for use in system planning. These consultations can be initiated by either party and vary in format and timing.

Enova and the Host Distributor counterparts also communicate and coordinate over daily operations, planned and emergency maintenance. These are ongoing consultations and there are no final deliverables.

2.2.3.12. (5.2.2.1) Telecommunications Entities

Enova engages regularly with telecommunications entities operating within its service territory to coordinate current and planned infrastructure activities. Enova representatives participate in monthly, in-person Utilities Coordination Committee (UCC) meetings with telecommunications companies to discuss capital projects, construction schedules, municipal road works, and opportunities to coordinate infrastructure investments. These meetings support effective planning, reduce construction conflicts, identify opportunities for coordinated construction, and facilitate communication among utilities undertaking work within common corridors.

In addition, Rogers, the most active telecommunications provider operating within Enova's service territory, exchanges infrastructure planning information with Enova on a weekly basis to support the coordination of its network expansion and infrastructure buildout. This ongoing collaboration helps identify opportunities to coordinate construction activities, minimize conflicts within municipal rights-of-way, and improve the efficiency of infrastructure deployment.

In the past, Enova also participated in coordination meetings with Telus regarding its Fibre-to-the-Home (FTTH) network expansion. While these meetings supported effective communication and coordination, the impact on Enova's distribution system was minimal because Telus's fibre infrastructure is being installed almost entirely underground, resulting in very limited interaction with Enova's electrical distribution infrastructure.

As part of the DSP customer engagement process, invitations to participate in the Customer Engagement Workshops were extended to 13 representatives from telecommunications companies operating within Enova's service territory.

No telecommunications representatives attended the customer engagement workshops. Consequently, Enova did not receive specific feedback from telecommunications entities through the workshop process. Enova will, however, continue to engage with these stakeholders through the established monthly UCC meetings, which remain the primary forum for ongoing coordination and discussion of current and future infrastructure projects.

Enova has no material capital investments included in this DSP that are specifically intended to facilitate the provision of telecommunications services. Over the forecast period, expenditures associated with accommodating or facilitating telecommunications infrastructure are expected to remain generally consistent with historical expenditure levels. Accordingly, Enova does not anticipate a material change in capital expenditures attributable to the provision or accommodation of telecommunications services over the DSP forecast period.

2.2.3.13. (5.2.2.2) Renewable Energy Generation (REG)

Enova's service territory falls within the Kitchener-Waterloo-Cambridge-Guelph (KWCG) region for regional planning purposes.

Enova is a member of the Technical Working Group and works with the IESO and the organizations listed below on regional planning.

- GrandBridge Energy Inc. (Cambridge area)
- Alectra Utilities Corporation (Guelph area)
- Hydro One Distribution (HONI Dx),
- Hydro One Transmission, (HONI Tx)

Enova has participated in the planning meetings and consulted with all of the aforementioned stakeholders.

Based on Enova's assessment, there is sufficient generation hosting capacity across its points of supply, transformer stations, and 13.8 kV feeders and 27.6 kV feeder systems to accommodate the anticipated number of REG connections over the forecast period.

There are no REG investments proposed in this DSP.

Enova's report on REG Investments and the IESO's comment letter are included in **Appendix D-1** and **Appendix D-2,** respectively.

2.2.4. Influence on the Distribution System Plan

Consultation with third parties directly influenced the development of this DSP by:

- refining the timing of major capital investments;
- identifying opportunities to coordinate construction with municipal infrastructure projects;
- confirming customer-driven capacity requirements;
- incorporating regional transmission planning assumptions;
- improving coordination with neighbouring electricity distributors;
- supporting telecommunications infrastructure planning; and
- ensuring proposed investments remain aligned with regional electricity planning objectives.

Overall, the feedback received through Enova's customer engagement activities was consistent with the investment priorities presented in the DSP. While customers identified several important areas of focus, including reliability, affordability, resilience, support for future growth, and environmental sustainability, the feedback did not indicate a need for material changes to Enova's proposed capital investment plans. Enova believes it has addressed customer needs for a balanced approach between infrastructure needs, customer needs and affordability.

Table 2-11 provides a high-level summary of the principal customer priorities identified during the engagement process and the corresponding initiatives contained within Enova's DSP that address those priorities.

Table 2-11: Customer Priorities from Engagement

Customer Feedback	DSP Investment	Expected Outcome	DSP Investment Areas
Improve Reliability - Momentary Interruptions (MAIFI)	Targeted inspections, vegetation management, animal guarding	Reduced MAIFI	O&M
Improve Reliability - Frequency (SAIFI)	Reduce Defective Equipment outages	Reduced outage frequency	System Renewal
Improve Reliability - Duration (SAIDI)	Automation (FLISR)	Reduced outage scope and duration.	System Service
Affordability	Energy Market Transaction Platform (small scale deployment); Save on Energy Programs. Free guidance from energy management specialists.	Leads to full adoption that will lower total costs to customers. Allow more customers to participate in energy markets. Customer energy savings.	System Service / OM&A
Environmental Sustainability	Support connection of DERs. Emissions and waste reduction, Reforestation grants, Green Fleet, Solar Generation, Public Charging Stations.	Community-focused green programs.	System Service / O&M / General Plant
Support Growth	Stations and OH line expansions	Capacity for development	System Access
Improve Resilience	Grid hardening	Storm resilience	System Renewal
Advanced Technologies/ Grid Modernization	AMI 2.0, early-stage DER deployment; Distributed Energy Resource Management System (DERMS).	Enhanced situational awareness and operational capabilities	System Service - Grid Modernization

Where appropriate, customer feedback has been incorporated into Enova's ongoing operational and planning activities, including increased attention to momentary interruption performance and continued coordination with municipalities and other infrastructure providers.

Overall, many customers commented that they found the process to be very informative and helpful to understanding Enova’s business. They also felt engaged and were satisfied with being consulted.

Enova will continue its ongoing customer engagement activities and will continue to take customer preferences into consideration in its business planning. Customer engagement and satisfaction will continue to be a top priority for Enova.

2.2.4.1. Reliability - Momentary Interruptions

During customer engagement activities, Enova's larger commercial and industrial customers indicated that momentary interruptions can be as disruptive to their operations as sustained outages. Even brief interruptions can disrupt sensitive manufacturing processes, automated production lines, information technology systems, and other critical business operations, resulting in production losses, equipment resets, reduced productivity, and increased operating costs.

Historically, momentary interruptions have had relatively little impact on most residential customers. However, the rapid growth in work-from-home arrangements has increased customer sensitivity to even brief power interruptions. Momentary outages can disrupt internet connectivity, virtual meetings, home offices, and other activities that increasingly depend on continuous electrical service. As customer expectations evolve, reducing the frequency of momentary interruptions has become an increasingly important component of distribution system reliability.

Enova continuously monitors both sustained and momentary outage performance and has historically responded to customer concerns through operational measures such as system inspections, vegetation management, and the installation of wildlife protection devices in areas experiencing repeated interruptions. These initiatives have generally been effective in maintaining relatively stable momentary interruption performance. Nevertheless, customer engagement confirmed that some customers are connected to feeders that experience comparatively higher frequencies of momentary interruptions, while others have business operations that make them particularly sensitive to even brief power disturbances. Consequently, the impacts of momentary interruptions are not experienced uniformly across Enova's customer base, with certain customers being disproportionately affected by this type of outage.

As shown in **Table 2-12**, Enova's historical momentary interruption performance has remained relatively stable over the historical period, averaging 373 momentary interruption events annually, excluding Loss of Supply (LOS) and Major Event Days (MED).

Table 2-12: Historical Momentary Interruption Events

Year	Momentary Operations (All Inclusive)	Momentary Operations (Excluding LOS & MED)
2020	398	366
2021	364	336
2022	438	404
2023	411	407
2024	359	354
Average	394	373

Customer feedback obtained through the DSP engagement process reinforced the importance of further improving momentary outage performance, particularly on feeders that experience recurring momentary interruptions. In response, Enova plans to adopt a more targeted, data-driven approach to identifying and improving the performance of these circuits.

Beginning in the 2027–2031 DSP period, Enova will develop feeder-level MAIFI performance rankings to identify the poorest-performing circuits across its service territory. These rankings will be incorporated into Enova's asset management and maintenance planning processes to better prioritize and target inspections, vegetation management, wildlife mitigation, and other preventive maintenance activities.

Enova will also review protection and coordination practices on feeders experiencing elevated levels of momentary interruptions to identify opportunities for improvement. In addition, Enova will investigate other technically and economically prudent options, including equipment modifications and operational improvements, where they are expected to reduce the frequency of momentary interruptions and provide measurable customer benefit.

Through this targeted, data-driven approach, Enova intends to direct existing maintenance and engineering resources to those areas of the distribution system where they are expected to deliver the greatest improvement in momentary outage performance and customer reliability while ensuring that available resources are focused on those areas providing the greatest value to customers.

Enova expects that this enhanced focus on reducing momentary interruptions can be accommodated within its existing Operations and Maintenance (O&M) expenditure envelope. The initiative primarily involves improved analysis of existing outage information and the reprioritization of established inspection, vegetation management, wildlife mitigation, and corrective maintenance activities, rather than the introduction of new maintenance programs. Accordingly, Enova does not anticipate requiring incremental O&M funding to implement this initiative during the 2027–2031 DSP period.

2.3. (CHAPTER 5.2.3) Performance Measurement for Continuous Improvement

2.3.1. (5.2.3.1) Distribution System Plan

2.3.1.1. Objectives for Continuous Improvement

Enova has harmonized premerger legacy objectives and has identified the following plans to achieve moving forward with this DSP. These objectives will be achieved through targeted and strategic investments across the Enova distribution system.

- The OEB's Scorecard reflects the measures by which a utility is evaluated in terms of meeting the four performance outcomes of the RRFE. Enova met or exceeded all scorecard targets and it is Enova's expectation to continue to meet this level of performance. It should be noted that although the 2024 scorecard shows the 2024 SAIDI as not meeting target, the SAIDI 5-year rolling average, on which the target was established, is being met. Both VS & CS achieved these objectives and it is Enova's objective to continue to meet this level of performance.

- Meet or exceed the OEB's Service Quality Indicators. On a 5-year rolling average basis, Enova and its legacy companies exceeded all SQI's. On an individual basis, only 2021 WNH and 2022 Enova did not meet the 90% target for appointment scheduling. Going forward, it is Enova's objective to continue to exceed the OEB's SQI.

- Meet or exceed OEB reliability targets. On a 5-year rolling average basis, Enova and its legacy companies have exceeded the OEB's targets for SAIDI and SAIFI. It is an Enova objective to continue this favourable level of performance over the forecast.

- Maintain System Loss performance. Over the historic period, Enova's system losses ranged between 2.7% and 3.3%, with a five-year average of 3.14%. Over the forecast period, it is Enova's objective to maintain system losses at 3% plus or minus 10%.

- Support the OEB's initiatives in grid modernization by making investments in Innovation and improving distribution capabilities to allow DER & EV integration.

- Support resilience and efficiency through greater use of the OEB's Vulnerability Assessment and System Hardening (VASH) Toolkit (EB-2024-0199).

Enova's continuous improvement process consistently measures, monitors and reports on its performance against these targets. Enova evaluates its performance through measures that are aligned with and support the achievement of the four key OEB performance outcomes as established in the Renewed Regulatory Framework for Electricity (RRFE) namely: Customer Focus, Operational Effectiveness, Public Policy Responsiveness and Financial Performance. These measures are also aligned with and support Enova's Corporate Mission, Vision, Values and Strategic Objectives as noted in **Section 1.4.2**. Meeting and exceeding these targets is Enova's desired outcome. When not achieved, action is taken to restore performance.

In 2024, Enova exceeded industry and corporate targets in all but one Scorecard measure, achieving exceptional ratings in customer satisfaction, billing accuracy, and safety. In addition, Enova has the twenty-fifth lowest total cost per customer out of fifty-three Ontario electricity distributors. Enova's system losses are well below the OEB system-loss threshold of 5% and industry performance.

All measures presented in this section are regularly reviewed by senior management and provide feedback as to the effectiveness of Enova's plans in achieving these outcomes. Enova considers both the absolute value of the measure and any significant trend in evaluating its own performance.

2.3.2. (5.2.3.2) Service Quality and Reliability

This section summarizes Enova's historical performance on the measures of the OEB's Performance Scorecard and additional performance measures Enova's uses to monitor the efficiency and effectiveness of Enova's operational and capital programs. A completed **Appendix 2-G_SQI** is filed in **Appendix F-2** of this DSP.

The information presented in this section is consistent with Enova's OEB scorecard.

The OEB-related performance measures are as follows:

- Customer Focus:
  - Service Quality
  - Customer Satisfaction

- Operational Effectiveness
  - Safety
  - System Reliability
  - Asset Management
  - Cost Control
- Public Policy Responsiveness
  - Connection of Renewable Generation
- Financial Performance
  - Financial Ratios

1) Customer Focus

Table 2-13 below provides a historical overview of Enova's Customer Focused performance metrics. There are no changes forecast in the DSP based on the historical performance of these indicators.

a. Service Quality

i. New Residential/Small Business Services Connected on Time

In 2024, Enova connected 1,408 low-voltage residential and small business customers within the five-day timeline prescribed by the OEB, achieving 99.02% of its total service connections on time and exceeding the industry target of 90%.

Over the historical period, this metric averaged 98.2%, well exceeding the OEB and Enova's target of 90%.

ii. Scheduled Appointments Met on Time

In 2024, 3,292 customer appointments were scheduled that required the customer or representative to be present. Enova staff were on time for the appointment 98.7% of the time, once again exceeding the industry standard of 90% of scheduled appointments met on time.

Over the historical period, this metric averaged 99.1%, well exceeding the OEB Enova's target of 90%.

iii. Telephone Calls Answered on Time

Of the 81,935 telephone calls answered by Enova's Customer Care team, 74.95% were answered within 30 seconds, exceeding the industry standard of 65% as set by the Ontario Energy Board. Enova continues to explore and develop new ways for customers to connect with its staff quickly and easily to reduce wait times, call volumes and improve customer satisfaction.

Over the historical period, this metric averaged 78.5%, well exceeding the OEB and Enova target of 65%.

b. Customer Satisfaction

i. First Contact Resolution

In 2014, LDC's were given an opportunity to define this measure in a manner that provides the most meaningful assessment. Enova defines First Contact Resolution as all telephone calls resolved by the call center on first contact and strives to handle each customer interaction quickly, efficiently and to the customer's satisfaction. As this measure evolves, Enova continues to monitor its progress and track best practices of other LDCs to improve its own customer service offering.

In 2024, 99.48% of phone calls received by the call center achieved First Contact Resolution thanks to the thoughtful, proactive service provided by Enova's Customer Care team.

Over the historical period, this metric averaged 99.0%, well exceeding Enova's target of 95%.

ii. Billing Accuracy

An accurate bill is defined as a bill that contains correct customer information, correct meter readings and correct rates. In 2024, Enova issued more than 1,974,177 electricity bills to over 163,400 customers achieving a billing accuracy rate of 99.98%.

Over the historical period, this metric averaged 99.96%, exceeding the OEB and Enova target of 98%.

Table 2-13: Customer Focus Metrics

Performance Outcomes	Performance Categories	Drivers	Measures	OEB Target	Enova Target	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2020-2021 Avg.
Customer Focus	Service Quality	Regulatory / Customer	New residential services connected on time	90%	90%	99.18%	97.77%	98.45%	96.44%	99.0%	98.2%
Services are provided in a manner that responds to identified customer preferences			Scheduled appointments met on time	90%	90%	98.79%	98.58%	99.42%	100.00%	98.7%	99.1%
			Telephone calls answered on time	65% (within 30 seconds)	65% (within 30 seconds)	87.61%	78.97%	81.34%	69.77%	74.95%	78.5%
	Customer Satisfaction	Customer	First contact resolution	Determined by the Utility	> 95%	99.44%	99.09%	98.37%	98.66%	99.48%	99.0%
			Billing accuracy	98%	98%	99.98%	99.91%	99.95%	99.97%	99.98%	99.96%
			Customer satisfaction survey results	A	A	A	A	A	A	A	A

i. Customer Satisfaction Survey Results

In 2023, Enova engaged an independent third party to conduct a comprehensive customer satisfaction survey, inviting customers to provide feedback on a range of topics including customer service, reliability, value for money, billing, and outage communications. Enova was pleased to receive an overall performance rating of "A", reflecting a high level of customer satisfaction across its service territory.

The survey was repeated in 2025 to measure customer perceptions following the integration of the legacy utilities and to assess changes in customer expectations. Enova again achieved an overall performance rating of "A", demonstrating that it has maintained a consistently high standard of service while continuing to invest in the reliability, resilience, and modernization of its electricity distribution system.

Category: Customer Care *(Overall A rating)*

Drivers and rating: Price and Value (B+); Customer Service (A)

Category: Company Image *(Overall A rating)*

Drivers and rating: Company Leadership (A); Corporate Stewardship (A)

Category: Management Operation *(Overall A rating)*

Drivers and rating: Operational Effectiveness (A); Power Quality and Reliability (A+)

The “A” rating has been consistent over the historic period.

Enova continues to review the survey results and feedback received from other areas to keep its investment plans and customer service offerings aligned with customer needs.

Overall, Enova exceeded all of its Customer-focused performance metrics. There are no changes forecast in the DSP due to the historical performance of these indicators.

2) Operational Effectiveness

Table 2-14 below provides a historical overview of Enova's Operational Effectiveness-focused performance metrics. There are no changes forecast in the DSP due to the historical performance of these indicators.

a. Safety

Enova's extensive public safety outreach program educates customers on overhead power line safety, underground electrical contact/locates, electrical safety and emergency preparedness, including participation in Fire Prevention Week, Emergency Preparedness Week and the Electrical Safety Authority's Powerline Safety Week.

On an ongoing basis, Enova shares public electrical safety messages through radio and newspaper advertising on its website, social media channels, eblasts and other outlets, providing residents and businesses in its service area with seasonally relevant public safety reminders.

In 2024, Enova provided electrical safety education to more than 3,800 grade five and six students in 50 schools across Enova's service territory.

Enova's safety program includes the award-winning one-minute animated videos featuring "Lucky the Squirrel," which teach viewers how stay safe around electricity in areas ranging from Call Before You Dig to proximity to overhead power lines. The videos are shared on Enova's social media platforms and are used in Enova's school safety program and modified versions are played three (3) times at every Kitchener Rangers Ontario Hockey League home game during the regular season.

i. Component A – Public Awareness of Electrical Safety

This component of the public safety measure is intended to measure the level of safety awareness of the general public within the electricity distributor's service territory.

Enova's score of 88.00% is the result of a standard safety survey performed by a third party in March 2024 in Enova's service area. Enova is using the

information gathered in this survey to develop and target its safety messages going forward.

ii. Component B – Compliance with Ontario Regulation 22/04

This component of the public safety measure addresses the level of distributor compliance to Ontario Regulation 22/04, which governs the safe design and construction of electrical distribution systems. Measurement includes an audit and declaration of compliance submitted by the distributor and due diligence inspections completed by the Electrical Safety Authority. Enova fully complies with the Ontario Regulation 22/04 safety standard for 2024.

iii. Component C – Serious Electrical Incident Index

A Serious Electrical Incident is defined as electrical contact, fire or explosion or equipment failure in the distribution system that causes or has the potential to cause loss of life or critical injury to a member of the general public. The guideline for reporting Serious Electrical Incidents was revised in 2017 to include a broader definition of incidents that now qualify. This component of Public Safety measures the number of serious electrical incidents involving members of the general public in Enova's service territory.

Enova had one serious electrical incident in the 2024 reporting period. Enova continues to prioritize public safety through its educational activities and programs.

Table 2-14: Operational Effectiveness Metrics

Performance Outcomes	Performance Categories	Drivers	Measures	OEB Target	Enova Target	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2020-2024 Avg.
Operational Effectiveness	Safety	Regulatory / Corporate / Customer	Public awareness	N/A	80%	82%	84%	84%	88%	88%	85%
Continuous improvement in productivity and cost performance is achieved, and distributors deliver on system reliability and quality objectives			Level of compliance with Ontario Regulation 22/04	Compliant	Compliant	Compliant	Compliant	Compliant	Compliant	Compliant	Compliant
			Serious Electrical - Number of General Public Incidents		2	4	2	1	0	1	0.77
			Incident Index	N/A	0.424	1.103	0.548	0.273	0	0.271	0.44
	System Reliability	Regulatory / Corporate	Customer hours of interruption (SAIDI)	0.84	0.84	0.63	0.58	1.03	0.66	0.96	0.77
			Average number of times that power to a customer is interrupted (SAIFI)	1.10	1.10	0.95	0.71	0.9	0.74	1.1	0.88
	Asset Management	Regulatory / Corporate	Distribution system plan implementation progress (over the forecast period)	N/A	N/A	100%	100%	100%	100%	105.7%	101%
	Cost Control	Regulatory / Corporate	Efficiency Assessment		3	3	3	3	3	3	3
			Total Cost per Customer			$ 622	$ 653	$ 711	$ 794	$ 831	$ 722
			Total Cost per km of Line			$ 26,867	$ 28,369	$ 31,080	$ 34,893	$ 16,745	$ 27,591

b. System Reliability

Table 2-15 provides a historical view of Enova's SAIDI and SAIFI performance. The OEB's reliability targets for Enova are SAIDI (0.84), SAIFI (1.10) and were set in 2022. Enova's 5-year average reliability performance metrics for SAIDI (0.77) and SAIFI (0.88) are below the OEB targets. Individual years metrics are all at or below target except for 2022 and 2024 SAIDI which were impacted by unusually high adverse weather events and defective equipment. Enova's SAIDI and SAIFI performance have also trended well below the industry averages over the period.

Table 2-15: Operational Effectiveness Metrics

MEASURES	2020	2021	2022	2023	2024	AVG.	Enova TARGETS
SAIDI (Excluding Loss of Supply and Major Events	0.63	0.58	1.03	0.66	0.96	0.77	0.84
SAIFI Excluding Loss of Supply and Major Events	0.95	0.71	0.90	0.74	1.10	0.88	1.10

Public updates on power outages are provided through Enova's online outage maps at oms.enovapower.com. It features an interactive map where the customer can view active power outages, track restoration progress, and report service interruptions in their area.

Starting in 2024, Enova's reliability reporting includes all Subcause Codes, consistent with the OEB's RRR filing requirements. Enova constantly monitors reliability performance indicators such as SAIDI, SAIFI and MAIFI. Performances of all Enova feeders are reviewed annually and the worst-performing feeders, based on three-year rolling CMI averages, are identified and flagged for action. Reliability issues, including leading causes, are identified and recommendations for action are provided.

A full summary of Enova's reliability performance for the historical period is included in **Appendix F-1** of this DSP.

c. Asset Management

i. Distribution System Plan Implementation Progress

Enova has a long-term asset management plan that allows it to effectively pace infrastructure replacement and investments.

Enova has incorporated elements of its ongoing asset management plan into a DSP beginning in 2021 for Waterloo North Hydro Inc. and 2020 for Kitchener-Wilmot Hydro Inc. Enova measures the progress of its DSP implementation by comparing actual total capital expenditures in service each year to the total amount of planned capital expenditures in the DSP for the corresponding year. A variance target of +/-10% is used to determine if the DSP is on target. The result for 2024 is 5.71% greater than the DSP amount or 105.71% compared to the DSP and shows that Enova is currently "On Target".

Over the historical period, this metric has averaged 101%, meeting Enova's target of 100%.

d. Cost Control

The following section commentary is based on figures generated by the Ontario Energy Board based on total cost benchmarking analysis conducted by the Pacific Economics Group Research LLC. The model used by the Ontario Energy Board is based on econometrics. This model establishes relationships between business conditions (i.e., number of customers, kWh deliveries, length of lines) and distributor costs. Many adjustments are made to a ensure fair comparison between distributors.

i. Efficiency Assessment

The efficiency assessment measure compares distributors' actual costs to costs predicted by the OEB model described above. LDCs with lower actual costs than predicted are considered better cost performers. Enova ranked twenty-fifth in the province for total cost per customer in 2024. Combined results of the legacy utilities result in a Group 3 cost efficiency level since their integration in 2022, which allows Enova to continue to provide exceptional customer service and high

reliability performance. Enova has maintained an Efficiency Assessment rating of 3 over the historical period.

ii. Total Cost per Customer

Enova's total cost per customer ranks twenty-fifth out of fifty-three utilities in Ontario. Distribution services include design, maintenance and construction of infrastructure, customer services and customer education. Enova's total cost in 2024 was $831 per customer. Enova's total cost per customer averaged $722 over the historical period.

iii. Total Cost per km of Line

In 2024, Enova's total cost per kilometer of line is $16,745, representing a significant reduction compared to prior years. The change is primarily due to the method in which the total kilometers of line were reported. In 2024, the cost per kilometer was calculated using both:

- Primary line kilometers: 3,736 km
- Secondary line kilometers: 4,738 km

This resulted in a lower per-kilometer cost. However, in prior years, the calculation included only the primary kilometers of line. If 2024 had been calculated using the prior methodology (primary line kilometers only), Enova's total cost per kilometer of line would have been $36,367.

3) Public Responsiveness

Table 2-16 below provides a historical view of Enova's Public Responsiveness metrics. This is provided only for completeness of the historical period as the reporting requirement ended after 2021.

For more detailed information regarding Enova's Renewable Energy Generation, please refer to **Appendix D-1 Renewable Energy Generation Investment Plan.**

Table 2-16: Public Responsiveness Metrics

Performance Outcomes	Performance Categories	Drivers	Measures	OEB Target	Enova Target	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2020 - 2024 Avg.
Public Responsiveness											
Distributors deliver on obligations mandated by regulation and code (e.g., legislation and regulatory requirements imposed further to Ministerial directives to the OEB)	Connection of Renewable Generation	Regulatory / Customer	Renewable generation connection impact assessments completed on time	90%	100%	100%	100%	N/A	N/A	N/A	N/A

4) Financial Performance

a. Financial Ratios

Table 2-17 below provides a historical view of Enova's Financial Performance metrics.

i. Liquidity: Current Ratio (Current Assets/Current Liabilities)

The current ratio is a liquidity ratio that measures a company's ability to pay short-term and long-term debt obligations. To gauge this financial metric, the current ratio considers the total current assets of a company relative to that company's total current liabilities. Enova maintains a current ratio that allows it to have a margin of safety to cover financial obligations on a timely basis. In 2024, Enova reported a Current Ratio of 1.04. Over the historical period, Enova's current ration averaged 1.14, within Enova's target range.

ii. Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio

The Ontario Energy Board uses a deemed capital structure of 60% debt and 40% equity for distributors when establishing rates. This equates to a debt-to-equity ratio of 1.5:1 Enova's 2024 actual debt-to-equity ratio of 0.55:1 indicates a conservative capital structure with significantly lower financial leverage than the OEB's deemed capital structure. Over the historical period 2020 to 2024, Enova averaged a Total Debt to Equity ratio of 0.61:1.

iii. Profitability: Regulatory Return on Equity – Deemed (included in rates)

2024 distribution rates included an expected (deemed) regulatory return on equity of 8.43%, which was approved by the OEB in Enova's MAADs application (EB-2022-0006). The Ontario Energy Board allows a distributor to earn within +/- 3% of the expected return on equity. When a distributor's performance is outside the deemed range, the actual performance may trigger a regulatory view of the distributor's revenue and cost structure by the OEB.

Table 2-17: Financial Performance Metrics

Performance Outcomes	Performance Categories	Drivers	Measures	OEB Target	Enova Target	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2020-2024 Avg.
Financial Performance **Financial viability is maintained: savings from operational effectiveness are sustainable**	Financial Ratios	Corporate	Liquidity: current ratio (current assets/current liabilities)	N/A	1.0 to 1.25	1.12	1.04	1.34	1.18	1.04	1.14
		Corporate	Leverage: total debt (includes short term and long term debt) to equity ratio	<= 60% Debt	< 57% Debt	0.76	0.71	0.5	0.51	0.55	0.61
		Corporate	Profitability: Regulatory Deemed	8.43% +/- 3%	8.43%	8.83%	8.43%	8.43%	8.43%	8.43%	8.51%
		Corporate	Return on equity - Achieved			9.12%	8.94%	8.07%	7.32%	6.77%	8.04%

iv. Profitability: Regulatory Return on Equity – Achieved

In 2024, Enova's regulatory return on equity achieved was 6.77%, which is below the deemed regulatory return on equity of 8.43% but is well within the +/-3% range allowed by the Ontario Energy Board. The average return over the past five years was 8.04%, which is also well within the allowed return included in Enova's approved rates.

There are no changes forecast in the DSP due to the historical performance of these performance indicators.

2.3.3. Other Performance Measures

2.3.3.1. Momentary Interruptions and MAIFI

Table 2-18 illustrates Enova's historical performance in total number of interruptions on its distribution system. The annual values have remained relatively stable varying through an envelope of approximately +/- 10%.

Table 2-18: Momentary Interruption Events

Year	# Momentary Operations (All Inclusive)	# Momentary Operations (Excluding LOS & MED)
2020	398	366
2021	364	336
2022	438	404
2023	411	407
2024	359	354
Avg.	394	373

Enova's experience points to animal contact, lightning and brush contact with vegetation as major causes of momentary events. To minimize these events, Enova maintains an active animal guarding program, is diligent in the application of lightning arrestors and maintains an active line clearing program.

Enova monitors its Momentary Average Interruption Frequency Index (MAIFI) performance due to the disruption momentary outages (less than 1 minute) have on customers.

$$\text{MAIFI} = \frac{\sum (\text{Number of Momentary Interruptions} \times \text{Number of Customers Interrupted})}{\text{Total Number of Customers Served}}$$

OEB does not require the reporting of MAIFI performance, making it challenging to benchmark with other LDCs.

Enova has characterised MAIFI performance as follows.

- **Excellent Performance:** Annual MAIFI < 1.0. Usually seen in modern urban grids with extensive undergrounding or advanced automated loop configurations.

- **Typical / Target Performance:** Annual MAIFI between 1.0 – 3.0. This is normal for balanced overhead distribution systems with functional tree-trimming and smart recloser programs.
- **Poor Performance:** Annual MAIFI > 5.0. Indicates that the grid is experiencing persistent, unresolved transient faults.

Table 2-19 illustrates a relatively stable MAIFI performance from 2020 to 2024 except in 2022. Enova and many other southern Ontario utilities in the Quebec City - Windsor corridor, experienced severe weather in 2022. More information can be found in **Appendix F-1 Distribution System Reliability Report**.

Enova's historical performance is consistent with expectations for an electricity distributor serving a territory with extensive overhead distribution infrastructure, where exposure to weather-related events and environmental conditions can have a greater impact on system performance.

Table 2-19: MAIFI

Enova	2020	2021	2022	2023	2024	5-year Avg.
MAIFI (ALL)	2.68	2.57	3.03	2.94	2.70	2.78
MAIFI(excluding LOS and MED)	2.58	2.53	2.88	2.91	2.41	2.66

Enova's objective is to maintain its MAIFI performance to < 3.0 on a 5-year rolling average. There are no changes forecast in the DSP due to the historical performance of this measure.

2.3.3.2. System Losses

Enova reviews its distribution system losses regularly and under the OEB's Reporting and Record Keeping Requirements (RRR), reports its actual distribution losses annually.

A summary of loss factors calculated from the "Consolidated Key Metrics of the Ontario Electricity Distributors Sector" found in the various Yearbooks and RRR filings.

Enova's reported distribution system losses are provided in **Table 2-20** and benchmarked against the average of Ontario LDCs. Enova's losses since 2022 have ranged between

2.82% – 3.05% averaging 2.96% over the same period. Including the legacy utilities, the 5-year average is 3.14%.

Table 2-20: Annual System Losses

Year	Provincial System Losses	Enova System Losses	% Diff
2020	4.00%	3.65%	0.35%
2021	3.90%	3.19%	0.71%
2022	4.36%	3.05%	1.31%
2023	4.47%	2.82%	1.65%
2024	3.89%	3.00%	0.89%
5-year Average (2020 - 2024)	4.12%	3.14%	0.98%
3-year Average (2022 - 2024)	4.24%	2.96%	1.28%

Enova's system losses are considerably below the OEB's recommended threshold of 5% as set out in the OEB's document "Ontario Electricity Distributor Practices Relating to Management of System Losses (June 23, 2008)" and also consistently below the average system losses of Ontario provincial LDCs.

Enova does not undertake capital projects solely for the purpose of loss reduction but instead incorporates loss reduction into its business practices including planning, design, operation and procurement activities.

Activities driven by other priorities that continue to mitigate line losses include:

- System Renewal investments that include:
  - converting to higher voltages (8.32 kV to 27.6 kV) to allow for longer feeder distances and improved end-of-line voltage regulation;
  - using larger conductors to connect larger loads;
  - eliminating lower voltage distribution stations that have higher transformer losses;
- installing capacitor banks to improve end-of-line feeder voltage;
- performing system optimization studies;
- balancing feeder and phase loading;
- purchasing criteria for distribution transformers that include loss evaluation;

- diligent adherence to Measurement Canada's Meter Accuracy Verification program;
- regular inspection and cross-phase testing of polyphase transformer-type meter installations;
- visual inspections of meters for broken seals, tampered meters and jumper wires;
- performing random audits of billing multipliers;
- investigating exception reports that highlight zero usage readings, meters that show consumption with no billing account, and other material variances in consumption;

Over the forecast period, Enova's performance objective for system losses is to remain in the 3.1% +/-10% range. Activities that have led to Enova's current historical performance are expected to continue over the forecast period. No line-loss specific investments are included in this DSP.

2.3.4. (5.2.3.3) Distributor Specific Reliability Targets

Enova has not developed its own distributor-specific reliability targets.

The OEB's reliability targets for Enova are SAIDI (0.84), SAIFI (1.10) and were set in 2022. Enova's 5-year average reliability performance metrics for SAIDI (0.77) and SAIFI (0.88) are below the OEB targets.

Enova uses its system-wide SAIFI and SAIDI metrics to inform its investment planning decisions, mainly in System Service and System Renewal projects. Maintaining below-target reliability performance has help shape Enova's System Service project selection, including the future application of Fault Location, Isolation, and Service Restoration (FLISR) software and the addition recloser/switch hardware. It has also shaped System Renewal investment in underground cable and pole replacements.

A full summary of Enova's reliability performance for the historical period is included in **Appendix F-1** of this DSP.

3. (CHAPTER 5.3) ASSET MANAGEMENT PROCESS

This section provides information on Enova's Asset Management Process and how it plans, prioritizes and optimizes expenditures to develop a comprehensive capital investment plan.

Enova's DSP is designed to provide prudent and cost-effective investment decisions that appropriately balance the needs and preferences of its customers, its distribution system requirements, and relevant public policy objectives. Enova's asset management process is a key component to achieving that goal.

3.1. (5.3.1) Planning Process

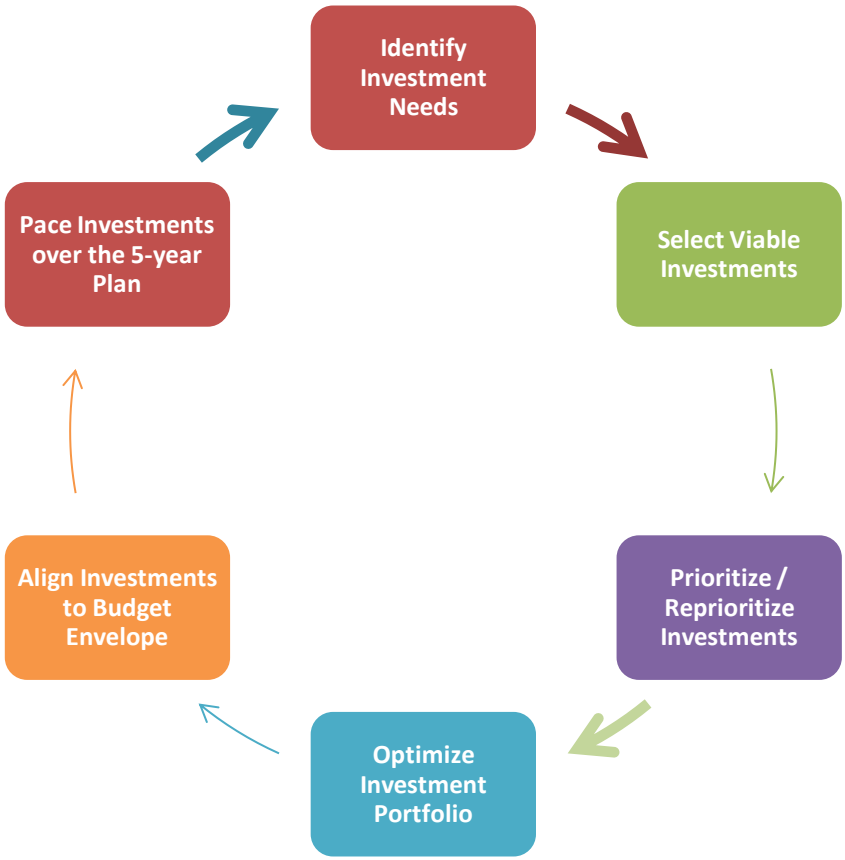
This section provides an overview of Enova's Asset Management Process (AMP). Included are descriptions of:

- Overview of the Planning Process
- Important Changes to Asset Management Processes

3.1.1. Overview of the Planning Process

This section provides a high-level overview of the planning process used to develop Enova's annual and 5-year capital plans. **Figure 3-1** illustrates the six-stage process Enova utilizes to develop its investment plan.

Figure 3-1: Enova's Capital Planning Process



3.1.1.1. Identification of Capital Expenditures

The first stage in developing a viable capital investment portfolio involves gathering and understanding stakeholder priorities, assessing distribution system asset condition and operational performance requirements, and incorporating public policy objectives and obligations.

Potential capital investments are characterized as :

1. Mandated - by regulation or code. Includes System Access investments in customer connections, expansions, metering and municipal roadway relocations.
2. Condition-based - Includes System Renewal investments resulting from inspection, maintenance, and asset health assessments.
3. Performance Based - Includes System Service and System Renewal investments focused on reliability, system losses, supply utilization and constraints.
4. Operations and Administration Support – Includes General Plant investments in Information technology (IT&OT), fleet, facilities, equipment & tools.

Corresponding business cases with recommended solutions are developed and categorized into one of the four OEB investment categories. Programs previously approved are still in the execution phase are included in the portfolio.

System Access

System Access investments are mainly driven by mandated and customer requirements and are identified through consultation processes with municipal planners, the development community, customers and other third parties as part of Enova's advanced planning for system development. These consultations can be initiated by either party. Enova also trends historical activity in some programs to aid in forecasting investments.

System Renewal

System Renewal investments are mainly driven by condition-based requirements but can also be driven by poor asset performance of functional obsolescence. They are identified through Enova's Asset Condition Assessment program which includes inspections, testing and other condition assessments. Health scores are developed for each asset and a condition rating is assigned. Assets that have low health scores will be in poor condition and near end-of-life are flagged for replacement.

System Service

System Service investment proposals are mainly driven by performance-based requirements. They are identified from Enova's assessment of distribution system performance, system capacity/constraint analysis, power quality, and stray voltage reports.

Appendix F-1: Enova's Distribution System Reliability Report identifies "worst performing feeders" and overall reliability. Reporting by cause codes allows more refined performance analysis and helps identify potential areas for improvement.

Appendix E: System Supply and Capacity Report, along with system load flow analysis and operational reports helps identify capacity constraints on the distribution system.

Power quality and stray voltage concerns are typically identified through customer-initiated reports.

General Plant

General Plant investments are mainly driven by operational and administrative support requirements.

Material building projects are identified through poor performance, inspection and maintenance with the assistance of third-party consultants in the building technologies and construction field.

Fleet/rolling stock vehicle replacements are determined through analysis of condition assessments, compliance with the Ontario Ministry of Transportation (MTO) safety requirements, maintenance and fuel consumption costing information (operation & maintenance), utilization (operating hours and total kilometers driven), and asset age. Costs are summarized annually and analyzed to determine maintenance cost trends by vehicle and equipment type.

Functional obsolescence forces the replacement of multiple software and hardware investments. As software becomes older, vendors may no longer provide technical support, new functionality or enhanced cybersecurity protection. For hardware, support and parts become unavailable or newer releases of software require more powerful hardware systems

to run. Over time, software may become incompatible with the platforms, applications, and technologies on which it depends, particularly in highly integrated operating environments. Other IT investments are made to reduce licensing and maintenance costs or improve operational or administrative efficiency.

3.1.1.2. Selection of Viable Capital Investments

Identified investments go through a pre-screening filter to demonstrate there is alignment with Enova's Strategic Objectives (**Table 1-2**) and the OEB's four RRFE outcomes Customer Focus, Operational Effectiveness, public policy, responsiveness and financial performance. Not all identified projects are selected in the same manner.

System Access

All investments that are mandated by code or regulations are automatically selected. These investments normally fall into the category of System Access and include customer connections, expansions, third party-requests, regulatory changes or mandated initiatives. The level of expenditure on these investments is driven by growth forecasts, various consultations, historical activity and public responsiveness measures.

System Renewal

System Renewal investments target the prevention of asset failures that represent a significant risk to Enova in terms of public safety and system reliability.

For Enova's three largest asset classes—distribution poles, underground primary cable, and distribution transformers—asset replacement prioritization is based on a risk-informed assessment that considers asset condition (derived from inspections, testing, and maintenance activities), cable and transformer loading, probability of failure (using industry failure curves), and consequence of failure, including the number of customers affected.

In 2019, Waterloo North Hydro (WNH) began using the METSCO Energy Solutions Inc. (METSCO) Asset Analysis, Prioritization and Optimization Tool (ENGIN) to support investment planning for these asset classes. Following the formation of Enova, the company

migrated to ENGIN 2.0 in 2025 after support for the original platform was discontinued. ENGIN 2.0 is now owned and supported by Engineered Intelligence Inc. (EII).

The migration to ENGIN 2.0 has required a significant effort to harmonize asset data, condition information, and data structures across the legacy utilities to enable consistent input into the new platform. This work remains ongoing at the time of preparing this DSP. Until the migration and data harmonization are complete, Enova will continue to refine its asset data and risk models as part of its broader post-merger asset management improvement program.

For all other asset classes, Enova utilized Health Index Frameworks, developed by METSCO and Enova, to develop asset health ratings for each asset. Potential investments are selected based on assets with the lowest health scores; assets in poorest condition.

System Service

Enova's performance-based investments fall under System Service. SS expenditures maintain or improve prescribed (OEB, IESO) or adopted (IEC, IEEE, CEA, industry best practices) performance targets. Customer feedback often points to areas where SS expenditures can address power quality or reliability issues. Supply and reliability are two of Enova's top three strategic objectives and have always been near the top of customer preferences.

For the most part, project selection is based on proposed benefits, risk mitigation and alignment with Enova's Strategic Objectives and the OEB's RRFE outcomes.

General Plant

Expenditures in General Plant are selected by the value they bring in supporting the operational and administrative function of the company. Value is based on proposed benefits, risk mitigation and alignment with Enova's Strategic Objectives and the OEB's RRFE outcomes.

3.1.1.3. Prioritization of Capital Expenditures

This step involves the weighted ranking of the selected projects in order of importance relative to each other. Enova applies a structured, objectives-based framework to evaluate and rank candidate capital programs and to inform the pacing and composition of its capital expenditure plan. The framework provides a consistent, transparent and repeatable basis for allocating capital across the four OEB investment categories, System Access, System Renewal, System Service and General Plant, consistent with the outcomes of the OEB's Renewed Regulatory Framework (Customer Focus, Operational Effectiveness, Public Policy Responsiveness and Financial Performance) and with the DSP requirements in Chapter 5 of the OEB's Filing Requirements for Electricity Distribution Rate Applications.

Strategic Alignment

The framework is anchored in Enova's corporate Strategic Objectives spanning safety, reliability and cyber security, supply adequacy, regulatory compliance, customer and community outcomes, operational and financial performance, environmental sustainability and enabling grid technologies. Each objective is assigned a relative weighting on a 0–5 scale reflecting its priority to Enova, its customers and its stakeholders, with Health and Safety weighted highest (5.0). The objectives and weightings are set out in the **Table 3-1** below.

Scoring and Ranking Methodology

Each candidate program is assessed against every objective using a defined relevance scale: 0 (Not Relevant), 1 (Somewhat Relevant) or 2 (Very Relevant). A program's Weighted Score is the sum of its objective scores multiplied by the corresponding objective weightings:

$$\textit{Weighted Score} = \Sigma\ (\textit{Program Score} \times \textit{Relative Weighting})$$

Programs are ranked in descending order of Weighted Score. Scores are derived from project and program-level condition and risk information where available; where such information is not available, scores are assigned based on of documented program characteristics. All inputs and results are recorded and are auditable.

Table 3-1: Prioritization Weighting Factors

#	Strategic Objectives	Asset Management Strategy	Relative Weighting (0–5)	Weighted Ranking (%)
1	Health and Safety (Public & Employee)	Protect public and employee health and safety through rigorous protocols and safety-enhancing technology.	5.0	100%
2	Supply	Ensure an adequate supply of electricity to meet customers' needs.	4.5	90%
3	Reliability & Cyber Security	Maintain grid reliability and safeguard systems and customer information.	4.5	90%
4	Regulatory Compliance	Meet OEB and other legal and regulatory obligations.	4.0	80%
5	Employee Relations and Development	Attract, develop and support a capable workforce.	3.5	70%
6	Operational Synergy & Financial Performance	Operate the business efficiently with a culture of continuous improvement.	3.0	60%
7	Customer Centric Services	Meet customer expectations and deliver value.	2.5	50%
8	Flexible Grid Technology	Enable non-wires alternatives, DSO, generation connection and demand response.	2.5	50%
9	Economic Development	Support regional economic development through infrastructure investment.	2.0	40%
10	Shareholder and Community Relations	Recognize and support shareholders and the community.	1.5	30%
11	System Aesthetics	Improve landscape aesthetics where feasible.	1.0	20%
12	Environmental Sustainability	Minimize environmental impact and comply with environmental requirements.	1.0	20%

Investment Classification

Investments are classified as either non-discretionary or discretionary:

- **Must Do** programs address statutory, regulatory or reactive obligations — for example, mandated third-party relocations, the obligation to connect load and generation, mandated metering, and emergency response to asset failure. These programs proceed regardless of score and are therefore not ranked.

- **Ranked** programs are discretionary and are scored and ranked as described above. The ranking informs investment pacing and the composition of the capital envelope, directing constrained capital first to the programs that contribute most to Enova's asset management objectives.

Governance and Transparency

The framework provides a producible, evidence-based basis for capital prioritization. It links each investment decision to Enova's corporate objectives and to the OEB's performance outcomes, supports year-over-year consistency, and enables transparent review by management and stakeholders.

3.1.1.4. Optimization of Capital Investments

Enova follows a risk-based approach that balances asset condition, performance, and lifecycle cost considerations in developing an investment plan. Enova strives to achieve an optimal investment plan by addressing the assets in poorest health and with the greatest potential impact of failure.

Mandated projects, such as those designated as System Access, are evaluated to better determine the order of execution; however, they are always part of the final investment portfolio.

For discretionary projects, the impact of failure is determined by the total number of customers and the load potentially affected by the project. The ratio of project cost to customer impact identifies the projects that are most effective at reducing risk on an investment dollar basis. The investment portfolio is then optimized by selecting projects that have the highest ratio of customer impact to project cost.

3.1.1.5. Aligning Investments with Budget Envelope

Initial annual budget envelopes are based on historical and planned expenditure levels. Annually, capital investment plans are constructed from the ground up based on gathering and understanding the various stakeholder priorities, assessing distribution system asset

condition and operational performance requirements, as well as incorporating public policy objectives and obligations.

After completing the prioritization and optimization processes, the portfolio of selected projects is compared with the budget envelope. Enova then goes through an iterative process to examine its ability to resource and finance the plan and the impact on customer bills.

If the planned expenditures exceed the budget envelope, Enova assesses the risk of deferring projects to later years, potentially creating greater risk and liability in future expenditures. The option of increasing the budget envelope is also examined with an analysis of bill impacts for all customer classes at the distribution, delivery and total bill level.

Conversely, if planned expenditures are less than the budget envelope, projects from future years may be pulled forward if it helps pace overall capital plan expenditures. Alternatively, if all available resources are committed, Enova may go forward with a lower capital budget.

There may be several iterations of examining the aforementioned options before a final budget envelope and investment plan is approved by the Enova Executive. The output of this stage is a one-year capital budget with project detail and a five-year capital expenditure plan with allocation of funds to each major budget and investment category.

The investment plans are then brought forward to the Enova Board of Directors for review and approval.

3.1.1.6. Pacing of Forecast Capital Investments 2027-2031

This section provides an overview of the Forecast Capital Plan and Investment Pace 2027–2031.

i. Pace of Investment by Category

System Access increases from approximately $23.9M in 2027 to a peak of approximately $42.1M in 2030, well above its historical average. Two factors drive the increase: the staged replacement of Enova's Advanced Metering Infrastructure with the next-generation system (AMI 2.0), and a new transformer station required to serve growth. All metering work, including AMI 2.0, is classified as System Access, even if the primary driver is age or condition of the infrastructure.

System Renewal increases from approximately $32.7M in 2027 to approximately $38.7M in 2029 before moderating by approximately $2.1M in 2030 and 2031. The increase is driven by asset age and condition across a range of asset classes, particularly, by cable replacement programs.

System Service is held at approximately $1.6M per year, consistent with historical norms, and funds grid-improvement work that supports reliability and operational flexibility.

General Plant is elevated in 2027 at approximately $20.5M, reflecting the VS HVAC Replacement and Facility Renovation Project and the major release upgrade of Enova's customer information system, and returns to approximately $8.8M to $10.6M for 2028–2031, within historical norms.

ii. Composition of the Plan: Core, Incremental, and Expansion

The gross plan can be viewed in two parts: regular programs, which comprise the recurring core programs together with one major System Access expansion (the New Station); and incremental programs, for which Enova may potentially seek recovery through the Incremental Capital Module (ICM) over the forecast period.

Presenting the plan in this manner distinguishes the program's disciplined, recurring base from the discrete, incremental drivers of year-over-year change. The composition, and the derivation of net capital, are summarized in **Table 3-2.**

Table 3-2: Capital Plan Composition (gross unless noted, $000s)

	2027	2028	2029	2030	2031
Regular programs	68,051	65,762	70,189	75,545	70,745
Planned Incremental programs	10,653	7,326	16,415	14,335	15,446
Total gross capital (A + B)	**78,705**	**73,089**	**86,604**	**89,880**	**86,192**
Capital contributions	$7,485	$7,495	$7,489	$6,783	$8,208
Net capital	**$78,697**	**$73,081**	**$86,596**	**$89,873**	**$86,184**

Figures are stated in thousands of dollars and are not adjusted for inflation; totals may not sum precisely due to rounding.

iii. Core Programs

Regular programs consist of the recurring core programs and the New Station expansion, as set out in **Table 3-3**. Recurring core programs are stable to modestly declining across the period, from approximately $65.4M in 2027 to approximately $60.1M in 2031, reflecting a disciplined base level of investment and pacing the programs according to available resources. The increase in the total plan over the forecast period is attributable to the incremental programs and the New Station (Enova 11TS) expansion, rather than to growth in the recurring core program. Toward the end of the forecast, most of the resources in the transformers station area are expected to be allocated to the final testing and commissioning efforts of the new station, resulting in a temporary reduction of the core station programs. These are expected to return to their normal level shortly beyond the forecast period.

Table 3-3: Regular Programs — Core and Station Expansion (gross, $000s)

Program Group	2027	2028	2029	2030	2031
Core programs	65,448	63,755	62,940	61,892	60,116
New Station	2,603	2,007	7,249	13,653	10, 629
Regular total (A)	**68,051**	**65,762**	**70,189**	**75,545**	**70, 745**

iv. Incremental Components

A portion of the 2027–2031 capital plan consists of discrete, incremental investments. These components are set out in **Table 3-4**. Each is material and non-recurring, is driven by an identified need, the VS HVAC Replacement and Facility Renovation Project, concurrently with this DSP, and the remaining components as the associated work proceeds.

Table 3-4: Incremental Components (gross, $000s)

Component	2027	2028	2029	2030	2031
Facility Renovation	7,360	–	–	–	–
Underground cable replacement	3,294	7,147	8,008	6,933	8,012
AMI 2.0	–	180	8,407	7,402	7,435
Total incremental capital	10,653	7,326	16,415	14,335	15,446

The incremental capital is comprised of three components. The VS HVAC Replacement and Facility Renovation Project expenditure is forecast to be approximately $7.4M in 2027. The underground cable replacement program represents cable replacement beyond the level provided for in the core programs and is driven by the assessed condition of aging subdivision and feeder cable; it is classified as System Renewal. AMI 2.0 is the staged replacement of Enova's first-generation smart meter population as those assets approach the end of their useful and sealed service life and is classified as System Access. Across the forecast period, incremental capital represents approximately 10% to 19% of total gross capital and is included within the gross capital reported for the corresponding investment categories. The new transformer station (Enova 11TS) is a distinct System Access expansion and is addressed separately under the New Station heading below.

v. New Station

The New Station (Enova 11TS) is presented separately because, while it is a System Access investment, it is neither a typical recurring core program. It is a major expansion driven primarily by one large commercial customer, comprising progress payments for station equipment and buildings which scale from approximately $2.6M in 2027 to a peak of

approximately $13.7M in 2030 before easing to approximately $10.6M in 2031. An expansion deposit is expected to be received from the customer at the start of the project; however, in accordance with OEB requirements, those monies will not be recorded as a capital contribution until the station is operational, which is beyond the horizon of this Plan. As a result, the New Station appears in the plan as gross capital without an offsetting capital contribution during the forecast period.

vi. Detailed Test Year (2027) and Forecast Basis (2028–2031)

The OEB's DSP filing requirements require the Test Year of the planning period be described in greater detail. For Enova's 2027–2031 DSP, the Test Year is 2027; the remaining years are presented at a higher forecast level by investment category. Representative 2027 projects are summarized in **Table 3-5**.

Table 3-5: Representative 2027 Projects by Category

Category	Representative 2027 projects
System Access	Customer connections, road relocations, new subdivisions, and line extensions; and the start of progress payments for transformers for the new transformer station as well as AMI 2.0 investments.
System Renewal	Progress payments for replacement transformers at Scheifele station; replacement switchgear at 6TS and 7TS; protection relay and RTU replacements at 1TS; cable replacement in Kitchener, Waterloo, and New Hamburg; and overhead line replacement across the territory.
System Service	New overhead tie circuits between Waterloo and Kitchener to improve system flexibility and reliability.
General Plant	Fleet, tools, and computer software and hardware; notably the VS HVAC Replacement and Facility Renovation Project associated with the ICM application and the major release upgrade of the customer information system.

For 2028–2031, recurring core programs are forecast on a stable, largely linear basis, while the incremental and expansion components follow the schedules described above. Figures are stated in nominal dollars and are not adjusted for inflation.

vii. Conclusion

Taken together, the 2027–2031 capital plan reflects a disciplined recurring base program, targeted System Renewal driven by objective asset condition data, and identified System Access growth associated with metering renewal and new load. The increase in the plan relative to historical levels is concentrated in discrete, incremental and expansion investments rather than in the core program. The incremental components could be the subject of potential requests for ICM funding for recovery that may come forward over the forecast period, each subject to OEB review and approval. Enova considers the resulting plan and its pace to be a reasonable and prudent reflection of identified distribution system needs over the forecast period.

3.1.2. Important Changes to Asset Management Processes

Since the merger, Enova has embarked upon a program to harmonize, consolidate, and where cost-effective, enhance legacy Asset Management Processes, data, and information systems that support the development of its investment plans. Listed below are some of the actions taken to improve the overall Asset Management Process and support Enova's continuous improvement in asset management.

- Enova's strategic objectives have been refreshed by the Executive Leadership Team to better reflect the vision, priorities, and long-term direction of the merged organization. The updated strategic objectives establish a common framework for decision-making across the enterprise and ensure that asset management, operational, financial, customer service, and organizational initiatives are aligned with Enova's corporate strategy.

  The refreshed objectives also strengthen the alignment between the Asset Management Program and Enova's broader business goals by ensuring that investment decisions appropriately balance customer needs, system reliability and resilience, safety, environmental stewardship, affordability, operational efficiency, and sustainable growth. These objectives continue to guide the prioritization of capital and operating investments and will be reviewed periodically to ensure they remain aligned

with changing customer expectations, regulatory requirements, and the evolving needs of the electricity distribution system.

- Two different GIS systems have been consolidated into one, modern, updated GIS system allowing for greater granularity of data, easier integration with other operational systems such a SCADA, OMS, load flow software, design software (AUD) and asset management software (ENGIN), as well as more rigorous structures for modelling power flows.

- Harmonization into the Automated Utility Design (AUD) network design platform built on AutoCAD and AutoCAD Map 3D. It bridges the gap between engineering and GIS by automating repetitive design tasks, validating engineering standards in real-time, and generating instant Bills of Materials.

- Asset data across the legacy utilities was not developed, structured, or digitized in a consistent manner prior to the 2022 merger. Differences in asset information models, data standards, inspection practices, and system configurations resulted in varying levels of data completeness, quality, and accessibility across the organization.

  As part of its post-merger integration, Enova has undertaken a comprehensive data harmonization initiative to standardize asset data structures, collection methodologies, validation procedures, and data warehousing practices. This work includes establishing common data standards, improving data governance, validating legacy records, eliminating inconsistencies, and enhancing the completeness and accuracy of asset information used throughout the Asset Management Program.

  The harmonization of asset data is fundamental to supporting consistent asset condition assessments, health index calculations, risk evaluations, and investment prioritization. It also improves the reliability of the information used in analytical tools such as ENGIN 2.0 and strengthens the transparency and defensibility of Enova's asset management and capital planning processes. This initiative is being implemented on a phased basis and remains an ongoing component of Enova's continuous improvement program.

- Enova has adopted ENGIN, an asset analysis, prioritization, and optimization platform, to support the development of its asset management plans across its major legacy asset classes. Originally developed by METSCO Energy Solutions, the software was subsequently spun off and is now maintained and supported by Engineered Intelligence Inc. (EII).

  Following the 2022 merger, Enova selected ENGIN as its common asset investment decision-support platform to harmonize the asset management practices of its legacy utilities. The version previously utilized by Waterloo North Hydro was no longer supported, requiring Enova to migrate to ENGIN 2.0 as part of its post-merger systems integration. Implementation and data harmonization are being completed on a phased basis as asset inventories, condition data, deterioration models, and risk parameters are standardized across the combined organization.

  Once fully implemented, ENGIN will provide a consistent, risk-based methodology for assessing asset condition, forecasting deterioration, prioritizing renewal needs, and optimizing capital investment plans. The platform will strengthen the transparency, consistency, and defensibility of Enova's asset management planning and investment decision-making processes and will support the ongoing continuous improvement of its Asset Management Program.

- Similarly, the METSCO Health Index Frameworks were not applied consistently across comparable asset classes within the legacy organizations. As part of its post-merger asset management harmonization initiative, Enova is standardizing the application of these Health Index Frameworks across all major asset categories. The frameworks establish consistent asset condition assessment criteria, deterioration models, and health grading methodologies, enabling assets of similar type to be evaluated using a common approach.

  The implementation of standardized Health Index Frameworks improves the consistency, transparency, and repeatability of asset condition assessments and strengthens the quality of the data used to support investment decisions. Once fully implemented, the frameworks will provide a common basis for comparing asset health

across the service territory, improving the prioritization of renewal investments, enhancing risk-based decision-making, and supporting the continued evolution of Enova's Asset Management Program.

- Enova has also expanded the use of electronic handheld devices for field inspections and asset condition assessments as part of its broader asset management modernization initiative. The transition from paper-based inspection records to digital data collection improves the efficiency, accuracy, and timeliness of field data capture while reducing administrative effort associated with manual data entry.

  Inspection results and asset condition information collected in the field are uploaded directly to Enova's asset information systems, improving data quality and ensuring that asset records remain current and readily available for analysis. This enhanced data collection process supports more informed asset condition assessments, risk evaluations, and investment planning. The rollout of electronic field data collection is being implemented on a phased basis across inspection programs and asset classes and remains an ongoing component of Enova's post-merger harmonization and continuous improvement initiatives.

3.1.3. (5.3.1.1) Process

A description of Enova's processes used to identify, select, prioritize (including reprioritizing), optimize, and pace the execution of investments over the term of the DSP is provided in **Section 3.1.1, Overview of the Planning Process**.

Enova believes it has taken a balanced approach in its capital plan to incorporate investments that directly address the feedback received from customers. Customers identified several important areas of focus, including reliability, affordability, resilience, support for future growth, and environmental sustainability, which are addressed in this DSP. The feedback did not indicate a need for material changes to Enova's proposed capital investment plans.

Although the forecast investments are significantly higher than the historical expenditures, Enova has made considerable effort to re-prioritize and pace projects based on risk, need, and customer benefit, and to defer or pace investments where appropriate. This approach seeks to balance affordability for customers with the need to maintain a safe, reliable, and resilient electricity distribution system.

Customer survey results indicate that Enova continues to be viewed favourably with respect to affordability and value for money. In Enova's most recent customer satisfaction survey, customers rated Enova positively on several cost and value measures, with results exceeding both the Ontario and national utility averages, as summarized in the following table.

Table 3-6: Cost/Value Attributes – Customer Survey Results

Attribute	Enova	National	Ontario
Provides good value for your money	75%	72%	72%
Operates a cost-effective electricity system	75%	74%	74%
Cost of electricity is reasonable compared to other utilities	73%	71%	71%

During Enova’s customer engagement workshops, customers recognized the importance of balancing affordability with the need for continued investment in critical electricity

infrastructure. Feedback indicated broad support for prudent investments that improve long-term reliability, resilience, and system capacity, even where such investments may result in modest increases in customer rates. Participants generally viewed proactive infrastructure renewal as preferable to deferring investment, recognizing that postponing necessary asset renewal would increase future reliability risks and potentially result in higher long-term costs. Consistent with this view, none of the respondents supported deferring renewal projects that could adversely affect system reliability as a means of keeping customer costs low.

These results demonstrate that customers perceive Enova as delivering good value while operating efficiently. The findings also support Enova's continued focus on balancing affordability with prudent investments in reliability, system renewal, capacity, and grid modernization. Maintaining this balance is a key objective of Enova's DSP, ensuring customers continue to receive safe, reliable, and cost-effective electricity service while preparing the distribution system to meet future needs. Additional information on the customer engagement findings is presented in **Section 2.2.1 Customer Engagement on the Distribution System Plan.**

Enova's planning process considers the potential risks associated with both proceeding with and deferring individual capital expenditures during the development of its capital expenditure plan. As discussed in the previous section, Enova undertook a comprehensive review of its investment portfolio and reprioritized and paced numerous investments into a future investment cycle to reduce capital expenditures over the forecast period. Before deferring any project, Enova's subject matter experts applied their engineering expertise, operational experience, and knowledge of the assets to assess the associated risks to system reliability, safety, regulatory compliance, asset condition, customer service, and future costs.

The projects selected for deferral were limited to station equipment and underground cable replacement projects where condition assessments, asset performance, and engineering judgement indicated that the assets could continue to operate reliably until the planned investment period. This risk-based approach enabled Enova to balance customer affordability with prudent asset management while maintaining an acceptable level of system risk.

Grid optimization is an integral component of Enova's planning process. Throughout the forecast period, Enova will continue to implement initiatives that improve the efficiency, reliability, and utilization of its distribution system. A key investment is the deployment of AMI 2.0, which will provide enhanced capabilities to monitor customer energy usage patterns and deliver near real-time operational visibility at a much more granular level than is currently available through SCADA or the existing AMI system. These enhanced data analytics will support improved system planning, operational decision-making, outage management, load forecasting, and asset optimization.

Enova has also implemented a number of grid optimization initiatives that have improved overall system efficiency. These include the strategic application of line capacitors to improve voltage regulation and power factor, reduce technical losses, and increase feeder capacity; the ongoing conversion of portions of the distribution system from 8.32 kV to 27.6 kV; and the retirement of distribution transformer stations as load is transferred to the higher-voltage distribution network. Collectively, these initiatives have contributed to a more efficient and resilient distribution system, with distribution system losses declining to 3.0% in 2024, well below the provincial average. The investments included in this DSP will build on these initiatives over the forecast period, further improving system efficiency, increasing available capacity, reducing technical losses, and supporting the continued electrification and growth of Enova's service territory.

Enova's planning process also identifies cost-effective opportunities to improve distribution system reliability. To support this objective, Enova is investing in Fault Location, Isolation and Service Restoration (FLISR) technology, electronic line reclosers, and other grid modernization technologies that improve reliability while maximizing the value of existing infrastructure. These technologies enable faults to be detected and isolated more quickly, reducing the geographic extent and duration of outages, accelerating service restoration, and reducing total customer outage minutes.

As part of its System Renewal program, Enova is also upgrading selected distribution circuits from 8.32 kV to 27.6 kV in conjunction with planned overhead line rebuilds. Coordinating these activities enables the voltage conversion to be completed at minimal incremental cost

while maximizing the value of planned capital investments and minimizing disruption to customers.

The conversion to 27.6 kV improves system connectivity, operational flexibility, and available capacity by enabling additional feeder interconnections and increasing Enova's ability to transfer load during planned maintenance and unplanned outages. These enhancements improve system reliability and resilience while supporting more effective implementation of FLISR and other advanced distribution automation technologies.

Eliminating these legacy assets avoids future investment in aging 8.32 kV distribution transformer stations, reduces long-term maintenance requirements, and standardizes the distribution system on a modern voltage platform. This coordinated approach lowers lifecycle costs, improves operational efficiency, enhances asset utilization, and contributes to a more reliable, resilient, and cost-effective electricity distribution system for customers.

The assessment of distribution rate-funded Non-Wires Solutions (NWSs) is also an integral component of Enova's planning process. Consistent with the Ontario Energy Board's ("OEB") Benefit-Cost Analysis Framework ("BCA Framework") and Non-Wires Solutions Guidelines ("NWS Guidelines"), Enova performs a pre-assessment of NWSs for material capital investment programs with projected capital costs exceeding $2 million. The NWS pre-assessment requirement applies to all electricity system needs exceeding the $2 million threshold across the 2027–2031 DSP planning horizon, excluding General Plant investments. As part of this process, Enova evaluates whether distribution rate-funded NWSs could cost-effectively defer or eliminate the need for traditional wires investments while continuing to meet customer, reliability, safety, and regulatory requirements. Material capital programs are systematically screened in accordance with the BCA Framework, and the results are documented in **Appendix P, Non-Wires Solutions Screening Register**.

The following distribution line and station capital programs exceed the $2 million threshold and therefore require documented consideration of NWS alternatives:

Table 3-7: NWS for material capital investment programs > $2M ($000s)

Code	Program Name	OEB Cat	2027 Budget	5yr Total	Result
R-OL-VU	OH Line Renewal – Voltage Upgrade	SR	$5,890	$29,430	NWS Not Viable
R-OL-RP	OH Line Renewal – Routine Projects	SR	$4,110	$20,540	NWS Not Viable
R-UL-S	UG Line Renewal – Subdivisions	SR	$11,140	$72,640	NWS Not Viable
E-SP	Relocations – Special Projects	SA	$3,130	$15,660	NWS Not Viable
R-SE	Station Equipment – Renewal	SR	$7,740	$41,620	NWS Not Viable

For all programs, the pre-assessment concludes that NWS is not a viable alternative. Detailed pre-assessments are provided in **Appendix K - Non Wires Solutions.**

Enova's forecast expenditures for innovative technologies support a coordinated portfolio of investments that will modernize the distribution system, facilitate the integration of distributed energy resources (DERs), and enable emerging electricity market functions. The program comprises three complementary initiatives: (1) a recurring innovation program that includes pilot projects and early-stage DER deployments; (2) the implementation of a Market Transaction Platform; and (3) the deployment of a Distributed Energy Resource Management System (DERMS).

On a gross capital basis, forecast expenditures are approximately $0.60 million in 2027, $0.68 million in 2028, $1.26 million in 2029, $1.85 million in 2030, and $0.86 million in 2031. The expenditure profile reflects a phased implementation strategy, beginning with pilot projects and foundational DER initiatives in 2027, followed by the development and deployment of the Market Transaction Platform and DERMS over the 2028–2030 period. Capital expenditures decline in 2031 as the major platform implementations are completed and the focus shifts from deployment to operational enhancement, optimization, and ongoing support. Collectively, these investments will enhance Enova's ability to monitor, manage,

and optimize distributed energy resources, improve operational visibility and system flexibility, and establish the digital capabilities required to support an increasingly decentralized and electrified electricity system.

Enova's planning process includes consideration of future capacity requirements associated with customer load growth, electrification, increased electric vehicle (EV) adoption, and distributed energy resource (DER) integration. Enova regularly analyzes the utilization and available capacity of transformer stations, distribution feeders, and distribution transformers to identify emerging system constraints and ensure sufficient capacity is available to serve existing and future customers. This analysis supports planning for load customers, generation customers, EV charging infrastructure, and DER connections.

Enova also prepares long-term load forecasts to identify when system reinforcements or capacity upgrades will be required. Based on these analyses, Enova has concluded that its distribution system has sufficient capacity to accommodate forecast load growth, EV adoption, and DER integration over the planning period. Additional information on system capacity, utilization, and planned capacity investments is provided in **Appendix E, System Supply and Capacity Report**.

Enova is working with the IESO and other members of the Kitchener–Waterloo–Cambridge–Guelph (KWCG) Regional Planning Technical Working Group to develop the next IRRP for the KWCG region. The load forecasting methodology described in the guideline *"Load Forecast Guideline for Ontario"* is consistent with the methodology used by Enova to prepare the load forecasts submitted to the working group in support of the IRRP. This ensures consistency between Enova's DSP. Load forecasting and the regional planning process.

3.1.4. (5.3.1.2) Data

Asset condition and performance data for Enova's major asset groups can be found in the following appendices. This data is used in the development of Enova's DSP and Capital Investment Plan.

- Appendix B-1 - Asset Condition Assessment (ACA) Report
- Appendix D-1 - Renewable Energy Generation Investment (REGI) Plan
- Appendix E - System Supply and Capacity Report
- Appendix F-1 - Distribution System Reliability Report
- Appendix F-2 - Appendix 2-G SQI & SRI
- Appendix G - Operations Maintenance Report
- Appendix H - Information Technology Management Plan
- Appendix I - Facilities Management Plan
- Appendix J - Fleet Management Plan
- Appendix N - OEB Appendix 5-A Unit Cost Metrics

Overall Asset Data Maturity Assessment

Enova's asset information systems provide a strong foundation for risk-based asset management and capital planning. Core datasets, including asset inventory, work history, GIS, reliability performance, and load information, are generally mature and support prudent investment decision-making.

During the 2027–2031 planning period, Enova will continue enhancing its asset management capabilities by improving condition assessment programs, expanding asset health indices, strengthening enterprise data governance, integrating operational systems, and increasing the use of predictive analytics. These initiatives will improve the quality, consistency, and accessibility of asset information, enabling increasingly data-driven investment decisions that optimize lifecycle costs, improve reliability, and deliver long-term value to customers.

Table 3-8 presents Enova's current assessment of the maturity of its major asset information systems that support its Asset Management Program. This assessment is used as part of

Enova's continuous improvement process to evaluate the quality, completeness, and reliability of the asset information used to support investment planning and decision-making. By identifying opportunities to enhance asset data and information systems, Enova continues to strengthen its risk-informed asset management practices and improve the evidence base supporting capital investment decisions.

Table 3-8 Enova Asset Data Maturity Assessment

Asset Information Category	Current Maturity	Current Practices	Opportunities for Improvement (2027–2031)	Expected Benefit
Asset Inventory	High	Comprehensive inventory with standardized asset identifiers.	Validate through inspections and GIS synchronization.	Improved planning accuracy.
Asset Age & Installation History	High	Installation dates available for most major assets.	Reconcile remaining unknown dates.	Improved lifecycle forecasting.
Asset Condition Data	Medium	Inspection and maintenance records support condition assessment.	Expand standardized condition assessments.	Better risk-based prioritization.
Asset Health Indices	Medium	Applied to major asset classes.	Extend methodology across more assets if practical.	Consistent replacement decisions.
Failure History	High	OMS and maintenance records capture failures.	Improve coding and root-cause analytics.	Better failure insights.
Asset Criticality	Medium	Critical assets identified qualitatively.	Develop quantitative scoring.	Enhanced prioritization.
Risk Assessment	Medium	Condition and reliability inform decisions.	Standardize with PoF/CoF methodology.	Transparent investment decisions.
GIS Integration	High	GIS supports planning and operations.	Strengthen GIS//OMS/Asset Management integration.	Improved planning efficiency.
Work History	High	Maintenance history maintained.	Improve coding consistency.	Lifecycle optimization.
Reliability Analytics	Medium-High	SAIDI/SAIFI monitored.	Expand predictive analytics.	Targeted reliability improvements.
Load & Capacity Data	High	Load monitoring supports planning.	Enhance forecasting tools.	Improved timing of investments.
Predictive Analytics	Low-Medium	Limited predictive modelling.	Expand predictive capabilities.	Earlier risk identification.
Data Governance	Medium	Governance procedures established.	Formalize quality metrics and audits.	Higher confidence in data.
Data Quality	Medium-High	Routine validation performed.	Automate validation and KPIs.	Improved regulatory evidence.

3.2. (5.3.2) Overview of Assets Managed

3.2.1. Overview of Distribution Service Area

Section 1.4.4 provides a high-level overview of Enova's distribution system. More detailed information can also be found in **Appendix E: System Supply and Capacity Report.**

3.2.2. Asset Information

Table 3-9 provides a summary of distribution asset types and quantities.

Table 3-9: Enova Distribution Asset Summary

Asset Group	Total	Asset Group	Total
STATIONS		**UNDERGROUND ASSETS**	
Grid Connected Transformer Stations	12	Underground Primary Circuits (km)	1,624
> 50 kV Power Transformers	27	Total Underground Primary Cable (km)	3,587
< 50 kV Power Transformers	10	Distribution Transformers - Pad Mount	5,627
HV Switches / Circuit Switches	24	Distribution Transformers - Submersible	4,065
Switchgear	34	Distribution Transformers - Vault Rooms	673
27.6 kV Feeders	15	Distribution Transformers - Network	32
13.8 kV Feeders	112	Electronic Reclosers / Switches	46
Circuit Breakers	224	Manual Load Break Switches / Switch vaults	554
Protective Relays	407	Non-Load Break Switches	543
OVERHEAD ASSETS		**METERING**	
Primary Circuits (km)	2,049	Retail Revenue Meters - Residential	148,043
Poles	45,814	Retail Revenue Meters - Commercial < 50kW	14,360
Distribution Transformers	8,555	Retail Revenue Meters - Commercial > 50kW	1,697
Electronic Reclosers	190	Retail Revenue Meter Installations	4,950
Manual Load Break Switches	880	Wholesale Revenue Meters	91
Non-Load Break Switches	7,102	AMI Communication Towers	11
Capacitor Banks	121		

Appendix B-1: **Distribution Assets Condition Assessment Report** provides asset condition assessment results, asset demographics, condition assessment criteria, and data availability by major asset type. The report also provides an overall health condition summary and asset replacement plan based on condition assessments.

Appendix E: **System Supply and Capacity Report** provides a full assessment of the degree to which the capacity of Enova's distribution system assets is utilized relative to equipment rating and planning criteria.

3.2.3. Transmission Assets Deemed as Distribution

Enova owns transformer stations that are connected to the Hydro One 115 kV and 230 kV transmission system. These stations connect to and distribute energy to Enova's distribution system at < 50 kV. Details can be found in **Appendix E: System Supply and Capacity Report.** These assets in the past have been deemed by the OEB as distribution assets.

This DSP includes System Access investments for the planned construction of the Enova 11TS station required to provide capacity for a new customer connection. A total of $36.6 million has been included over the forecast period. Enova is asking the OEB to deem the > 50kV assets associated with Enova 11TS as distribution assets.

3.2.4. Host / Embedded Distributor Arrangements

Enova is an embedded distributor at two < 50 kV delivery points.

- HONI Dx on the Fergus TS 77M7 feeder (44 kV).
- GrandBridge Energy on the Preston TS 21M25 feeder (27.6 kV).

These delivery points provide less than 1.0% of Enova's supply. The remaining supply comes from HONI transmission and embedded generation.

Table 3-10: Enova Gross Summer Peak Load MW (2024)

Supply Voltage (kV)	2024 Load (MW)	% Total Load by Delivery Point
230	322.0	46.7%
115	333.0	48.3%
< 50	5.8	0.8%
Embedded Gen. (various)	28.9	4.2%
Total	689.7	100%

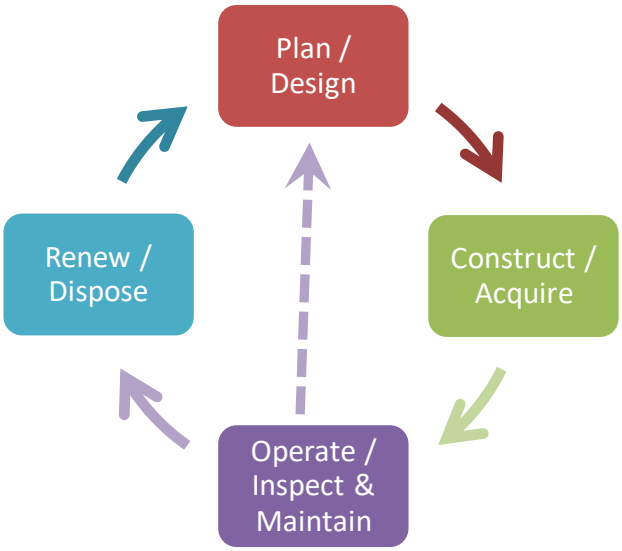
Hydro One Networks (HONI) is registered as an embedded distributor to Enova on the Elmira TS 33M2 feeder (27.6 kV). HONI's share of the feeder load is approximately 45% or 6.3 MW. There is a separate Embedded Distributor customer class for HONI.

3.3. (5.3.3) Asset Lifecycle Optimization Policies and Practices

3.3.1. Overview of Enova's asset lifecycle optimization policies and practices

Enova's Asset Management Strategy uses a full lifecycle approach to managing its distribution assets which is illustrated in **Figure 3-2.** Enova utilizes this approach to optimize asset performance and useful life, while delivering maximum value to customers in terms of system reliability, safety, regulatory requirements, cost, and customer service. This section describes Enova's practices and lifecycle optimization methodologies that support the Asset Management Process in identifying investment needs, sustaining in-service assets, and planning System Renewals.

Figure 3-2: Enova Asset Lifecycle Process



Plan / Design – Annually, Enova prepares a one-year capital budget and a five-year capital investment plan which are informed by inspection and maintenance findings, regular asset condition assessments (ACA), operational performance, regulatory compliance, customer consultations, load growth and corporate business needs. These factors are evaluated against Enova business plans, strategic objectives, reliability targets, health index targets, and asset utilization limits. Risks are identified and investments are prioritized. Enova attempts to optimize its investment portfolio by selecting investments that provide the greatest reduction in risk per investment dollar. Financial and resource constraints inform the pacing of investments over the forecast period.

During the design stage, standards, material specifications, operational performance, inspections and maintenance all inform the design process to improve and optimize project spending.

Construct / Acquire - After the planning and design phase is completed, the asset is acquired or the project is constructed and placed into service. Costs to place assets into service are reviewed and compared to estimates. Material variances are analyzed in an effort to inform and improve the design process.

Operate, Inspect and Maintain – The longest phase of the asset life cycle, this stage is focused on asset performance and condition assessments. Data collection is ongoing through the asset lifecycle and maintained in an asset register. Regular review and analysis of asset data health and performance inform the planning and design stage to improve the next cycle of asset additions or replacements. Analysis also informs the disposal / decommissioning stage by helping develop trend data to estimate asset EOL.

Renew / Dispose - Assets reach EOL based on a combination of factors such as health, performance, risk and functional obsolescence. Not all assets end their lifecycle in the same manner or at the same time. Review and analysis of asset data health and performance at EOL informs the planning and design stage to improve the next cycle of asset additions or replacements.

3.3.1.1. Asset Replacement and Refurbishment Policies

Assets reach EOL based on a combination of technical and economic factors including asset performance, condition, age, probability of failure, criticality or consequence of failure, maintenance options, replacement and refurbishment cost and lead time options. A determination must be made from one of several options. Enova utilizes a three-part strategy to minimize the lifecycle cost of an asset.

1. Asset Maintenance – normally maintenance has been conducted on the asset to achieve its TUL or extend its in-service life if still economically prudent. Additional maintenance

at the EOL stage is often though not effective or efficient in extending the assets life and many assets do not have viable maintenance options.

2. Asset Refurbishment – As part of developing any EOL option, asset refurbishment (Life Extension) is always considered. Many distribution assets such as wire, insulators, lightning arrestors and poles for example do not lend themselves to refurbishment. Assets such as distribution transformers can be refurbished but generally not in a cost-effective manner. Additionally, some assets are not appropriate candidates for refurbishment as compliance with Ontario Reg. 22/04 may not be attainable and the asset cannot be reused on new construction. Refurbishment becomes a more viable option for high cost specialized assets. Even then, the co-benefits that new equipment brings, such as improved performance, lower losses, higher ratings, reduced future maintenance and parts availability can outweigh the cost savings of refurbishment.

   In the past, Enova has performed cost-effective life extending refurbishments on assets such as station transformers, switchgear, circuit breakers, tap changers, voltage regulators, switchgear and fleet. The savings that accrue from the refurbishment of assets are highly dependent on the type of asset, asset condition and performance. Refurbishments also involve extensive feasibility discussions with third-party vendors or suppliers.

3. Asset Replacement - for most Enova assets, replacement is the only option. Enova utilizes one of the following replacement strategies depending on the asset function, asset condition, and the cost-effectiveness of each strategy.

   a. “Do not replace”, is always an option to be considered. The asset’s function may have become surplus, redundant or surpassed by the benefits of alternative solutions. At Enova, the rebuilding of 8.32 kV distribution lines at 27.6 kV is eliminating 8.32 kV distribution stations, line voltage regulators and capacitor banks.

b. Proactive Replacements are planned asset replacements based on the technical and economic factors. Enova utilizes two types of proactive replacement strategies:

   i. Like-for-like replacements are performed if functional or performance requirements have not changed during the past asset lifecycle. Some of Enova's System Renewal investments fall into this category.

   ii. When new standards, performance or functionality requirements do not allow for a like-for-like replacement, a higher level of asset replacement (upgrade) is the only option. This makes up the majority of Enova's System Renewal investment as the 30 to 60-year-old assets being replaced today do not meet current-day requirements for new construction.

c. Reactive Replacement (Run-to-Failure) maximizes an asset's service life; however, can also have negative impacts on reliability, safety and cost. This strategy is used mainly for low-value, low-risk distribution assets where like-for-like replacement is possible and incidents of failure are relatively low. When incidents of asset failure accelerate or cluster and become a cause for concern, a switch to a proactive replacement strategy is employed. Assets that are commonly run to failure include distribution transformers, pole line hardware, lightning arrestors and underground cable in duct.

4. Future capacity upgrades in life-cycle planning.

   Whenever assets are replaced, Enova looks to future capacity requirements to establish if there is a viable cost-effective option. Some examples where Enova has been using this approach are:

   Rebuilding of pole lines - Enova examines system planning objectives and load forecasts to see if additional capacity (circuits) in that section of the distribution system may be warranted in the future. Although the extra circuit may not be required until future years, in increasing the height of the pole to accommodate the future circuit during the current rebuild, is minimal compared to the alternative of rebuilding the line in the future just to accommodate an additional circuit.

This DSP includes investments to replace large power transformers. Enova has opted for a marginal increase in transformer rating for each. Again, the marginal cost on a per kilowatt basis to increase the size of a transformer less than to purchase that additional capacity on a standalone basis

A similar principle applies to certain underground cable replacement projects included in this plan. Where existing cables require replacement, Enova will, where appropriate, increase conductor size from 600 kcmil to 750 kcmil. The incremental cost of installing the larger conductor as part of the planned replacement is relatively small compared with the cost of providing equivalent future capacity through the installation of additional parallel cables. Accordingly, upsizing conductors during planned renewal projects represents a prudent and cost-effective means of accommodating future load growth while minimizing future customer disruption and overall lifecycle costs.

All these considerations inform the Planning/Design stage and help optimize the new lifecycle of asset investments.

3.3.1.2. System Renewal Program Spending Optimization

Enova is focused on evidence-based decision making to support and optimize System Renewal investment decisions. Enova strives to achieve an optimal System Renewal Investment Plan by addressing the assets in the poorest health and with the greatest potential impact of failure while maintaining staff and public safety risks to an acceptable level.

Enova utilizes condition and performance data for its asset condition assessments, which become the foundation of its System Renewal decisions. Condition and performance data comes from many sources, including inspections, maintenance, testing, reliability performance, failure rates and loading. Enova ENGIN software and Asset Condition Assessment Frameworks apply condition based metrics and targets to asset condition data to develop Health Index scores for each asset. Ranked by health score, assets are placed into health categories, whereby those identified as in Very Poor or Poor condition are candidates for near term replacement, within the current forecast window. Assets

categorized a Fair condition tend to longer term replacements. They may be outside the current forecast window or just inside, depending on the degradation rate of the assets.

Assets in Good or Very Good condition are longer-term and outside the current forecast window.

Where feasible, assets in the poorest condition ranked by their health score are geospatially grouped into constructible projects; projects that can be more effectively and efficiently constructed. Potential projects are selected and prioritized based on health score and weighted by the project's alignment with Enova's Strategic objectives.

Projects are then developed, cost-estimated, and prioritized based on the risk and customer consequences associated with asset failure. Where assets have similar condition profiles, Enova evaluates additional factors such as the number of circuits affected, the number of downstream customers served, load characteristics, network configuration, and operational considerations to distinguish between competing projects. This process identifies the investments that provide the greatest reduction in system risk and customer outage exposure.

System Renewal expenditures are optimized by prioritizing projects that provide the highest customer benefit relative to their cost, thereby maximizing the reduction in reliability risk for each dollar invested. At present, this optimization is performed through a structured engineering review conducted by Enova's engineering staff using asset condition information, operational experience, and engineering judgement.

As Enova completes the implementation and data harmonization required for the ENGIN 2.0 asset investment optimization platform, this prioritization process will transition to a fully data-driven methodology. Once fully implemented, ENGIN 2.0 will provide a consistent, transparent, and repeatable optimization process that systematically evaluates asset condition, probability of failure, consequence of failure, customer impacts, and project costs to produce an optimized portfolio of System Renewal investments.

3.3.1.3. Balancing customer's need for reliability and capital expenditure costs

Enova closely monitors system reliability performance and benchmarks that performance against three major factors; OEB Targets, Enova Historical Reliability Performance and Industry Reliability Performance. **Figure 3-3** and **Figure 3-4** illustrate the results of that benchmarking. Although Enova's SAIDI and SAIFI increased in 2024, Enova's 5-year average performance is below the OEB's maximum targets and well below industry averages.

Figure 3-3: SAIDI (2020 – 2024)

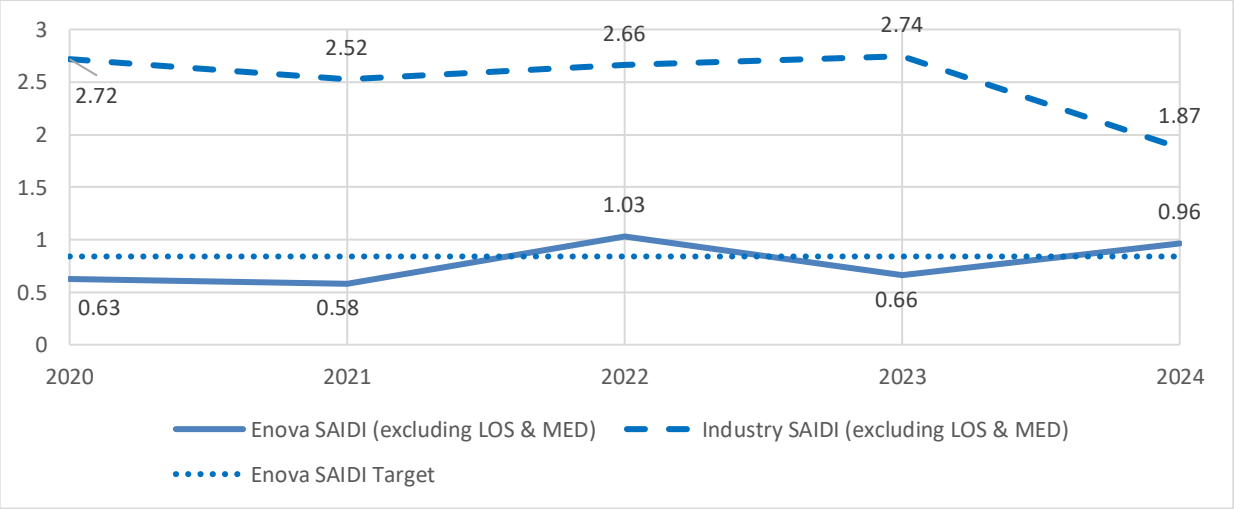
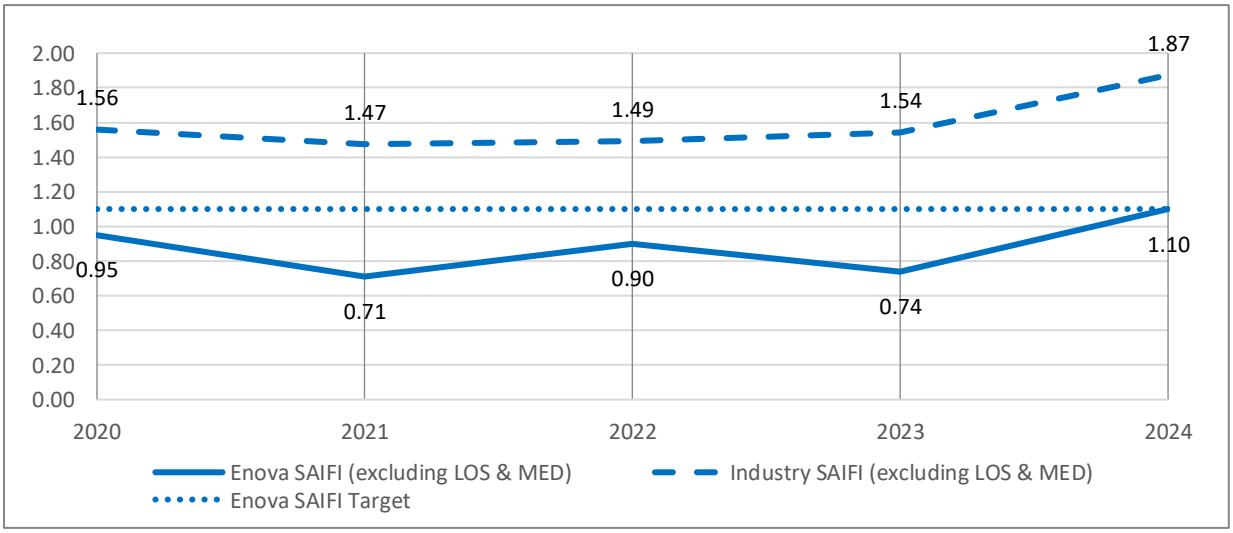


Figure 3-4: SAIFI (2020 – 2024)



Over the forecast period Enova is continuing to make System Service Investments in the implementation of FLISR and electronic reclosures to an additional 69 feeders.

In addition, System Renewal investments are targeting assets in the poorest condition. Defective Equipment related CHI has ranked 2nd (20.7%) in total sustained interruption hours over the last 5 years. Excluding MEDs, Defective Equipment is the leading cause (30.1%) of CHI with underground primary cable and submersible transformers making the largest contributions.

Enova's objective is to maintain a sustainable baseline level of distribution system reliability that consistently meets or exceeds the Ontario Energy Board's (OEB) reliability performance targets while remaining generally consistent with its historical performance and customer expectations. Where prudent and cost-effective, Enova will continue to evaluate and implement measures that further improve system reliability. This approach reflects a balanced and responsible investment strategy that supports the efficient use of capital while maintaining a high standard of service. It is also supported by recent customer engagement, which found that 91% of customers indicated Enova's current level of reliability met or exceeded their expectations.

Throughout the 2027–2031 DSP forecast period, Enova will continue to monitor, benchmark, and evaluate its reliability performance using established industry reliability indices, internal performance targets, and comparisons with historical performance. Reliability results will be reviewed regularly to assess the effectiveness of completed investments, identify emerging trends, and detect areas where additional attention or corrective action may be warranted.

If monitoring indicates that reliability performance is not meeting established objectives, Enova will reassess its investment priorities through its Asset Management Program and, where appropriate, adjust the pacing, scope, or prioritization of future capital investments. This may include directing additional resources toward the highest-risk assets, the poorest-performing feeders, or targeted reliability improvement initiatives where they are expected to deliver the greatest benefit to customers.

This adaptive, risk-based planning approach ensures that Enova remains responsive to changing system conditions while maintaining an appropriate balance between reliability, affordability, and long-term asset stewardship. By continuously monitoring performance and incorporating new information into its investment planning process, Enova will continue to optimize capital expenditures, manage system risk, and deliver safe, reliable, and cost-effective electricity service that meets the high expectations of its customers.

3.3.1.4. Enova Inspection and Maintenance Programs

Enova's asset condition assessments are based on well-established comprehensive inspection, testing and maintenance programs. These O&M programs have been developed and refined over time from manufacturers' recommendations, industry best practices, historical findings, Enova's experience and prescribed requirements. These programs are executed at various times and by various means which are described further in this section. For the most part, asset condition assessment data is collected in electronic format and then downloaded and reviewed. The asset register is updated and the data informs Enova's asset management process.

Generally, relatively simple, low-hazard level deficiencies are remediated at the time of inspection to eliminate the need for a return trip. This may include replacement of broken guy guards or missing phase markers, replacement of missing signs etc.

Critical deficiencies presenting an imminent risk of asset failure, risk to public safety or reliability are also corrected at the time of inspection if possible. If not, they are reported to the Distribution Superintendent to schedule immediate corrective action.

The remaining deficiencies are reviewed and prioritized through Enova's proactive maintenance program which will prioritize corrective action based on cause, severity and hazard level. Recurring deficiencies are also identified and channeled into either an enhanced maintenance or capital replacement programs.

3.3.1.4.1. Enova Inspection Programs

Requirements of the OEB's Distribution System Code (DSC) outline the minimum inspection standards and intervals required. Specifically, Table C-1 of the DSC identifies the maximum intervals for visual patrols: 3 years for most urban facilities, and 6 years for rural facilities. For stations the intervals are 1 month, 6 months, 1 year or 3 years depending on the type of station. In addition, Enova has grid connected Transformer Stations which have inspection requirements identified in the OEB Transmission System Code.

Enova's service area is comprised of two urban areas, serving the City of Kitchener and the City of Waterloo, and three rural areas serving the Township of Wellesley, the Township of Wilmot and the Township of Woolwich. For OEB inspection purposes, Enova divides its service area into 10 parts as illustrated in **Figure 3.5**. This is to facilitate workload management and form the basis for Enova's implementation of systematic and routine visual patrols in compliance with the OEB minimum inspection requirements.

Visual patrols of the major distribution facilities are comprehensive and the level of detail exceeds the patrol inspection requirements as defined in Appendix C of the DSC.

Figure 3-5: Enova OEB Inspection Areas

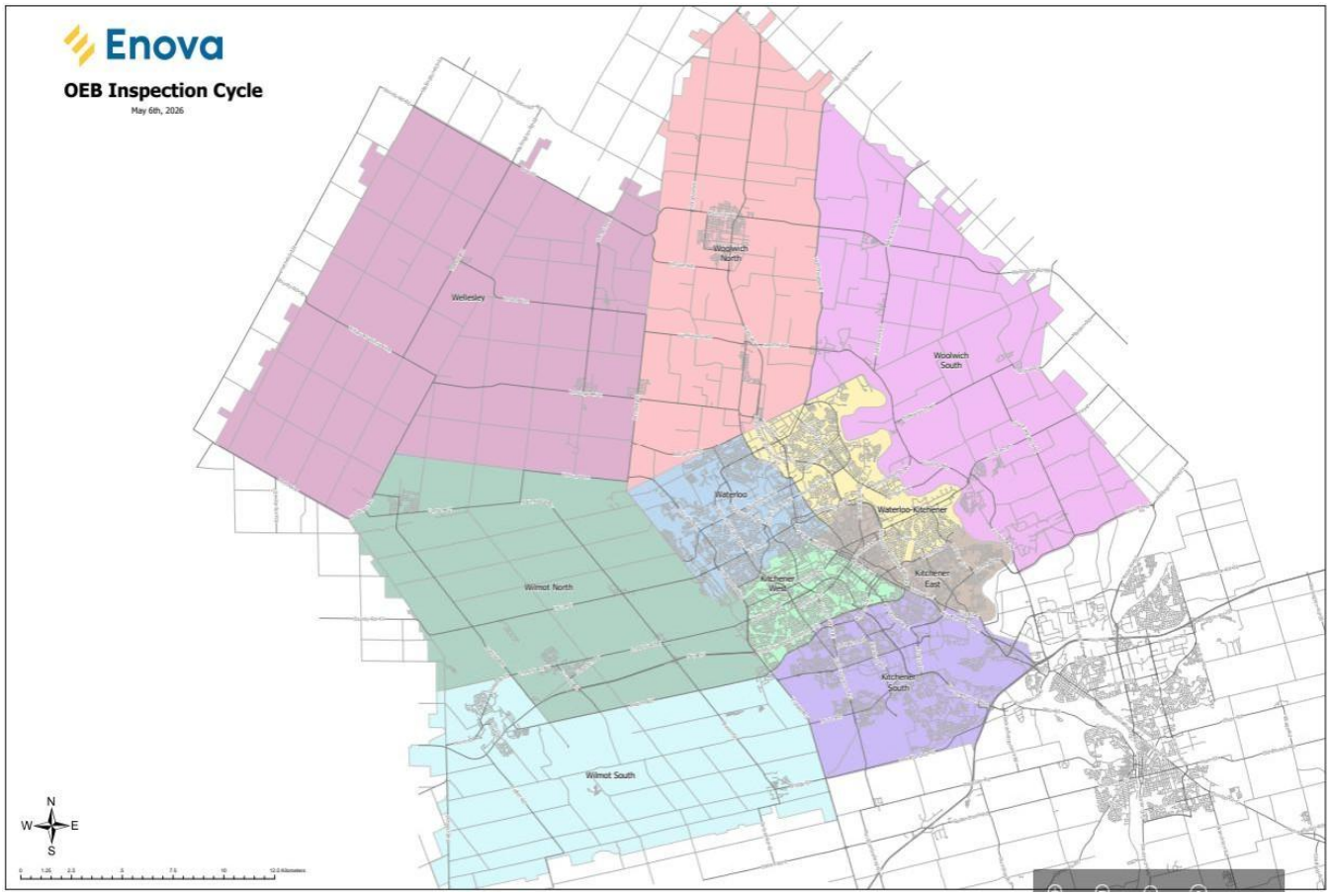


Table 3-11 to **Table 3-13** inclusive provides samples of Enova's inspection schedules.

Table 3-11: Inspections – Overhead and Underground Lines

OVERHEAD AND UNDERGROUND LINES	FREQUENCY
OEB Inspections (Urban)	3 year
OEB Inspections (Rural)	6 year
Inspection of major overhead crossings of Highways 85, 7 and 8	Annual
Inspections of overhead crossings of rivers and railways	Annual
Inspections of overhead and underground plant located adjacent to schools and playgrounds	Annual
Inspections of pole mounted capacitor banks	Annual
Infrared Thermography	Annual

Table 3-12: Inspections – Municipal and Rural Distribution Stations (DS)

DISTRIBUTION STATIONS INSPECTIONS	FREQUENCY
All Station Equipment (e.g. Transformers, switchgear, reclosers, capacitor banks, fencing, lighting, radio/RTU)	Monthly
Infrared Thermography	Annual

Table 3-13: Inspections – Transformer Stations (TS)

GRID CONNECTED TRANSFORMER STATION INSPECTIONS	FREQUENCY
All Station Equipment (e.g. transformers, switchgear, reclosers, batteries, fans & pumps, fencing, lighting, radio/RTU)	Monthly
Infrared Thermography	Annual

A) Inspection of Overhead Systems

Enova currently inspects a minimum one-third of the urban region and one-sixth of the rural regions annually. The visual patrol serves as a condition-based assessment of overhead assets, including poles and their supports and attachments, pole-mounted distribution transformers, switches and other protective devices, conductor, grounding and surrounding vegetation. The inspection further serves to confirm the existence of other assets on the overhead distribution system such as third-party communications equipment. Inspections are conducted by Enova PLTs or a qualified PLT contractor. Staff are provided with GIS-based maps of the region and electronic tablets for identifying and locating assets during the visual patrol. During the inspection, PLTs identify and record deficiencies or concerns regarding the condition of an asset. **Table 3-14** presents typical deficiencies, which may be routinely identified.

Table 3-14: Typical Overhead Deficiencies

ASSET	DEGRADATION FACTORS
Pole	Rotting, cracked, feathering, insect damage, leaning, woodpecker holes
Cross Arm	Rotting, twisted, bolt pulling through
Insulator	Flashed, broken, loose / tipped down
Arrester	Blown, flashed over
Switch	Loose, flashed over, porcelain insulators
Grounding	Not connected, exposed ground rod, damaged or missing conductor
Guying	Loose, broken, damaged, anchor pulled, strain insulator broken
Guy Guard	Missing, cracked
Conductor	Frayed, broken strands, tie wire broken, corrosion
Cable Guard	Loose, exposed conductor, corrosion, grounding
Transformer	Rusted, leaking, cracked bushings, overheating
All	Vegetation / Overgrown, interference
All	Burning, tracking, lightning damage

Annually, wood fibre strength pole testing is performed on a portion of Enova's wood pole population. While the contractor is on site visual inspections are also performed and recorded, the results of which are used to refresh the inspection database.

Major Crossings

Inspections and condition assessments of all overhead circuits crossing major four-lane highways, railway lines and rivers are performed annually. The greater frequency reflects the higher risk that is associated with these parts of the distribution system. Crossings typically have longer spans and taller poles making them more susceptible to wind and ice loading damage. Along major roadways there is greater exposure to salt contamination and corrosion. River crossings also tend to be more remote making deterioration or storm damage less likely to be observed. All crossings are uniquely identified in Enova's GIS system. Their inspection process is the same as that described in the previous section.

Parks, Playgrounds & Schoolyards

The inspection of overhead line assets in or near parks, playground and schoolyards is performed annually. The greater frequency reflects the greater risk associated with children in these areas. Visible hazards such as broken ground wire, missing guy guards, damaged riser conduits, indications of tampering or climbing are identified. Such deficiencies are documented and remediated at the time of inspection if possible. Those deficiencies for which corrective action could not be immediately performed are addressed through Enova's proactive maintenance program.

Capacitors

Capacitor banks on the Enova distribution system are inspected according to the DSC inspection requirements. PLTs look for signs of tracking, burning, tank swelling or overheating along with the condition of fused switches and hot-line clamps. Those deficiencies for which corrective action could not be immediately performed are addressed through Enova's proactive maintenance program.

Load-Break Switches

All load-break switches on the Enova distribution system are inspected according to the DSC inspection requirements. PLTs identify switch deficiencies such as lightning damage overheating, burning, blade and mechanism operation, grounding and ground mat condition.

Those deficiencies for which corrective action could not be immediately performed are addressed through Enova's proactive maintenance program.

B) Inspection of Underground Systems

Unless otherwise noted, the inspection frequency for underground systems is derived from Appendix C of the DSC which requires that at least a minimum one-third of urban areas and one-sixth of rural areas be inspected annually. The visual inspections identify obvious structural/mechanical and hazardous conditions that may exist with accessible underground distribution system assets and the vegetation surrounding these assets. These assets include distribution transformers, switching cubicles and vault rooms. The data collection and reporting processes are the same as those previously described for the Overhead System Assets. **Table 3-15** presents typical deficiencies that may be routinely identified.

Table 3-15: Typical Underground Deficiencies

ASSET	DEGRADATION FACTORS
Note	The items below are in addition to the physical inspections all equipment receives for signs of damage, overheating, wear, tampering or vandalism.
Transformer (Tx)	Rusted, leaking, cracked bushings, overheating, misaligned with pad, locks
Tx Concrete Pad	Concrete deterioration, settlement or misalignment
Tx Below Grade Vaults	Concrete deterioration, settlement or misalignment, water, foreign materials, locks, vault lid security
Elbows & Bushings	Tracking, seating, cleanliness
Arrester (Elbow)	Blown, flashed over
Switches (Gas Insulated)	Tracking, flashover, seating, cleanliness
Switches (Solid Dielectric)	Tracking, flashover, cleanliness
Grounding	Connection, exposed ground rod, damaged or missing conductor
Conductor Terminator & Bushings	Tracking, jacket condition
All	Vegetation / Overgrown, interference
All	Burning, tracking, lightning damage

Distribution Transformers

Enova's underground distribution system incorporates pad-mounted, submersible, vault room and network distribution transformers. In addition to the inspection frequency, Enova's condition assessments are also based on Appendix C of the DSC, as reflected in the

reporting form, 'Inspection of Underground Transformer and Switching Units. This form provides a guideline for the condition assessment and allows for documentation of deficiencies (or lack thereof) concerning the physical condition, oil leaks, placement on pad, locks and locking mechanisms, grading, access changes, phasing indicators, nomenclature, inadequate signage, vegetation growth around equipment, indications of tampering and internal/external apparatus such as cracked elbow connectors.

Switching Kiosks

As with distribution transformers, the frequency of inspection and condition assessments are based on the DSC's Minimum Inspection Requirements for switching kiosks and includes at a minimum, identification of deficiencies concerning paint, locking mechanisms, accessibility and structural condition. The full list of deficiencies is available in Appendix C of the DSC.

Vault Rooms

Vault room inspections are conducted annually and are performed in conjunction with infrared thermography. The greater frequency of inspection reflects the greater risk associated with vault rooms due to their location adjacent to or inside of buildings, near schools or higher traffic areas and the risk of exposure to energized equipment should unauthorized access be gained inside the vault room. Inspection points include those associated with transformers and switches in addition to accessibility, ventilation, overheating, rodent and water damage or signs of trespass. Deficiencies with the vault room itself are reported to the building's owner who is responsible for all of the structural elements of the room. Deficiencies and condition assessments of the electrical equipment inform Enova's asset management plan.

Transformer Enclosures

Inspections of transformer enclosures are conducted annually. These customer-owned facilities are open-air, fenced or walled structures (without a roof or ceiling) that house and protect larger pad-mounted distribution transformers and associated switching equipment.

The annual inspection frequency reflects the higher risks associated with these installations. Transformer enclosures are often located adjacent to buildings, schools, or other high-traffic

areas where unauthorized access could expose members of the public to energized electrical equipment. Regular inspections help ensure that both public safety and system reliability are maintained.

Routine inspections assess the condition of transformers and switching equipment, the structural integrity of the enclosure, locking mechanisms and overall security, accessibility, evidence of trespass or vandalism, water accumulation or drainage issues, and vegetation growth within and surrounding the enclosure.

Deficiencies associated with the enclosure itself are reported to the property owner, who is responsible for maintaining the structural components of the facility. The results of inspections and condition assessments of the electrical equipment are incorporated into Enova's asset management program and are used to support maintenance planning and renewal prioritization.

Vegetation management is an integral component of the inspection program. Trees, brush, and other vegetation can impede safe access, reduce required electrical clearances, accelerate asset deterioration, and create operational and public safety risks. Although these transformer enclosures are customer-owned, Enova performs vegetation control activities within and immediately surrounding the enclosures because of the safety risks associated with working in close proximity to energized electrical equipment. This work helps maintain safe access for employees and contractors, preserve equipment accessibility, ensure required electrical clearances are maintained, and support the safe and reliable operation of the distribution system.

C) Inspection of Stations

As with the overhead and underground distribution systems, Enova performs comprehensive station inspections and condition assessments, the more important of which are described in **Table 3-16**.

Table 3-16: Typical Station Deficiencies

ASSET	DEGRADATION FACTORS
Switchyard	Lightning & wind damage, insulator tracking, connections
Transformer	Oil level and temperature, winding temperature, bushings, fans, pumps, silica gel breathers, oil leakage, containment
Tap Changers	Operational counts, oil level, oil leakage
Switchgear	Audible signs of corona, SF6 gas pressure
Protections	Displays, flags
Battery, Chargers, Inverters	Fluid levels, cell gassing, voltage
Building	Security, physical damage, water ingress, rodents
Grounding (all exposed)	Broken or missing conductor, overheating, connections
Auxiliary Equipment	Note (2)
Capacitor Banks	Audible signs of corona, connections
Site	Fence integrity, security cameras, soil erosion, vegetation management

Note (1) - Every TS is somewhat unique in the equipment on site. Not all stations have the features listed in the Table 3-15.
Note (2) - The items in Table 3-15 are in addition to the physical inspections all station equipment receives for signs of damage, overheating, wear, tampering or vandalism.

Transmission Connected Transformer Stations (TS)

Enova incorporates the requirements of the OEB's DSC, Transmission Code, manufacturer recommendations, and industry best practices as the basis for its TS inspection program. Under the direction of the Protection & Control (P&C)/Substation Electrician Supervisors, TS inspections are performed by station personnel on a monthly and yearly basis.

Enova has developed detailed inspection criteria to collect data and provide guidance during the monthly inspection process. All station equipment is inspected for signs of damage, deterioration, or tampering. Records of inspection are maintained electronically for asset registry purposes.

All records of inspection are reviewed by the P&C/Substation Electrician Supervisors. The asset register is updated and the data informs Enova's asset management process. Critical deficiencies presenting an imminent risk of asset failure, risk to public safety or reliability are reported immediately and addressed through Enova's proactive maintenance program.

Distribution Stations (DS)

Enova incorporates the requirements of the OEB's DSC, manufacturer recommendations, and industry best practices as the basis for its DS inspection program. Under the direction of the P&C/Substation Electrician Supervisors, DS inspections are performed by station personnel on a monthly and yearly basis.

Although these stations are smaller, they typically have the same major equipment as the transformer stations. **Table 3-15** provides a list of the typical inspection points at DS stations, although not all stations will have the same equipment. The inspection process is the same as described previously for the transformer stations.

3.3.1.4.2. Enova Maintenance Programs

Enova has extensive maintenance programs for its various assets. These programs contribute to the effective and successful management of distribution assets and drive continuous system improvement and performance, ensuring long term capacity, supply availability and reliability to meet customer needs.

Enova employs three maintenance strategies in its programs.

A) Reactive Maintenance (RM)

When assets have failed or are found to be near failing during inspections, reactive maintenance becomes an option to employ in order to restore the asset to a safe and operable state. Normally unplanned and sporadic in nature, reactive maintenance is often associated with longer customer interruptions, collateral damage to nearby equipment and after-hours call-out of staff.

Reactive maintenance is aligned with the Asset Management strategy of Run-to-Failure which is used for equipment with low consequences of failure.

When assets have failed and reactive maintenance is not an option, Reactive Replacement of the asset is normally employed.

B) Preventative Maintenance (PM)

Preventative maintenance activities are schedule or time-driven and are normally employed on assets where condition-based monitoring is cost prohibitive, or feasible. Simple and low-cost to set up, the preventative maintenance strategy is most commonly used at Enova. **Table 3-17** and **Table 3-18** provide a summary of Enova's preventative maintenance schedules for overhead and underground distribution lines.

C) Condition-Based (Predictive) Maintenance (CBM)

Condition-based or predictive maintenance is based on asset condition and is normally used on high-value assets such as station equipment due to the cost of applying asset monitoring equipment. CBM provides more timely condition information so that maintenance activities can intervene before failure occurs.

Table 3-17: Enova Maintenance Programs – Overhead Lines

OVERHEAD LINES	FREQUENCY
Load break switches (1/6 population)	Annual
Infrared Thermography	Annual
Pole Testing (fibre strength) approx. 10% of all poles > 25 years of age	Annual
Insulator Washing	Annually or as needed

Table 3-18: Enova Maintenance Programs – Underground Lines

UNDERGROUND LINES	FREQUENCY
Pad mounted Switching Cubicles	Annual
Pad mounted Transformers	Annual
Infrared Thermography	Annual

In addition, Enova complies with inspection and reverification standards identified in the OEB Transmission Code for grid-connected transformer stations.

D) Maintenance of Overhead Systems

Generally, deficiencies discovered during regularly scheduled inspections are corrected to remediate the deficiency either at the time of inspection or as soon as possible following inspection. If further corrective action is required, or cannot be performed concurrently with the inspection, the Distribution Superintendent is notified to allow for the required lead-time to procure materials or coordinate with third parties. Additionally, corrective action to remediate minor deficiencies may also be performed during the visual patrol. This may include replacement of broken guy guards or missing phase markers. Remaining deficiencies are reviewed by the Line Superintendent and prioritized for corrective action.

All maintenance performed is documented for review and analysis by the Line Superintendent and archived. Through analysis of maintenance data (further elaborated below), recurring deficiencies may be identified and channeled into a capital program for asset replacement.

Assets that require immediate maintenance or replacement are brought to the attention of the Line Superintendent.

Crossings

The type of deficiencies found at crossings and the maintenance performed to remediate the deficiencies are no different from those in other parts of the overhead distribution system. Crossings however are unique in the challenges they present to complete the work. River crossings have accessibility challenges due to terrain and seasonal conditions. Some require specialized equipment for access. Work on highway crossings can require extensive coordination of police and Ministry of Transportation (MTO) staff if a road closure is required. Deficiencies are documented, reviewed by the Line Superintendent and prioritized for corrective action. Remediation is scheduled allowing time for coordination with appropriate authorities and seasonal conditions.

Parks, Playgrounds & Schoolyards

If possible, deficiencies are remediated during the visual patrol. Corrective action is documented to allow for subsequent review and/or reporting. Remaining deficiencies are also documented, reviewed by the Line Superintendent and prioritized for corrective action. Critical deficiencies are reported immediately and typically remediated within one week, allowing for coordination with appropriate parties; non-critical deficiencies may be remediated in coordination with other maintenance programs.

Load-Break Switches

Preventative maintenance of load-break switches includes replacement of nomenclature, phase markers, arresters, replacing porcelain insulators with composite insulators and replacement or repair of switch components; also included is cleaning, lubrication and testing of switching operation. Preventative maintenance activities are documented on the appropriate reporting form, as well as surrounding or non-related deficiencies which required corrective action.

Preventative maintenance to address critical deficiencies is typically performed within 24 hours of the inspection and entails either refurbishment or complete replacement of the

switch, depending on the nature of the deficiency. Refurbishment is the preferred methodology where peripheral or secondary components to the switch are critically deficient, for example a corroded connector with the potential to burn the line. In the event of extensive damage, the switch will be replaced.

Vegetation Management

Vegetation management, or line clearing, is a preventative maintenance program for intrusive vegetation growth around electrical plant. It is scheduled on a rotational basis over Enova's service area and completed annually. This activity is executed according to the previously established Ontario Hydro guidelines and completed by qualified arborists or line-clearing contractors that have specialized knowledge of growth rates of various vegetation.

Approximately 20% of the annual program is comprised of reactive line clearing work in response to storms, customer requests or as identified by Enova staff observations. Such requests are documented via customer request sheets or work orders and prioritized following an inspection. Vegetation that has caused an interruption is deemed critical and addressed immediately whereas tree growth with the potential to cause an outage is scheduled. Enova takes additional preventative measures in its vegetation management program during the execution of capital projects.

Infrared Thermography

Infrared (IR) thermography is performed annually on the three phase portion of the overhead distribution system by a qualified contractor. This non-destructive, non-invasive, condition-based assessment of three-phase lines and equipment, allows thermal deficiencies to be identified. During this process, severe thermal anomalies, representing dangerous overheating with potential to disrupt supply or damage equipment, are reported on a daily basis to the Line Superintendent. Critical deficiencies are generally remediated within 24 to 48 hours, allowing for customer and/or outage coordination where applicable.

A summary report, following completion of IR thermography, is prepared and outlines fault locations, severity of the fault (prioritized based on thermal anomaly) and notes and recommendations. In addition to the severe thermal anomalies previously identified, the

report also identifies intermediate and minor hot spots. Maintenance to address the faults, as noted in the report, is subsequently prioritized and scheduled based on the potential impact of failure and fault severity (temperature rise above ambient temperature). Remediation work may be grouped together based on deficiency location as a cost-savings measure. All anomalies are remediated within the calendar year in which they were first identified. The Line Superintendent subsequently documents the date of remediation on the original summary report.

Insulator Washing

Insulator washing is typically performed annually on 27.6 kV and 44 kV insulators in areas known to have high salt contamination, for example at expressway crossings, as identified through previous washings and general reporting. The frequency of insulator washing may be prompted by other environmental factors such as industrial contamination.

Insulator washing is performed by a qualified contractor who, during the washing, will also report general concerns such as broken or damaged insulators. Because of the contractor's experience and qualifications, they are able to prioritize deficiencies whereby critical concerns, such as those potentially resulting in an outage, are immediately reported to Enova's Control Room and internally remediated within 24 hours. Less critical damage is reported to the Line Superintendent and remediated within one week.

Pole Testing

Enova has a Wood Pole Testing Program in place whereby poles are tested for baseline fibre strength. Poles chosen for testing are determined by age, risk to public safety and potential impact on system reliability. GIS-produced maps are provided to qualified testing contractors to identify and locate the poles to be tested. Results are provided in an electronic database, analyzed and determinations made as to the action required. On average Enova annually tests approximately 10% of the wood pole population greater than 25 years of age.

Poles with remaining fibre strength less than 50% are scheduled for replacement within 12 months. Depending on the location of the pole and complexity of the work, replacement may take from several days to several weeks.

Poles with remaining fibre strength between 50% and 60% are normally scheduled to be replaced in within the next 12 - 24 months. If the replacements can be combined into larger constructible projects or added to an existing planned project, Enova will perform a detailed structural analysis on the poles to determine if they can remain in service for up to an additional 24 months. This improves design and construction efficiency while providing an opportunity to upgrade to current standards. Poles that can be replaced like-for-like will normally be replaced within the current or following budget year.

Poles with remaining fibre strength between 60% and 75% are scheduled to be retested in 3-5 years. During the testing procedure a detailed visual inspection is also completed. Serious observed defects may require replacement of the pole regardless of the fibre strength testing results.

Poles with remaining fibre strength greater than 75% are scheduled to be retested in 5 years if > 35 years of age, or 10 years otherwise.

This pole testing program is in addition to the general patrol and inspection of the overhead system previously noted. Inspection and testing data are archived and becomes a direct input to Enova's Asset Condition Assessment program (ENGIN).

E) Maintenance of Underground Systems

Distribution Transformers

Minor maintenance can often be performed on distribution transformers during inspections; however, it is generally limited to renumbering elbow tags for visibility, installing new exterior or interior nomenclature where absent, provided this can be completed safely at the time. Where remediation of more critical deficiencies cannot be completed at the time of inspection due to outage coordination requirements with a customer for example, corrective action is scheduled for the earliest opportunity.

Deficiencies are prioritized by the Distribution Superintendent and scheduled along with other corrective maintenance work. Corrective action is documented and archived. Through

analysis of maintenance data, recurring deficiencies may be identified and channeled into a capital program, as required for asset replacement.

Switching Kiosks

Remediation of critical deficiencies involving access and security such as temporarily securing lids with broken hinges or locks, is performed at the time of inspection to provide adequate safety and/or reliability until replacement can be coordinated. Deficiencies of a lower priority, identified during the inspection and condition assessment, are documented and archived in the inspections database. Outstanding deficiencies are listed, categorized and prioritized according to the required corrective action. The deficiencies are then channelled into various maintenance programs for rehabilitation or into a capital program for replacement.

Vault Rooms

Deficiencies specific to vault rooms are documented and reported to the Line Superintendent for prioritization and remediation, typically as soon as possible allowing for coordination and outage scheduling. Deficiencies involving security such as door and lock conditions are dealt with immediately.

Infrared Thermography (IR)

IR thermography on the underground distribution system is completed annually in conjunction with the overhead system and includes identification of thermal anomalies in transformer vault rooms, pad-mounted transformers and switching cubicles, and underground risers.

As with the IR thermography of the overhead system, severe deficiencies presenting an immediate safety or reliability concern are reported daily to the Line Superintendent and remediated within 48 hours, or at the earliest opportune time, allowing for outage coordination where required. Following a review of the summary report outlining IR thermography activities and thermal anomalies, corrective action to remediate intermediate and minor deficiencies are prioritized and scheduled based on the severity of a deficiency.

F) Maintenance of Transformer Stations and Distribution Stations

Enova has well-established and comprehensive preventative and condition-based maintenance programs that provide the basis for the condition assessment and remediation of Transformer Station and Distribution Station equipment. In addition to satisfying the reporting requirements of the OEB's DSC, the IESO mandates additional requirements for grid-connected Transformer Stations that Enova must meet.

More than any other group of assets, equipment testing of station assets is extensive and the major component of input data needed for condition assessments and the detection of deficiencies. Identified deficiencies are documented and categorized as critical or non-critical, with the former having an immediate impact on health/safety or system capability, and the latter having a longer-term impact on performance or asset health. Critical or non-critical minor deficiencies may be remediated during the inspection, provided materials are on-hand or as warranted. Those not remediated at the time are subsequently reviewed by the P&C/Substation Electrician Supervisors and compiled into a single deficiency list. Critical deficiencies are addressed at the earliest opportunity, considering material lead-times or outage coordination. Conversely, non-critical deficiencies are addressed within one year or coordinated with preventative maintenance activities to mitigate outage time, if required. Following remediation, specific information about corrective action taken and the completion date is documented.

The decision on whether corrective action is best implemented through maintenance or capital replacement is made by Stations Engineering department through analysis.

Table 3-19 and **Table 3-20** provide a summary of major components and planned maintenance intervals for TS and DS assets.

Table 3-19: Enova Maintenance Programs – Stations (TS)

	INTERVAL				
TRANSFORMER STATION MAINTENANCE	**1 YEAR**	**2 YEAR**	**4 YEAR**	**5 YEAR**	**10 YEAR**
Transformer			X		
Circuit Switchers, HV Switches			X		
Bus					X
Protections Transformer/Line/CBF			X		
Bus Protections			X		
Bank and Tie Breakers			X		
Feeders (breakers/cables/protections)			X		
Battery Banks	X				
Sustained Alarms			X		
Full SCADA Check			X		
IR Thermography	X				
Transformer Oil Testing (DGA & Oil Condition)	X				
Painting					X
Vibration Analysis (Tx oil cooling fans and pumps)		X			

Table 3-20: Enova Maintenance Programs – Stations (DS)

TRANSFORMER STATION (DS) MAINTENANCE	**INTERVAL**				
	1 YEAR	**2 YEAR**	**4 YEAR**	**5 YEAR**	**10 YEAR**
Transformers				X	
HV Switches				X	
Bus Inspection					X
Station 24/48 Battery Banks	X				
Breakers / Reclosers/ Protections				X	
Capacitor Banks & Switches				X	
SCADA/Local Alarms				X	
Feeders				X	
Transformer Oil Testing (DGA & Oil Condition)	X				
IR Thermography	X				
Painting					X

Although Enova follows IESO-mandated fixed maintenance frequencies with TS assets, Enova also utilizes condition-based parameters for a predictive maintenance approach. These parameters include;

- transformer online dissolved gas analysis, oil condition;

- tap changer oil condition, vibration analysis, operations counter
- transformer cooling pumps & fans vibration analysis

Infrared Thermography

IR thermography of all stations is completed annually and coordinated with thermography of the overhead and underground distribution system, following the IR processes previously described for preventative maintenance on the overhead and underground system. Following the IR thermography inspection, a report is produced outlining inspection activities, thermal anomalies and recommendations. The report is reviewed by the P&C/Substation Electrician Supervisors and recommendations may be implemented for remediation of anomalies or, if more extensive, coordinated with Stations Engineering.

Vegetation Management

Vegetation control around transformer stations, rural distribution stations and transformer enclosures is carried out annually under the direction of the P&C/Substation Electrician Supervisors by Enova stations staff or a qualified contractor. The main activities consist of the control of vegetation in the station granular material to reduce step potential hazards, the prevention of climbing access into station yards and the creation of clear sight lines along station fence lines for security reasons.

Insulator Washing

Insulator washing is typically performed on selected 27.6 kV and 44 kV station structures in areas known to have high salt contamination (mostly from roadway spray), as identified through previous inspections. The work is coordinated with the annual overhead line's insulator-washing program.

Vibration Monitoring

In addition to regular visual inspections, Enova performs vibration analysis every two years to assess the condition of oil cooling fans and oil circulation pumps associated with grid-connected transformers. Vibration analysis aids in the prediction of impending failures that can directly lead to the derating of the transformers. Enova contracts this specialized work with a third party. A report is produced outlining anomalies and recommendations. The report

is reviewed by the P&C/Substation Electrician Supervisors and recommendations may be implemented for remediation of anomalies or, if more extensive, coordinated with Stations Engineering.

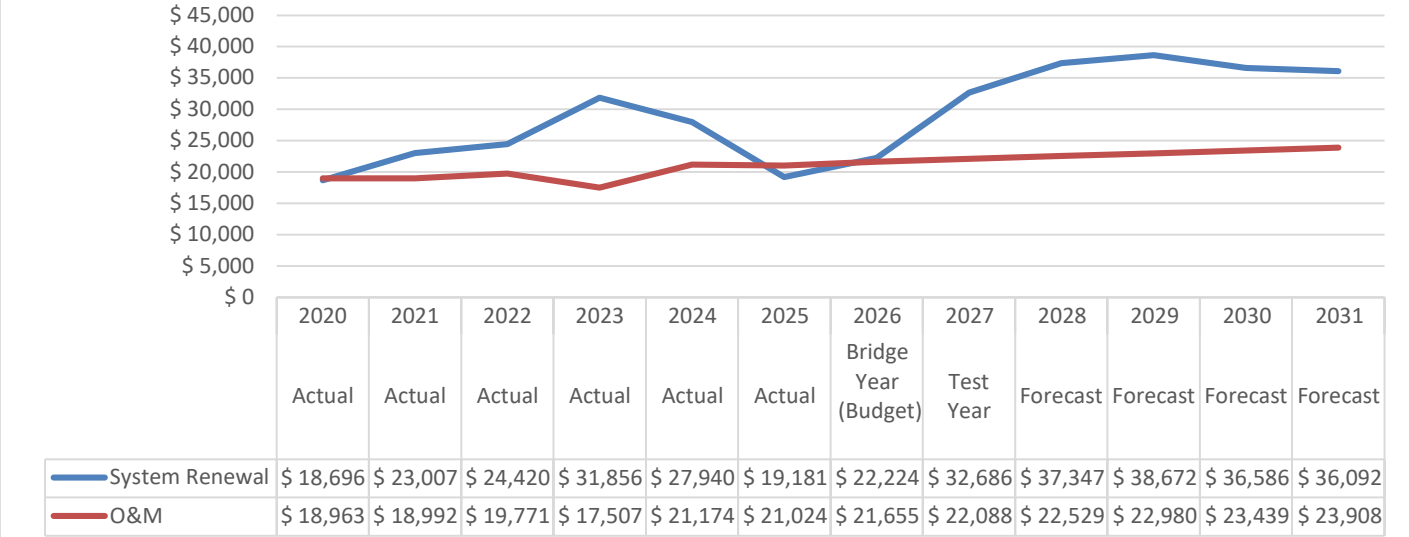
Transformer Oil Testing

Transformer oil condition and dissolved gas analysis (DGA) is performed on all power substation transformers on an annual basis. Oil sampling is coordinated by the P&C/Substation Electrician Supervisors using internal staff. Enova contracts the specialized work of oil testing and analysis with a third party. A report is produced outlining anomalies and recommendations. Stations Engineering reviews the report and provides direction for remediation of anomalies.

3.3.1.5. Impact of System Renewal Investments on Routine O&M

Figure 3-6 illustrates Enova's historical and forecast expenditures in System Renewal and total O&M.

Figure 3-6: System Renewal vs O&M Expenditures ($000s)



	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Actual	2026 Bridge Year (Budget)	2027 Test Year	2028 Forecast	2029 Forecast	2030 Forecast	2031 Forecast
System Renewal	$ 18,696	$ 23,007	$ 24,420	$ 31,856	$ 27,940	$ 19,181	$ 22,224	$ 32,686	$ 37,347	$ 38,672	$ 36,586	$ 36,092
O&M	$ 18,963	$ 18,992	$ 19,771	$ 17,507	$ 21,174	$ 21,024	$ 21,655	$ 22,088	$ 22,529	$ 22,980	$ 23,439	$ 23,908

Over the long term, Enova believes that System Renewal investments do help moderate the rise in routine O&M costs. Replacing assets in poor condition with new assets defers some near-term maintenance costs into future years; however, the annual amount of assets replaced typically represents only a fraction of the existing asset base. In the short term, it is difficult to quantify the reduction in maintenance costs due to System Renewal investments. From **Figure 3-6** it can be seen that over the short term, both maintenance and System Renewal expenditures have increased. Any incremental savings tend to be absorbed by inflationary cost increases. Also to be considered is the significant portion of asset base that remains and continues to age and deteriorate, attracting incremental increases in maintenance costs.

Asset additions that result from System Access and System Renewal investments add to the workload of inspection and maintenance programs placing additional upward pressure on O&M expenditures and making it again difficult to quantify any reductions due to System Renewal investments alone.

Over the historical period, Enova's O&M costs increased on average by 2.3% annually.

3.3.2. Asset life optimization policies, processes, and tools

Enova's current asset lifecycle optimization policies and processes are a harmonization of those employed by the legacy LDCs. Fundamentally, both legacy LDCs were aligned in terms of policies and processes of life-cycle management and that alignment is reflected in how Enova is moving forward today. The tools used by the legacy LDC's varied; however, that has changed through the harmonization process that has occurred since the merger. These tools are now used corporate wide.

- Geographical Information System Software (GIS) (2025)
- Asset Management Software (ENGIN 2.0) (2025)
- Meter Data Management System (MDM) (2026)
- Automated Utility Design (AUD) 2022
- Power flow analysis software (Synergii) (2026)
- Outage Management System (OMS) (2025)
- Supervisory Control and Data Acquisition (SCADA) (2025)
- Enterprise Resource Management Software (JD Edwards) (2025)

3.4. (5.3.4) System Capability Assessment for Renewable Energy Generation and Distributed Energy Resources

Overall, Enova has approximately 130 MW (71%) of generation capacity (thermal) remaining on its power transformers; however, overall generation capacity is limited to 95 MW (52%) due to short-circuit limitations on some of Enova's switchgear and circuit breakers.

Based on Enova's assessment of distribution system capacity and utilization, there is sufficient hosting capacity for REGs and DERs across its points of supply, transformer stations, and 13.8 kV feeders and 27.6 kV feeder systems to accommodate the anticipated number of connection requests over the forecast period.

At this time, Enova cannot adequately comment on transmission capacity constraints over the forecast period until there is greater certainty regarding the outcome of the KWCG IRRP which, at the time of preparing this report, is still in progress.

Through Enova's ongoing System Renewal program, equipment will be replaced or refurbished where the trigger driver is asset condition. The modern replacement equipment inherently has higher fault-current ratings, thereby increasing the capacity to connect future generation as a co-benefit of these investments. The short-circuit limitations at constrained stations will be progressively relieved over time, increasing hosting capacity.

Given the already sufficient hosting capacity on the distribution system, and given that, as a co-benefit of Enova's System Renewal investments in station assets, that hosting capacity will be further increased, Enova has not included any investments specifically targeted to increase hosting capacity over the forecast period.

The capabilities of Enova's distribution system, hosting capacity, connection forecast, restricted feeder information and plans to improve hosting capacity are presented in detail in the following sections of this DSP;

- **Section 2.2.3.13:** Renewable Energy Generation (REG)
- **Appendix D-1:** Renewable Energy Generation Investment (REGI) Plan.

3.5. (5.3.5) Non-Wires Solutions (NWS) to Address System Needs

During development of the 2027–2031 DSP, Enova screened all material capital investment programs to determine whether non-wires solutions could reasonably defer, reduce, or eliminate the need for traditional distribution infrastructure investments. The screening process considered the nature of the system need, the level of investment discretion, customer impacts, technical feasibility, timing requirements, lifecycle costs, and overall cost-effectiveness.

Asset replacement programs driven primarily by deteriorated equipment, safety, regulatory compliance, or end-of-life infrastructure were generally screened out because non-wires solutions cannot mitigate the physical condition of aging assets. Conversely, projects associated with load growth, system capacity, distributed energy resources, and grid modernization were evaluated for potential non-wires opportunities, including demand response, conservation, distributed generation, energy storage, managed electric vehicle charging, and operational technologies.

Appendix K – Non-Wires Solutions (NWS) presents Enova's non-wires solutions pre-screening methodology and the results of its initial screening of proposed capital investments. The appendix demonstrates that Enova has established a systematic process for evaluating the potential applicability of non-wires solutions as part of its integrated distribution system planning process.

As this is Enova's first formal implementation of an NWS screening framework, Enova has not yet had sufficient opportunity to implement non-wires solutions where they may provide value comparable to, or greater than, traditional wires-based investments. However, the pre-screening process establishes a consistent foundation for future evaluations by identifying projects that warrant more detailed NWS assessment as planning needs evolve.

Enova will continue to mature its NWS framework over future planning cycles by refining its screening criteria, evaluating feasible non-wires alternatives for applicable investment needs, and incorporating cost-effective solutions where they are technically feasible, economically justified, and consistent with maintaining the safety, reliability, and performance of the distribution system

3.6. (5.3.6) Climate Vulnerability Assessment and System Hardening

In compliance with the OEB's Vulnerability Assessment and System Hardening (VASH) policy (EB-2024-0199), Enova has undertaken a best-efforts assessment of climate-related vulnerabilities affecting its distribution pole fleet. The detailed analysis is provided in **Appendix M: VASH - Climate Vulnerability of Distribution Pole Assets**. This section summarizes the key findings, methodology, and Enova's plan for continued refinement of its climate resilience planning.

Enova's VASH assessment was informed by its active participation in the Utilities Standards Forum (USF) VASH working group, where member utilities collaboratively examined the OEB's VASH Toolkit methodology, conducted structural modelling using SPIDAcalc software, and engaged directly with OEB project staff to ensure consistent interpretation of the framework. This collaborative process provided the foundation for the input parameters and assumptions used in Enova's assessment.

The vulnerability assessment focused on Enova's wood distribution pole fleet, analyzing approximately 7,000 degraded poles (roughly 15% of the total wood pole population) with remaining structural strength below 60% of original design capacity. Wind failure thresholds for each pole sub-class were derived from the USF working group's SPIDAcalc structural modelling, which evaluated pole performance under CSA C22.3 No. 1:25 loading conditions. These CSA loading conditions incorporate the combined effects of wind, ice accretion, and temperature, meaning that the failure thresholds used in this assessment inherently account for the compound effects of wind and ice on pole structural integrity — not wind in isolation. The VASH Toolkit's climate projection module then evaluates the probability of exceeding these thresholds under the RCP 8.5 climate scenario for the Kitchener-Waterloo service territory.

The vulnerability heatmap results indicate that multi-circuit degraded poles (2-circuit and 3-circuit configurations) represent the more vulnerable segment of the fleet, falling in the Medium vulnerability classification with annual wind exceedance probabilities of approximately 10.5% in 2025, rising to 11.3% by 2090. Single-circuit and single-phase

degraded poles fall in the Low vulnerability classification. Poles meeting current CSA design standards show no vulnerability across the entire projection period.

Using the OEB's BCA Toolkit, Enova evaluated an Early Retirement project for the 7,000 degraded poles, producing a benefit-cost ratio in the range of 0.75 to 0.85 based on sensitivity analysis across key input parameters. While the BCR falls below 1.0, the analysis demonstrates that proactive pole replacement delivers meaningful reliability benefits, including an estimated lifetime reduction of approximately 399,000 customer-minutes of interruption. The forward-looking climate trajectory shows increasing vulnerability over the asset planning horizon, supporting the value of sustained investment in pole renewal as part of Enova's broader asset management program.

Enova recognizes that this initial VASH assessment represents a starting point, and is committed to the following refinements in future filings:

- **Expanded climate peril analysis:** The current assessment uses failure thresholds derived under CSA combined wind-ice-temperature loading, and the Toolkit's climate projections focus on wind speed exceedance as the primary peril. In future assessments, Enova intends to evaluate ice accretion as an independent climate peril, particularly for dead-end, angle, and tension-change poles where ice loading without significant wind can govern structural performance.

- **Feeder-level project analysis:** Transition from system-wide assessment to targeted BCAs for the highest-vulnerability feeders, consistent with the VASH Report's preferred approach of matching outage calibration data to specific project locations.

- **Integration with asset management:** Embed VASH vulnerability outputs into Enova's existing asset condition assessment and capital planning processes, ensuring that climate resilience considerations are systematically incorporated alongside traditional investment drivers such as equipment condition, safety, and reliability performance.

Enova will continue to participate in the USF VASH working group and maintain dialogue with the OEB to ensure its approach remains aligned with evolving regulatory expectations and industry best practices.

4. (5.4) CAPITAL EXPENDITURE PLAN

This section describes Enova's capital expenditure plan over a seven-year historical period covering 2020 to 2026 and a five-year forecast period covering 2027 to 2031. The Bridge Year and Test Year are 2026 and 2027, respectively.

For the premerger years, 2020 to 2022, information is shown both by legacy LDCs and on a consolidated basis. Moving forward from 2022, all financial information in the post-merger years, 2023 - 2031 is shown on a consolidated basis. All Enova capital investments are allocated into the four OEB categories as prescribed in Chapter 5.

Historical variance analyses, both historical plan-to-actual and budget-to-actual are provided. Forecast variance analyses are provided on a year-to-year basis including comparisons to historic expenditure levels.

The threshold of materiality applied to capital investments is provided in **Table 4-1**

Table 4-1: Materiality Thresholds ($000s)

Enova: 2023-2026	$400
KWH: 2020-2022	$200
WNH: 2020-2022	$190

Unless otherwise stated, the information provided in this section is current as of Dec 31, 2025.

For capital projects with a project life cycle greater than one year, all direct and attributable costs, including applicable borrowing costs incurred during construction are capitalized and recorded as Construction Work-in-Progress (CWIP). Interest costs are capitalized from the commencement of construction activities until the asset is substantially complete and available for its intended use. Upon completion, the accumulated CWIP balance, including capitalized interest, is transferred to the appropriate Property, Plant and Equipment asset category and depreciated over the asset's estimated useful life.

There are no expenditures planned for non-distribution assets in Enova's budget.

4.1. (5.4.1) Capital Expenditure Summary

Enova's five-year capital plan has been developed through an integrated planning process that aligns identified system needs with prudent, risk-informed investment decisions and measurable customer outcomes. Each proposed investment addresses one or more strategic drivers, including asset condition, reliability, load growth, safety, regulatory compliance, grid modernization, and operational efficiency, while supporting Enova's asset management objectives.

Collectively, these investments are expected to achieve Enova's reliability targets, reduce asset risk, accommodate customer growth, modernize the distribution system, and optimize lifecycle costs while maintaining affordability for customers. The capital plan reflects Enova's commitment to balancing cost, risk, and performance, ensuring that investment decisions provide sustainable long-term value and support the Ontario Energy Board's expectations for prudent, evidence-based distribution system planning.

Table 4-2 summarizes Enova's investment needs and expected customer outcomes.

Table 4-2 Enova Needs-to-Investment-to-Outcomes Alignment

Strategic System Need	Primary Investment Programs	Business Driver	Expected Customer & System Outcomes	Supporting DSP Sections
Replace distribution assets in poor condition and at end-of-life	Pole replacements, underground cable and transformer replacement, transformer station renewal	Asset condition (ACA)	Reduced failures and improved safety. Improved Resilience	Asset Condition (ACA); Capital Plan
Maintain distribution reliability below maximum targets	Automation and reclosers, FLISR, System Renewal program	Reliability	Improved SAIDI/SAIFI and restoration. Improved resilience	Reliability
Maintain capacity	Station and feeder expansions	Load growth	Support customer growth	System Capacity & Utilization Report
Modernize grid	Monitoring and communications DSO Readiness	Modernization Public Policy	Greater visibility and resilience NWS Support	Grid Modernization Innovation
Reduce asset risk	Risk-based replacement	Asset management	Optimized lifecycle cost	Asset Management
Support electrification	DER and EV readiness	Electrification	Higher hosting capacity	System Capacity & Utilization Report
Meet compliance	Protection and cybersecurity	Compliance	Regulatory compliance	Compliance
Improve efficiency	Fleet and work management, System Loss reduction	Efficiency	Lower lifecycle cost, Lower Line Loss Adjustment Factor % Bill	Operations
Optimize spending	Portfolio prioritization	Optimization	Reduced rate impacts	Capital Planning
Deliver long-term value	Integrated planning	Cost/risk/performance	Reliable affordable service	DSP

Tables 4-3 and **Table 4-4** provide a completed **Appendix 2-AB – Capital and O&M Expenditure Summary Table** for each of KWH and WNH premerger years 2020 to 2022.

Table 4-5 provides a completed **Appendix 2-AB – Capital Expenditure Summary Table** for Enova with two exceptions. Due to the staggered nature of the last DSPs filed by Enova's legacy LDCs, capital plan amounts (OEB approved after adjustments) are only available up to 2024 for KWH and 2025 for WNH resulting in no comparable plan amounts available in 2025. At the time of preparation, there were no actual amounts available for Enova's 2026 Test Year. The amounts for years 2020 - 2022 are the consolidated amounts provided in **Tables 4-3 and 4-4**.

Also included are Enova's actual operating and maintenance (O&M) expenditures over the same periods.

Table 4-6 provides a completed **Appendix 2-AA – Capital Projects Table** with one exception. Actual capital expenditures by project are provided from 2020 – 2025. At the time of filing, no 2026 actual expenditure amounts were available. For 2026, Enova board approved budget amounts were provided. The 2027 forecast amounts are also provided

It should be noted that the COVID-19 pandemic had a significant impact on Enova's historical capital investment program. In 2020, public health restrictions, supply chain disruptions, labour constraints, and uncertainty surrounding customer activity resulted in lower capital spending than would otherwise have occurred. Capital activity began to recover in 2021 and 2022 as restrictions eased; however, the pending merger of Kitchener-Wilmot Hydro Inc. and Waterloo North Hydro Inc. introduced additional uncertainty. During this period, several discretionary and strategic capital investment decisions were deferred until the merger was completed, allowing the newly formed utility to evaluate investment priorities on a consolidated basis and avoid duplicative or suboptimal expenditures.

Enova's first fully integrated capital expenditure plan was developed for the 2023 fiscal year, only a few months after the merger was completed. Consequently, the 2023 capital program reflected the initial consolidation of the legacy utilities' planning processes, investment priorities, and asset management strategies. While the 2023 plan established a common

capital planning framework, Enova has continued to refine its investment planning processes, asset information, and program integration in subsequent years as the organization has matured.

Table 4-3: KWH Appendix 2-AB – Capital Expenditure Summary ($000s) 2020-2022

OEB Investment Category	Historical Period														
	2020					2021					2022				
KWH	Plan	Budget	Actual	Var % Actual to Plan	Var % Actual to Budget	Plan	Budget	Actual	Var % Actual to Plan	Var % Actual to Budget	Plan	Budget	Actual	Var % Actual to Plan	Var % Actual to Budget
System Access	$ 7,065	$ 7,374	$ 7,739	9.5%	5.0%	$ 7,767	$ 7,333	$ 6,676	-14.1%	-9.0%	$ 7,817	$ 7,625	$ 8,633	10.4%	13.2%
System Renewal	$ 9,415	$ 9,105	$ 10,065	6.9%	10.5%	$ 10,350	$ 10,640	$ 11,931	15.3%	12.1%	$ 10,650	$ 11,640	$ 12,889	21.0%	10.7%
System Service	$ 3,200	$ 3,200	$ 1,240	-61.3%	-61.3%	$ 3,200	$ 3,050	$ 1,003	-68.6%	-67.1%	$ 2,800	$ 3,000	$ 999	-64.3%	-66.7%
General Plant	$ 6,495	$ 6,945	$ 7,097	9.3%	2.2%	$ 3,275	$ 4,160	$ 6,767	106.6%	62.7%	$ 3,565	$ 3,491	$ 1,985	-44.3%	-43.2%
Gross CAPEX	$ 26,175	$ 26,623	$ 26,141	-0.1%	-1.8%	$ 24,592	$ 25,182	$ 26,377	7.3%	4.7%	$ 24,832	$ 25,756	$ 24,506	-1.3%	-4.9%
Contributed Capital	$ 4,000	$ 3,914	$ 4,390	9.7%	12.2%	$ 4,000	$ 4,047	$ 5,832	45.8%	44.1%	$ 4,000	$ 3,936	$ 5,927	48.2%	50.6%
Net CAPEX	$ 22,175	$ 22,709	$ 21,751	-1.9%	-4.2%	$ 20,592	$ 21,135	$ 20,545	-0.2%	-2.8%	$ 20,832	$ 21,820	$ 18,579	-10.8%	-14.9%
Total O&M	$ 13,162	$ 12,191	$ 11,591	-11.9%	-4.9%	$ 13,162	$ 12,552	$ 11,176	-15.1%	-11.0%	$ 13,162	$ 12,536	$ 12,338	-6.3%	-1.6%

Table 4-4: WNH Appendix 2-AB – Capital Expenditure Summary ($000s) 2020-2022

OEB Investment Category	Historical Period														
	2020					2021					2022				
WNH	Plan	Budget	Actual	Var % Actual to Plan	Var % Actual to Budget	Plan	Budget	Actual	Var % Actual to Plan	Var % Actual to Budget	Plan	Budget	Actual	Var % Actual to Plan	Var % Actual to Budget
System Access	$ 6,822	$ 5,358	$ 8,797	29.0%	64.2%	$ 5,840	$ 6,249	$ 8,200	40.4%	31.2%	$ 6,166	$ 7,892	$ 7,578	22.9%	-4.0%
System Renewal	$ 8,440	$ 9,617	$ 8,631	2.3%	-10.3%	$ 8,947	$ 9,451	$ 11,076	23.8%	17.2%	$ 9,572	$ 10,170	$ 11,531	20.5%	13.4%
System Service	$ 1,763	$ 846	$ 827	-53.1%	-2.2%	$ 2,194	$ 1,281	$ 1,068	-51.3%	-16.7%	$ 1,346	$ 937	$ 845	-37.2%	-9.8%
General Plant	$ 2,353	$ 3,555	$ 1,866	-20.7%	-47.5%	$ 2,776	$ 2,776	$ 2,038	-26.6%	-26.6%	$ 3,853	$ 2,994	$ 2,282	-40.8%	-23.8%
Gross CAPEX	$ 19,378	$ 19,375	$ 20,121	3.8%	3.8%	$ 19,757	$ 19,758	$ 22,382	13.3%	13.3%	$ 20,938	$ 21,993	$ 22,236	6.2%	1.1%
Contributed Capital	$ 2,599	$ 2,066	$ 2,542	-2.2%	23.0%	$ 2,695	$ 2,694	$ 3,696	37.1%	37.2%	$ 2,710	$ 3,778	$ 2,542	-6.2%	-32.7%
Net CAPEX	$ 16,779	$ 17,309	$ 17,579	4.8%	1.6%	$ 17,061	$ 17,064	$ 18,686	9.5%	9.5%	$ 18,228	$ 18,215	$ 19,694	8.0%	8.1%
Total O&M	$ 7,907	$ 6,476	$ 7,373	-6.8%	13.8%	$ 8,214	$ 6,257	$ 7,815	-4.9%	24.9%	$ 8,378	$ 6,133	$ 7,433	-11.3%	21.2%

Table 4-5: Enova Appendix 2-AB – Capital Expenditure Summary ($000s) Consolidated 2020-2031

OEB Investment Category	Plan	Budget	Actual	% Variance	% Variance	Plan	Budget	Actual	% Variance	% Variance	Plan	Budget	Actual	% Variance	% Variance	Plan	Budget	Actual	% Variance	% Variance
	2020	2020	2020	Actual - Plan	Actual - Budget	2021	2021	2021	Actual - Plan	Actual - Budget	2022	2022	2022	Actual - Plan	Actual - Budget	2023	2023	2023	Actual - Plan	Actual - Budget
System Access	$ 13,887	$ 12,731	$ 16,536	19.1%	29.9%	$ 13,607	$ 13,581	$ 14,876	9.3%	9.5%	$ 13,983	$ 15,516	$ 16,211	15.9%	4.5%	$ 13,676	$ 15,577	$ 14,527	6.2%	-6.7%
System Renewal	$ 17,855	$ 18,722	$ 18,696	4.7%	-0.1%	$ 19,297	$ 20,091	$ 23,007	19.2%	14.5%	$ 20,222	$ 21,810	$ 24,420	20.8%	12.0%	$ 20,898	$ 25,508	$ 31,856	52.4%	24.9%
System Service	$ 4,963	$ 4,046	$ 2,067	-58.4%	-48.9%	$ 5,394	$ 4,331	$ 2,071	-61.6%	-52.2%	$ 4,146	$ 3,937	$ 1,844	-55.5%	-53.2%	$ 3,613	$ 3,097	$ 1,356	-62.5%	-56.2%
General Plant	$ 8,848	$ 10,500	$ 8,963	1.3%	-14.6%	$ 6,051	$ 6,936	$ 8,805	45.5%	26.9%	$ 7,418	$ 6,485	$ 4,266	-42.5%	-34.2%	$ 7,373	$ 7,247	$ 4,053	-45.0%	-44.1%
Gross CAPEX	$ 45,553	$ 45,999	$ 46,262	1.6%	0.6%	$ 44,349	$ 44,940	$ 48,759	9.9%	8.5%	$ 45,770	$ 47,748	$ 46,741	2.1%	-2.1%	$ 45,561	$ 51,429	$ 51,792	13.7%	0.7%
Contributed Capital	$ 6,599	$ 5,980	$ 6,932	5.0%	15.9%	$ 6,695	$ 6,741	$ 9,528	42.3%	41.3%	$ 6,710	$ 7,714	$ 8,469	26.2%	9.8%	$ 6,536	$ 7,420	$ 6,664	2.0%	-10.2%
Net CAPEX	$ 38,954	$ 40,019	$ 39,330	1.0%	-1.7%	$ 37,653	$ 38,199	$ 39,231	4.2%	2.7%	$ 39,060	$ 40,034	$ 38,272	-2.0%	-4.4%	$ 39,025	$ 44,009	$ 45,128	15.6%	2.5%
Total O&M	$ 21,069	$ 18,667	$ 18,963	-10.0%	1.6%	$ 21,376	$ 18,809	$ 18,992	-11.2%	1.0%	$ 21,540	$ 18,669	$ 19,771	-8.2%	5.9%	$ 21,708	$ 17,683	$ 17,507	-19.4%	-1.0%

OEB Investment Category	Plan	Budget	Actual	% Variance	% Variance	Plan	Budget	Actual	% Variance	% Variance	Plan	Bridge Year	Actual	% Variance	% Variance	Test Year	Forecast	Forecast	Forecast	Forecast
	2024	2024	2024	Actual - Plan	Actual - Budget	2025	2025	2025	Actual - Plan	Actual - Budget	2026	2026 (Budget)	2026	Actual - Plan	Actual - Budget	2027	2028	2029	2030	2031
System Access	$ 14,215	$ 21,653	$ 15,581	9.6%	-28.0%		$ 22,045	$ 21,357		-3.1%	$ -	$ 25,572				$23,903	$23,466	$36,935	$42,035	$39,644
System Renewal	$ 21,143	$ 21,588	$ 27,940	32.1%	29.4%		$ 23,573	$ 19,181		-18.6%	$ -	$ 22,224				$32,686	$37,347	$38,672	$36,586	$36,092
System Service	$ 3,736	$ 2,219	$ 1,068	-71.4%	-51.9%		$ 3,928	$ 2,873		-26.9%	$ -	$ 2,854				$1,643	$1,643	$1,643	$1,643	$1,643
General Plant	$ 6,156	$ 12,600	$ 8,741	42.0%	-30.6%		$ 17,592	$ 13,776		-21.7%	$ -	$ 19,489				$20,473	$10,632	$9,353	$9,617	$8,813
Gross CAPEX	$ 45,250	$ 58,059	$ 53,330	17.9%	-8.1%		$ 67,139	$ 57,187		-14.8%	$ -	$ 70,139				$78,705	$73,089	$86,604	$89,880	$86,192
Contributed Capital	$ 6,819	$ 9,700	$ 6,472	-5.1%	-33.3%		$ 8,405	$ 8,988		6.9%	$ -	$ 11,504				$7,485	$7,495	$7,489	$6,783	$8,208
Net CAPEX	$ 38,431	$ 48,359	$ 46,858	21.9%	-3.1%		$ 58,734	$ 48,199		-17.9%	$ -	$ 58,635				$71,220	$65,594	$79,115	$83,097	$77,984
Total O&M	$ 21,879	$ 19,897	$ 21,174	-3.2%	6.4%		$ 20,425	$ 21,024		2.9%		$ 21,753				$ 22,128	$ 22,228	$ 22,228	$ 22,328	$ 22,328

Table 4-6: Appendix 2-AA – Capital Projects Table ($000s)

Projects	2020 Actual			2021 Actual			2022 Actual			2023 Actual	2024 Actual	2025 Actual	2026 Bridge	2027 Test	2028 Forecast	2029 Forecast	2030 Forecast	2031 Forecast
	WNH	KWH	Total	WNH	KWH	Total	WNH	KWH	Total	Enova	Enova	Enova	Enova	Enova	Enova	Enova	Enova	Enova
Reporting Basis	*MIFRS*	*MIFRS*	*MIFRS*	*MIFRS*	*MIFRS*	*MIFRS*	*MIFRS*	*MIFRS*	*MIFRS*	*MIFRS*	*MIFRS*	*MIFRS*	*MIFRS*	*MIFRS*	*MIFRS*	*MIFRS*	*MIFRS*	*MIFRS*
System Access																		
Relocations - Routine Projects	$ 1,308	$ 2,450	$ 3,759	$ 1,540	$ 763	$ 2,303	$ 765	$ 1,734	$ 2,499	$ 597	$ 2,395	$ 3,511	$ 1,388	$ 727	$ 1,227	$ 1,227	$ 1,227	$ 1,227
Relocations - Special Projects	$ 0	$ 0	$ 0	$ 3	$ 0	$ 3	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 3,322	$ 3,131	$ 3,131	$ 3,131	$ 2,831	$ 3,431
Customer Connections - Loads	$ 3,030	$ 2,044	$ 5,074	$ 2,853	$ 2,523	$ 5,376	$ 2,993	$ 2,966	$ 5,959	$ 5,905	$ 5,950	$ 6,858	$ 8,553	$ 8,027	$ 7,527	$ 7,527	$ 7,527	$ 7,527
Customer Connections - Generation	$ 384	$ 30	$ 414	$ 363	$ 72	$ 435	$ 85	$ 70	$ 155	$ 200	$ 199	$ 328	$ 371	$ 299	$ 299	$ 299	$ 299	$ 299
OH Line Expansions	$ 1,425	$ 0	$ 1,425	$ 764	$ 0	$ 764	$ 608	$ 0	$ 608	$ 971	$ 638	$ 3,817	$ 976	$ 729	$ 729	$ 729	$ 729	$ 729
UG Line Expansions - Feeders	$ 946	$ 256	$ 1,201	$ 186	$ 1,810	$ 1,995	$ 1,339	$ 1,209	$ 2,548	$ 2,213	$ 1,252	$ 650	$ 1,055	$ 2,794	$ 2,794	$ 2,794	$ 2,794	$ 2,794
UG Line Expansions - Subdivisions	$ 929	$ 2,549	$ 3,478	$ 1,802	$ 1,163	$ 2,965	$ 1,129	$ 2,305	$ 3,434	$ 3,521	$ 4,143	$ 4,450	$ 5,852	$ 4,165	$ 4,165	$ 4,165	$ 4,165	$ 4,165
Station Buildings - Expansions	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 334	$ 323	$ 0	$ 0	$ 0	$ 0
Station Equipment - Expansions	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 2,357	$ 2,280	$ 2,007	$ 7,249	$ 13,653	$ 10,629
SCADA Equipment - Expansions	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
Meters - Retail	$ 774	$ 409	$ 1,184	$ 690	$ 346	$ 1,036	$ 661	$ 348	$ 1,008	$ 1,120	$ 1,004	$ 1,743	$ 1,363	$ 1,427	$ 1,587	$ 9,814	$ 8,809	$ 8,842
Sub-Total	**$ 8,797**	**$ 7,739**	**$ 16,535**	**$ 8,200**	**$ 6,676**	**$ 14,876**	**$ 7,578**	**$ 8,633**	**$ 16,211**	**$ 14,527**	**$ 15,581**	**$ 21,357**	**$ 25,572**	**$ 23,903**	**$ 23,466**	**$ 36,935**	**$ 42,035**	**$ 39,644**
System Renewal																		
OH Line Renewal - Routine Projects	$ 3,418	$ 3,187	$ 6,605	$ 3,893	$ 5,431	$ 9,324	$ 6,756	$ 4,784	$ 11,540	$ 11,582	$ 6,171	$ 2,415	$ 2,270	$ 4,107	$ 4,107	$ 4,107	$ 4,107	$ 4,107
OH Line Renewal - Failing Conductor	$ 478	$ 0	$ 478	$ 1,493	$ 0	$ 1,493	$ 0	$ 0	$ 0	$ 0	$ 515	$ 171	$ 1,917	$ 1,941	$ 541	$ 541	$ 541	$ 541
OH Line Renewal - Voltage Upgrade	$ 616	$ 1,180	$ 1,796	$ 566	$ 664	$ 1,231	$ 497	$ 1,456	$ 1,953	$ 2,469	$ 3,070	$ 1,090	$ 3,520	$ 6,364	$ 5,364	$ 5,364	$ 5,364	$ 5,364
OH Line Renewal - Proactive	$ 539	$ 0	$ 539	$ 745	$ 0	$ 745	$ 516	$ 0	$ 516	$ 1,762	$ 767	$ 1,675	$ 358	$ 337	$ 337	$ 337	$ 337	$ 337
OH Line Renewal - Reactive	$ 610	$ 0	$ 610	$ 191	$ 0	$ 191	$ 398	$ 0	$ 398	$ 414	$ 772	$ 336	$ 1,055	$ 684	$ 684	$ 684	$ 684	$ 684
UG Line Renewal - Feeders	$ 0	$ 0	$ 0	$ 150	$ 650	$ 799	$ 0	$ 0	$ 0	$ 852	$ 880	$ 116	$ 2,251	$ 185	$ 2,252	$ 1,793	$ 1,118	$ 997
UG Line Renewal - Subdivisions	$ 1,292	$ 3,662	$ 4,954	$ 2,517	$ 3,962	$ 6,480	$ 2,329	$ 4,550	$ 6,879	$ 7,469	$ 6,009	$ 5,251	$ 2,312	$ 8,244	$ 12,930	$ 14,250	$ 13,850	$ 15,050
UG Line Renewal - Customer Connections	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 22	$ 200	$ 200	$ 200	$ 200	$ 200
UG Line Renewal - Network System	$ 0	$ 63	$ 63	$ 0	$ 186	$ 186	$ 0	$ 258	$ 258	$ 214	$ 573	$ 223	$ 0	$ 130	$ 130	$ 130	$ 130	$ 130
UG Line Renewal - Proactive	$ 340	$ 0	$ 340	$ 282	$ 0	$ 282	$ 347	$ 0	$ 347	$ 640	$ 721	$ 807	$ 1,113	$ 934	$ 434	$ 440	$ 441	$ 441
UG Line Renewal - Reactive	$ 0	$ 84	$ 84	$ 11	$ 53	$ 64	$ 0	$ 101	$ 101	$ 102	$ 521	$ 141	$ 957	$ 969	$ 969	$ 969	$ 969	$ 969
Station Building - Renewal	$ 358	$ 100	$ 458	$ 31	$ 0	$ 31	$ 0	$ 76	$ 76	$ 391	$ 596	$ 181	$ 617	$ 848	$ 432	$ 432	$ 432	$ 190
Station Equipment - Renewal	$ 844	$ 1,778	$ 2,622	$ 1,092	$ 974	$ 2,067	$ 675	$ 1,664	$ 2,339	$ 5,921	$ 7,232	$ 6,773	$ 5,769	$ 7,742	$ 8,966	$ 9,424	$ 8,411	$ 7,081
SCADA Equipment - Renewal	$ 137	$ 11	$ 148	$ 103	$ 11	$ 114	$ 14	$ 0	$ 14	$ 40	$ 113	$ 0	$ 63	$ 0	$ 0	$ 0	$ 0	$ 0
Sub-Total	**$ 8,631**	**$ 10,065**	**$ 18,696**	**$ 11,076**	**$ 11,931**	**$ 23,007**	**$ 11,531**	**$ 12,889**	**$ 24,420**	**$ 31,856**	**$ 27,940**	**$ 19,181**	**$ 22,224**	**$ 32,686**	**$ 37,347**	**$ 38,672**	**$ 36,586**	**$ 36,092**
SystemService																		
Grid Improvements - Connectivity	$ 0	$ 99	$ 99	$ 16	$ 287	$ 304	$ 0	$ 363	$ 363	$ 0	$ 2	$ 0	$ 64	$ 928	$ 928	$ 928	$ 928	$ 928
Grid Improvements - Automation	$ 786	$ 1,140	$ 1,926	$ 884	$ 716	$ 1,600	$ 0	$ 636	$ 636	$ 132	$ 304	$ 475	$ 433	$ 615	$ 615	$ 615	$ 615	$ 615
Grid Improvements - Resiliency	$ 0	$ 0	$ 0	$ 30	$ 0	$ 30	$ 251	$ 0	$ 251	$ 0	$ 0	$ 0	$ 307	$ 100	$ 100	$ 100	$ 100	$ 100
Station Building - Upgrades	$ 0	$ 0	$ 0	$ 66	$ 0	$ 66	$ 70	$ 0	$ 70	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
Station Equipment - Upgrades	$ 0	$ 0	$ 0	$ 62	$ 0	$ 62	$ 211	$ 0	$ 211	$ 0	$ 34	$ 115	$ 90	$ 0	$ 0	$ 0	$ 0	$ 0
SCADA Equipment - Upgrades	$ 0	$ 0	$ 0	$ 9	$ 0	$ 9	$ 260	$ 0	$ 260	$ 1,157	$ 728	$ 2,032	$ 1,903	$ 0	$ 0	$ 0	$ 0	$ 0
Meters - Wholesale	$ 41	$ 0	$ 41	$ 0	$ 0	$ 0	$ 52	$ 0	$ 52	$ 67	$ 0	$ 251	$ 58	$ 0	$ 0	$ 0	$ 0	$ 0
Sub-Total	**$ 827**	**$ 1,240**	**$ 2,066**	**$ 1,068**	**$ 1,003**	**$ 2,071**	**$ 845**	**$ 999**	**$ 1,844**	**$ 1,356**	**$ 1,068**	**$ 2,873**	**$ 2,854**	**$ 1,643**	**$ 1,643**	**$ 1,643**	**$ 1,643**	**$ 1,643**
General Plant																		
Fleet	$ 247	$ 847	$ 1,094	$ 569	$ 924	$ 1,493	$ 890	$ 904	$ 1,794	$ 2,011	$ 1,955	$ 3,476	$ 2,975	$ 3,315	$ 2,925	$ 2,995	$ 2,960	$ 2,985
Tools, Equipment, and Instruments	$ 0	$ 229	$ 229	$ 0	$ 92	$ 92	$ 92	$ 226	$ 318	$ 288	$ 451	$ 382	$ 361	$ 399	$ 401	$ 406	$ 406	$ 411
Hardware - IT	$ 296	$ 325	$ 621	$ 146	$ 168	$ 315	$ 281	$ 218	$ 500	$ 690	$ 442	$ 380	$ 1,148	$ 1,049	$ 947	$ 752	$ 752	$ 783
Software - IT	$ 626	$ 4,565	$ 5,191	$ 420	$ 3,507	$ 3,926	$ 126	$ 226	$ 351	$ 278	$ 4,586	$ 7,769	$ 4,875	$ 6,720	$ 3,247	$ 2,737	$ 2,467	$ 2,367
Cyber Security	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 125	$ 250	$ 250	$ 250	$ 250
Software - Distribution Support	$ 406	$ 0	$ 406	$ 575	$ 0	$ 575	$ 346	$ 0	$ 346	$ 267	$ 123	$ 0	$ 1,113	$ 958	$ 1,043	$ 1,619	$ 2,213	$ 1,448
Software - Administration Support	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 250	$ 0	$ 0	$ 0	$ 0	$ 0
Buildings	$ 89	$ 649	$ 738	$ 121	$ 673	$ 794	$ 187	$ 377	$ 564	$ 176	$ 365	$ 1,576	$ 8,093	$ 7,645	$ 1,455	$ 230	$ 205	$ 205
Furniture and Office Devices	$ 152	$ 8	$ 160	$ 118	$ 64	$ 182	$ 231	$ 35	$ 266	$ 174	$ 212	$ 85	$ 62	$ 7	$ 107	$ 107	$ 107	$ 107
Land and Land Rights	$ 47	$ 474	$ 521	$ 16	$ 1,339	$ 1,356	$ 50	-$ 1	$ 49	$ 57	$ 561	$ 24	$ 230	$ 200	$ 200	$ 200	$ 200	$ 200
Station Decommissioning	$ 3	$ 0	$ 3	$ 73	$ 0	$ 73	$ 78	$ 0	$ 78	$ 113	$ 46	$ 85	$ 381	$ 55	$ 57	$ 57	$ 57	$ 57
Sub-Total	**$ 1,866**	**$ 7,097**	**$ 8,963**	**$ 2,038**	**$ 6,767**	**$ 8,805**	**$ 2,282**	**$ 1,985**	**$ 4,266**	**$ 4,053**	**$ 8,741**	**$ 13,776**	**$ 19,489**	**$ 20,473**	**$ 10,632**	**$ 9,353**	**$ 9,617**	**$ 8,813**
Adjustment to CWIP	-$ 417	-$ 218	-$ 635	-$ 733	$ 0	-$ 733	$ 1,985	-$ 380	$ 1,605	$ 116	$ 53	-$ 344	$ 0					
Total	**$ 19,704**	**$ 25,922**	**$ 45,626**	**$ 21,649**	**$ 26,377**	**$ 48,026**	**$ 24,220**	**$ 24,125**	**$ 48,346**	**$ 51,908**	**$ 53,383**	**$ 56,843**	**$ 70,139**	**$ 78,705**	**$ 73,089**	**$ 86,604**	**$ 89,880**	**$ 86,192**

Figure 4-1 provides an overview of Enova's historical and forecast capital and operating (O&M) expenditures. Enova's capital program consists of a combination of asset renewal and asset addition investments, each of which has a different relationship with ongoing operating costs.

Asset renewal investments are primarily intended to maintain the reliability, safety, and performance of the existing distribution system. While these investments may reduce maintenance requirements for specific assets—such as replacing aging station equipment

with modern equipment requiring less routine maintenance—they generally do not result in significant reductions in inspection and operating activities. This is because the majority of Enova's asset base continues to age and requires ongoing inspection, maintenance, and operational support.

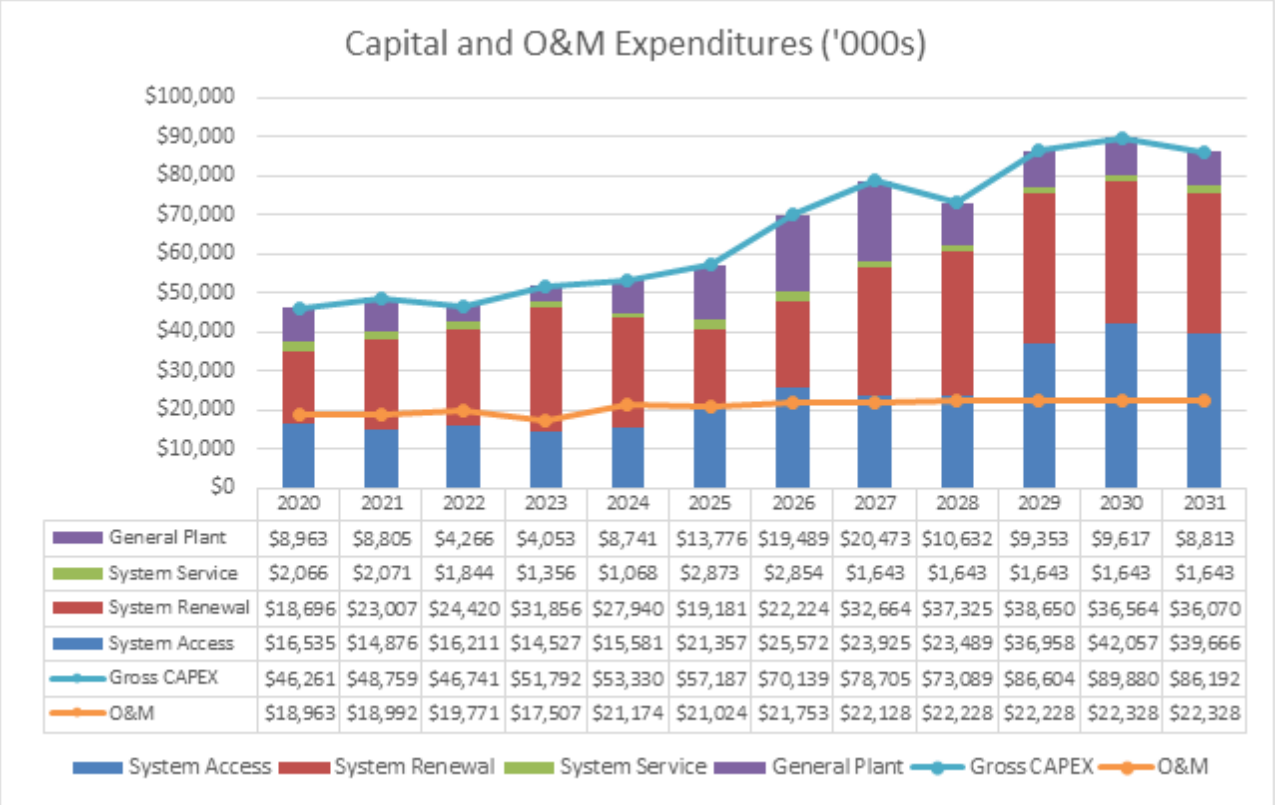
Asset addition investments, by contrast, expand the overall distribution system to accommodate customer growth, increased demand, and changing system requirements. As new assets are placed into service, they become part of the ongoing inspection, maintenance, and operating program, resulting in incremental O&M requirements over time.

When selecting new equipment and technologies, Enova considers lifecycle costs, including future operating and maintenance requirements, as part of its investment decision-making process. Accordingly, opportunities to reduce long-term O&M costs are incorporated where prudent and cost-effective. Examples include replacing legacy oil-filled switching equipment with gas-insulated switchgear and deploying modern equipment that requires less routine maintenance while improving reliability and operational performance.

Over the historical period, actual O&M expenditures increased at an average annual rate of approximately 2.3%. Analysis of historical spending indicates that capital investments did not have a material impact on overall O&M expenditures, as maintenance savings associated with individual asset replacements were largely offset by the continued aging of the broader asset base and the addition of new assets to the system.

Over the forecast period, O&M expenditures are expected to increase annually at approximately 0.52% above inflation. Similar to the historical experience, Enova does not expect its forecast capital program to materially reduce overall O&M expenditures. Although individual capital projects may generate localized maintenance efficiencies, these benefits are expected to be substantially offset by the ongoing maintenance requirements associated with an expanding asset base, increasing system complexity, and the continued need to inspect, operate, and maintain existing distribution assets.

Figure 4-1: Actual Capital and O&M Expenditures 2020-2031



	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
General Plant	$8,963	$8,805	$4,266	$4,053	$8,741	$13,776	$19,489	$20,473	$10,632	$9,353	$9,617	$8,813
System Service	$2,066	$2,071	$1,844	$1,356	$1,068	$2,873	$2,854	$1,643	$1,643	$1,643	$1,643	$1,643
System Renewal	$18,696	$23,007	$24,420	$31,856	$27,940	$19,181	$22,224	$32,664	$37,325	$38,650	$36,564	$36,070
System Access	$16,535	$14,876	$16,211	$14,527	$15,581	$21,357	$25,572	$23,925	$23,489	$36,958	$42,057	$39,666
Gross CAPEX	$46,261	$48,759	$46,741	$51,792	$53,330	$57,187	$70,139	$78,705	$73,089	$86,604	$89,880	$86,192
O&M	$18,963	$18,992	$19,771	$17,507	$21,174	$21,024	$21,753	$22,128	$22,228	$22,228	$22,328	$22,328

4.1.1. Historical Capital Expenditures (2020-2026)

Enova's historical capital investment program has been driven primarily by the need to renew aging infrastructure, maintain system reliability, accommodate customer growth, modernize the electricity distribution system, and improve operational efficiency. Following the 2022 merger of Kitchener-Wilmot Hydro Inc. and Waterloo North Hydro Inc., operational efficiency became an increasingly important investment driver as Enova implemented initiatives to harmonize systems, processes, information technology, and operational practices across the newly integrated utility.

Table 4-7 and **Figure 4-2** summarize Enova's historical capital expenditures for the period 2020 to 2026. Expenditures reported for 2020 through 2022 represent the combined historical investments of the legacy utilities prior to the merger. Detailed historical expenditure analyses for each legacy LDC are provided further in this Section. At the time this DSP was prepared, 2026 actual expenditures were not yet available; accordingly, the

values presented for 2026 represent Enova's Board-approved capital budget for the bridge year.

Table 4-7: Summary of 2020 - 2026 Capital Expenditures by OEB Category ($000s)

OEB Investment Category	Actual	Actual	Actual	Actual	Actual	Actual	Bridge Year (Budget)	Average Annual Investment	% of Annual Investment
ENOVA	2020	2021	2022	2023	2024	2025	2026	2020-2026	2020-2026
System Access	$ 16,535	$ 14,876	$ 16,211	$ 14,527	$ 15,581	$ 21,357	$ 25,572	$ 17,809	33%
System Renewal	$ 18,696	$ 23,007	$ 24,420	$ 31,856	$ 27,940	$ 19,181	$ 22,224	$ 23,903	45%
System Service	$ 2,066	$ 2,071	$ 1,844	$ 1,356	$ 1,068	$ 2,873	$ 2,854	$ 2,019	4%
General Plant	$ 8,963	$ 8,805	$ 4,266	$ 4,053	$ 8,741	$ 13,776	$ 19,489	$ 9,727	18%
Gross CAPEX	$ 46,261	$ 48,759	$ 46,741	$ 51,792	$ 53,330	$ 57,187	$ 70,139	$ 53,458	100%
Contributed Capital	$ 6,932	$ 9,528	$ 8,469	$ 6,664	$ 6,472	$ 8,988	$ 11,504	$ 8,365	16%
Net CAPEX	$ 39,329	$ 39,231	$ 38,272	$ 45,128	$ 46,858	$ 48,199	$ 58,635	$ 45,093	84%
O&M	$ 18,963	$ 18,992	$ 19,771	$ 17,507	$ 21,174	$ 21,024	$ 21,753	$ 19,883	37%

Over the historical period, System Renewal represented the largest component of Enova's capital program, accounting for approximately 45% of total gross capital expenditures. These investments were primarily directed toward replacing aging distribution assets, reducing asset-related risk, maintaining system reliability, and addressing deteriorating asset condition. System Access investments represented approximately 33% of historical capital expenditures and were largely driven by customer growth, new customer connections, capacity expansion requirements and relocation of assets in municipal rights-of-way.

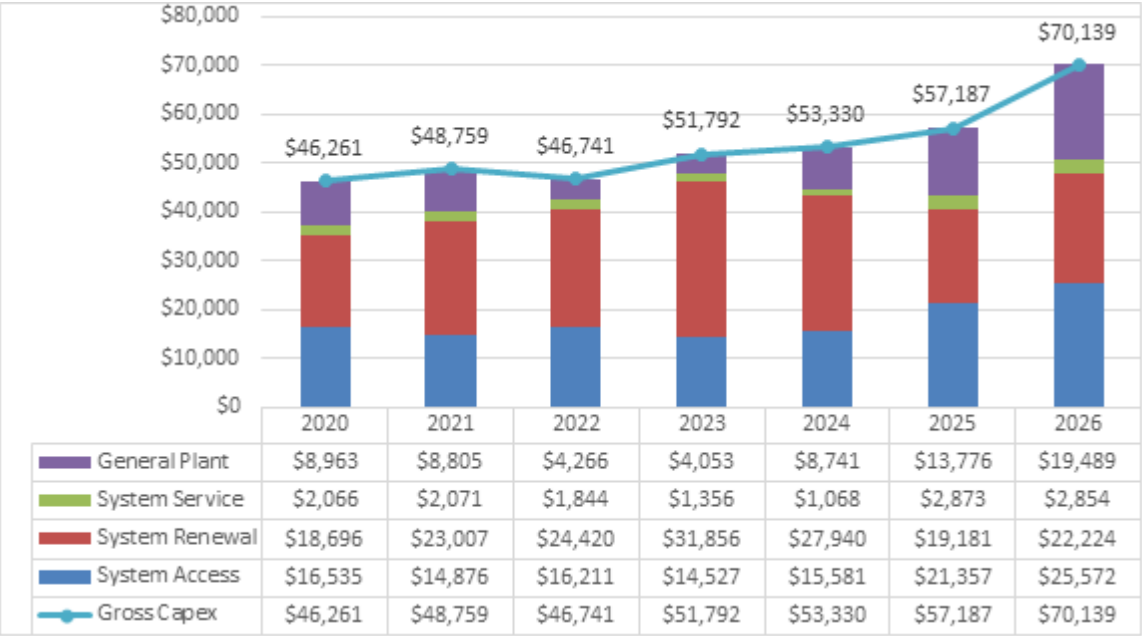
Beginning in 2025 and continuing into the 2026 bridge year, System Access expenditures increased significantly and became the largest annual investment category. This increase reflects higher levels of customer-driven and mandated work programs associated with regional growth, intensified development activity, and expanded system capacity requirements. These investments are partially offset through contributed capital.

General Plant investments accounted for approximately 18% of historical capital expenditures and reflect Enova's post-merger investments in information technology,

operational technology, fleet, facilities, and business systems required to integrate the legacy organizations and improve operational effectiveness. Harmonization efforts, such as control room operations, SCADA, GIS, outage management system (OMS), meter data management system (MDMS), billing system (CIS), enterprise resource system (ERP) and others began in 2023 and continue into 2026.

System Service investments represented approximately 4% of total historical expenditures and included targeted investments to improve system reliability, automation, communications, and grid modernization capabilities.

Figure 4-2: Historical Capital Expenditures ($000s)

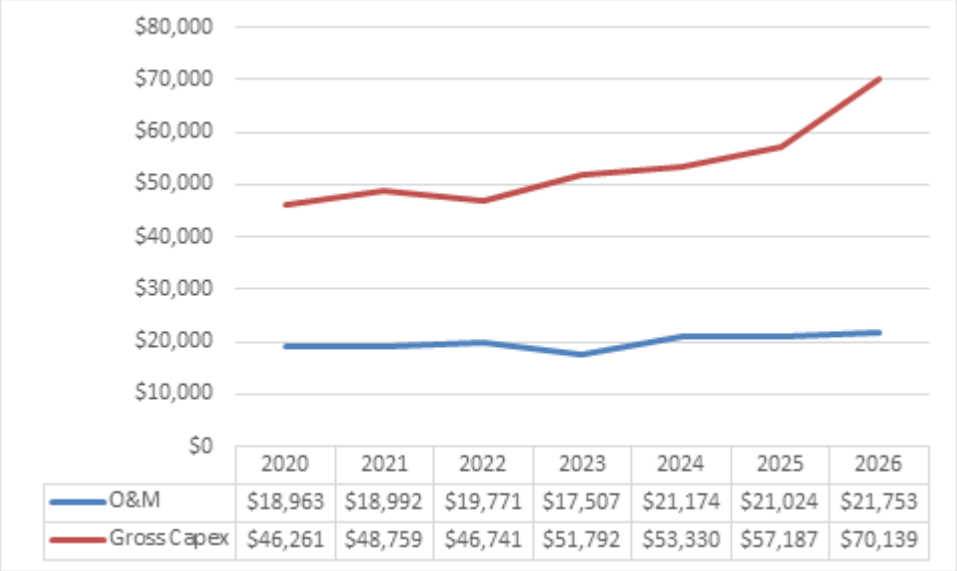


	2020	2021	2022	2023	2024	2025	2026
General Plant	$8,963	$8,805	$4,266	$4,053	$8,741	$13,776	$19,489
System Service	$2,066	$2,071	$1,844	$1,356	$1,068	$2,873	$2,854
System Renewal	$18,696	$23,007	$24,420	$31,856	$27,940	$19,181	$22,224
System Access	$16,535	$14,876	$16,211	$14,527	$15,581	$21,357	$25,572
Gross Capex	$46,261	$48,759	$46,741	$51,792	$53,330	$57,187	$70,139

Historical gross capital expenditures increased from $46.3 million in 2020 to an Enova Board-approved bridge-year budget of $70.1 million in 2026, representing an average annual growth rate of approximately 7.2%. Over the same period, contributed capital increased at an average annual rate of approximately 8.8%, reflecting increased levels of customer-funded distribution system expansion. As a result, net capital expenditures increased at an average annual rate of approximately 6.9%.

Figure 4-3 illustrates the relationship between gross capital and O&M expenditures over the historic period. O&M expenditures remained relatively flat over the historic period, increasing 2.3% annually. As discussed further in Section 4.2, historical capital investment levels did not materially reduce O&M requirements, as a significant portion of capital spending was directed toward replacing existing assets with modern equivalents rather than reducing inspection or operational activities. In addition, continued customer growth and expansion of the distribution system increased the asset base requiring inspection, operation, and maintenance.

Figure 4-3: Historical Capital vs O&M Expenditures ($000s)



	2020	2021	2022	2023	2024	2025	2026
O&M	$18,963	$18,992	$19,771	$17,507	$21,174	$21,024	$21,753
Gross Capex	$46,261	$48,759	$46,741	$51,792	$53,330	$57,187	$70,139

4.1.1.1. Historical Variance Analysis - Year to Plan (2020)

Table 4-8: 2020 WNH Capital Variance – Year to Plan ($000s)

OEB Investment Category	Plan	Budget	Actual	Variance	% Variance	Variance	% Variance
WNH	2020	2020	2020	Actual - Plan	Actual - Plan	Actual - Budget	Actual - Budget
System Access	$ 6,822	$ 5,358	$ 8,797	$ 1,975	29.0%	$ 3,439	64.2%
System Renewal	$ 8,440	$ 9,617	$ 8,631	$ 191	2.3%	$ (986)	-10.3%
System Service	$ 1,763	$ 846	$ 827	$ (936)	-53.1%	$ (19)	-2.2%
General Plant	$ 2,353	$ 3,555	$ 1,866	$ (487)	-20.7%	$ (1,689)	-47.5%
Gross CAPEX	$ 19,378	$ 19,375	$ 20,121	$ 743	3.8%	$ 746	3.8%
Contributed Capital	$ 2,599	$ 2,066	$ 2,542	$ (57)	-2.2%	$ 476	23.0%
Net CAPEX	$ 16,779	$ 17,309	$ 17,579	$ 800	4.8%	$ 270	1.6%

Despite the challenges posed by the COVID-19 pandemic, WNH was able to carry out most of its planned 2020 capital work program. The pandemic affected capital programs to varying degrees, with field activities constrained by public health requirements related to staff separation and physical distancing. Office personnel transitioned to work-from-home arrangements wherever practical.

Overall, WNH's 2020 gross capital expenditure budget was $3 thousand (0.02%) below the approved plan. Actual capital expenditures before customer contributions exceeded plan by approximately $743 thousand (3.8%), primarily due to higher-than-anticipated System Access customer-driven investments. Capital contributions were approximately $57 thousand (2.2%) below budget, resulting in net capital expenditures of approximately $800 thousand (4.8%) above plan.

System Access (SA)

System Access expenditures were budgeted lower than the approved plan by $1.46 million (-21.5%). Actual expenditures exceeded plan by $1.98 million (29%) and budget by $3.4 million (64.2%) due to higher-than-anticipated customer-driven subdivision construction activity. This work was less affected by COVID-19 restrictions because construction crews were generally able to maintain physical distancing while working in the field.

System Access expenditures associated with municipal road relocation projects also exceeded plan. Many municipalities accelerated road construction programs during the pandemic to take advantage of significantly reduced traffic volumes resulting from widespread work-from-home practices. This created additional opportunities for coordinated utility relocations and associated System Access investments.

System Renewal (SR)

Although Enova had budgeted for a higher level of activity in this category, the residential underground cable replacement program was curtailed, minimizing planned outages that would adversely impact people working from home. SR projects were deferred to 2021 and resources were diverted due to increased SA activity. In response to the economic uncertainty and potential impacts on revenue WNH also deferred certain equipment purchases and vendor payments to preserve capital. Actual expenditures came in $191 thousand over plan and $986 thousand (-10.3%) under budget.

System Service (SS)

The SS budget was less than plan by $918 thousand (-52%) as WNH paced 2020 expenditures by spreading the implementation of circuit breakers and reclosers over a two-year period rather than completing the program in a single year. This resulted in expenditures of $936 thousand (-53.1%) below plan and $19 thousand (-2.2%) below budget.

General Plant (GP)

Enova had budgeted for a higher level of activity, $1.2 million (51%), due to major IT systems' upgrades. Deferred SR projects prevented removing a Municipal Station from service and deferred the planned decommissioning and environmental work. Planned IT software projects were deferred as work shifted to enable the organization's work-from-home capabilities in response to COVID-19. This resulted in net capital expenditures lower than plan by $487 thousand (-20.7%) and $1.6 million (-47.5%) under budget.

Table 4-9: 2020 KWH Capital Variance – Year to Plan ($000s)

OEB Investment Category	Plan	Budget	Actual	Variance	% Variance	Variance	% Variance
KWH	2020	2020	2020	Actual - Plan	Actual - Plan	Actual - Budget	Actual - Budget
System Access	$ 7,065	$ 7,374	$ 7,739	$ 674	9.5%	$ 366	5.0%
System Renewal	$ 9,415	$ 9,105	$ 10,065	$ 650	6.9%	$ 960	10.5%
System Service	$ 3,200	$ 3,200	$ 1,240	$ (1,960)	-61.3%	$ (1,960)	-61.3%
General Plant	$ 6,495	$ 6,945	$ 7,097	$ 602	9.3%	$ 152	2.2%
Gross CAPEX	$ 26,175	$ 26,623	$ 26,141	$ (34)	-0.1%	$ (482)	-1.8%
Contributed Capital	$ 4,000	$ 3,914	$ 4,390	$ 390	9.7%	$ 476	12.2%
Net CAPEX	$ 22,175	$ 22,709	$ 21,751	$ (424)	-1.9%	$ (958)	-4.2%

Overall, KWH's 2020 gross capex budget was $448 thousand above plan (1.7%). The 2020 plan vs actual capex shows an under expenditure of approximately $34 thousand (-0.1%). This is largely due to the rebalancing of work programs due to COVID-19 impacts. Capital contributions came in higher than expected by approximately $390 thousand (9.7%). KWH experienced COVID-19 impacts similar to those previously mentioned for WNH. The resulting net capital expenditures were $424 thousand or (-1.9%) below planned and $958 thousand (-4.2%) below budget.

System Access (SA)

SA expenditures were budgeted higher than plan by $309 thousand (4.4%) due to increased customer-driven subdivision construction activity and line relocations. System expansion projects included the extension and rebuilding of pole lines for subdivision servicing and site servicing. The construction of the underground distribution system was primarily focused on the relocation of ducts and cables to facilitate road reconstruction work. Stronger than forecast developer activity led to actual expenditures exceeding plan by $674 thousand (9.5%) and budget by $366 thousand (5.0%).

System Renewal (SR)

The SR budget was lower than plan by $310 thousand (-3.3%). SR expenditures were above plan by $650 thousand (6.9%). Enova took advantage of a significant decrease in SS expenditures to perform additional SR work. At 5TS, upgrades of the switchgear to an Arc Resistant standard including remote breaker racking functionality were completed. A major

upgrade to the protection and control equipment at 6TS was started late in the year with completion in 2021.

System Service (SS)

SS expenditures were budgeted as planned. Actual expenditures were lower by $1.96 million (-61.3%) in total. Deferrals of three different projects accounted for $1.7 million of the reduction. Two major projects, underground feeders from 4TS to downtown Kitchener and cable conduits/switchgear work in downtown Kitchener were deferred due to developer activity that did not materialize. The 9M2 feeder riser cable work was also deferred due to reprioritization of projects. Enova took advantage of decreased SS expenditures to perform additional SR work.

General Plant (GP)

GP budget was above plan by $450 thousand (6.9%) and included $3.88 million for Phase One of a multi-year CIS replacement project. Post-budget, additional expenditures were required to enable the organization to operate remotely in response to COVID-19. Actual expenditures were above plan by $602 thousand (9.3%) and $152 thousand (2.2%) above budget.

4.1.1.2. Historical Variance Analysis - Year to Plan (2021)

Table 4-10: 2021 WNH Capital Variance – Year to Plan ($000s)

OEB Investment Category	Plan	Budget	Actual	Variance	% Variance	Variance	% Variance
WNH	2021	2021	2021	Actual - Plan	Actual - Plan	Actual - Budget	Actual - Budget
System Access	$ 5,840	$ 6,249	$ 8,200	$ 2,360	40.4%	$ 1,951	31.2%
System Renewal	$ 8,947	$ 9,451	$ 11,076	$ 2,129	23.8%	$ 1,625	17.2%
System Service	$ 2,194	$ 1,281	$ 1,068	$(1,126)	-51.3%	$ (213)	-16.7%
General Plant	$ 2,776	$ 2,776	$ 2,038	$ (738)	-26.6%	$ (738)	-26.6%
Gross CAPEX	$ 19,757	$ 19,758	$ 22,382	$ 2,625	13.3%	$ 2,624	13.3%
Contributed Capital	$ 2,695	$ 2,694	$ 3,696	$ 1,001	37.1%	$ 1,002	37.2%
Net CAPEX	$ 17,061	$ 17,064	$ 18,686	$ 1,625	9.5%	$ 1,622	9.5%

WNH's 2021 budget equaled planned expenditures. Overall gross capex exceeded plan by $2.63 million (13.3%) mainly due to developer-driven SA activity. Net capex was mitigated by capital contributions exceeding plan by approximately $1.0 million. Also, some SS and GP work was deferred to help pace overall expenditures. Overall, net capex exceeded plan and budget by approximately $1.63 million (9.5%)

System Access (SA)

Subdivisions that were deferred in 2020 due to COVID-19 were completed in 2021. Developers' additional demand for new subdivision servicing also increased. SA expenditures exceeded plan by $2.36 million (40.4%) and budget by $1.95 million (31.2%)

System Renewal (SR)

The 2021 SR expenditures were budgeted higher than plan due, in part, to the number of 2020 overhead pole replacements deferred due to COVID-19. The program came in higher than expected due to additional poles needing replacement, resulting in expenditures exceeding plan by $2.13 million (23.8%) and budget by $1.63 million (17.2%). Capital expenditures were also higher during 2021 as WNH started to address a backlog of underground subdivision rebuild projects that had been deferred in 2020 due to COVID-19-related work-from-home mandates and associated operational constraints. As restrictions

were lifted and field activities resumed, resulting in elevated capital expenditures during the catch-up period.

System Service (SS)

SS expenditures were budgeted lower than plan $912 thousand (-41.6%) due to reprioritization and pacing of the work program.

Planned station building and equipment work also had to be deferred due to emergency station HMSTS"A" bus duct repairs and short staffing in Stations Engineering. Resulting expenditures were $1.13 million (-51.3%) below plan and $214 thousand (-16.7%) below budget.

General Plant (GP)

WNH's 2021 GP budget equalled its planned expenditures. General Plant (GP) expenditures were $738 thousand (26.6%) below plan and budget. Several IT initiatives were intentionally deferred to offset increased capital spending within the SA and SR programs. The most significant deferral was the planned Customer Information System (CIS) upgrade, which was postponed until a post-merger harmonized solution could be developed. This approach avoided duplicative investment in legacy systems and ensured that future expenditures would support a single, integrated platform for Enova's combined operations.

In addition to the planned deferral of certain IT initiatives, several fleet vehicle and equipment purchases were delayed due to supply chain disruptions and extended delivery schedules. These timing-related deferrals shifted expenditures into subsequent years and did not materially impact Enova's operational capabilities or the execution of its capital program.

Table 4-11: 2021 KWH Capital Variance – Year to Plan ($000s)

OEB Investment Category	Plan	Budget	Actual	Variance	% Variance	Variance	% Variance
KWH	2021	2021	2021	Actual - Plan	Actual - Plan	Actual - Budget	Actual - Budget
System Access	$ 7,767	$ 7,333	$ 6,676	$ (1,091)	-14.1%	$ (657)	-9.0%
System Renewal	$ 10,350	$ 10,640	$ 11,931	$ 1,581	15.3%	$ 1,291	12.1%
System Service	$ 3,200	$ 3,050	$ 1,003	$ (2,197)	-68.6%	$ (2,047)	-67.1%
General Plant	$ 3,275	$ 4,160	$ 6,767	$ 3,492	106.6%	$ 2,607	62.7%
Gross CAPEX	$ 24,592	$ 25,182	$ 26,377	$ 1,785	7.3%	$ 1,194	4.7%
Contributed Capital	$ 4,000	$ 4,047	$ 5,832	$ 1,832	45.8%	$ 1,785	44.1%
Net CAPEX	$ 20,592	$ 21,135	$ 20,545	$ (47)	-0.2%	$ (591)	-2.8%

Overall, the 2021 KWH's budget exceeded the plan by $590 thousand (2.4%). This was due to increased work in GP, namely a major CIS upgrade. Actual expenditures exceeded plan by $1.79 million (7.3%). Net capex was mitigated in part by rebalancing the work program, deferments in planned SA and SS expenditures and higher than expected amounts of contributed capital in the amount of $1.83 million (45.8%). This reduced net capex to $47 thousand (-0.2%) under plan and $591 thousand (-2.8%) under budget.

System Access (SA)

SA expenditures were budgeted $435 thousand (-5.6%) lower than plan. Actual expenditures were $1.09 million below plan.

Deferrals occurred in budgeted metering projects (-$158k), and road relocations Ottawa St. ($250k), Sports World ($280k), and Westmount Road West ($350k). Higher post-COVID-19 construction costs also caused developers to scale back on new development.

System Renewal (SR)

SR expenditures were budgeted higher than plan by $290 thousand. SR expenditures exceeded plan by $1.58 million. Resources were redirected from deferred SA and SS projects to work on a backlog of pole replacement projects.

System Service (SS)

Selected SS road relocations on Strasburg Rd Stage 2 South of Strassburg Creek to Robert Ferrie Dr. and Bleams Rd, Homer Watson Blvd to Strassburg Rd ($550k) were deferred by the municipality.

General Plant (GP)

In 2021, GP actual expenditures exceeded plan by $3.49 million. The variance is directly attributed to extra costs associated with the CIS replacement project and the purchasing of two properties on West Avenue, Kitchener.

The CIS budget for 2021 was $1.5 million while the actual expenditures were $3.5 million. The increase in expenditures can be attributed to additional costs associated with software customization for the Ontario market. KWH's CIS system (CC&B) went into service in 2021.

KWH also took advantage of an opportunity to acquire the properties located at 164 and 172 West Avenue, Kitchener. Situated directly across the street from Enova's Victoria Street operations and equipment storage yard, these properties provide strategically located additional space for the storage of materials and equipment, improving operational efficiency and supporting future operational requirements. As the opportunity arose unexpectedly, the acquisition was not included in the approved capital budget.

These variances were partially compensated for by deferred expenditures in other investment areas.

4.1.1.3. Historical Variance Analysis - Year to Plan (2022)

Table 4-12: 2022 WNH Capital Variance – Year to Plan ($000s)

OEB Investment Category	Plan	Budget	Actual	Variance	% Variance	Variance	% Variance
WNH	2022	2022	2022	Actual - Plan	Actual - Plan	Actual - Budget	Actual - Budget
System Access	$ 6,166	$ 7,892	$ 7,578	22.9%	-4.0%	$ 6,166	$ 7,892
System Renewal	$ 9,572	$ 10,170	$ 11,531	20.5%	13.4%	$ 9,572	$ 10,170
System Service	$ 1,346	$ 937	$ 845	-37.2%	-9.8%	$ 1,346	$ 937
General Plant	$ 3,853	$ 2,994	$ 2,282	-40.8%	-23.8%	$ 3,853	$ 2,994
Gross CAPEX	$ 20,938	$ 21,993	$ 22,236	6.2%	1.1%	$ 20,938	$ 21,993
Contributed Capital	$ 2,710	$ 3,778	$ 2,542	-6.2%	-32.7%	$ 2,710	$ 3,778
Net CAPEX	$ 18,228	$ 18,215	$ 19,694	8.0%	8.1%	$ 18,228	$ 18,215

This was a transition year for WNH as harmonization began to take place after the September 1, 2022, merger date. A number of programs were deferred until a post-merger harmonized approach could be developed.

WNH's 2022 budget exceeded planned expenditures by $1.06 million (5.0%). Overall, actual gross capital expenditures exceeded plan by $1.3 million (6.2%). This is due, in part, to a one time capitalization of inventoried transformers which added an additional $1.3 million to SR expenditures. WNH continued to catch up on a backlog of work that was deferred due to COVID-19 impacts.

System Access (SA)

WNH budgeted for stronger developer activity in subdivision work; however, some developments were again deferred. Activity was higher than plan by $1.4 million (22.9%) but lower than budget by $314 thousand (-4%).

System Renewal (SR)

System Renewal (SR) expenditures exceeded the plan by $1.96 million (20.5%) and the budget by $1.36 million (13.4%). The variance was primarily attributable to the completion of overhead pole replacement projects that had been deferred during the COVID-19 pandemic. With pandemic-related restrictions easing, Enova completed the remaining deferred work in 2022 to address the accumulated renewal backlog and reduce asset risk.

In addition, Enova experienced significant post-pandemic cost escalation for distribution system materials. Distribution transformer prices increased sharply, along with other key construction materials, resulting in an overall increase of approximately 10% to 12% in overhead line construction costs. These industry-wide supply chain constraints and inflationary pressures contributed to the higher-than-planned System Renewal expenditures.

As part of the MAADs application, Enova agreed to adopt the accounting policies, including estimates, of legacy KWH. IFRS rules required that the accounting policies of the larger organization (KWH) be adopted by the smaller organization (WNH). Enova identified approximately $1.83 million worth of items at legacy WNH that were recorded as inventory, and that would meet KWH's criteria for "Major Spare Parts and Stand-by Equipment" as defined in IAS 16 and the OEB's Accounting Procedures Handbook (APH). To conform with KWH's policy and process, these items were capitalized in 2022 and a one-time capitalization of inventoried transformers added an additional $1.3 million in SR expenditures.

System Service (SS)

SS expenditures were budgeted lower than plan by $409 thousand (-30%). Actual expenditures were $501 thousand (-37.2%) under plan and $92 thousand (-9.8%) under budget. The variance was primarily attributable to the deferral of several projects to allow Enova to develop and implement a harmonized approach following the merger, ensuring that investments were coordinated and aligned with future system-wide standards and priorities.

General Plant (GP)

The GP budget was $859 thousand (-22.3%) lower than plan. IT software enhancements of the JOMAR CIS, COGNOS Reporting and HR modules were deferred until a post-merger harmonized plan could be developed. Actual expenditures were $1.57 million (-40.8%) below plan and $713 thousand (-23.8%) under budget.

Table 4-13: 2022 KWH Capital Variance – Year to Plan ($000s)

OEB Investment Category	Plan	Budget	Actual	Variance	% Variance	Variance	% Variance
KWH	2022	2022	2022	Actual - Plan	Actual - Plan	Actual - Budget	Actual - Budget
System Access	$ 7,817	$ 7,625	$ 8,633	$ 816	10.4%	$ 1,009	13.2%
System Renewal	$ 10,650	$ 11,640	$ 12,889	$ 2,239	21.0%	$ 1,249	10.7%
System Service	$ 2,800	$ 3,000	$ 999	$ (1,801)	-64.3%	$ (2,001)	-66.7%
General Plant	$ 3,565	$ 3,491	$ 1,985	$ (1,580)	-44.3%	$ (1,506)	-43.2%
Gross CAPEX	$ 24,832	$ 25,756	$ 24,506	$ (326)	-1.3%	$ (1,250)	-4.9%
Contributed Capital	$ 4,000	$ 3,936	$ 5,927	$ 1,927	48.2%	$ 1,991	50.6%
Net CAPEX	$ 20,832	$ 21,820	$ 18,579	$ (2,253)	-10.8%	$ (3,241)	-14.9%

The merger between WNH and KWH occurred on September 1, 2022. Some programs were deferred until a post-merger harmonized approach could be developed.

KWH's 2022 budget was $924 thousand (3.7%) above plan. Actual-plan gross capital expenditures were lower by $326 thousand (-1.3%). Contributed capital exceeded plan by $1.93 million (48.2%) and budget by $1.99 million (50.6%) due to higher SA activity. This resulted in a net capex of $2.25 million (-10.8%) below plan and $3.24 million (-14.9%) below budget.

System Access (SA)

KWH's 2022 budget was slightly lower than plan by $193 thousand (-2.5%). Stronger than forecast developer-activity in subdivision work resulted in expenditures exceeding plan by $816 thousand (10.4%) and budget by $1.01 million (13.2%). Contributed capital also exceeded budget by $1.99 million (50.6%).

System Renewal (SR)

SR budget exceeded plan by $990 thousand (9.3%). Post COVID-19, Enova experienced sharp increases in distribution transformer purchasing costs; $329 thousand (10%) above budget. Underground conduit, duct and cable work exceeded budget by $505 thousand (6.3%). SR expenditures exceeded plan by $2.24 million (21.0%) and budget by $1.25 million (7.5%).

System Service (SS)

SS budget exceeded plan by $200 thousand (7.1%). Actual expenditures were below plan by $ 1.80 million (-64.3%) and below budget by $2.0 million (-66.7%)

The following projects were deferred;

- Overhead to underground conversion on Glasgow St. ($450k).
- New underground feeder U/G feeder from 4TS to downtown Kitchener to supply load growth deferred due to project delays ($1.0M).

Hydro One Right of Way, Fisher-Hallman to Woodbine overhead line rebuild was completed adding $500 thousand.

Resources planned for SS projects were reallocated to SA and SR programs.

General Plant (GP)

The GP budget was slightly lower than plan by $74 thousand (-2.1%). Actual expenditures were below plan by $1.58 million (-44.3%) and below budget by $1.51 million (43.2%). Approximately $950 thousand in IT software enhancements and $400 thousand in facilities upgrades were deferred until a post-merger harmonized plan could be developed for each.

4.1.1.4. Historical Variance Analysis - Year to Plan (2023)

Table 4-14: 2023 Enova Capital Variance – Year to Plan ($000s)

OEB Investment Category	Plan	Budget	Actual	Variance	% Variance	Variance	% Variance	Historical Average	% Variance
Enova	2023	2023	2023	Actual - Plan	Actual - Plan	Actual - Budget	Actual - Budget	2020-2026	Actual - Historical Avg.
System Access	$13,676	$15,577	$14,527	$850	6.2%	($1,050)	-6.7%	$17,809	-18.4%
System Renewal	$20,898	$25,508	$31,856	$10,958	52.4%	$6,348	24.9%	$23,903	33.3%
System Service	$3,613	$3,097	$1,356	($2,257)	-62.5%	($1,741)	-56.2%	$2,019	-32.8%
General Plant	$7,373	$7,247	$4,053	($3,320)	-45.0%	($3,194)	-44.1%	$9,727	-58.3%
Gross CAPEX	$45,561	$51,429	$51,792	$6,231	13.7%	$362	-82.2%	$53,458	-3.1%
Contributed Capital	$6,536	$7,420	$6,664	$128	2.0%	($756)	-10.2%	$8,365	-20.3%
Net CAPEX	$39,025	$44,009	$45,128	$6,103	15.6%	$1,118	2.5%	$45,093	0.1%

The merger between WNH and KWH occurred September 1, 2022. The 2023 budget was Enova's first budget harmonizing WNH and KWH operations and capital programs.

In 2023, Enova's budget exceeded plan by $5.87 million (12.9%) mainly due to additional planned SA and SR work plans. Contributed capital was also budgeted higher than plan by $884 thousand (13.5%); however, contributions did not fully materialize, falling short by $756 thousand (-10.2%). Resulting net capital expenditures exceeded plan by $6.10 million (15.6%) and exceeded budget by $1.12 million (2.5%).

System Access (SA)

Enova's SA budget exceeded plan by $1.90 million (13.9%) due to forecast increases in activity. A number of proposed road relocations were ultimately deferred by municipalities (Sportsworld, Ottawa St, Fisher-Hallman roundabout, Bridgeport, Highland, Roxborough, Bridgeport / Caroline, Northfield, Bridge to University) resulting in SA expenditures exceeding plan by only $850 thousand (6.2%) but coming under budget by $1.05 million (-6.7%).

System Renewal (SR)

Enova's SR budget exceeded plan by $4.61 million (22.1%). SR expenditures came in at $10.96 million (52.4%) over plan and $6.35 million (24.9%) over budget. With large deferrals occurring in SS and GP, these planned expenditures were redirected to targeted SR projects:

- Overhead line rebuilds $1.4M
- Overhead voltage conversions $1.5M
- Underground subdivision renewal $2.5M

Enova also experienced significant increases in material costs following the COVID-19 pandemic. Key distribution materials, including distribution transformers, underground duct, and primary cable, were subject to substantial price escalation driven by global supply chain disruptions, persistent inflationary pressures, and heightened worldwide demand. While material availability improved over time, pricing remained well above pre-pandemic levels, reflecting a permanent shift in market conditions for many critical distribution assets.

These sustained increases in material costs contributed directly to higher capital project costs across the capital program and were a significant factor in the growth of capital expenditures during the historical period. Enova incorporated these higher input costs into its capital planning and budgeting processes to ensure that investment forecasts remained realistic and sufficient to deliver the required scope of work.

System Service (SS)

Enova's SS budget was lower than plan by $516 thousand (-14.3%) due to anticipated changes in the SS work program. Further deferrals were made throughout the year to reassess priorities and harmonize the SS capital work programs of the legacy LDCs. The following SS projects were deferred;

- Grid modernization ($352k),
- Growth driven, overhead line along Hydro One right-of-way to City of Kitchener ($500k)
- Overhead feeder tie between 9TS and MTS#3 ($456k)

- Lackner Blvd load relief ($315k)
- Underground duct work from 4TS to downtown deferred ($1.35M)

Changes in the program resulted in expenditures $1.74 million (-56.2%) below budget and $2.26 million (-62.5%) below plan.

General Plant (GP)

Enova's GP budget was lower than plan by $126 thousand (-1.7%) due to anticipated changes in the GP work program. As the year progressed, projects were deferred in order to reassess priorities in the GP capital work program. Enova needed time to develop a harmonized approach to IT software development.

As issues with the VS facility (legacy KWH office) mounted, Enova deferred previous VS HVAC Replacement and Facility Renovation Project decisions in order to develop a more efficient and effective approach to the work.

Ultimately, GP expenditures were $3.32 million (-45.0%) below plan and $3.19 million (44.1%) below budget. These reductions helped offset the increased expenditures in SA and SR.

4.1.1.5. Historical Variance Analysis - Year to Plan (2024)

Table 4-15: 2024 Enova Capital Variance – Year to Plan ($000s)

OEB Investment Category	Plan	Budget	Actual	Variance	% Variance	Variance	% Variance	Historical Average	% Variance
Enova	2024	2024	2024	Actual - Plan	Actual - Plan	Actual - Budget	Actual - Budget	2020-2026	Actual - Historical Avg.
System Access	$14,215	$21,653	$15,581	$1,367	9.6%	($6,071)	-28.0%	$17,809	-12.5%
System Renewal	$21,143	$21,588	$27,940	$6,797	32.1%	$6,352	29.4%	$23,903	16.9%
System Service	$3,736	$2,219	$1,068	($2,668)	-71.4%	($1,150)	-51.9%	$2,019	-47.1%
General Plant	$6,156	$12,600	$8,741	$2,585	42.0%	($3,859)	-30.6%	$9,727	-10.1%
Gross CAPEX	$45,250	$58,059	$53,330	$8,080	17.9%	($4,728)	-8.1%	$53,458	-0.2%
Contributed Capital	$6,819	$9,700	$6,472	($347)	-5.1%	($3,228)	-33.3%	$8,365	-22.6%
Net CAPEX	$38,431	$48,359	$46,858	$8,427	21.9%	($1,500)	-3.1%	$45,093	3.9%

In 2024, Enova's budget exceeded plan by $12.81 million (28.3%) mainly due to additional work planned in SA, SR and GP categories. Gross capital expenditures exceeded plan by $8.08 million (17.9%). A number of additional projects added to the budget did not materialize as forecast. Contributed capital, also budgeted higher than plan by $2.88 million (42.2%), did not fully materialize, falling short of plan by $347 thousand (-5.1) and short of budget by $3.23 million (-33.3%). The resulting net capital expenditures exceeded plan by $8.43 million (21.9%) but also came in $1.50 million (-3.1%) under budget.

System Access (SA)

Enova's SA budget exceeded plan by $7.44 million (52.3%) due to forecasted increases in customer-driven activity. As the year progressed, higher interest rates slowed the economy leading to an economic slowdown. Several new subdivisions were pushed to 2025 by the developer with Middlebrook and Fountain St, deferring $1.2M in expenditures, and South Woods subdivision, Elmira deferring $550 thousand.

Additionally, a number of municipally driven relocation projects did not materialize.

- Ottawa Street S., Fisher-Hallman Rd to Mowat Blvd, Fischer-Hallman and New Dundee, Wilson Avenue, Frederick Street, Victoria St to Bruce St ($850k)
- Bearinger Road, Laurel Wood to Pine Ridge was pushed to 2025. ($750k)

- Fisher-Hallman, Columbia to Laurel Wood ($637k)
- Bridgeport Rd., Regina to King Street and overhead to underground conversion was placed on hold. ($1.55M)
- Union St., King St to Mary, municipal line relocation and undergrounding was cancelled by the municipality ($400k).
- Several other smaller road relocations deferred ($550k)

SA expenditures exceeded plan by $1.37 million (9.6%); however, deferred work resulted in a budget underspend of $6.07 million (-28.0%).

System Renewal (SR)

Enova's SR budget exceeded plan by $455 thousand (2.1%). SR expenditures exceeded plan by $6.80 million (32.1%) and budget by $6.35 million (29.4%).

A progress payment for 5TS transformer was originally budgeted for 2023 however payment did not occur until 2024. ($1.65M unbudgeted).

A Connection and Cost Recovery Agreement (CCRA) payment of $1.8 million was made to Hydro One. The load on 8TS did not materialize as forecast due to the closure of a large customer, Budd Canada, an automotive parts manufacturing plant. The loss of load was within the agreement's 15-year connection horizon.

With the deferrals in SA projects, Enova redirected resources to SR projects.

- Westcourt Place and Northlake subdivisions' cable replacements were advanced ($2.8M).
- Pole line renewal and voltage conversion projects ($1.6M)

System Service (SS)

Enova's SS budget was lower than plan by $1.52 million (-40.6%). SS expenditures were $2.67 million (-71.4%) under plan and $1.15 million (-51.9%) under budget due to the following deferrals and attempts to better pace the capital work program;

- Grid Modernization project was deferred due to lack of resources. ($384k)

- Strasburg Road, new three phase circuit, new feeders 8M1 and 8M9, south of Kitchener ($500k).
- Lackner Boulevard rebuild with an additional circuit ($314k).
- New underground feeders, 8M1 and 8M9 along Hydro One right-of-away, south Kitchener ($400k).
- Overhead to underground conversion, Trussler Road/Highway #8 to solve access issue. ($400k).

General Plant (GP)

Enova's General Plant (GP) budget exceeded the plan by $6.44 million (104.7%). The increase primarily reflected the addition of two significant initiatives that were not contemplated when the original plan was developed: the Customer Information System (CIS/CC&B) replacement project and the Victoria Street (VS) HVAC Replacement and Facility Renovation Project.

Actual GP expenditures exceeded the plan by $2.59 million (42.0%) but were $3.86 million (30.6%) below budget. The variance from budget was primarily attributable to the deferral of the Victoria Street Facility Renovation Project while Enova developed a more comprehensive strategy to address the facility's growing infrastructure deficiencies. In addition, the procurement process for the CIS (CC&B) replacement, including the request for quotations (RFQ) and contract award, took longer than anticipated, resulting in a portion of the planned expenditures being deferred beyond 2024.

4.1.1.6. Historical Variance Analysis - Year to Plan (2025)

Table 4-16: 2025 Enova Capital Variance – Year to Plan ($000s)

OEB Investment Category	Plan	Budget	Actual	Variance	% Variance	Variance	% Variance	Historical Average	% Variance
Enova	2025	2025	2025	Actual - Plan	Actual - Plan	Actual - Budget	Actual - Budget	2020-2026	Actual - Historical Avg.
System Access		$22,045	$21,357			($687)	-3.1%	$17,809	-3.9%
System Renewal		$23,573	$19,181			($4,392)	-18.6%	$23,903	-18.4%
System Service		$3,928	$2,873			($1,055)	-26.9%	$2,019	-52.3%
General Plant		$17,592	$13,776			($3,817)	-21.7%	$9,727	-39.2%
Gross CAPEX		$67,139	$57,187			($9,951)	-14.8%	$53,458	-18.6%
Contributed Capital		$8,405	$8,988			$583	6.9%	$8,365	7.0%
Net CAPEX		$58,734	$48,199			($10,534)	-17.9%	$45,093	-23.4%

There are no KWH OEB approved plan expenditures to report for 2025. KWH's last DSP filing did not extend past 2024. The variance analysis performed for 2025 utilizes Enova budget to actual expenditures.

The political landscape in the United States changed dramatically and almost overnight, high tariffs were imposed causing great uncertainty, fears of recession and job losses in the community. As a result, some subdivision developers chose to pause development. Enova also thought it prudent to scale back planned programs as fears of a declining economy could force customers into default, placing Enova's revenue and ability to fund operations at risk.

Due to the scaling back in 2025, Enova's gross capital expenditures were reduced by $9.95 million (-14.8%). Contributed capital did exceed budget by $583 thousand (6.9%). Resulting net capital expenditures were $10.53 million (-17.9%) below budget.

System Access (SA)

Actual expenditures were lower than the budget by $687 thousand (-3.1%) due to lower developer activity.

System Renewal (SR)

SR actual expenditures came in lower than the budget by $4.39 million (-18.6%).

5TS cable replacements ($2.5M) were deferred due to work at 4TS and a line outage to accommodate customer-driven work. That resulted in the temporary loss of station tie capability that would have supported the cable replacement outages.

Unexpected circuit breaker and feeder cable failures at 5TS in 2024 caused other 2024 station projects to be pushed into 2025 ($1.56M).

Other line construction projects were also deferred (Lackner Blvd) ($400K) as were other overhead renewal projects ($600k).

System Service (SS)

SS expenditures were $1.06 million (-26.9%) under budget. Enova received an NRCan grant and prioritized the use of the grant funds for its innovation & grid modernization projects.

General Plant (GP)

The under expenditure of $3.82 million (-21.7%) was primarily due to the Victoria Street (VS) Facility Renovation deferrals.

4.1.1.7. Historical Variance Analysis - Year to Plan (2026 - Bridge Year)

There are no OEB approved plan expenditures to report for 2026. The last DSP filings for both legacy LDCs did not extend past 2025. There are no actual expenditures available at the time of preparing this report. **Table 4-17** provides a summary of Enova's 2026 capital budget.

Table 4-17: 2026 Enova Capital Variance – 2025 to 2026 B ($000s)

OEB Investment Category	Budget	Actual	Budget	Variance	% Variance	Variance	% Variance	Historical Average	% Variance
Enova	2025	2025	2026	2026B-2025A	2026B-2025A	2026B-2025B	2026B-2025B	2020-2026	Actual - Historical Avg.
System Access	$22,045	$21,357	$25,572	$4,215	19.1%	$3,528	16.0%	$17,809	19.8%
System Renewal	$23,573	$18,837	$22,224	$3,387	14.4%	($1,349)	-5.7%	$23,903	-5.6%
System Service	$3,928	$2,873	$2,854	($19)	-0.5%	($1,074)	-27.3%	$2,019	-53.2%
General Plant	$17,592	$13,776	$19,489	$5,713	32.5%	$1,896	10.8%	$9,727	19.5%
Gross CAPEX	$67,139	$56,843	$70,139	$13,296	19.8%	$3,000	4.5%	$53,458	5.6%
Contributed Capital	$8,405	$8,988	$11,504	$2,516	29.9%	$3,099	36.9%	$8,365	37.0%
Net CAPEX	$58,734	$47,855	$58,635	$10,780	18.4%	($99)	-0.2%	$45,093	-0.2%

Overall, Enova's 2026 gross capital budget is $3.0 million (4.5%) higher than the 2025 budget and $13.3 million (19.8%) above 2025 actual expenditures. The increase relative to 2025 actuals is primarily attributable to the unusually low level of capital spending in 2025, when expenditures declined by approximately $10.5 million as a result of the economic conditions and project deferrals discussed in the previous section.

As economic conditions began to stabilize, Enova returned to its normal capital planning assumptions in developing the 2026 budget. Consequently, the 2026 gross capital budget reflects a modest increase of $3.0 million (4.5%) over the 2025 budget to resume a more typical level of capital investment.

Enova also forecast higher capital contributions in 2026, primarily reflecting the anticipated resumption of previously deferred System Access projects. As a result, despite the increase in gross capital expenditures, forecast net capital expenditures are expected to decrease by approximately $99 thousand (0.2%) compared with the 2025 budget.

The principal capital projects and investment drivers supporting the 2026 budget are described in the following sections and summarized in **Table 4-18** and **Table 4-19**.

System Access (SA)

SA expenditures were forecast to increase by $3.53M (16%) due to the resumption of previously deferred SA projects. Customer demand in connections and subdivision expansions account for 56.3% of the planned expenditures in this category. Municipally driven road relocations account for another 18.4% of the total. The remaining 25% of SA expenditures are meters, station and line expansions.

The timing of relocation work is established by third-party and municipal commitments and is not within Enova's control. Relocations undertaken under the Public Service Works on Highways Act (PSWHA) are subject to statutory cost-sharing, while relocations outside the PSWHA framework — including works associated with light rail transit — are subject to the applicable cost-responsibility arrangements with the requesting authority. Both are reflected in the higher contributed capital forecast for 2026. The largest relocation projects in 2026 are Victoria Street South (Fischer-Hallman Road to Lawrence Avenue, $0.88M), King Street East (Sportsworld Crossing to Sportsworld Drive, $0.73M, associated with LRT Stage 2), and Lancaster Street (Bridgeport Road to Elizabeth Street, $0.70M).

System Renewal (SR)

SR expenditures were reduced by $1.35 million (-5.7%) as resources are being redirected to higher priority SA projects. Of the total SR expenditures, overhead line projects account for 41% of the underground line projects account for another 30% with the remaining 29% composed of station projects. These projects are driven by either asset condition or safety factors.

Overhead renewal is concentrated on line renewal and voltage conversion, including Line 86 (Kissing Bridge Trailway to Listowel Road, $0.76M), Lavery Road (Posey Line to Line 86, $0.67M), and Huron Road (Walker Road to Bender Road, $0.61M). These voltage-conversion projects reduce station loading, improve capacity and reliability, and support the eventual decommissioning of legacy stations. Underground renewal is dominated by feeder

cable replacement at Station 5TS ($2.0M across circuits 5M14, 5M15, 5M17, 5M21, and 5M22), replaced on the basis of age and assessed condition in response to increasing in-field cable failure rates, together with voltage conversion and subdivision rehabilitation in Wilmot ($1.7M), which addresses deteriorated direct-buried primary cable and submersible and mini-pad transformers.

System Service (SS)

SS expenditures were reduced by $1.07 million (-27.3%) as resources were redirected to higher priority SA projects. Of the total SS expenditures, approximately 66% is being driven by SCADA equipment upgrades, with another 28% targeted to grid improvements involving automation, resiliency, and connectivity. The remaining 6% it's made up of wholesale metering and station building upgrades.

General Plant (GP)

GP expenditures were forecast higher by $1.89 million (10.8%) due, in part, to the start of the VS HVAC Replacement and Facility Renovation Project. Of the total GP expenditures, 38% is driven by information technology hardware and software projects, 41% is driven by the VS Renovation Project and 15% is driven by fleet upgrades. Approximately 2% of the expenditures are targeted to the decommissioning of one 8.32 kV station and the remaining 4% encompasses furniture, office devices, tools, equipment, and instruments.

The information technology component includes the consolidation of mobile field applications related to the already harmonized core geospatial information systems (GIS), together with enterprise licensing, mobile applications, and web services. Also included is the last phase of harmonizing the ERP software, focusing on harmonizing the processes for purchasing and tracking transformers through their asset lifecycle. Fleet expenditures are driven by the age and condition of the existing fleet.

Summary of Major Projects

The tables below summarize the major overhead and underground projects underlying the 2026 capital budget. Renewal and voltage-conversion projects are driven by conductor, pole,

and cable condition; relocation projects are driven by third-party road and transit works; and expansion projects are driven by customer and developer activity.

Table 4-18: Major 2026 Overhead Projects

Project	Scope	Driver / Category	Gross ($000s)
Katherine St – Largo Woods to Hunsberger Rd	2 CCT, 45 poles	Distribution system renewal (SR)	1,000
Victoria St S – Fischer Hallman Rd to Lawrence Ave	2 CCT, 35 poles	Routine relocation (SA)	880
Line 86 – Kissing Bridge Trailway to Listowel Rd	1 CCT, 55 poles	Line renewal / voltage conversion (SR)	760
King St E – Sportsworld Crossing to Sportsworld Dr	2 CCT, 15 poles	Special relocation – LRT Stage 2 (SA)	730
Lancaster St – Bridgeport Rd to Elizabeth St	3 CCT, 23 poles	Special relocation (SA)	700
Lavery Rd – Posey Line to Line 86	1 CCT, 55 poles	Line renewal / voltage conversion (SR)	670
Huron Rd – Walker Rd to Bender Rd	1 CCT, 46 poles	Line renewal / voltage conversion (SR)	610
Queen St – Bleams Rd to Hwy 7/8	2 CCT, 23 poles	Overhead line renewal (SR)	600

Table 4-19: Major 2026 Underground Projects

Project	Scope	Driver / Category	Gross ($000s)
Wilmot UG voltage conversion / subdivision rehabilitation (multiple sites)	Replace direct-buried primary cable and submersible / mini-pad transformers	Asset condition – renewal (SR)	1,700
5TS feeder cable replacement – 5M14, 5M17, 5M21	Feeder cable replacement	Age and condition (SR)	1,200
5TS feeder cable replacement – 5M15, 5M22	Feeder cable replacement	Age and condition (SR)	800
321 Courtland Ave – expansion (civil)	Underground expansion for site development; civil work only	Customer-driven expansion (SA)	630
4M12 / 4M27 railway crossing burial – Waterloo St to Victoria St	Pole line burial	Third party – new GRT transit terminal (SA)	600

The overhead and underground programs are further supported by recurring proactive renewal (poor-pole replacement, line re-insulation, underground transformer replacement,

and fault-indicator deployment) and by reactive renewal for storm and equipment damage. The concentration of feeder cable replacement in 2026 reflects the most urgent condition-driven feeder work being addressed in this year.

4.1.2. Forecast Capital Expenditures, 2027-2031

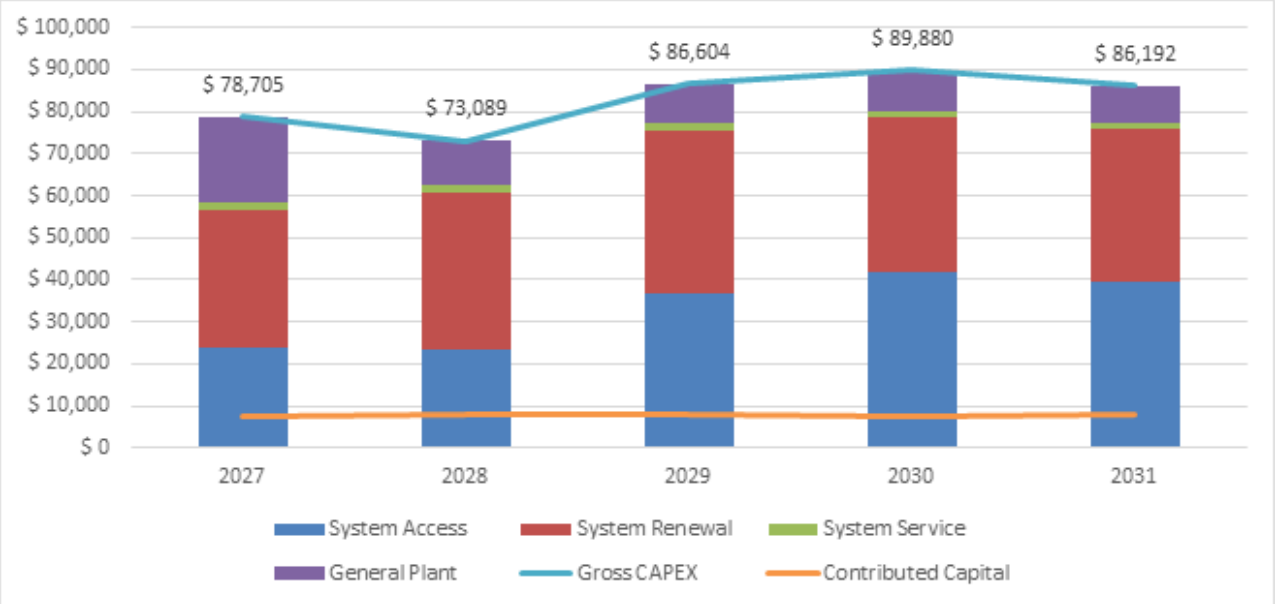
There are no expenditures for non-distribution activities in Enova's forecast capital investment plan.

Table 4-20 and **Figure 4-4** provide an overview of Enova's forecast capital expenditures from 2027–2031. The key elements of Enova investment plans over the forecast period are in the areas of System Renewal and System Access. Over the entire forecast period these two categories account for 84% of total planned investments.

Table 4-20: Forecast Expenditures (2027-2031) ($000s)

OEB Investment Category	Test Year	Forecast	Forecast	Forecast	Forecast	Average Annual Investment	% of Annual Investment	Average Annual Investment
ENOVA	2027	2028	2029	2030	2031	2027 – 2031	2027 – 2031	2020 - 2026
System Access	$23,903	$23,466	$36,935	$42,035	$39,644	$33,197	40%	$17,809
System Renewal	$32,686	$37,347	$38,672	$36,586	$36,092	$36,277	44%	$23,903
System Service	$1,643	$1,643	$1,643	$1,643	$1,643	$1,643	2%	$2,019
General Plant	$20,473	$10,632	$9,353	$9,617	$8,813	$11,777	14%	$9,727
Gross CAPEX	$78,705	$73,089	$86,604	$89,880	$86,192	$82,894	100%	$53,458
Contributed Capital	$7,485	$7,495	$7,489	$6,783	$8,208	$7,492	9%	$8,365
Net CAPEX	$71,220	$65,594	$79,115	$83,097	$77,984	$75,402	91%	$45,093
O&M	$22,128	$22,228	$22,228	$22,328	$22,328	$22,248	27%	$22,989

Figure 4-4: Forecast Capex ($000s)



4.1.2.1. Major Drivers in Forecast Capital Expenditures, 2027-2031

The investments presented here are the major known drivers for capital expenditures over the forecast period and align with the strategic objectives identified in Enova's DSP. Enova considers the resulting expenditure profile to be a reasonable reflection of identified system needs over the forecast period.

System Access (SA) – Metering AMI 2.0

Enova's SA forecast rises sharply in 2029 mainly due to the staged replacement of Enova's first-generation AMI 1.0 smart meter population. The AMI 2.0 program has been developed and paced to replace approximately 165,000 meters over an eight-year period. With a TUL of 15 years the first meters to be replaced in 2029 will be 22 years old (147% TUL). By the time the program is complete, the last of the AMI 1.0 meters will be 25 years old (167% TUL). In addition to replacing meters at end of life, these new investments will modernize metering equipment and systems to improve operational flexibility and enable the expanded use of customer data in operations and planning. More information on the AMI 1.0 meters can be found in **Appendix B-1 Asset Condition Assessment (ACA) Report**. Expenditures required during the current forecast period are estimated at $0.18M in 2028, $8.4M in 2029, $7.4M in 2030, and $7.4M in 2031. Enova is participating with approximately 12 other LDC's in the Grid Smart City AMI 2.0 project to scope out requirements and issue an RFP to procure the next generation of smart meters. The RFP is expected to be completed by July of this year, after which it will be sent to the meter manufacturers.

Enova is evaluating the potential submission of an Incremental Capital Module (ICM) application to obtain supplemental funding for this program.

System Access (SA) – Region of Waterloo, Light Rapid Transit (LRT) Phase Two

The Region of Waterloo will be proceeding with Phase Two of the ION LRT project. Estimated to cost between $3.1 and $4.3 billion, this project consists of extending the existing LRT line 17 km from Fairview Mall in Kitchener, through the south end of Kitchener and into the City of Cambridge. The Region of Waterloo Council unanimously approved the

full LRT extension plans following the completion of the Initial Business Case. Regional staff are now pursuing full project funding from the provincial and federal governments.

The project has moved into the detailed design and pre-construction phases. In this phase, work will continue with heritage assessments, utility relocations, environmental field work and detailed design.

The following work has been identified and completed by Enova to support this project.

1, King St – Sportsworld Dr south to Service Boundary (completed in 2024/2025)

- Overhead line relocation work completed in 2024 - $196k
- Underground relocation work completed in 2025 - $280k

2. King St – HWY 8 to Sportsworld Dr (planned for 2026)

- Overhead line relocation work completed in 2024 - $610k
- Underground relocation work completed in 2025 - $300k

Future hydro relocations are expected to be needed in the 2028-2031 timeframe. Costs have been estimated as follows,

- Overhead line relocation work - $800k
- Underground relocation work - $500k

System Access (SA) - Stations

The largest single contributor to the year-over-year variation is the planned 11TS station expansion required to provide capacity for a new customer connection. The associated expenditures are approximately $2.4M in 2027, $2.3M in 2028, $7.2M in 2029, $13.7M in 2030, and $10.6M in 2031; this profile is the principal driver of the increases in 2029 and 2030 and of the reduction in 2031.

This is a customer-driven System Access investment. Funding for this project is currently unclear. The timing of this work follows the customer's development schedule; however, the IESO’s System Impact Assessment requirements have not yet been fully determined. During

forecast preparation, customer-side information required to complete the connection studies, undertaken by Enova in coordination with the IESO was delayed, and the associated expenditures were deferred by one year. The profile presented herein reflects this revised schedule; however, it remains tentative until the System Impact Assessment requirements have been fully determined.

In the latter part of the forecast period, early-stage planning will begin for additional station capacity to address forecast load growth. This work is triggered as defined station capacity thresholds are approached and is presented at this time for information only.

System Renewal (SR) – Stations

Enova's forecast stations capital expenditures vary across the 2027–2031 period. On a gross (total capital) basis, the program is approximately $7.8M in 2027, $9.0M in 2028, $9.5M in 2029, $8.5M in 2030, and 7.1M in 2031. This variation reflects the timing and nature of identified station investments and arises principally from two sources: the sequencing of System Renewal projects, and the timing of System Access (expansion) work driven by a new customer connection. A third element, early-stage planning for new station capacity, is scheduled for the latter part of the forecast period.

The recurring base of the program is System Renewal investment, identified through Enova's Asset Condition Assessment (ACA) program, and ranges from approximately $8.44M to $10.66M over the period. The principal assets — power transformers, switchgear and circuit breakers, and protection and control systems — are replaced as discrete projects as they reach end-of-life, lose manufacturer support, or become difficult to sustain through available spare parts. These projects carry long procurement lead times for major station equipment and are executed over multiple years, with engineering and procurement, construction, and in-service occurring in successive periods. For these projects, outages need to be coordinated with the transmitter and system operations. The year-over-year renewal profile therefore reflects the scheduling of individual projects. Where aging units are replaced with modern equipment, certain renewals also restore or increase station capacity; however, the main driver, and the vast majority of the capital expenditures, are driven by System Renewal considerations.

System Renewal (SR) – Overhead Lines

Enova has increased its overhead line renewal program based on the results of its most recent ACA. Over the historical period, Enova averaged approximately 900 – 1,000 pole replacements per year. This program will be increasing pole replacements to between 1400 and 1500 annually over the forecast period and will be a major part of Enova's System Renewal program. **Table 4-20** provides the activity and expenditure profile for this program. Figures are stated in nominal dollars with no escalation for inflation applied. The 2028–2031 regular program is held at the 2027 level on a stable, linear basis.

Table 4-21: Forecast Overhead Line Renewal Program (2027-2031) ($000s)

System Renewal - Overhead Lines	2027	2028	2029	2030	2031
Forecast annual expenditures	$11,000	$11,000	$11,000	$11,000	$11,000
Pole Replacement	1,460	1,400	1,394	1,382	1,441

System Renewal (SR) – Underground Lines

Enova plans to increase its annual expenditures for the replacement of underground lines in poor condition. Supported by condition assessments, failure rates and age, the volume of cable to be replaced has been paced by Enova's capacity to plan, design and execute this work program. The estimated amounts are provided in **Table 4-21** below. Figures are stated in nominal dollars with no escalation for inflation applied.

Table 4-22: Forecast Underground Cable Renewal Program (2027-2031) ($000s)

System Renewal - Underground Lines	2027	2028	2029	2030	2031
Additional annual expenditures	$ 8,429	$ 15,182	$ 16,043	$ 14,968	$ 16,047
Cable Replacement (km)	15.4	19.7	23.0	22.0	25.0

This information is being presented at this time to identify the project to the OEB and interested stakeholders of a potential future ICM request. An application is not being made at this time.

System Service (SS) – Innovation

Enova's forecast innovation capital expenditures fund a coordinated set of investments that position the distribution system to integrate distributed energy resources (DERs), enable emerging market functions, and modernize the distribution system. The program is organized into three related streams: a recurring innovation program that includes early-stage DER deployments; a Market Transaction Platform; and a Distributed Energy Resource Management System (DERMS). On a gross (total capital) basis, the program is approximately $0.60M in 2027, $0.68M in 2028, $1.26M in 2029, $1.85M in 2030, and $0.86M in 2031 — year-over-year changes of approximately +$0.09M, +$0.58M, +$0.59M, and −$0.99M, respectively. The profile reflects a transition from early-stage DER small-scale deployment in 2027 to the build-out of distribution-support platforms over 2028–2030, supported by a steady annual innovation program, before declining in 2031 as the principal platform implementations complete and move into ongoing enhancement and optimization.

Innovation activity begins in 2027 with two distributed energy resource small-scale deployments — a Managed EV Charging deployment ($0.32M) and a Residential Energy Storage deployment ($0.28M) — that assess DER integration ahead of broader deployment. From 2028, the program is supported by a recurring annual innovation allocation of approximately $0.50M that sustains continuing DER and distribution-innovation program across the forecast period. This recurring component is broadly level year over year and does not, on its own, drive the variation in the total.

The increase through 2030 is driven principally by two platform investments. The largest single contributor is the DERMS platform, which enables Enova to monitor, coordinate, and dispatch distributed energy resources connected to the distribution system. DERMS implementation and integration builds from approximately $0.15M in 2028 to $0.53M in 2029 and $0.83M in 2030, after which its implementation phase completes; associated enhancement work rises from approximately $0.11M in 2029 to $0.30M in each of 2030 and 2031. The Market Transaction Platform, which supports Enova's participation in emerging distribution-level market functions, follows a similar but smaller profile — implementation and integration of approximately $0.03M in 2028, $0.11M in 2029, and $0.17M in 2030, with enhancement work of approximately $0.02M to $0.06M from 2029. Together with the

recurring innovation program, these builds drive the increase to the 2030 peak of approximately $1.85M.

The reduction in 2031 reflects completion of the principal DERMS and Market Transaction Platform implementation and integration phases.

Taken together, the 2027–2031 innovation capital forecast comprises a recurring DER and innovation program and two distribution-support platform implementation and integration — DERMS and the Market Transaction Platform — that position Enova to integrate distributed energy resources and support emerging distribution-system and market functions. The year-over-year profile is governed by the timing of the platform implementations rather than by any change in the recurring program. These investments are consistent with the strategic objectives identified in Enova's DSP, and Enova considers the resulting expenditure profile to be a reasonable reflection of identified innovation needs over the forecast period.

Table 4-23 Innovation Capital Forecast, 2027–2031 (Gross $) ($000s)

Project	2027	2028	2029	2030	2031	Total
Managed EV Charging Program	$320	—	—	—	—	$320
Residential Energy Storage Program	$275	—	—	—	—	$275
EV and DER Program	—	$500	$500	$500	$500	$2,000
Market Transaction Platform Implementation	—	$30,000	$105	$165	—	$300
Market Transaction Platform Enhancement	—	—	$21	$60	$60	$141
DERMS Implementation	—	$150	$525	$825	—	$1,500
DERMS Enhancement	—	—	$105	$300	$300	$705
Total	$595	$680	$1,256	$1,850	$860	$5,241

Amounts are gross capital expenditures; no escalation has been applied. No capital contributions are forecast.

The reduction in 2031 reflects completion of the DERMS and Market Transaction Platform capital builds, after which expenditure comprises the recurring innovation envelope and the ongoing maintenance of the new platforms.

These investments position Enova to integrate distributed energy resources and support emerging distribution-system and market functions, consistent with the strategic objectives

identified in Enova's DSP. Enova considers the resulting expenditure profile to be a reasonable reflection of identified innovation needs over the forecast period.

General Plant (GP) – Information Technology

Enova's forecast information technology (IT) capital expenditures decline across the 2027–2031 period. On a gross (total capital) basis, the program is approximately $7.9M in 2027, $4.4M in 2028, $3.7M in 2029, $3.5M in 2030, and $3.4M in 2031. The profile is shaped principally by two factors: a one-time application CC&B upgrade ($3.9M) concentrated in 2027, and the scheduling of discrete, project-based system investments that taper over the period. Underlying these is a recurring base of evergreen software maintenance, hardware lifecycle replacement, and cybersecurity investment.

General Plant (GP) – Fleet

Please refer to Appendix **J, Enova's Fleet Management Plan** for a more detailed treatment of these assets.

General Plant (GP) – Facilities

Please refer to Appendix **I, Enova's Facilities Management Plan** for a more detailed treatment of these assets.

4.1.2.2. Test Year - 2027

This section provides an overview of Enova's 2027 capital expenditures programs and material investments by OEB category. A high level summary is provided in **Table 4-23**.

Table 4-24: Summary of 2027 Investments ($000s)

OEB Investment Category	# Programs / Projects	Total Category($)	% Total CAPEX	# Material Projects (> $400k)	Total $	% Total OEB Category
System Access	41	$ 23,281	29.6%	16	$ 23,281	29.6%
System Renewal	75	$ 30,985	39.4%	22	$ 28,609	36.3%
System Service	3	$ 1,543	2.0%	2	$ 1,543	2.0%
General Plant	29	$ 17,680	22.5%	6	$ 16,043	20.4%
Total	148	$ 73,489	93.4%	46	$ 69,476	88.3%
Total 2027 CAPEX		$ 78,705	100.0%		$ 78,705	100.0%
Variance		$ 5,216	6.6%		$ 9,229	11.7%

Enova's 2027 capital investment plan prioritizes System Access and System Renewal investments. System Access investments are led by customer connections, subdivision expansions and relocations. These are customer-driven and mandated investments and are considered must do projects. System Renewal investments are led by subdivision underground cable replacements, station equipment renewal, and overhead line voltage upgrades. These data-driven investments targeting aging infrastructure in poor condition.

The following tables provide a high level summary of 2027 capital investment programs by investment category, their relative weighting to the investment category and to the total 2027 capital investment plan. Each investment decision is supported by one or more identifiable drivers and corporate strategic imperatives.

Table 4-25: 2027 System Access Investment Summary

Program Code	Program Name	OEB Cat.	# of Projects	# of Material Projects	Total Budget ($000s)
E-ME-R	Meters - Retail	SA	11	0	$ 1,427
E-UL-F	UG Line Expansions - Feeders	SA	5	4	$ 2,794
E-UL-S	UG Line Expansions - Subdivisions	SA	7	3	$ 4,165
E-SE	Station Equipment - Expansion	SA	1	1	$ 2,280
E-OL	OH Line Expansions	SA	2	1	$ 729
E-CC-L	Customer Connections - Loads	SA	4	4	$ 8,027
E-SP	Relocations - Special Projects	SA	8	3	$ 3,131
E-RP	Relocations - Routine Projects	SA	3	0	$ 727

Table 4-26: 2027 System Renewal Investment Summary

Program Code	Program Name	OEB Cat.	# of Projects	# of Material Projects	Total Budget ($000s)
R-UL-R	UG Line Renewal - Reactive	SR	4	1	$ 969
R-OL-R	OH Line Renewal - Reactive	SR	2	1	$ 684
R-OL-FC	OH Line Renewal - Failing Conductor	SR	4	2	$ 1,941
R-UL-P	UG Line Renewal - Proactive	SR	4	0	$ 934
R-SE	Station Equipment - Renewal	SR	23	4	$ 5,366
R-OL-VU	OH Line Renewal - Voltage Upgrade	SR	13	6	$ 6,364
R-UL-S	UG Line Renewal - Subdivisions	SR	18	4	$ 8,244
R-OL-RP	OH Line Renewal - Routine Projects	SR	7	4	$ 4,107

Table 4-27: 2027 System Service Investment Summary

Program Code	Program Name	OEB Cat.	# of Projects	# of Material Projects	Total Budget ($000s)
U-GI-C	Grid Improvements - Connectivity	SS	2	1	$ 929
U-GI-A	Grid Improvements - Automation	SS	1	1	$ 615

Table 4-28: 2027 General Plant Investment Summary

Program Code	Program Name	OEB Cat.	# of Projects	# of Material Projects	Total Budget ($000s)
G-SW-IT	Software - IT (CIS)	GP	21	2	$ 5,083
G-BL	Buildings	GP	4	1	$ 7,645
G-FL	Fleet	GP	4	3	$ 3,315

Overall, Enova's 2027 investment plan totals $78.7 million. This is an increase of 12.2 % over 2026 planned expenditures. **Section 4.1.2.3** provides greater detail on this variance.

More detailed information for material projects/programs is located in

- **Section 4.2.2 Material Investments**
- **Appendix A - 2027 Material Capital Investments**.

4.1.2.3. Forecast Variance Analysis - Year to Year (2027 - Test Year)

Table 4-29: 2027 Y-Y Capital Variances by Investment Category ($000s)

Enova	Bridge Year	Test Year			Historical Average	Variance to Historical Average	Variance to Historical Average
OEB Investment Category	2026	2027	2027-2026		2020-2026	2027 – Avg.	2027 – Avg.
	Budget	Forecast	Variance	% Diff		Variance	% Variance
System Access	$25,572	$23,925	($1,647)	-6.4%	$17,809	$6,116	34.3%
System Renewal	$22,224	$32,664	$10,440	47.0%	$23,903	$8,761	36.6%
System Service	$2,854	$1,643	($1,211)	-42.4%	$2,019	($376)	-18.6%
General Plant	$19,489	$20,473	$984	5.1%	$9,727	$10,746	110.5%
Gross CAPEX	$70,139	$78,705	$8,566	12.2%	$53,458	$25,247	47.2%
Contributed Capital	$11,504	$7,485	($4,019)	-34.9%	$8,365	($880)	-10.5%
Net CAPEX	$58,635	$71,220	$12,585	21.5%	$45,093	$26,127	57.9%

Overall, Enova plans to increase 2027 gross capital expenditures by $8.57 million (12.2%) over 2026. Contributed capital has been forecast to decrease by $4.02 million (34.9%) resulting in an increase in net capex of $12.59 million (21.5%) over 2026, and a $26.1 million (57.9%) increase over historical expenditures.

Detailed project/program descriptions for 2027 material expenditures is provided in **Appendix A - 2027 Material Capital Investment**s.

System Access (SA)

SA expenditures are forecast to decrease by $1.65 million (-6.4%) in 2027 driven by the completion of large road relocations by the end of 2026.

System Renewal (SR)

SR expenditures are expected to increase in 2027 by $10.44 million (47%) due to the following condition-based (ACA) projects,

- Overhead line renewal projects ($1.89 M)
- Underground cable renewal projects ($6.4 M)
- Stations renewal projects ($2.1 M)

System Service (SS)

SS expenditures are expected to decrease in 2027 by $1.21 million (-42.4%) as planned projects in Scada / OT network and wholesale metering improvement projects come to completion at the end of 2026.

General Plant (GP)

GP expenditures are expected to increase in 2027 by $984 thousand (5.1%). IT software expenditures are expected to increase by $1.85 million. This increase is mitigated by reductions in buildings of $448 thousand, station decommissioning and software support of $405 thousand.

4.1.2.4. Forecast Variance Analysis - Year to Year (2028)

Table 4-30: 2028 Y-Y Capital Variances by Investment Category ($000s)

Enova	Test Year				Historical Average	Variance to Historical Average	Variance to Historical Average
OEB Investment Category	2027	2028	2028-2027		2020-2026	2028 – Avg.	2028 – Avg.
	Forecast	Forecast	Variance	% Diff		Variance	% Variance
System Access	$23,903	$23,466	($436)	-1.8%	$17,809	$5,658	31.8%
System Renewal	$32,686	$37,347	$4,661	14.3%	$23,903	$13,443	56.2%
System Service	$1,643	$1,643	$0	0.0%	$2,019	($376)	-18.6%
General Plant	$20,473	$10,632	($9,841)	-48.1%	$9,727	$905	9.3%
Gross CAPEX	$78,705	$73,089	($5,616)	-7.1%	$53,458	$19,630	36.7%
Contributed Capital	$7,485	$7,495	$10	0.1%	$8,365	($870)	-10.4%
Net CAPEX	$71,220	$65,594	($5,626)	-7.9%	$45,093	$20,500	45.5%

Overall, Enova plans a decrease in 2028 gross capital expenditures of $5.62 million (-7.1%) over 2027. Contributed capital has been forecast to remain unchanged from 2028 resulting in a decrease in net capex of $5.63 million (-7.9%) over 2027.

System Access (SA)

SA expenditures are forecast to decrease by $436 thousand (-1.8%) in 2028 due to lower expenditures in station buildings and station equipment.

System Renewal (SR)

SR expenditures are expected to increase in 2028 by $4.66 million (14.3%) due to an ACA driven increase of $3.85 million for underground cable replacements, and an $807 thousand increase in stations projects.

System Service (SS)

SS expenditures are not expected to increase in 2028.

General Plant (GP)

GP expenditures are expected to decrease by $9.84 million (-48.1%) in 2028. The completion of the VS Facilities Renovation project by the end of 2027 accounts for $6.1 million of the decrease. The completion of the IT related CC&B major release upgrade accounts for another $3.47 million of the decrease.

4.1.2.5. Forecast Variance Analysis - Year to Year (2029)

Table 4-31: 2029 Y-Y Capital Variances by Investment Category ($000s)

Enova					Historical Average	Variance to Historical Average	Variance to Historical Average
OEB Investment Category	2028	2029	2029-2028		2020-2026	2029 – Avg.	2029 – Avg.
	Forecast	Forecast	Variance	% Diff		Variance	% Variance
System Access	$23,489	$36,958	$13,469	57.3%	$17,809	$19,149	107.5%
System Renewal	$37,325	$38,650	$1,325	3.5%	$23,903	$14,747	61.7%
System Service	$1,643	$1,643	$0	0.0%	$2,019	($376)	-18.6%
General Plant	$10,632	$9,353	($1,279)	-12.0%	$9,727	($374)	-3.8%
Gross CAPEX	$73,089	$86,604	$13,515	18.5%	$53,458	$33,146	62.0%
Contributed Capital	$7,495	$7,489	($6)	-0.1%	$8,365	($876)	-10.5%
Net CAPEX	$65,594	$79,115	$13,521	20.6%	$45,093	$34,022	75.4%

Overall Enova is planning an increase in 2029 gross capital expenditures of $13.52 million (18.5%) over 2028. Contributed capital has been forecast to reduce slightly by $6.0 thousand (0.1%) resulting in an increase in net capex of $13.52 million (20.6%) over 2028.

System Access (SA)

SA expenditures in total are expected to increase in 2029 by $13.47 million (57.3%). The start of the AMI 2.0 smart meter replacement program will add $8.2 million in 2029. Enova expects to replace approximately 20,000 meters per year starting in 2029. With a population of approximately 165,000 meters, this represents a replacement of 12.1% annually. Progress payments for the new 11TS station totalling $5.24 million are also expected to occur in 2029.

System Renewal (SR)

SR expenditures are expected to increase in 2029 by $1.33 million (3.6%) due to an increase the cable replacement program of $862 thousand and station equipment replacements of $458 thousand.

System Service (SS)

SS expenditures are not expected to increase in 2029.

General Plant (GP)

GP expenditures are expected to decrease in 2029 by $1.28 million (-12.0%) due mainly to the completion of two facilities projects by the end of 2028 (-$ 1.22 M).

4.1.2.6. Forecast Variance Analysis - Year to Year (2030)

Table 4-32: 2030 Y-Y Capital Variances by Investment Category ($000s)

Enova	Bridge Year	Test Year			Historical Average	Variance to Historical Average	Variance to Historical Average
OEB Investment Category	2029	2030	2030-2029		2020-2026	2030 – Avg.	2030 – Avg.
	Budget	Forecast	Variance	% Diff		Variance	% Variance
System Access	$36,935	$42,035	$5,099	13.8%	$17,809	$ 24,226	136.0%
System Renewal	$38,672	$36,586	($2,087)	-5.4%	$23,903	$ 12,682	53.1%
System Service	$1,643	$1,643	$0	0.0%	$2,019	$ (376)	-18.6%
General Plant	$9,353	$9,617	$264	2.8%	$9,727	$ (111)	-1.1%
Gross CAPEX	$86,604	$89,880	$3,277	3.8%	$53,458	$ 36,422	68.1%
Contributed Capital	$7,489	$6,783	($706)	-9.4%	$8,365	$ (1,582)	-18.9%
Net CAPEX	$79,115	$83,097	$3,983	5.0%	$45,093	$ 38,004	84.3%

Overall, Enova plans to increase 2030 gross capital expenditures by $3.28 million (3.8%) over 2029. Contributed capital has been forecast to decrease by $706 thousand from 2029, resulting in an increase in net capex of $3.98 million (5%) over 2029.

System Access (SA)

SA expenditures are expected to increase in total by $5.1 million (13.8%). Increased expenditures of $6.4 million are forecast for the new 11TS in preparation for a 2031 in-service date.

The AMI 2.0 smart meter replacement program continues in 2030 with an expenditure level of $7.4 million, $1.0 million lower than in 2029.

System Renewal (SR)

SR expenditures are expected to decrease by $2.09 million (-5.4%) in 2030. A reduction of $1.08 million in the feeder cable replacement program was made to balance resources and pace expenditures. A further reduction of $1.01 million occurs due to the completion of a stations project by the end of 2029.

System Service (SS)

SS expenditures are not expected to increase in 2030.

General Plant (GP)

GP expenditures are expected to increase by $264 thousand (2.8%) in 2030 attributable to normal fluctuations in the timing and sequencing of General Plant investments.

4.1.2.7. Forecast Variance Analysis - Year to Year (2031)

Table 4-33: 2031 Y-Y Capital Variances by Investment Category ($000s)

Enova	Bridge Year	Test Year			Historical Average	Variance to Historical Average	Variance to Historical Average
OEB Investment Category	2030	2031	2031-2030		2020-2026	2031 – Avg.	2031 – Avg.
	Budget	Forecast	Variance	% Diff		Variance	% Variance
System Access	$42,035	$39,644	($2,390)	-5.7%	$17,809	$21,836	122.6%
System Renewal	$36,586	$36,092	($494)	-1.4%	$23,903	$12,188	51.0%
System Service	$1,643	$1,643	$0	0.0%	$2,019	-$376	-18.6%
General Plant	$9,617	$8,813	($804)	-8.4%	$9,727	-$915	-9.4%
Gross CAPEX	$89,880	$86,192	($3,688)	-4.1%	$53,458	$32,733	61.2%
Contributed Capital	$6,783	$8,208	$1,425	21.0%	$8,365	-$157	-1.9%
Net CAPEX	$83,097	$77,984	($5,113)	-6.2%	$45,093	$32,891	72.9%

Overall, Enova plans a decrease in 2031 gross capital expenditures of $3.69 million (-4.1%) over 2030. Contributed capital has been forecast to increase by $1.43 million (-21.0%) over 2030 resulting in a decrease in net capex of $5.11 million (-6.2%) over 2030.

System Access (SA)

SA expenditures in total are expected to decrease in 2031 by $2.39 million (-5.7%). The 11TS project will see a reduction of $3.0 million as the project nears completion. Line relocation work is expected to increase by $600 thousand.

The AMI 2.0 smart meter replacement program continues in 2031 with expenditures of $7.4 million. This represent a similar expenditure level as 2030.

System Renewal (SR)

SR expenditures are expected to decrease in 2031 by $494 thousand (-1.4%). Cable replacement expenditures are forecast to increase by $1.08 million while the stations program will decrease by $1.57 million.

This reduction is temporary and is driven by the planned allocation of station resources to the completion of the 11TS project. As the project approaches the end of the forecast period,

final testing, commissioning, and energization activities will require a significant commitment of Enova's station engineering and technical resources. Given the scale and complexity of the project, these activities are expected to utilize the majority of available station staff.

Accordingly, routine station renewal programs will be temporarily scaled back and deferred to ensure the successful completion and commissioning of the new station. These deferred renewal activities are expected to resume immediately after 11TS is placed into service, which is beyond the end of the 2027–2031 forecast period. This temporary reprioritization of resources reflects prudent portfolio management and ensures that critical capital investments are delivered safely and efficiently while minimizing overall project execution risk.

System Service (SS)

SS expenditures are not expected to increase in 2031.

General Plant (GP)

GP expenditures are expected to decrease in 2031 by $804 thousand (-8.4%). Reductions in IT Software and Software - Distribution Support programs will result in reductions of $100 thousand and $765 thousand respectively.

4.1.2.8. Forecast vs Historical Capital Expenditure Analysis

Table 4-34 provides a comparison of forecast and historical expenditures.

Table 4-34: Forecast vs Historical Expenditures ($000s)

OEB Investment Categories	Historical Average 2020-2026	Forecast Average 2027-2031	Variance Forecast - Historical	% Variance
System Access	$17,809	$33,219	$15,410	86.5%
System Renewal	$23,903	$36,254	$12,351	51.7%
System Service	$2,019	$1,643	-$376	-18.6%
General Plant	$9,727	$11,777	$2,050	21.1%
Gross Capex	$53,458	$82,894	$29,435	55.1%
Contributed Capital	$8,271	$7,492	-$779	-9.4%
Net CAPEX	$45,187	$75,402	$30,215	66.9%
O&M	$19,883	$22,268	$2,385	12.0%

Overall, average forecast capital expenditures are 55% higher than historical expenditures with SA and SR exhibiting the highest increases. There is no offsetting contributed capital with the major SA expenditures for AMI 2.0 and Enova 11TS resulting in an overall reduction of -9.4%.

Although forecast expenditures are shown in 2025 dollars, increases due to inflation, COVID-19 supply chain disruptions and US tariffs have infiltrated their way into the cost of goods and services.

Average forecast SA expenditures have increased 86.5% in large part due to the planned replacement of first-generation smart meters that are nearing end-of-life and the planned addition of a customer-driven 11TS transformer station.

Average forecast SR expenditures have increased by 51.7% as replacement activity is increasing, driven by infrastructure age and condition assessments.

Average SS expenditures have declined somewhat, as Enova paces its Grid modernization efforts.

Average forecast GP expenditures have increased by an average of 21%, driven mostly by IT software development/upgrades and fleet vehicle replacements. The forecast amounts also include the second year of the Victoria Street Facility Renovation project.

4.1.2.9. Important Modifications to Capital Programs Since Last Distribution System Plan

Changes in Programs Changes Nomenclature

This is Enova's first DSP following the 2022 merger. As part of the post-merger integration and harmonization of business processes and information systems, Enova implemented a revised capital program structure during 2025. This resulted in changes to both the identification and the number of capital programs reported within each OEB investment category.

The revised program structure was developed to provide greater consistency, granularity, and transparency in the planning, management, and reporting of capital expenditures across the combined utility. To facilitate historical comparisons, capital program categories from each legacy LDC were mapped to the new Enova capital program structure.

As the legacy capital program classifications were not identical, the mapping process does not result in a one-to-one correspondence between historical and current program categories. Consequently, apparent changes in historical expenditures within certain capital programs should not be interpreted as changes in Enova's investment philosophy, asset management approach, or underlying investment priorities. Rather, these differences primarily reflect the reclassification of historical expenditures into the new reporting framework.

Enova believes that the harmonized capital program structure provides improved visibility into investment drivers, enhances the consistency and transparency of capital expenditure reporting, and supports more meaningful analysis of capital investment trends over time. This enhanced reporting framework will also improve future regulatory reporting and strengthen the linkage between identified system needs, investment decisions, and capital expenditures.

It is important to emphasize that these reporting changes did not alter the underlying investment drivers, asset management philosophy, or the classification of investments within the OEB's prescribed investment categories. The changes were administrative in nature and

related solely to the harmonization and refinement of Enova's internal capital program structure and reporting framework. Accordingly, the underlying needs addressed by the investments and their allocation to the applicable OEB investment categories remain unchanged.

Changes in Asset Investment Allocation

Enova's forecast capital investment plan is approximately 55.1% higher, on an annualized basis, than its historical average. While the overall capital expenditure envelope increases over the forecast period, the relative allocation of expenditures among the OEB investment categories remains generally consistent with historical trends. **Table 4-34** illustrates how annual capital expenditure allocations have evolved historically and are expected to change over the 2027–2031 forecast period.

System Access expenditures are forecast to increase from an historical annual average of 33% to approximately 40% of total capital expenditures. This increase is primarily attributable to significant customer-driven investments, including the construction of the new 11TS transformer station to accommodate long-term load growth and capacity requirements, together with the planned implementation of the AMI 2.0 program during the latter part of the forecast period (2029–2031).

System Renewal expenditures are forecast to decrease modestly from 46% to 44% of total capital expenditures. Despite this slight reduction in relative share, System Renewal continues to represent the largest component of Enova's capital investment plan, reflecting the utility's ongoing commitment to replacing aging infrastructure, managing asset condition risks, and maintaining long-term system reliability.

System Service expenditures are also forecast to decline marginally as a proportion of the overall capital program. This reflects the prudent pacing of Enova's grid modernization initiatives to align investment timing with organizational capacity, technology readiness, and customer value while continuing to advance modernization objectives over the longer term.

General Plant expenditures are forecast to decrease from 18% to 14% of total capital expenditures. This reduction reflects the completion of major post-merger information

technology (IT) and operational technology (OT) integration initiatives, allowing a greater proportion of capital funding to be directed toward investments in core distribution system infrastructure.

Overall, the forecast allocation of capital expenditures demonstrates Enova's continued focus on balancing customer growth, asset renewal, reliability, and operational modernization while strategically pacing investments to optimize customer value and maintain the long-term sustainability of the distribution system.

Table 4-35: Historical and Forecast Expenditures as Percentage of Total Expenditures

OEB Investment Category	Actual	Actual	Actual	Actual	Actual	Actual	Bridge Year (Budget)	Test Year	Forecast	Forecast	Forecast	Forecast	Historical Average	Forecast Average
ENOVA	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2020-2026**	**2027-2031**
System Access	36%	31%	35%	28%	29%	37%	36%	30%	32%	43%	47%	46%	33%	40%
System Renewal	40%	47%	52%	62%	52%	34%	32%	42%	51%	45%	41%	42%	46%	44%
System Service	4%	4%	4%	3%	2%	5%	4%	2%	2%	2%	2%	2%	4%	2%
General Plant	19%	18%	9%	8%	16%	24%	28%	26%	15%	11%	11%	10%	18%	14%
Gross CAPEX	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Contributed Capital (1)	15%	20%	17%	13%	12%	16%	16%	10%	10%	9%	8%	10%	15%	9%
Net CAPEX (1)	85%	80%	83%	87%	88%	84%	84%	90%	90%	91%	92%	90%	85%	91%
O&M (1)	41%	39%	42%	34%	40%	37%	31%	28%	30%	26%	25%	26%	38%	27%

Note (1)Given as a percentage of Gross Capex

Contributed capital as a percentage of gross capital is expected to fall from 15% to 9% on average. This is mainly due to the forecast capital plan having fewer System Access projects that attract contributed contributions such as AMI 2.0. Other than inflation, O&M increases are forecast to remain fairly flat, resulting in the O&M to gross capex declining from 38% to 27% .

4.2. (5.4.2) Justifying Capital Expenditures

4.2.1. Overall Plan

Enova has developed its capital expenditure plan to ensure that all proposed investments are prudent, cost-effective, and deliver clear value to customers across its service territory. The plan reflects Enova's obligation to provide safe, reliable, and efficient electricity distribution services while supporting growth and the ongoing transition of the electricity sector. Consistent with the Ontario Energy Board's expectations, Enova demonstrates that both individual capital investments and the overall capital envelope are justified through evidence-based planning, robust analysis, and a strong focus on customer outcomes.

At the project level, Enova applies a comprehensive asset management framework that integrates asset condition data, system performance metrics, risk assessment, and load forecasting. Investments in system renewal are primarily driven by deteriorating infrastructure within legacy service areas, where asset condition assessments indicate increasing probability of failure. These projects are prioritized to mitigate reliability risks and maintain acceptable service levels. System access investments are informed by customer connection requirements and regional growth forecasts, particularly in rapidly developing areas within Enova's consolidated service territory. For each proposed project, Enova has evaluated feasible alternatives, including non-wires solutions and operational measures, to ensure that the selected option represents the most economical and effective approach to meeting identified needs.

Enova has robust inspection, testing and maintenance programs (Section 3.3.1.4) and performs extensive consultations with third parties (Section 2.2) all of which leads to the identification of asset investment needs.

Enova employs a structured prioritization and optimization process to sequence capital investments across the planning horizon. Projects are ranked based on Enova's strategic objectives and aligned with the four key OEB performance outcomes as established in the Renewed Regulatory Framework for Electricity: Customer Focus, Operational Effectiveness, Public Policy Responsiveness and Financial Performance. This approach

enables Enova to target capital resources toward investments that provide the greatest overall benefit while maintaining flexibility to respond to emerging needs.

Strong customer driven demand for connections and expansions along with a growing backlog of deteriorating underground, overhead and stations infrastructure make System Access and System Renewal investments 84% of the total capital envelope.

Pacing of expenditures over the forecast period has been challenging for Enova. Strong customer driven needs are driving mandatory System Access investments to 40% of total planned expenditures. This represents an average annual increase of 86.5% over the historical average.

Enova's System Renewal forecast investments have also increased substantially (51.7%) over the historical period. Investments in underground cable replacements have increased from approximately $5 million annually to $14.5 million annually. At this pace, the program will only reduce the backlog of Poor and Very Poor cables by 39%. Enova did take steps to pace this program and move expenditures into the next investment cycle; however, it is expected that the backlog will continue to grow. Enova also deferred a number of investments in overhead line renewal and station equipment renewal into the next investment cycle in order to mitigate rate increases at Enova's next Cost of Service.

Variations in annual spending levels are driven by the timing of larger projects, including station refurbishments, capacity upgrades, and system modernization initiatives. Enova has provided context for these fluctuations and assessed their long-term rate impacts to demonstrate that the proposed capital plan remains affordable for customers while addressing system needs in a timely manner.

Customer value is a central consideration in Enova's capital planning process. The proposed investments are expected to maintain Enova's favourable reliability performance and enhance system resilience in the face of extreme weather and evolving demand patterns. In addition, Enova is incorporating cost-effective innovative solutions (**Section 2.19**) such as grid automation, advanced monitoring technologies, and enhanced data analytics. These

investments support a more flexible and responsive distribution system while maintaining a disciplined focus on cost control.

Consistent with the OEB's objective of facilitating innovation in the electricity sector, Enova's forecast innovation capital expenditures (**Section 2.1.7**) fund a coordinated set of investments that position the distribution system to integrate distributed energy resources (DERs), enable emerging market functions, and modernize the distribution system.

Enova's capital plan also reflects its long-term strategic objectives following the integration of its legacy utilities. The plan supports harmonization of system standards, optimization of asset management practices, and realization of operational efficiencies across the combined service territory. By aligning capital investments with these objectives, Enova is positioned to deliver sustained value to customers over the long term.

Through this approach, Enova demonstrates that its capital expenditures are justified at both the individual project level and in aggregate. The plan reflects prudent decision-making, appropriate prioritization and pacing, and a clear linkage between proposed investments and customer outcomes. As such, Enova submits that its capital expenditure plan represents a reasonable and necessary investment in the continued reliability, safety, and modernization of its distribution system.

4.2.2. (5.4.2.1) Material Investments

This section provides details for all 2027 projects/programs that meet or exceed the materiality threshold of $400,000. **Table 4-36** provides a summary of 2027 proposed expenditures by OEB category.

Table 4-36: Summary of 2027 Material Investments ($000s)

OEB Investment Category	# Programs / Projects	Total Category($)	% Total CAPEX	# Material Projects (> $400k)	Total $	% Total OEB Category
System Access	41	$ 23,281	29.6%	16	$ 23,281	29.6%
System Renewal	75	$ 30,985	39.4%	22	$ 28,609	36.3%
System Service	3	$ 1,543	2.0%	2	$ 1,543	2.0%
General Plant	29	$ 17,680	22.5%	6	$ 15,758	20.0%
Total	148	$ 73,489	93.4%	46	$ 69,191	87.9%
Total 2027 CAPEX		$ 78,705	100.0%		$ 78,705	100.0%
Variance		$ 5,216	6.6%		$ 9,514	12.1%

Enova's 2027 capital investment plan consists of 148 individual projects. Of these, 46 projects exceed the threshold of materiality and are grouped into 21 material capital investment summaries presented in **Appendix A – 2027 Material Capital Investments**. Collectively, these material investments account for approximately 87.9% of Enova's total 2027 capital expenditure program. The remaining 12.1% of the capital program comprises numerous smaller projects, each below the materiality threshold. While individually immaterial, these projects are necessary to support the ongoing renewal, operation, and reliability of Enova's distribution system.

Tables 4–37 provides a list of individual material project/programs, identified by OEB category and priority ranking. Descriptions can be found the materiality sheets located in **Appendix A.**

Figure 4-5 presents the list of major 2027 programs and projects, ordered from lowest to highest projected level of expenditure.

Figure 4-5: Material Program / Project Expenditures (2027)

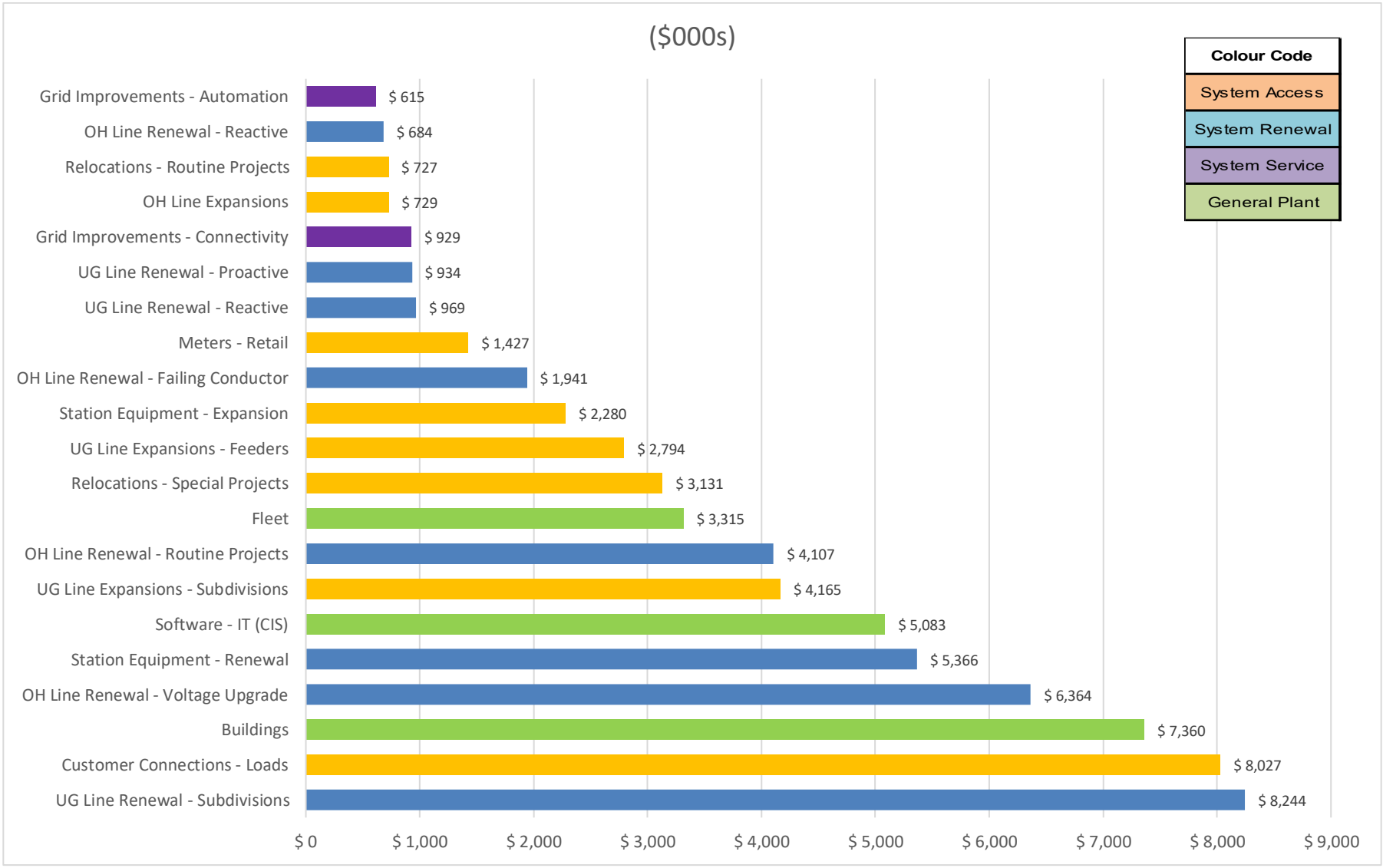


Table 4-37: 2027 Material Investments in Rank Order

OEB Category	Program Code	Program/Project Description	Costs ($)	Rank	Justification
System Access	E-ME-R	Meters - Retail	1,426,646	1	Mandated by regulation or code / condition / critical business support
System Access	E-UL-F	Underground Line Expansions - Feeders	2,794,422	1	Mandated by regulation or code (new load customers)
System Access	E-UL-S	Underground Line Expansions - Subdivisions	4,165,479	1	Mandated by regulation or code (new load customers)
System Access	E-SE	Station Equipment - Expansion	2,279,916	1	Mandated by regulation or code (new load customers)
System Access	E-OL	Overhead Line Expansions	728,522	1	Mandated by regulation or code (new load customers)
System Access	E-CC-L	Customer Connections - Loads	8,027,227	1	Mandated by regulation or code (new load customers)
System Access	E-SP	Relocations - Special Projects	3,131,253	1	Mandated by regulation or code (relocations)
System Access	E-RP	Relocations - Routine Projects	727,221	1	Mandated by regulation or code (relocations)
System Renewal	R-UL-R	Underground Line Renewal - Reactive	969,476	2	Immediate unplanned replacement — cable/transformer failure / public safety risk
System Renewal	R-OL-R	Overhead Line Renewal - Reactive	684,432	3	Immediate unplanned replacement — failure / public safety risk
System Renewal	R-OL-FC	Overhead Line Renewal - Failing Conductor	1,941,158	4	Planned replacement – poor condition / high public safety risk
System Renewal	R-UL-P	Underground Line Renewal - Proactive	933,600	5	Unplanned replacement — poor condition / public safety risk
System Renewal	R-SE	Station Equipment – Renewal Material Projects: HSTS B Transformer Replacement 6TS Switchgear Replacement 7TS Switchgear Replacement 1TS P&C and RTU Replacement	5,365,721	6	Planned replacement — poor condition of critical assets / high customer impact / worker safety risk
System Renewal	R-OL-VU	Overhead Line Renewal - Voltage Upgrade	6,363,623	7	Planned replacement — poor condition / voltage upgrade efficiencies
General Plant	G-SW-IT	Software – IT Material Projects: CIS Upgrade CIS Major Systems	5,083,333	8	Planned replacement — obsolescence, efficiency & customer service
System Service	U-GI-C	Grid Improvements - Connectivity	928,500	9	Improve grid capacity, reliability & efficiencies
System Renewal	R-UL-S	Underground Line Renewal - Subdivisions	8,243,755	10	Planned replacement — poor condition / voltage upgrade efficiencies support
General Plant	G-BL	Buildings Material Project: HVAC Replacement and Facility Renovation	7,359,754	11	Planned replacement — poor condition / obsolescence / efficiencies
General Plant	GP-FL	Fleet	3,315,000	12	Planned replacement — poor condition / worker safety / efficiencies
System Renewal	R-OL-RP	Overhead Line Renewal - Routine Projects	4,107,173	13	Planned replacement — poor condition
System Service	U-GI-A	Grid Improvements - Automation	614,680	14	Improve reliability and efficiency

4.3. (5.4.2.2) Benefit-Cost Analysis Framework

This section provides the results of Enova's pre-assessment of non-wires solutions ("NWS") for material capital investment programs with projected capital costs exceeding $2 million, as required by the Ontario Energy Board's ("OEB") Benefit-Cost Analysis Framework ("BCA Framework") and Non-Wires Solutions Guidelines ("NWS Guidelines").

The NWS pre-assessment requirement was applied to all electricity system needs exceeding $2 million across the full DSP planning horizon (2027–2031), excluding general plant. The pre-assessments were performed on material programs in two categories: (a) distribution line programs, and (b) station capital programs.

The following programs exceed the $2 million threshold and require documented NWS consideration:

Table 4-38: 2027 NWS Pre-assessment Results

Code	Program Name	OEB Cat	2027 Budget	5yr Total	Result
R-OL-VU	OH Line Renewal – Voltage Upgrade	SR	$5.89M	$29.43M	NWS Not Viable
R-OL-RP	OH Line Renewal – Routine Projects	SR	$4.11M	$20.54M	NWS Not Viable
R-UL-S	UG Line Renewal – Subdivisions	SR	$11.14M	$72.64M	NWS Not Viable
E-SP	Relocations – Special Projects	SA	$3.13M	$15.66M	NWS Not Viable
R-SE	Station Equipment – Renewal	SR	$7.74M	$41.62M	NWS Not Viable

For all programs, the pre-assessment concludes that NWS is not a viable alternative.

Detailed information in **Appendix K - NWS Pre-Assessment.**

(Page Intentionally left blank)

APPENDIX A
2027 Material Capital Investments

Enova Power Corp.

2027 DSP Capital – Program Summary Index

Category	Program Name	Page Number
System Renewal	UG Line Renewal - Subdivisions	1
	OH Line Renewal – Voltage Upgrade	3
	OH Line Renewal – Failing Conductor	5
	OH Line Renewal – Routine Projects	8
	OH Line Renewal - Reactive	11
	UG Line Renewal - Proactive	13
	UG Line Renewal - Reactive	15
	Waterloo HSTS B Transformer Replacements	17
	Kitchener 6TS Switchgear Replacement	20
	Kitchener 7TS Switchgear Replacement	22
	Kitchener 1TS Relay & RTU Replacement	25
System Access	Station Equipment - Expansion	28
	Relocations – Special Projects	31
	Relocations – Routine Projects	33
	OH Line Expansions	35
	Customer Connections - Loads	37
	UG Line Expansions - Feeders	39
	UG Line Expansions - Subdivisions	41
	Meters - Retail	43
System Service	Grid Improvements - Connectivity	45
	Grid Improvements - Automation	47
General Plant	Fleet Replacement Program	49
	Customer Information System (CIS) Major Release Upgrade	51
	Customer Information System (CIS) Major Systems	53
	Facility Renovation – Victoria Street Property	55

UG Line Renewal - Subdivisions

General Information on the project/program (5.4.2.1.A)

Project Name UG Line Renewal - Subdivisions
Program Code R-UL-S
OEB Investment Category System Renewal

Project Description

This program involves the planned renewal of underground distribution infrastructure in residential subdivision areas. Underground assets in subdivisions were installed primarily during the 1970s and 1980s residential development period and are approaching or past their typical useful life.

The program scope includes underground cable replacement, transformer pad and vault rehabilitation, voltage conversion from legacy voltages to the system standard, submersible vault drain installation, and associated civil works. Multiple projects involve complete transformer loop rebuilds including both electrical and civil components.

Projects within this program are prioritized based on a combination of cable failure history, asset age, and the number of customers served by the affected infrastructure.

Detailed SubProjects

The following individual projects are covered by this project category:

Project	Sub Project	Project Name	Total
R-UL-S		184 Arrowhead Cres Tx Addition	$66,932
R-UL-S		192 Brewery St TH T2 loop	$2,025
R-UL-S		192 Brewery St TH T2 loop	$57,290
R-UL-S		218 Boulee St, NH	$85,935
R-UL-S		Astor Cres & Conestoga Rd, NH - T2 Loop	$170,456
R-UL-S		Hostetler St, NH - T1 and T2 Loop	$297,239
R-UL-S		Submersible Vault Drains [20 units]	$107,036
R-UL-S		Westvale Rehab North Part 1	$4,163,218
R-UL-S		Country Creek Drive & Village Green Way T4 Loop Voltage Conversion	$971,896
R-UL-S		Elizabeth St, Baden - T2 & T3 loops	$584,493
R-UL-S		Joseph St, NH - T1 Loop	$220,981
R-UL-S		Morningside Park, NH - T5 loop Replace all min-pads	$94,010
R-UL-S		Morningside Park, NH T1-T4 loops	$1,226,975
R-UL-S		Underground System Renewal - Voltage Conversion	$195,270
		Total	$8,243,755

Capital Investment

Total Capital **$8,243,755**

O&M Costs (if applicable) **$0** Not Applicable

Capital Contributions to a Transmitter

CCRA Contribution $0

Customer Attachments/Load (kVA)

Customer Attachments (#): 1289
Customer Load (peak kVA) 2374

Project Timing

Start Date January 1, 2027 Engineering
End Date December 31, 2027 Construction

Expected In-Service Date December 1, 2027

Expenditure Timing

2027 Q1	20%	$1,648,751
2027 Q2	30%	$2,473,126
2027 Q3	30%	$2,473,126
2027 Q4	20%	$1,648,751

Schedule Risk and Risk Mitigation

Underground subdivision renewal projects involve extensive civil construction including excavation, duct installation, and surface restoration. These projects are weather-sensitive and are typically scheduled for the April through November construction season.

Coordination with municipal infrastructure (water, sewer, gas) and other utility companies (Bell/Rogers) is required for all excavation work. In some areas, particularly in older subdivisions, the accuracy of underground utility locates may be limited, requiring additional care during excavation.

Projects involving voltage conversion require coordination with station-side work to ensure the new voltage is available before the underground conversion is energized.

Comparative Information

Comparable investments in previous years are as follows:

2020:	$4,953,771
2021:	$6,479,699
2022:	$6,878,596
2023:	$7,469,456
2024:	$6,008,720
2025:	$5,250,922
2026 (Bridge):	$2,312,034

Total Capital & OM&A Costs Associated with REG Investments

Not Applicable

Leave to Construct Approval

Not Applicable

Evaluation Criteria and information requirements for each project/program (5.4.2.1.B)

Efficiency, Customer Value, Reliability

Main Driver	The main driver for this program is the age and condition of the existing plant.
Related Objectives/Performance Targets	Enova Strategic Objectives: Grid Resiliency (SAIDI/SAIFI targets) and Health, Safety and Environment, as identified in the DSP.
Source and Nature of the Information Used to Justify the Investment	The source of the information used to justify this investment is a combination of cable diagnostic testing, failure history analysis, asset age data, and Enova's Asset Condition Assessment (ACA) program. Underground cable insulation deterioration is assessed through diagnostic testing which identifies cables with elevated risk of failure. Enova's distribution-specific SAIDI/SAIFI reliability targets are used as inputs to the prioritization of renewal investments. Underground cable failures result in extended restoration times compared to overhead faults, making proactive cable replacement a high-priority reliability investment.
Secondary Driver(s)	Where applicable, underground renewal projects incorporate voltage conversion to eliminate legacy voltage levels, improving operational flexibility and reducing the need for dedicated station transformer capacity.
Good Utility Practice	Enova utilizes Utility Standards Forum (USF) and internal Engineer sealed design standards for underground construction. Underground cable selection, installation, and testing follow CSA and IEEE standards. Underground renewal projects are designed to current standards including improved duct bank configurations, modern cable types, and enhanced vault drainage to extend asset service life and reduce future maintenance costs.
Investment Priority	System Access investments are ranked as top priority, as they are mandated by regulation or code. System Renewal assets are prioritized by the health condition of the assets developed through Enova's ACA program. Assets found at risk of imminent failure or high public safety risk are prioritized for immediate replacement. Enova utilizes METSCO's Asset Analysis, Prioritization, and Optimization Tool (ENGIN) to aid in prioritizing asset replacement. Assets flagged for replacement are geospatially grouped to create constructible projects. Projects are ranked by taking into account their overall health condition, customer impact, alignment with Enova's Strategic Objectives such as reliability, safety, financial or environmental risk and additional drivers and benefits. The greater the customer impact or the more drivers or benefits that are attributed to a project the higher its priority. Investments in System Service and General Plant categories are prioritized in a similar fashion. Analysis of impact on customers and consideration of impact of project deferral are also considered. The compiled list of projects is reviewed and prioritized by Enova Engineering, Operations, and Finance staff. Based on the outcome of this process, this program ranks 15 out of 25. Refer to the DSP prioritization table for further details.
Analysis of the Project and Project Alternatives	Underground assets under this program have been identified as approaching or past end of life based on diagnostic testing, age, and failure history. Enova considered the following alternatives: a) Do Nothing - this option results in increased risk of cable faults, extended customer outages, and potential safety hazards. Underground cable failures are more costly and time-consuming to repair than overhead faults. This option is not considered appropriate. b) Refurbish/Rehabilitate - cable injection (silicone treatment) can extend the life of certain cable types, but is not appropriate for cables that have already exhibited significant insulation deterioration or for cable types that are not compatible with injection. Where applicable, Enova has considered cable injection as an alternative. c) Replace Like for Like - this is the preferred option for cables operating at their ultimate planned voltage. Modern cable insulation materials (TR-XLPE) provide improved performance and longer service life. d) Replace with Voltage Conversion - where the project area also requires voltage conversion from legacy levels, the preferred option is to install cable rated for the target voltage, eliminating the need for future re-cabling.
Effect on system operation efficiency and cost effectiveness	Renewal of these assets will typically eliminate the need for ongoing emergency repairs and reactive maintenance, reducing future operations and maintenance costs. Where applicable, modernized construction standards improve the efficiency of maintenance activities by providing improved access and standardized equipment.
Net benefits accruing to customers	The renewal of this infrastructure will have the following benefits: the aversion of potentially adverse effects on reliability and safety, avoidance of an increase to maintenance costs, and where applicable, provide for increased flexibility of the system via harmonization of distribution voltages, a decrease in line losses, and an increase in capacity for connection of DERs.
Impact of Investment on reliability performance (including on the frequency and duration of outages)	These projects ensure the elimination of safety hazards and that reliability is maintained. Underground cable failures result in extended restoration times (typically 8–24 hours compared to 2–4 hours for overhead faults) due to the need for fault location, excavation, and cable repair or replacement. Proactive renewal of deteriorated cables eliminates this risk before failure occurs. Modern cable insulation materials (TR-XLPE) provide superior resistance to water treeing, thermal cycling, and voltage stress compared to the legacy cable types being replaced.
Scheduling Alternatives	System Renewal investments are instrumental in reducing the risk of critical asset failures, maintaining reliability and safety performance measures and keeping expensive reactive maintenance activities to a minimum. Scheduling changes within the calendar year due to weather, coordination with third parties and resource constraints can usually be accommodated for smaller projects. Rescheduling larger projects can increase costs due to the reassignment of labour and materials and the risk of asset failure. Enova evaluates the risk and cost of rescheduling any project to achieve the most cost effective outcome.
Ownership and/or Funding Alternatives	These projects are constructed in the public right-of-way and will consist solely of Enova's assets. There are no ownership or funding alternatives.

Safety

Underground renewal eliminates the risk of cable faults which can present safety hazards including arc flash, ground potential rise, and manhole events. Modern cable and equipment designs incorporate improved safety features and fault containment capability.

Cyber-security, Privacy

Not Applicable

Co-ordination, Interoperability

Coordination with utilities, regional planning and/or links with 3rd parties (where applicable)	Enova will meet with the area Utility Coordinating Council and municipal staff (where applicable) as well as third party stakeholders to exchange project details to coordinate construction. This coordination typically occurs in Q3-Q4 of the year preceding construction.
Enabling of future technological functionality or addressing of future operational requirements	New underground cable systems incorporate modern insulation materials and duct configurations that provide improved performance and longer service life. Where applicable, conduit spare capacity is provided to facilitate future cable additions without additional civil construction. Modern switchgear incorporates provisions for SCADA communication and automated switching capability.

Environmental Benefits

Possibility of reduced oil spills and reduced excavation requirements if underground cable fails prematurely.

Non-Wires Solutions Consideration

Enova's consideration of non-wires solutions for this program is documented in accordance with the NWS Guidelines (EB-2024-0118) and the BCA Framework. See details below.

Benefit-Cost Analysis Framework (5.4.2.2.)

In accordance with the OEB's BCA Framework (May 2024), Enova conducted a pre-assessment of non-wires solution (NWS) viability for this program. The pre-assessment concluded that NWS is not a viable alternative because the system need is driven by asset condition, not capacity constraint. Refer to the NWS Pre-Assessment appendix of this DSP for details.

OH Line Renewal - Voltage Upgrade

General Information on the project/program (5.4.2.1.A)

Project Name OH Line Renewal - Voltage Upgrade
Program Code R-OL-VU
OEB Investment Category System Renewal

Project Description

This program involves the planned rebuilding of overhead lines where the primary driver is the age and deteriorated condition of existing plant combined with the conversion of operating voltage from legacy 8.32 kV to the system standard of 27.6 kV. Voltage conversion eliminates the need for expensive dedicated station transformer capacity, provides operational flexibility through voltage harmonization, reduces system losses, and increases capacity for the connection of distributed energy resources.

Projects within this program are prioritized based on condition of the assets from Enova's ACA results, with additional priority given to lines where voltage conversion will yield the optimal operational benefit.

Detailed SubProjects

The following individual projects are covered by this project category:

Project	Sub Project	Project Name	Total
R-OL-VU		Glasgow St - Highland Rd to Ira Needles Blvd	$773,611
R-OL-VU		Pineridge & Westmount - Bearinger to Benjamin	$684,759
R-OL-VU		Huron Rd - Bender to Oxford Rd 5	$289,110
R-OL-VU		Notre Dame St - HWY7,8 to Snyder's Rd	$247,576
R-OL-VU		Notre Dame St - Snyder's Rd to Erbs Rd	$821,456
R-OL-VU		Northfield Dr E - Country Spring Walk to Jigs Hollow Rd	$649,806
R-OL-VU		Northfield Dr E - Line 86 to Scotch Line Rd	$992,606
R-OL-VU		Scotch Line Rd - New Jerusalem Rd to Northfield Dr E	$410,606
R-OL-VU		Floradale Rd - 2372 Floradale Rd to Sandy Hills Dr	$240,607
R-OL-VU		Walker Rd - Concession Rd to Huron Rd	$253,486
R-OL-VU		Cox Creek Rd - Lundy Rd to Crowsfoot incl. Crowsfoot	$389,723
R-OL-VU		Jesse Pl - Floradale Rd to EOL	$210,659
R-OL-VU		Oxford Waterloo Rd - Tye Rd to Walker Rd	$399,618
		Total	$6,363,623

Capital Investment

Total Capital **$6,363,623**

O&M Costs (if applicable) **$0** Not Applicable

Capital Contributions to a Transmitter

CCRA Contribution $0

Customer Attachments/Load (kVA)

Customer Attachments (#): 2480
Customer Load (peak kVA) 20019

Project Timing

Start Date January 1, 2027 Engineering
End Date December 31, 2027 Construction

Expected In-Service Date December 1, 2027

Expenditure Timing

2027 Q1	20%	$1,272,725
2027 Q2	30%	$1,909,087
2027 Q3	30%	$1,909,087
2027 Q4	20%	$1,272,725

Schedule Risk and Risk Mitigation

Voltage conversion projects require coordination with Enova's Supply Planning and Stations groups to ensure that station-side voltage conversion work is completed and energized prior to the overhead line conversion. Delays in station readiness can affect the scheduling of line conversion projects.

Projects along regional roads require Region of Waterloo road occupancy permits and coordination with municipal road construction schedules. Enova coordinates with the Region's Utility Coordinating Council to align project timing.

The 2027 program includes multiple projects in the Wilmot and Woolwich service areas where some sections run under HONI transmission lines, requiring authorization and special construction conditions.

Comparative Information

Comparable investments in previous years are as follows:

2020:	$1,796,002
2021:	$1,230,509
2022:	$1,952,733
2023:	$2,468,748
2024:	$3,070,461
2025:	$1,090,247
2026 (Bridge):	$3,519,877

Total Capital & OM&A Costs Associated with REG Investments

Not Applicable

Leave to Construct Approval

Not Applicable

Evaluation Criteria and information requirements for each project/program (5.4.2.1.B)

Efficiency, Customer Value, Reliability

Main Driver	The main driver for this program is the age and condition of the existing plant, and operation flexibility.
Related Objectives/Performance Targets	Enova Strategic Objectives: Grid Resiliency (SAIDI/SAIFI targets) and Health, Safety and Environment, as identified in the DSP.
Source and Nature of the Information Used to Justify the Investment	The source of the information used to justify this investment is the Asset Condition Assessment (ACA), as further detailed in the Asset Management section of the DSP. These lines were originally installed between the 1960s and 1980s and have Health Index ratings in the Poor and Very Poor category. These ratings were developed through Enova's ACA program using asset degradation factors such as age, pole treatment, inspection and testing data to develop a Health Index (HI) for each pole asset. The HI is converted into a condition rating ranging from Very Good to Very Poor. Assets in Poor and Very Poor condition are identified and grouped into executable projects. Enova's distribution-specific SAIDI/SAIFI reliability targets, established in accordance with the OEB's EB-2021-0307 framework, are used as inputs to the prioritization of renewal investments. Defective equipment is a leading cause of sustained outages on Enova's system, and this program directly addresses the condition-driven failure risk.
Secondary Driver(s)	Secondary drivers include voltage standardization (conversion from legacy 8.32 kV to 27.6 kV), increased capacity for distributed energy resource (DER) connection, improved operational flexibility for switching and load transfer, and reduced system losses.
Good Utility Practice	Enova utilizes Utility Standards Forum (USF) design standards. These standards are based on CSA C22.3 No 1-15 Overhead Systems Heavy Weather Loading design standards. Newer construction standards and materials provide for more weather resilient assets to help maintain safety and reliability. Enova overhead designs facilitate the future incorporation of grid modernization equipment and renewable energy generation. Enova conducts annual inspection and testing programs, evaluates the results and reprioritizes the replacement of assets if required. Although pole condition is normally the main driver for overhead renewal projects, other assets such as transformers, insulators, wire, and arrestors are also replaced as part of pole line rebuild. These assets are nearing end of life and would not normally survive a second life cycle. Replacing these assets all at the same time is more cost effective and less disruptive than waiting until individual assets fail or reach end of life.
Investment Priority	System Access investments are ranked as top priority, as they are mandated by regulation or code. System Renewal assets are prioritized by the health condition of the assets developed through Enova's ACA program. Assets found at risk of imminent failure or high public safety risk are prioritized for immediate replacement. Enova utilizes METSCO's Asset Analysis, Prioritization, and Optimization Tool (ENGIN) to aid in prioritizing asset replacement. Assets flagged for replacement are geospatially grouped to create constructible projects. Projects are ranked by taking into account their overall health condition, customer impact, alignment with Enova's Strategic Objectives such as reliability, safety, financial or environmental risk and additional drivers and benefits. The greater the customer impact or the more drivers or benefits that are attributed to a project the higher its priority. Investments in System Service and General Plant categories are prioritized in a similar fashion. Analysis of impact on customers and consideration of impact of project deferral are also considered. The compiled list of projects is reviewed and prioritized by Enova Engineering, Operations, and Finance staff. Based on the outcome of this process, this program ranks 8 out of 25. Refer to the DSP prioritization table for further details.
Analysis of the Project and Project Alternatives	All pole line sections under this program have been identified as being in poor condition and in need of replacement. In light of this fact, Enova considered the following alternatives: a) Do Nothing - this option results in the perpetuation of operational issues, increased risk of safety incidents, and further deterioration resulting in a decrease in reliability, and is therefore not considered appropriate. b) Refurbish the Lines - these line sections are not appropriate candidates for refurbishment as most poles are too short and structurally too weak to comply with today's safety standards as required by O.Reg 22/04. c) Replace the Lines with Underground Lines - in most situations overhead line burial is technically feasible but often cost prohibitive. Enova's typical line burial costs range between 5x (for local single phase lines) to 10x (for three phase trunk circuits) the equivalent overhead rebuild costs. Due to cost impacts this option is not considered feasible. d) Replace Like for Like to New Standards - this is the preferred option for those line sections already operating at their ultimate planned voltage. Today's safety standards require same class and height of poles for all voltage levels. e) Replace Like for Like with Provisions for Operation at Higher Voltages - this option allows for replacement of aged or unsafe equipment, allows for ultimate conversion to higher operating voltage with minimal equipment change when conversion takes place, and is therefore the preferred option for lines presently operating at 8.32 kV.
Effect on system operation efficiency and cost effectiveness	The renewal of lines under this program will permit the operation of lines at 27.6 kV, which will increase flexibility of the system as a whole in outage scenarios and day to day switching. It will also contribute to a reduction of line loss on the system.
Net benefits accruing to customers	The renewal of this infrastructure will have the following benefits: the aversion of potentially adverse effects on reliability and safety, avoidance of an increase to maintenance costs, and where applicable, provide for increased flexibility of the system via harmonization of distribution voltages, a decrease in line losses, and an increase in capacity for connection of DERs.
Impact of Investment on reliability performance (including on the frequency and duration of outages)	These projects ensure the elimination of safety hazards and that reliability is maintained. Additionally, the standards to which assets must be built today compared to the existing assets ensures they are able to withstand more adverse weather conditions and increases the clearances around the conductors to assist in reducing both the frequency and duration of outages.
Scheduling Alternatives	System Renewal investments are instrumental in reducing the risk of critical asset failures, maintaining reliability and safety performance measures and keeping expensive reactive maintenance activities to a minimum. Scheduling changes within the calendar year due to weather, coordination with third parties and resource constraints can usually be accommodated for smaller projects. Rescheduling larger projects can increase costs due to the reassignment of labour and materials and the risk of asset failure. Enova evaluates the risk and cost of rescheduling any project to achieve the most cost effective outcome.
Ownership and/or Funding Alternatives	These projects are constructed in the public right-of-way and will consist solely of Enova's assets. There are no ownership or funding alternatives.

Safety

The new construction standards make work on pole lines much safer for all workers due to increased separation of high voltage conductors between themselves as well as from low voltage conductors. The replacement also minimizes the risk of unexpected pole failures in these areas, decreasing risk to the public.

Cyber-security, Privacy

Not Applicable

Co-ordination, Interoperability

Coordination with utilities, regional planning and/or links with 3rd parties (where applicable)	Enova will meet with the area Utility Coordinating Council and municipal staff (where applicable) as well as third party stakeholders to exchange project details to coordinate construction. This coordination typically occurs in Q3-Q4 of the year preceding construction.
Enabling of future technological functionality or addressing of future operational requirements	New lines generally incorporate larger conductor, increased strength, and where available, higher voltages. As a result, the system is better able to withstand poor weather conditions; provide increased capacity and siting options for the connection of renewable energy generation, electric vehicles, energy storage; provide increased physical space for third party communications and smart grid devices; and reduce power quality issues and losses.

Environmental Benefits

Not Applicable

Non-Wires Solutions Consideration

Enova's consideration of non-wires solutions for this program is documented in accordance with the NWS Guidelines (EB-2024-0118) and the BCA Framework. See details below.

Benefit-Cost Analysis Framework (5.4.2.2.)

In accordance with the OEB's BCA Framework (May 2024), Enova conducted a pre-assessment of non-wires solution (NWS) viability for this program. The pre-assessment concluded that NWS is not a viable alternative because the system need is driven by asset condition, not capacity constraint. Refer to the NWS Pre-Assessment appendix of this DSP for details.

OH Line Renewal - Failing Conductor

General Information on the project/program (5.4.2.1.A)

Project Name OH Line Renewal - Failing Conductor
Program Code R-OL-FC
OEB Investment Category System Renewal

Project Description

This project category comprises overhead lines that pose a safety risk and are in poor condition. This program involves the full rebuilding of overhead pole lines in poor condition, where the added trigger is the presence of small gauge conductors (#6, #4 and #2 copper and aluminum). These conductors are particularly susceptible to fatigue-related failures caused by aeolian vibration, corrosion, and repeated thermal cycling. Conductor sizes of this vintage are attached to equally aged poles that lack the structural strength and height to meet current construction standards.

A downed small gauge conductor represents a heightened public safety hazard. Proactive replacement of these pole lines eliminates this critical safety risk while also improving reliability. The program scope is a complete pole line rebuild. Poles, conductors, cross-arms, insulators, transformers, and associated equipment are all replaced to current standards, providing increased ampacity, improved weather resilience, and compliance with O.Reg 22/04.

Detailed SubProjects

The following individual projects are covered by this project category:

Project	Sub Project	Project Name	Total
R-OL-FC		Sandhills Dr - Bleams Rd to 2583 Sandhills Rd	**$6,603**
R-OL-FC		Wilby Rd - Sandhills West to EoL	**$11,886**
R-OL-FC		Wilmot Side Roads Small Conductor Rebuilds	**$1,400,000**
R-OL-FC		Bridge St - Walker Rd to 3107 Bridge St	**$522,669**
		Total	**$1,941,158**

Capital Investment

Total Capital **$1,941,158**

O&M Costs (if applicable) **$0** Not Applicable

Capital Contributions to a Transmitter

CCRA Contribution $0

Customer Attachments/Load (kVA)

Customer Attachments (#): 500
Customer Load (peak kVA) 2000

Project Timing

Start Date January 1, 2027 Engineering
End Date December 31, 2027 Construction

Expected In-Service Date December 1, 2027

Expenditure Timing

2027 Q1	20%	$388,232
2027 Q2	30%	$582,347
2027 Q3	30%	$582,347
2027 Q4	20%	$388,232

Schedule Risk and Risk Mitigation

These projects are full overhead pole line rebuilds and carry similar scheduling considerations to the R-OL-RP and R-OL-VU programs. The primary scheduling risk is the availability of construction crews, as these rebuilds compete for the same line crew resources as other overhead renewal programs. Enova manages this risk through integrated scheduling of all overhead capital programs.

Projects located along regional roads require road occupancy permits and coordination with municipal road construction schedules. Projects in established areas containing mature trees require public consultation and coordination with tree management contractors. Enova coordinates with affected customers and municipal staff well in advance of construction.

Comparative Information

Comparable investments in previous years are as follows:

2020:	$497,011
2021:	$1,493,493
2022:	$0
2023:	$0
2024:	$514,764
2025:	$171,266
2026 (Bridge	$1,917,038

Total Capital & OM&A Costs Associated with REG Investments

Not Applicable

Leave to Construct Approval

Not Applicable

Evaluation Criteria and information requirements for each project/program (5.4.2.1.B)

Efficiency, Customer Value, Reliability

Main Driver	The main driver for this program is the age and condition of the existing pole lines, with a specific focus on the public safety risk posed by small gauge failing conductors. When these conductors break and fall to the ground, their high resistivity often prevents Enova's protection systems from detecting sufficient fault current to clear the circuit, resulting in an energized downed wire that is not automatically de-energized. This represents a critical public safety hazard that cannot be adequately mitigated through inspection or maintenance alone. The only effective remediation is the full replacement of these pole lines.
Related Objectives/Performance Targets	Enova Strategic Objectives: Grid Resiliency (SAIDI/SAIFI targets) and Health, Safety and Environment, as identified in the DSP.
Source and Nature of the Information Used to Justify the Investment	The source of the information used to justify this investment is the Asset Condition Assessment (ACA), as further detailed in the Asset Management section of the DSP. These pole lines were originally installed as early as the 1950s through the 1970s and have Health Index ratings in the Poor and Very Poor categories. These ratings were developed through Enova's ACA program using asset degradation factors such as age, pole treatment, inspection and testing data to develop a Health Index (HI) for each pole asset. The HI is converted into a condition rating ranging from Very Good to Very Poor. Assets in Poor and Very Poor condition are identified and grouped into executable projects. Enova's distribution-specific SAIDI/SAIFI reliability targets, established in accordance with the OEB's EB-2021-0307 framework, are used as inputs to the prioritization of renewal investments. Defective equipment is a leading cause of sustained outages on Enova's system, and this program directly addresses the condition-driven failure risk.
Secondary Driver(s)	Where applicable, overhead line rebuilds incorporate provisions for future voltage conversion and DER accommodation. New construction standards also improve weather resilience and provide physical space for smart grid devices and third-party communications attachments.
Good Utility Practice	Enova utilizes Utility Standards Forum (USF) design standards. These standards are based on CSA C22.3 No 1-15 Overhead Systems Heavy Weather Loading design standards. Newer construction standards and materials provide for more weather resilient assets to help maintain safety and reliability. Enova overhead designs facilitate the future incorporation of grid modernization equipment and renewable energy generation. Enova conducts annual inspection and testing programs, evaluates the results and reprioritizes the replacement of assets if required. Although pole condition is normally the main driver for overhead renewal projects, other assets such as transformers, insulators, wire, and arrestors are also replaced as part of pole line rebuild. These assets are nearing end of life and would not normally survive a second life cycle. Replacing these assets all at the same time is more cost effective and less disruptive than waiting until individual assets fail or reach end of life.
Investment Priority	System Access investments are ranked as top priority, as they are mandated by regulation or code. System Renewal assets are prioritized by the health condition of the assets developed through Enova's ACA program. Assets found at risk of imminent failure or high public safety risk are prioritized for immediate replacement. Enova utilizes METSCO's Asset Analysis, Prioritization, and Optimization Tool (ENGIN) to aid in prioritizing asset replacement. Assets flagged for replacement are geospatially grouped to create constructible projects. Projects are ranked by taking into account their overall health condition, customer impact, alignment with Enova's Strategic Objectives such as reliability, safety, financial or environmental risk and additional drivers and benefits. The greater the customer impact or the more drivers or benefits that are attributed to a project the higher its priority. Investments in System Service and General Plant categories are prioritized in a similar fashion. Analysis of impact on customers and consideration of impact of project deferral are also considered. The compiled list of projects is reviewed and prioritized by Enova Engineering, Operations, and Finance staff. Based on the outcome of this process, this program ranks 4 out of 25. Refer to the DSP prioritization table for further details.
Analysis of the Project and Project Alternatives	All pole line sections under this program have been identified as being in poor condition and in need of replacement. In light of this fact, Enova considered the following alternatives: a) Do Nothing - this option results in the perpetuation of operational issues, increased risk of safety incidents, and further deterioration resulting in a decrease in reliability, and is therefore not considered appropriate. b) Refurbish the Lines - these line sections are not appropriate candidates for refurbishment as most poles are too short and structurally too weak to comply with today's safety standards as required by O.Reg 22/04. c) Replace the Lines with Underground Lines - in most situations overhead line burial is technically feasible but often cost prohibitive. Enova's typical line burial costs range between 5x (for local single phase lines) to 10x (for three phase trunk circuits) the equivalent overhead rebuild costs. Due to cost impacts this option is not considered feasible. d) Replace Like for Like to New Standards - this is the preferred option for those line sections already operating at their ultimate planned voltage. Today's safety standards require same class and height of poles for all voltage levels. e) Replace Like for Like with Provisions for Operation at Higher Voltages - this option allows for replacement of aged or unsafe equipment, allows for ultimate conversion to higher operating voltage with minimal equipment change when conversion takes place, and is therefore the preferred option for lines presently operating at 8.32 kV. In accordance with the OEB's BCA Framework (May 2024), Enova conducted a pre-assessment of non-wires solution (NWS) viability for this program. The pre-assessment concluded that NWS is not a viable alternative because the system need is driven by asset condition, not capacity constraint. Refer to the NWS Pre-Assessment appendix of this DSP for details.
Effect on system operation efficiency and cost effectiveness	Renewal of these assets will eliminate the need for ongoing emergency repairs and reactive maintenance, reducing future operations and maintenance costs. Where applicable, modernized construction standards improve the efficiency of maintenance activities by providing improved access and standardized equipment.
Net benefits accruing to customers	The renewal of this infrastructure will have the following benefits: the aversion of potentially adverse effects on reliability and safety, avoidance of an increase to maintenance costs, and where applicable, provide for increased flexibility of the system via harmonization of distribution voltages, a decrease in line losses, and an increase in capacity for connection of DERs.
Impact of Investment on reliability performance (including on the frequency and duration of outages)	These projects ensure the elimination of safety hazards and that reliability is maintained. Additionally, the standards to which assets must be built today compared to the existing assets ensures they are able to withstand more adverse weather conditions and increases the clearances around the conductors to assist in reducing both the frequency and duration of outages. Enova's distribution-specific reliability targets (SAIDI and SAIFI), established in accordance with the OEB's EB-2021-0307 framework, are used as inputs to the prioritization of investments in this program. Defective equipment is a leading contributor to SAIDI on Enova's system, and this program directly addresses condition-driven failure risk.
Scheduling Alternatives	System Renewal investments are instrumental in reducing the risk of critical asset failures, maintaining reliability and safety performance measures and keeping expensive reactive maintenance activities to a minimum. Scheduling changes within the calendar year due to weather, coordination with third parties and resource constraints can usually be accommodated for smaller projects. Rescheduling larger projects can increase costs due to the reassignment of labour and materials and the risk of asset failure. Enova evaluates the risk and cost of rescheduling any project to achieve the most cost effective outcome.
Ownership and/or Funding Alternatives	These projects are constructed in the public right-of-way and will consist solely of Enova's assets. There are no ownership or funding alternatives.

Safety

The new construction standards make work on pole lines much safer for all workers due to increased separation of high voltage conductors between themselves as well as from low voltage conductors. The replacement also minimizes the risk of unexpected pole failures in these areas, decreasing risk to the public.

Cyber-security, Privacy

Not Applicable

Co-ordination, Interoperability

Coordination with utilities, regional planning and/or links with 3rd parties (where applicable)	Enova will meet with the area Utility Coordinating Council and municipal staff (where applicable) as well as third party stakeholders to exchange project details to coordinate construction. This coordination typically occurs in Q3-Q4 of the year preceding construction.
Enabling of future technological functionality or addressing of future operational requirements	New lines generally incorporate larger conductor, increased strength, and where available, higher voltages. As a result, the system is better able to withstand poor weather conditions; provide increased capacity and siting options for the connection of renewable energy generation, electric vehicles, energy storage; provide increased physical space for third party communications and smart grid devices; and reduce power quality issues and losses.

Environmental Benefits

Not Applicable

Non-Wires Solutions Consideration

Enova's consideration of non-wires solutions for this program is documented in accordance with the NWS Guidelines (EB-2024-0118) and the BCA Framework. See details below.

Benefit-Cost Analysis Framework (5.4.2.2.)

Not Applicable (below $2M threshold)

General Information on the project/program (5.4.2.1.A)

Project Name OH Line Renewal - Routine Projects
Program Code R-OL-RP
OEB Investment Category System Renewal

Project Description

This program involves the planned rebuilding of overhead lines in poor condition. Typically these lines involve assets that are past their typical useful life (TUL), cannot be refurbished and if not replaced represent a risk to public safety and customer power reliability.

These lines were originally installed between the 1960s and 1980s, are 40 to 60+ years of age, and have Health Index ratings in the Poor and Very Poor category. These ratings were developed through age, field inspection and pole testing criteria. The program consists of individual projects involving the replacement of poles, transformers and overhead line. The lines being replaced serve customers directly connected to them as well as customers connected downstream.

The project scope includes design, construction and installation of new poles designed to conform to O.Reg 22/04 compliant standards as well as new wire, insulators, transformers and equipment. Newer construction standards and materials provide for more weather resilient assets to help maintain safety and reliability.

Projects within this program are prioritized based on condition of the assets from Enova's ACA results. Projects are scheduled and executed over the course of the year based on coordination with third parties and available resources.

Detailed SubProjects

The following individual projects are covered by this project category:

Project	Sub Project	Project Name	Total
R-OL-RP		6TS Hwy Xing @ Ottawa St	$250,798
R-OL-RP		Archer Pl, Lyndhurst Dr, Deerfield Ave, Bursank Rd	$763,063
R-OL-RP		Belleview Ave, Donald St, Kenwood Dr	$696,781
R-OL-RP		Block Line - Homer Watson to Strasburg Rd	$361,271
R-OL-RP		Strasburg Rd - Ottawa St to Bleams Rd	$913,668
R-OL-RP		Bleams Rd - Queen St to Hwy 7	$1,070,072
R-OL-RP		Line 86 - 6798 Line 86 to Northfield Dr E	$51,519
		Total	$4,107,173

Capital Investment

Total Capital	**$4,107,173**	
O&M Costs (if applicable)	**$0**	Not Applicable

Capital Contributions to a Transmitter

CCRA Contribution	$0

Customer Attachments/Load (kVA)

Customer Attachments (#):	3898
Customer Load (peak kVA)	10141

Project Timing

Start Date	January 1, 2027	Engineering
End Date	December 31, 2027	Construction
Expected In-Service Date	December 1, 2027	

Expenditure Timing

2027 Q1	0%	$0
2027 Q2	30%	$1,232,152
2027 Q3	50%	$2,053,586
2027 Q4	20%	$821,435

Schedule Risk and Risk Mitigation

Projects in this program are located in a mix of urban and rural areas. Enova's past experience with similar projects has found that scheduling outages with commercial customers in urban areas is challenging due to the impact on their operations. Enova engages in extensive communication with each individual site owner to minimize impacts and delays.

Projects located in established urban areas containing mature trees require greater public consultation to avoid delays due to public objections. To help mitigate this risk, Enova reaches out to all customers well in advance of the project to inform them of upcoming work, provide options and to take customer input into consideration in the final design.

Projects running under Hydro One Networks Inc. (HONI) transmission lines require special conditions and authorization which can take time to work out. Enova is familiar with the requirements of this work and has experience obtaining the appropriate approvals prior to finalizing the design.

Comparative Information

Comparable investments in previous years are as follows:

2020:	$6,604,619
2021:	$9,323,870
2022:	$11,540,397
2023:	$11,582,110
2024:	$6,171,313
2025:	$2,414,772
2026 (Bridge):	$2,269,704

Total Capital & OM&A Costs Associated with REG Investments

Not Applicable

Leave to Construct Approval

Not Applicable

Evaluation Criteria and information requirements for each project/program (5.4.2.1.B)

Efficiency, Customer Value, Reliability

Main Driver	The main driver for this program is the age and condition of the existing plant.
Related Objectives/Performance Targets	Enova Strategic Priorities: Grid Resiliency (SAIDI/SAIFI targets) and Health, Safety and Environment, as identified in the DSP.
Source and Nature of the Information Used to Justify the Investment	The source of the information used to justify this investment is the Asset Condition Assessment (ACA), as further detailed in the Asset Management section of the DSP. These lines were originally installed between the 1960s and 1980s and have Health Index ratings in the Poor and Very Poor category. These ratings were developed through Enova's ACA program using asset degradation factors such as age, pole treatment, inspection and testing data to develop a Health Index (HI) for each pole asset. The HI is converted into a condition rating ranging from Very Good to Very Poor. Assets in Poor and Very Poor condition are identified and grouped into executable projects. Enova's distribution-specific SAIDI/SAIFI reliability targets, established in accordance with the OEB's EB-2021-0307 framework, are used as inputs to the prioritization of renewal investments. Defective equipment is a leading cause of sustained outages on Enova's system, and this program directly addresses the condition-driven failure risk.
Secondary Driver(s)	Where applicable, overhead line rebuilds incorporate provisions for future voltage conversion and DER accommodation. New construction standards also improve weather resilience and provide physical space for smart grid devices and third-party communications attachments.
Good Utility Practice	Enova utilizes Utility Standards Forum (USF) design standards. These standards are based on CSA C22.3 No 1-15 Overhead Systems Heavy Weather Loading design standards. Newer construction standards and materials provide for more weather resilient assets to help maintain safety and reliability. Enova overhead designs facilitate the future incorporation of grid modernization equipment and renewable energy generation. Enova conducts annual inspection and testing programs, evaluates the results and reprioritizes the replacement of assets if required. Although pole condition is normally the main driver for overhead renewal projects, other assets such as transformers, insulators, wire, and arrestors are also replaced as part of pole line rebuild. These assets are nearing end of life and would not normally survive a second life cycle. Replacing these assets all at the same time is more cost effective and less disruptive than waiting until individual assets fail or reach end of life.
Investment Priority	System Access investments are ranked as top priority, as they are mandated by regulation or code. System Renewal assets are prioritized by the health condition of the assets developed through Enova's ACA program. Assets found at risk of imminent failure or high public safety risk are prioritized for immediate replacement. Enova utilizes METSCO's Asset Analysis, Prioritization, and Optimization Tool (ENGIN) to aid in prioritizing asset replacement. Assets flagged for replacement are geospatially grouped to create constructible projects. Projects are ranked by taking into account their overall health condition, customer impact, alignment with Enova's Strategic Priorities such as reliability, safety, financial or environmental risk and additional drivers and benefits. The greater the customer impact or the more drivers or benefits that are attributed to a project the higher its priority. Investments in System Service and General Plant categories are prioritized in a similar fashion. Analysis of impact on customers and consideration of impact of project deferral are also considered. The compiled list of projects is reviewed and prioritized by Enova Engineering, Operations, and Finance staff. Based on the outcome of this process, this program ranks 17 out of 25. Refer to the DSP prioritization table for further details.
Analysis of the Project and Project Alternatives	All pole line sections under this program have been identified as being in poor condition and in need of replacement. In light of this fact, Enova considered the following alternatives: a) Do Nothing - this option results in the perpetuation of operational issues, increased risk of safety incidents, and further deterioration resulting in a decrease in reliability, and is therefore not considered appropriate. b) Refurbish the Lines - these line sections are not appropriate candidates for refurbishment as most poles are too short and structurally too weak to comply with today's safety standards as required by O.Reg 22/04. c) Replace the Lines with Underground Lines - in most situations overhead line burial is technically feasible but often cost prohibitive. Enova's typical line burial costs range between 5x (for local single phase lines) to 10x (for three phase trunk circuits) the equivalent overhead rebuild costs. Due to cost impacts this option is not considered feasible. d) Replace Like for Like to New Standards - this is the preferred option for those line sections already operating at their ultimate planned voltage. Today's safety standards require same class and height of poles for all voltage levels. e) Replace Like for Like with Provisions for Operation at Higher Voltages - this option allows for replacement of aged or unsafe equipment, allows for ultimate conversion to higher operating voltage with minimal equipment change when conversion takes place, and is therefore the preferred option for lines presently operating at 8.32 kV.
Effect on system operation efficiency and cost effectiveness	Renewal of these assets will eliminate the need for ongoing emergency repairs and reactive maintenance, reducing future operations and maintenance costs. Where applicable, modernized construction standards improve the efficiency of maintenance activities by providing improved access and standardized equipment.
Net benefits accruing to customers	The renewal of this infrastructure will have the following benefits: the aversion of potentially adverse effects on reliability and safety, avoidance of an increase to maintenance costs, and where applicable, provide for increased flexibility of the system via harmonization of distribution voltages, a decrease in line losses, and an increase in capacity for connection of DERs.
Impact of Investment on reliability performance (including on the frequency and duration of outages)	These projects ensure the elimination of safety hazards and that reliability is maintained. Additionally, the standards to which assets must be built today compared to the existing assets ensures they are able to withstand more adverse weather conditions and increases the clearances around the conductors to assist in reducing both the frequency and duration of outages.
Scheduling Alternatives	System Renewal investments are instrumental in reducing the risk of critical asset failures, maintaining reliability and safety performance measures and keeping expensive reactive maintenance activities to a minimum. Scheduling changes within the calendar year due to weather, coordination with third parties and resource constraints can usually be accommodated for smaller projects. Rescheduling larger projects can increase costs due to the reassignment of labour and materials and the risk of asset failure. Enova evaluates the risk and cost of rescheduling any project to achieve the most cost effective outcome.
Ownership and/or Funding Alternatives	These projects are constructed in the public right-of-way and will consist solely of Enova's assets. There are no ownership or funding alternatives.

Safety

The new construction standards make work on pole lines much safer for all workers due to increased separation of high voltage conductors between themselves as well as from low voltage conductors. The replacement also minimizes the risk of unexpected pole failures in these areas, decreasing risk to the public.

Cyber-security, Privacy

Not Applicable

Co-ordination, Interoperability

Coordination with utilities, regional planning and/or links with 3rd parties (where applicable)	Enova will meet with the area Utility Coordinating Council and municipal staff (where applicable) as well as third party stakeholders to exchange project details to coordinate construction. This coordination typically occurs in Q3-Q4 of the year preceding construction.
Enabling of future technological functionality or addressing of future operational requirements	New lines generally incorporate larger conductor, increased strength, and where available, higher voltages. As a result, the system is better able to withstand poor weather conditions; provide increased capacity and siting options for the connection of renewable energy generation, electric vehicles, energy storage; provide increased physical space for third party communications and smart grid devices; and reduce power quality issues and losses.

Environmental Benefits

Not Applicable

Non-Wires Solutions Consideration

Enova's consideration of non-wires solutions for this program is documented in accordance with the NWS Guidelines (EB-2024-0118) and the BCA Framework. See details below.

Benefit-Cost Analysis Framework (5.4.2.2.)

In accordance with the OEB's BCA Framework (May 2024), Enova conducted a pre-assessment of non-wires solution (NWS) viability for this program. The pre-assessment concluded that NWS is not a viable alternative because the system need is driven by asset condition, not capacity constraint. Refer to the NWS Pre-Assessment appendix of this DSP for details.

General Information on the project/program (5.4.2.1.A)

Project Name OH Line Renewal - Reactive
Program Code R-OL-R
OEB Investment Category System Renewal

Project Description

This program provides for the reactive replacement of overhead assets that fail unexpectedly due to storm damage, motor vehicle accidents, equipment malfunction, or other unplanned events. The program also covers the replacement of overhead transformers that have failed in service.

Reactive renewal expenditures are inherently unpredictable but are budgeted based on historical experience. Enova maintains an inventory of critical spare equipment to minimize restoration times following unplanned failures.

Detailed SubProjects

The following individual projects are covered by this project category:

Enova Project	Sub Project	Project Name	Total
R-OL-R		Reactive Overhead Transformer Replacement	$103,834
R-OL-R		Reactive Renewal - Storm and Equipment Damage	$580,598
		Total	$684,432

Capital Investment

Total Capital **$684,432**

O&M Costs (if applicable) **$0** Not Applicable

Capital Contributions to a Transmitter

CCRA Contribution $0

Customer Attachments/Load (kVA)

Customer Attachments (#): N/A
Customer Load (peak kVA) N/A

Project Timing

Start Date January 1, 2027 Engineering
End Date December 31, 2027 Construction

Expected In-Service Date December 1, 2027

Expenditure Timing

2027 Q1	20%	$136,886
2027 Q2	30%	$205,330
2027 Q3	30%	$205,330
2027 Q4	20%	$136,886

Schedule Risk and Risk Mitigation

Reactive renewal expenditures are inherently unpredictable in timing and scope. Enova maintains spare equipment inventory and standing contractor arrangements to ensure rapid response to unplanned failures. Storm damage restoration may temporarily divert resources from planned capital work; this risk is managed through the integrated scheduling of all overhead programs.

Comparative Information

Comparable investments in previous years are as follows:

2020:	$609,957
2021:	$191,237
2022:	$397,536
2023:	$414,140
2024:	$772,208
2025:	$335,622
2026 (Bridge)	$1,055,029

Total Capital & OM&A Costs Associated with REG Investments

Not Applicable

Leave to Construct Approval

Not Applicable

Evaluation Criteria and information requirements for each project/program (5.4.2.1.B)

Efficiency, Customer Value, Reliability

Main Driver	The main driver for this program is the age and condition of the existing plant, as well as external factors like storm.
Related Objectives/Performance Targets	Enova Strategic Objectives: Grid Resiliency (SAIDI/SAIFI targets) and Health, Safety and Environment, as identified in the DSP.
Source and Nature of the Information Used to Justify the Investment	The source of the information used to justify this investment is the Asset Condition Assessment (ACA), as further detailed in the Asset Management section of the DSP. These lines were originally installed between the 1960s and 1980s and have Health Index ratings in the Poor and Very Poor category. These ratings were developed through Enova's ACA program using asset degradation factors such as age, pole treatment, inspection and testing data to develop a Health Index (HI) for each pole asset. The HI is converted into a condition rating ranging from Very Good to Very Poor. Assets in Poor and Very Poor condition are identified and grouped into executable projects. Enova's distribution-specific SAIDI/SAIFI reliability targets, established in accordance with the OEB's EB-2021-0307 framework, are used as inputs to the prioritization of renewal investments. Defective equipment is a leading cause of sustained outages on Enova's system, and this program directly addresses the condition-driven failure risk.
Secondary Driver(s)	Where applicable, overhead line rebuilds incorporate provisions for future voltage conversion and DER accommodation. New construction standards also improve weather resilience and provide physical space for smart grid devices and third-party communications attachments.
Good Utility Practice	Enova utilizes Utility Standards Forum (USF) design standards. These standards are based on CSA C22.3 No 1-15 Overhead Systems Heavy Weather Loading design standards. Newer construction standards and materials provide for more weather resilient assets to help maintain safety and reliability. Enova overhead designs facilitate the future incorporation of grid modernization equipment and renewable energy generation. Enova conducts annual inspection and testing programs, evaluates the results and reprioritizes the replacement of assets if required. Although pole condition is normally the main driver for overhead renewal projects, other assets such as transformers, insulators, wire, and arrestors are also replaced as part of pole line rebuild. These assets are nearing end of life and would not normally survive a second life cycle. Replacing these assets all at the same time is more cost effective and less disruptive than waiting until individual assets fail or reach end of life.
Investment Priority	System Access investments are ranked as top priority, as they are mandated by regulation or code. System Renewal assets are prioritized by the health condition of the assets developed through Enova's ACA program. Assets found at risk of imminent failure or high public safety risk are prioritized for immediate replacement. Enova utilizes METSCO's Asset Analysis, Prioritization, and Optimization Tool (ENGIN) to aid in prioritizing asset replacement. Assets flagged for replacement are geospatially grouped to create constructible projects. Projects are ranked by taking into account their overall health condition, customer impact, alignment with Enova's Strategic Objectives such as reliability, safety, financial or environmental risk and additional drivers and benefits. The greater the customer impact or the more drivers or benefits that are attributed to a project the higher its priority. Investments in System Service and General Plant categories are prioritized in a similar fashion. Analysis of impact on customers and consideration of impact of project deferral are also considered. The compiled list of projects is reviewed and prioritized by Enova Engineering, Operations, and Finance staff. Based on the outcome of this process, this program ranks 3 out of 25. Refer to the DSP prioritization table for further details.
Analysis of the Project and Project Alternatives	All pole line sections under this program have been identified as being in poor condition and in need of replacement. In light of this fact, Enova considered the following alternatives: a) Do Nothing - this option results in the perpetuation of operational issues, increased risk of safety incidents, and further deterioration resulting in a decrease in reliability, and is therefore not considered appropriate. b) Refurbish the Lines - these line sections are not appropriate candidates for refurbishment as most poles are too short and structurally too weak to comply with today's safety standards as required by O.Reg 22/04. c) Replace the Lines with Underground Lines - in most situations overhead line burial is technically feasible but often cost prohibitive. Enova's typical line burial costs range between 5x (for local single phase lines) to 10x (for three phase trunk circuits) the equivalent overhead rebuild costs. Due to cost impacts this option is not considered feasible. d) Replace Like for Like to New Standards - this is the preferred option for those line sections already operating at their ultimate planned voltage. Today's safety standards require same class and height of poles for all voltage levels. e) Replace Like for Like with Provisions for Operation at Higher Voltages - this option allows for replacement of aged or unsafe equipment, allows for ultimate conversion to higher operating voltage with minimal equipment change when conversion takes place, and is therefore the preferred option for lines presently operating at 8.32 kV.
Effect on system operation efficiency and cost effectiveness	Renewal of these assets will eliminate the need for ongoing emergency repairs and reactive maintenance, reducing future operations and maintenance costs. Where applicable, modernized construction standards improve the efficiency of maintenance activities by providing improved access and standardized
Net benefits accruing to customers	The renewal of this infrastructure will have the following benefits: the aversion of potentially adverse effects on reliability and safety, avoidance of an increase to maintenance costs, and where applicable, provide for increased flexibility of the system via harmonization of distribution voltages, a decrease in line losses, and an increase in capacity for connection of DERs.
Impact of Investment on reliability performance (including on the frequency and duration of outages)	These projects ensure the elimination of safety hazards and that reliability is maintained. Additionally, the standards to which assets must be built today compared to the existing assets ensures they are able to withstand more adverse weather conditions and increases the clearances around the conductors to assist in reducing both the frequency and duration of outages.
Scheduling Alternatives	System Renewal investments are instrumental in reducing the risk of critical asset failures, maintaining reliability and safety performance measures and keeping expensive reactive maintenance activities to a minimum. Scheduling changes within the calendar year due to weather, coordination with third parties and resource constraints can usually be accommodated for smaller projects. Rescheduling larger projects can increase costs due to the reassignment of labour and materials and the risk of asset failure. Enova evaluates the risk and cost of rescheduling any project to achieve the most cost effective outcome.
Ownership and/or Funding Alternatives	These projects are constructed in the public right-of-way and will consist solely of Enova's assets. There are no ownership or funding alternatives.

Safety

The new construction standards make work on pole lines much safer for all workers due to increased separation of high voltage conductors between themselves as well as from low voltage conductors. The replacement also minimizes the risk of unexpected pole failures in these areas, decreasing risk to the public.

Cyber-security, Privacy

Not Applicable

Co-ordination, Interoperability

Coordination with utilities, regional planning and/or links with 3rd parties (where applicable)	Enova will meet with the area Utility Coordinating Council and municipal staff (where applicable) as well as third party stakeholders to exchange project details to coordinate construction. This coordination typically occurs in Q3-Q4 of the year preceding construction.
Enabling of future technological functionality or addressing of future operational requirements	New lines generally incorporate larger conductor, increased strength, and where available, higher voltages. As a result, the system is better able to withstand poor weather conditions; provide increased capacity and siting options for the connection of renewable energy generation, electric vehicles, energy storage; provide increased physical space for third party communications and smart grid devices; and reduce power quality issues and losses.

Environmental Benefits

Not Applicable

Non-Wires Solutions Consideration

Enova's consideration of non-wires solutions for this program is documented in accordance with the NWS Guidelines (EB-2024-0118) and the BCA Framework. See details below.

Benefit-Cost Analysis Framework (5.4.2.2.)

Not Applicable (below $2M threshold)

General Information on the project/program (5.4.2.1.A)

Project Name UG Line Renewal - Proactive
Program Code R-UL-P
OEB Investment Category System Renewal

Project Description

This program provides for proactive underground system renewal activities identified through OEB inspection findings, cable testing results, or engineering assessment. Activities include targeted cable replacement, equipment upgrades, and minor civil repairs that do not warrant a full subdivision renewal project.

Expenditures in this program address specific deficiencies as they are identified, providing flexibility to respond to emerging condition issues between planned renewal cycles.

Detailed SubProjects

The following individual projects are covered by this project category:

Enova Project	Sub Project	Project Name	Total
R-UL-P		Proactive Renewal - Locking System/Sensor on vault lids	$83,600
R-UL-P		UG Primary Cable Testing & Replacement	$150,000
R-UL-P		Underground Proactive System Renewal - CS	$350,000
R-UL-P		Underground Proactive System Renewal - VS	$350,000
		Total	$933,600

Capital Investment

Total Capital **$933,600**

O&M Costs (if applicable) **$0** Not Applicable

Capital Contributions to a Transmitter

CCRA Contribution $0

Customer Attachments/Load (kVA)

Customer Attachments (#): N/A
Customer Load (peak kVA) N/A

Project Timing

Start Date January 1, 2027 Engineering
End Date December 31, 2027 Construction

Expected In-Service Date December 1, 2027

Expenditure Timing

2027 Q1	20%	$186,720
2027 Q2	30%	$280,080
2027 Q3	30%	$280,080
2027 Q4	20%	$186,720

Schedule Risk and Risk Mitigation

Proactive underground renewal activities are scheduled to complement the full subdivision renewal program. The primary scheduling risk is the availability of underground construction crews.

Comparative Information

Comparable investments in previous years are as follows:

2020:	$339,787
2021:	$282,389
2022:	$346,955
2023:	$639,721
2024:	$720,738
2025:	$806,871
2026 (Bridge):	$1,113,429

Total Capital & OM&A Costs Associated with REG Investments

Not Applicable

Leave to Construct Approval

Not Applicable

Evaluation Criteria and information requirements for each project/program (5.4.2.1.B)

Efficiency, Customer Value, Reliability

Main Driver	The main driver for this program is the age and condition of the existing plant.
Related Objectives/Performance Targets	Enova Strategic Priorities: Grid Resiliency (SAIDI/SAIFI targets) and Health, Safety and Environment, as identified in the DSP.
Source and Nature of the Information Used to Justify the Investment	The source of the information used to justify this investment is a combination of cable diagnostic testing, failure history analysis, asset age data, and Enova's Asset Condition Assessment (ACA) program. Underground cable insulation deterioration is assessed through diagnostic testing which identifies cables with elevated risk of failure. Deteriorating underground civil infrastructure (pull boxes, vaults, access lids, etc.) are inspected and if suitable structural replacement is completed prior to becoming satefy risks or concerns. Electrical infrastructure that is visually declining (transformer rusting/oil leaks, secondary mole degradation, etc.) are also replaced prior to possibility of failure. Enova's distribution-specific SAIDI/SAIFI reliability targets are used as inputs to the prioritization of renewal investments. Underground cable failures result in extended restoration times compared to overhead faults, making proactive cable replacement a high-priority reliability investment.
Secondary Driver(s)	Where applicable, underground renewal projects incorporate voltage conversion to eliminate legacy voltage levels, improving operational flexibility and reducing the need for dedicated station transformer capacity.
Good Utility Practice	Enova utilizes Utility Standards Forum (USF) design standards for underground construction. Underground cable selection, installation, and testing follow CSA and IEEE standards. Enova employs advanced diagnostic testing techniques to assess cable condition and prioritize replacement. Underground renewal projects are designed to current standards including improved duct bank configurations, modern cable types, and enhanced vault drainage to extend asset service life and reduce future maintenance costs.
Investment Priority	System Access investments are ranked as top priority, as they are mandated by regulation or code. System Renewal assets are prioritized by the health condition of the assets developed through Enova's ACA program. Assets found at risk of imminent failure or high public safety risk are prioritized for immediate replacement. Enova utilizes METSCO's Asset Analysis, Prioritization, and Optimization Tool (ENGIN) to aid in prioritizing asset replacement. Assets flagged for replacement are geospatially grouped to create constructible projects. Projects are ranked by taking into account their overall health condition, customer impact, alignment with Enova's Strategic Priorities such as reliability, safety, financial or environmental risk and additional drivers and benefits. The greater the customer impact or the more drivers or benefits that are attributed to a project the higher its priority. Investments in System Service and General Plant categories are prioritized in a similar fashion. Analysis of impact on customers and consideration of impact of project deferral are also considered. The compiled list of projects is reviewed and prioritized by Enova Engineering, Operations, and Finance staff. Based on the outcome of this process, this program ranks 4 out of 25. Refer to the DSP prioritization table for further details.
Analysis of the Project and Project Alternatives	Underground assets under this program have been identified as approaching or past end of life based on diagnostic testing, age, and failure history. Enova considered the following alternatives: a) Do Nothing - this option results in increased risk of cable faults, extended customer outages, and potential safety hazards. Underground cable failures are more costly and time-consuming to repair than overhead faults. This option is not considered appropriate. b) Refurbish/Rehabilitate - cable injection (silicone treatment) can extend the life of certain cable types, but is not appropriate for cables that have already exhibited significant insulation deterioration or for cable types that are not compatible with injection. Where applicable, Enova has considered cable injection as an alternative. c) Replace Like for Like - this is the preferred option for cables operating at their ultimate planned voltage. Modern cable insulation materials (TR-XLPE) provide improved performance and longer service life. d) Replace with Voltage Conversion - where the project area also requires voltage conversion from legacy levels, the preferred option is to install cable rated for the target voltage, eliminating the need for future re-cabling. In accordance with the OEB's BCA Framework (May 2024), Enova conducted a pre-assessment of NWS viability for programs exceeding $2M. The pre-assessment concluded that NWS is not a viable alternative because underground cable insulation deterioration requires physical cable replacement. Refer to the NWS Pre-Assessment appendix.
Effect on system operation efficiency and cost effectiveness	Renewal of these assets will eliminate the need for ongoing emergency repairs and reactive maintenance, reducing future operations and maintenance costs. Where applicable, modernized construction standards improve the efficiency of maintenance activities by providing improved access and standardized equipment.
Net benefits accruing to customers	The renewal of this infrastructure will have the following benefits: the aversion of potentially adverse effects on reliability and safety, avoidance of an increase to maintenance costs, and where applicable, provide for increased flexibility of the system via harmonization of distribution voltages, a decrease in line losses, and an increase in capacity for connection of DERs.
Impact of Investment on reliability performance (including on the frequency and duration of outages)	These projects ensure the elimination of safety hazards and that reliability is maintained. Additionally, the standards to which assets must be built today compared to the existing assets ensures they are able to withstand more adverse weather conditions and increases the clearances around the conductors to assist in reducing both the frequency and duration of outages.
Scheduling Alternatives	System Renewal investments are instrumental in reducing the risk of critical asset failures, maintaining reliability and safety performance measures and keeping expensive reactive maintenance activities to a minimum. Scheduling changes within the calendar year due to weather, coordination with third parties and resource constraints can usually be accommodated for smaller projects. Rescheduling larger projects can increase costs due to the reassignment of labour and materials and the risk of asset failure. Enova evaluates the risk and cost of rescheduling any project to achieve the most cost effective outcome.
Ownership and/or Funding Alternatives	These projects are constructed in the public right-of-way and will consist solely of Enova's assets. There are no ownership or funding alternatives.

Safety

Underground renewal eliminates the risk of cable faults which can present safety hazards including arc flash, ground potential rise, and manhole events. Modern cable and equipment designs incorporate improved safety features and fault containment capability.

Cyber-security, Privacy

Not Applicable

Co-ordination, Interoperability

Coordination with utilities, regional planning and/or links with 3rd parties (where applicable)	Enova will meet with the area Utility Coordinating Council and municipal staff (where applicable) as well as third party stakeholders to exchange project details to coordinate construction. This coordination typically occurs in Q3-Q4 of the year preceding construction.
Enabling of future technological functionality or addressing of future operational requirements	New underground cable systems incorporate modern insulation materials and duct configurations that provide improved performance and longer service life. Where applicable, conduit spare capacity is provided to facilitate future cable additions without additional civil construction. Modern switchgear incorporates provisions for SCADA communication and automated switching capability.

Environmental Benefits

Not Applicable

Non-Wires Solutions Consideration

Enova's consideration of non-wires solutions for this program is documented in accordance with the NWS Guidelines (EB-2024-0118) and the BCA Framework. See details below.

Benefit-Cost Analysis Framework (5.4.2.2.)

Not Applicable (below $2M threshold)

General Information on the project/program (5.4.2.1.A)

Project Name UG Line Renewal - Reactive
Program Code R-UL-R
OEB Investment Category System Renewal

Project Description

This program provides for the reactive renewal of underground distribution assets — primarily underground cables, distribution transformers, and associated civil infrastructure — that fail in service or must be replaced on an emergency basis to restore supply and to address public and worker safety. Expenditures are event driven and cannot be scheduled in advance.

Detailed SubProjects

The following individual projects are covered by this project category:

EnovaProject	Sub Project	Project Name	Total
R-UL-R		Reactive Renewal - Underground Storm and Equipment Damage	$41,242
R-UL-R		Reactive Renewal - Underground Transformer Replacement	$928,234
		Total	$969,476

Capital Investment

Total Capital **$969,476**

O&M Costs (if applicable) **$0** Not Applicable

Capital Contributions to a Transmitter

CCRA Contribution $0

Customer Attachments/Load (kVA)

Customer Attachments (#): N/A
Customer Load (peak kVA) N/A

Project Timing

Start Date January 1, 2027 Engineering
End Date December 31, 2027 Construction

Expected In-Service Date December 1, 2027

Expenditure Timing

2027 Q1	20%	$193,895
2027 Q2	30%	$290,843
2027 Q3	30%	$290,843
2027 Q4	20%	$193,895

Schedule Risk and Risk Mitigation

Reactive renewal expenditures are inherently unpredictable in timing and scope. Enova maintains spare equipment inventory and standing contractor arrangements to ensure rapid response to unplanned failures. Storm damage restoration may temporarily divert resources from planned capital work; this risk is managed through the integrated scheduling of all overhead programs.

Comparative Information

Comparable investments in previous years are as follows:

2020:	$84,348
2021:	$63,884
2022:	$100,913
2023:	$101,871
2024:	$521,002
2025:	$141,479
2026 (Bridge):	$956,813

Total Capital & OM&A Costs Associated with REG Investments

Not Applicable

Leave to Construct Approval

Not Applicable

Evaluation Criteria and information requirements for each project/program (5.4.2.1.B)

Efficiency, Customer Value, Reliability

Main Driver	The main driver behind the majority of these projects is the requirement to replace failed assets or end of life assets that were not scheduled for replacement, but due to their present condition must be replaced immediately to ensure that safety and reliability are not further compromised.
Related Objectives/Performance Targets **Source and Nature of the Information Used to Justify the Investment**	Enova Strategic Priorities: Grid Resiliency (SAIDI/SAIFI targets) and Health, Safety and Environment, as identified in the DSP. Asset condition at the time of discovery and consequences of not doing anything provide the justification required.
Secondary Driver(s)	Not applicable — reactive replacements are like-for-like restorations of failed underground assets.
Good Utility Practice	Good utility practice is to react and respond immediately to remove the public safety hazards and replace damaged assets to meet current safety Code and Standards. Investigate and apply engineering measures to reduce and mitigate the risk of public safety should this this type of unforeseeable events occur.
Investment Priority	System Access investments are ranked as top priority, as they are mandated by regulation or code. System Renewal assets are prioritized by the health condition of the assets developed through Enova's ACA program. Assets found at risk of imminent failure or high public safety risk are prioritized for immediate replacement. Enova utilizes METSCO's Asset Analysis, Prioritization, and Optimization Tool (ENGIN) to aid in prioritizing asset replacement. Assets flagged for replacement are geospatially grouped to create constructible projects. Projects are ranked by taking into account their overall health condition, customer impact, alignment with Enova's Strategic Priorities such as reliability, safety, financial or environmental risk and additional drivers and benefits. The greater the customer impact or the more drivers or benefits that are attributed to a project the higher its priority. Investments in System Service and General Plant categories are prioritized in a similar fashion. Analysis of impact on customers and consideration of impact of project deferral are also considered. The compiled list of projects is reviewed and prioritized by Enova Engineering, Operations, and Finance staff. Based on the outcome of this process, this program ranks 2 out of 25. Refer to the DSP prioritization table for further details.
Analysis of the Project and Project Alternatives	Alternatives are rarely considered for these projects due to the urgency of the need. Majority of the projects involve like for like replacements to current safety standards. At times, pole heights will be adjusted to align to future needs and transformer sizing may be increased or decreased based on actual loading information. Both adjustments are made to avoid future costs.
Effect on system operation efficiency and cost effectiveness	Renewal of these assets will eliminate the safety harzard present by the failed equipment. Where applicable, modernized construction standards improve the efficiency of maintenance activities by providing improved access and standardized equipment.
Net benefits accruing to customers	The renewal of this infrastructure will have the following benefits: the aversion of potentially adverse effects on reliability and safety, avoidance of an increase to maintenance costs, and where applicable, provide for increased flexibility of the system via harmonization of distribution voltages, a decrease in line losses, and an increase in capacity for connection of DERs.
Impact of Investment on reliability performance (including on the frequency and duration of outages)	These projects ensure the elimination of safety hazards and that reliability is maintained. Additionally, the standards to which assets must be built today compared to the existing assets ensures they are able to withstand more adverse weather conditions and increases the clearances around the conductors to assist in reducing both the frequency and duration of outages.
Scheduling Alternatives	System Renewal investments are instrumental in reducing the risk of critical asset failures, maintaining reliability and safety performance measures and keeping expensive reactive maintenance activities to a minimum. Scheduling changes within the calendar year due to weather, coordination with third parties and resource constraints can usually be accommodated for smaller projects. Rescheduling larger projects can increase costs due to the reassignment of labour and materials and the risk of asset failure. Enova evaluates the risk and cost of rescheduling any project to achieve the most cost effective outcome.
Ownership and/or Funding Alternatives	These projects are constructed in the public right-of-way and will consist solely of Enova's assets. There are no ownership or funding alternatives.

Safety

Renewal to current construction standards makes work on the underground distribution system safer for workers, and removes failed assets that present a public-safety risk.

Cyber-security, Privacy

Not Applicable

Co-ordination, Interoperability

Coordination with utilities, regional planning and/or links with 3rd parties (where applicable)	Enova will meet with the area Utility Coordinating Council and municipal staff (where applicable) as well as third party stakeholders to exchange project details to coordinate construction. This coordination typically occurs in Q3-Q4 of the year preceding construction.
Enabling of future technological functionality or addressing of future operational requirements	New lines generally incorporate larger conductor, increased strength, and where available, higher voltages. As a result, the system is better able to withstand poor weather conditions; provide increased capacity and siting options for the connection of renewable energy generation, electric vehicles, energy storage; provide increased physical space for third party communications and smart grid devices; and reduce power quality issues and losses.

Environmental Benefits

Not Applicable

Non-Wires Solutions Consideration

Enova's consideration of non-wires solutions for this program is documented in accordance with the NWS Guidelines (EB-2024-0118) and the BCA Framework. See details below.

Benefit-Cost Analysis Framework (5.4.2.2.)

Not Applicable (below $2M threshold)

Waterloo HSTS B Transformer Replacements

General Information on the project/program (5.4.2.1.A)

Project Name Waterloo HSTS B Transformer Replacements
Program Code R-SE
OEB Investment Category System Renewal

Project Description

This program involves the replacement of aging power transformers at the Howard Scheifele B Transformer Station that have been identified through Enova's ACA program as approaching end-of-life and requiring replacement to maintain the safe and reliable operation of the distribution system. Replacing these assets mitigates the increasing risk of equipment failure, reduces long-term maintenance requirements, and maintains the reliability and performance of the station.

As part of the replacement program, the existing transformers will be replaced with modern, standardized units that provide modestly increased transformation capacity. This approach addresses the immediate asset renewal need while providing the additional benefit of supporting forecasted load growth within the service area and improving long-term system flexibility.

Projects within this program are identified through asset condition assessments, system planning studies, and load forecasting analyses that evaluate transformer health, loading, available station capacity, and long-term system requirements. The scope of work includes the removal of the existing transformer units and the installation, testing, and commissioning of new power transformers, together with the associated station modifications required to integrate the replacement equipment into the transmission and distribution system.

Detailed SubProjects

The following individual projects are covered by this project category:

Enova Project	Sub Project	Project Name	Total
R-SE		Waterloo HSTS B Transformer Replacement	$1,160,542
		Total	$1,160,542

Capital Investment

Total Capital **$1,160,542**

O&M Costs (if applicable) **$0** Not Applicable

Capital Contributions to a Transmitter

CCRA Contribution $0

Customer Attachments/Load (kVA)

Customer Attachments (#): 22198
Customer Load (peak kVA) 97000

Project Timing

Start Date April 1, 2026
End Date December 1, 2030

Expected In-Service Date December 1, 2030

Expenditure Timing
2026-2030

Schedule Risk and Risk Mitigation

Transformer replacement projects require coordination with the transmitter, station operations, and system control groups to schedule planned outages and switching activities necessary for the removal and installation of major station equipment. The project schedule is also dependent on long-lead procurement timelines for power transformers and associated high-voltage equipment, as well as on the availability of specialized contractors and commissioning resources. Project risks are mitigated through early equipment procurement, coordination with the ACA and outage planning groups, detailed construction sequencing, and advance scheduling of required system outages to minimize impacts on customers and system operations.

Comparative Information

Comparable investments in previous years are as follows:

2020:	$2,622,384
2021:	$2,066,593
2022:	$2,339,449
2023:	$5,920,502
2024:	$7,232,120
2025:	$6,773,375
2026 (Bridge):	$5,769,460

Total Capital & OM&A Costs Associated with REG Investments

Not Applicable

Leave to Construct Approval

Not Applicable

Evaluation Criteria and information requirements for each project/program (5.4.2.1.B)

Efficiency, Customer Value, Reliability

Main Driver	The main driver for this project is the replacement of power transformers identified through Enova's ACA program as approaching end-of-life. The investment is required to mitigate the increasing risk of asset failure and maintain the safe, reliable, and efficient operation of the Howard Scheifele B Transformer Station.
Related Objectives/Performance Targets	Enova Strategic Objectives: Asset Renewal, Reliability Performance (SAIDI/SAIFI), Grid Resiliency, and Health, Safety and Environment, as identified in the DSP.
Source and Nature of the Information Used to Justify the Investment	The source of the information used to justify this investment includes Enova's ACA program, transformer condition assessments, asset maintenance history, engineering evaluations, equipment age, manufacturer supportability, and operational risk assessments. The project was identified through Enova's asset management process as the existing transformer assets are approaching end-of-life and present an increasing risk to the reliable operation of the station.
Secondary Driver(s)	Secondary drivers include right-sizing the replacement transformers by installing modern, standardized units with modestly higher capacity than the existing assets. This approach captures additional transformation capacity at the time of asset renewal, improving operational flexibility, supporting forecasted customer load growth, increasing potential DER hosting capacity, improving equipment standardization, and reducing long-term maintenance requirements.
Good Utility Practice	The transformer replacement project is designed and executed in accordance with applicable CSA and IEEE standards, utility engineering best practices, and the technical requirements of the supplying transmitter and the IESO. The station design and equipment specifications are developed in coordination with transmitter interconnection requirements, protection and control standards, system operating requirements, and applicable reliability criteria. Construction, testing, and commissioning activities are completed in accordance with applicable safety regulations, utility standards, and industry accepted commissioning and asset management practices to ensure the continued safe and reliable operation of the station and the bulk electric system.
Investment Priority	System Access investments are ranked as top priority, as they are mandated by regulation or code. System Renewal assets are prioritized by the health condition of the assets developed through Enova's ACA program. Assets found at risk of imminent failure or high public safety risk are prioritized for immediate replacement. Enova utilizes METSCO's Asset Analysis, Prioritization, and Optimization Methodology to aid in prioritizing Station asset replacement. Assets flagged for replacement are geospatially grouped to create constructible projects. Projects are ranked by taking into account their overall health condition, customer impact, alignment with Enova's Strategic Objectives such as reliability, safety, financial or environmental risk and additional drivers and benefits. The greater the customer impact or the more drivers or benefits that are attributed to a project the higher its priority. Investments in System Service and General Plant categories are prioritized in a similar fashion. Analysis of impact on customers and consideration of impact of project deferral are also considered. The compiled list of projects is reviewed and prioritized by Enova Engineering, Operations, and Finance staff. Based on the outcome of this process, this program ranks 6 out of 25. Refer to the DSP prioritization table for further details.
Analysis of the Project and Project Alternatives	Enova considered the following alternatives: a) Do Nothing – This option does not address the identified end-of-life condition of the existing transformer assets and would increase the risk of equipment failure, unplanned outages, and reduced system reliability. This option was not considered acceptable. b) Refurbishment of Existing Transformers – Enova considered refurbishment and continued maintenance of the existing transformer assets. Due to the age, condition, capacity limitations, and long-term reliability concerns associated with the existing units, full replacement was determined to be the preferred long-term solution. c) Replace with Equivalent Capacity Transformers – Enova considered replacing the existing transformers with new units of the same capacity. While this option would address the identified asset condition concerns, it would not provide additional transformation capacity to accommodate forecasted load growth and would likely require a future station upgrade within the planning horizon. d) Replace with Larger Standardized Transformers (Preferred Option) – Enova selected the replacement of the existing transformers with modern, standardized transformer units that provide modestly increased transformation capacity. This option addresses the primary need to replace the aging end-of-life assets while providing the secondary benefit of supporting forecasted load growth, improving operational flexibility, enhancing equipment standardization, and avoiding the need for a separate future capacity upgrade. Based on recent procurement experience and budgetary market information, Enova expects that increasing the transformer size as part of the planned replacement represents only a modest premium over an equivalent-capacity replacement. Given the relatively small incremental investment, replacing the transformers with larger standardized units provides better long-term value by addressing both the immediate asset renewal need and forecasted future capacity requirements. e) Non-Wires Solutions – Enova considered whether non-wires alternatives, including distributed energy resources and load transfer solutions, could defer the investment. As the primary need is the replacement of end-of-life transformer assets, non-wires alternatives would not address the underlying asset condition and were therefore not considered a viable alternative.
Effect on system operation efficiency and cost effectiveness	The replacement of aging transformer assets with newer higher-capacity units will improve operational efficiency and reduce maintenance requirements associated with aging equipment. The upgraded transformers will improve station performance, increase operational flexibility, and reduce the likelihood of unplanned outages and reactive maintenance activities.
Net benefits accruing to customers	The renewal of this infrastructure will provide the following benefits: reduced risk of prolonged customer outages resulting from transformer failure, improved system reliability and resiliency, increased station capacity to accommodate future customer growth, reduced maintenance costs associated with aging equipment, and improved long-term operational flexibility of the distribution system.
Impact of Investment on reliability performance (including on the frequency and duration of outages)	These projects ensure continued safe and reliable operation of the station by replacing aging transformer assets that are approaching end-of-life, while ensuring sufficient capacity for future loading requirements. The installation of modern transformer equipment improves system resiliency and reduces the likelihood of transformer-related outages that could impact a significant number of customers. The upgraded equipment is designed to current utility standards, reducing both the frequency and duration of outages.
Scheduling Alternatives	System Renewal investments are instrumental in reducing the risk of critical asset failures, maintaining reliability and safety performance measures, and minimizing reactive maintenance activities. Transformer replacement projects require extensive coordination with the transmitter, outage planning groups, manufacturers, contractors, and commissioning resources. Due to the long lead times associated with power transformer procurement and the complexity of station outages, significant schedule changes may increase project costs and prolong exposure to asset failure risk. Enova evaluates the operational and financial impacts of project rescheduling to achieve the most cost-effective outcome while maintaining system reliability.
Ownership and/or Funding Alternatives	The transformer station assets associated with this project will remain solely owned and operated by Enova. There are no ownership or funding alternatives associated with this investment.

Safety

The replacement transformer infrastructure will be designed and constructed in accordance with applicable CSA standards, IEEE standards, utility engineering practices, and transmitter and IESO requirements. The replacement of aging station assets improves worker and public safety by reducing the risks associated with equipment deterioration, equipment failure, and operation of obsolete infrastructure. Modern transformer equipment also incorporates updated protection, monitoring, and operational features that improve the safe operation and maintenance of the station.

Cyber-security, Privacy

Where applicable, equipment control, monitoring, and communication systems associated with the transformer replacement project will be designed and implemented in accordance with Enova's cyber security policies, utility operational requirements, and applicable industry standards for critical electrical infrastructure. No customer privacy impacts are anticipated as part of this project.

Co-ordination, Interoperability

Coordination with utilities, regional planning and/or links with 3rd parties (where applicable)	Enova has identified the transformer replacement requirements through the KWCG Integrated Regional Planning process and will continue to coordinate with the supplying transmitter and the IESO throughout the planning, design, outage scheduling, and commissioning stages of the project. This coordination ensures alignment with regional system planning assumptions, outage requirements, and operational constraints. Enova has also engaged with multiple equipment manufacturers to confirm transformer specifications and procurement lead times from various vendors and manufacturing facilities, in order to support project scheduling and mitigate supply chain risks.
Enabling of future technological functionality or addressing of future operational requirements	The transformer replacement project will improve station capacity, operational flexibility, and system resiliency while supporting future operational requirements of the electrical system. The upgraded infrastructure will accommodate future load growth and provide improved capability to support evolving grid requirements, including enhanced system monitoring, protection, automation, and potential future DER integration.

Environmental Benefits

Not Applicable

Non-Wires Solutions Consideration

Enova's consideration of non-wires solutions for this program is documented in accordance with the NWS Guidelines (EB-2024-0118) and the BCA Framework. See details below.

Benefit-Cost Analysis Framework (5.4.2.2.)

In accordance with the OEB's BCA Framework (May 2024), Enova conducted a pre-assessment of non-wires solution (NWS) viability for this program. The pre-assessment concluded that NWS is not a viable alternative because the system need is driven by asset condition, not capacity constraint. Refer to the NWS Pre-Assessment appendix of this DSP for details.

General Information on the project/program (5.4.2.1.A)

Project Name Kitchener 6TS Switchgear Replacement
Program Code R-SE
OEB Investment Category System Renewal

Project Description

The Kitchener 6TS Switchgear Replacement project involves the replacement of aging switchgear and circuit breakers identified through Enova's ACA program as approaching end-of-life. Replacement parts and repair services for the existing breakers remain available for now, however, they are increasingly costly and require higher maintenance effort to manage operational, reliability, and safety risks associated with aging equipment.

The project will replace the existing equipment with modern switchgear and circuit breakers that provide improved reliability, reduced maintenance requirements, enhanced operational flexibility, and higher short-circuit interrupting ratings. The replacement will also introduce arc-resistant switchgear, replacing equipment that was not designed to modern arc-resistant standards and significantly improving worker safety by mitigating the effects of internal arc faults during equipment operation and maintenance. The upgraded equipment will improve long-term station performance while supporting future system requirements, including additional load growth and potential generation interconnections.

Detailed SubProjects

The following individual projects are covered by this project category:

Enova Project	Sub Project	Project Name	Total
R-SE		Kitchener 6TS Switchgear Replacement	$1,985,280
		Total	$1,985,280

Capital Investment

Total Capital **$1,985,280**

O&M Costs (if applicable) **$0** Not Applicable

Capital Contributions to a Transmitter

CCRA Contribution $0

Customer Attachments/Load (kVA)

Customer Attachments (#): 18260
Customer Load (peak kVA) 66000

Project Timing

Start Date June 1, 2026
End Date December 31, 2028

Expected In-Service Date December 31, 2028

Expenditure Timing
2027 100% $1,985,280

Schedule Risk and Risk Mitigation

Switchgear replacement projects require coordination with the transmitter, outage planning groups, contractors, and station operations to schedule outages and construction activities while maintaining system reliability. The switchgear and breaker equipment has procurement lead times of approximately 12–16 months, requiring early engagement with manufacturers and ongoing communication regarding production schedules and supply chain risks. Project risks are mitigated through advance equipment procurement, detailed outage planning, coordination with external stakeholders, and regular vendor communication to minimize the potential impacts of global supply chain disruptions and changing market conditions.

Comparative Information

Comparable investments in previous years are as follows:
2020: $2,622,384
2021: $2,066,593
2022: $2,339,449
2023: $5,920,502
2024: $7,232,120
2025: $6,773,375
2026 (Bridge): $5,769,460

Total Capital & OM&A Costs Associated with REG Investments

Not Applicable

Leave to Construct Approval

Not Applicable

Evaluation Criteria and information requirements for each project/program (5.4.2.1.B)

Efficiency, Customer Value, Reliability

Main Driver	The main driver for the Kitchener 6TS Replacement Program is the replacement of aging switchgear and circuit breakers identified through Enova's ACA program as approaching end-of-life.
Related Objectives/Performance Targets	Enova Strategic Objectives: Grid Resiliency, Reliability Performance (SAIDI/SAIFI), Asset Renewal, Operational Sustainability, and Health, Safety and Environment, as identified in the DSP. The project also supports long-term system reliability and operational flexibility through the replacement of end of life station equipment with modern switchgear technology designed to current utility and industry standards.
Source and Nature of the Information Used to Justify the Investment	The investment is justified through Enova's ACA program, station asset condition assessments, maintenance history, manufacturer support, equipment failure risk analysis, and engineering evaluations identifying the existing switchgear and breakers as approaching end-of-life.
Secondary Driver(s)	Secondary drivers include replacing the existing non-arc-resistant switchgear with modern arc-resistant equipment to significantly improve worker safety, reducing maintenance requirements, increasing short-circuit interrupting capability, improving operational flexibility, and supporting future load growth and potential generation interconnections.
Good Utility Practice	The switchgear replacement project is designed and executed in accordance with applicable CSA, IEEE, and IEC standards, utility engineering best practices, and transmitter and IESO requirements. The new switchgear and breaker equipment will be installed, tested, and commissioned in accordance with manufacturer specifications and industry-accepted practices to ensure safe and reliable operation. Modern protection, control, grounding, and arc-resistant design features improve worker safety, operational reliability, and long-term maintainability while supporting continued compliance with utility operational and system performance requirements.
Investment Priority	System Access investments are ranked as top priority, as they are mandated by regulation or code. System Renewal assets are prioritized by the health condition of the assets developed through Enova's ACA program. Assets found at risk of imminent failure or high public safety risk are prioritized for immediate replacement. Enova utilizes METSCO's Asset Analysis, Prioritization, and Optimization Methodology to aid in prioritizing Station asset replacement. Assets flagged for replacement are geospatially grouped to create constructible projects. Projects are ranked by taking into account their overall health condition, customer impact, alignment with Enova's Strategic Objectives such as reliability, safety, financial or environmental risk and additional drivers and benefits. The greater the customer impact or the more drivers or benefits that are attributed to a project the higher its priority. Investments in System Service and General Plant categories are prioritized in a similar fashion. Analysis of impact on customers and consideration of impact of project deferral are also considered. The compiled list of projects is reviewed and prioritized by Enova Engineering, Operations, and Finance staff. Based on the outcome of this process, this program ranks 6 out of 25. Refer to the DSP prioritization table for further details.
Analysis of the Project and Project Alternatives	a) Do Nothing – This option would retain aging switchgear and circuit breakers that are approaching end-of-life and would continue to require increasing maintenance effort and cost. This option is not considered viable due to rising operational risk, reduced reliability, and increased likelihood of equipment failure over time. b) Continue Maintenance of Existing Equipment – Continued operation with ongoing maintenance and procurement of available spare parts was evaluated. While parts remain available, the equipment is increasingly costly to maintain and does not address underlying obsolescence, aging insulation systems, or long-term reliability concerns. This option does not provide a sustainable long-term solution. c) Refurbishment/Retrofit of Existing Switchgear – Refurbishment was considered; however, this option would not increase short-circuit interrupting ratings, would not fully address end-of-life insulation conditions, and would retain legacy equipment within the switchgear structure, limiting long-term performance and safety improvements. d) Full Replacement with Modern Switchgear (Preferred Option) – Replacement with modern switchgear and breakers provides improved reliability, enhanced worker safety, reduced maintenance requirements, and increased short-circuit capability. This option also ensures long-term supportability and improves operational flexibility, while better aligning with future system growth requirements including load increases and potential generation interconnections. e) Non-Wires Solutions – Enova reviewed and determined Non-Wires Solutions to be unsuitable for addressing the core issues, which relate to equipment condition, safety, and end of life asset replacement. As such, this option was not considered viable.
Effect on system operation efficiency and cost effectiveness	The replacement of obsolete switchgear with modern equipment will improve operational efficiency by reducing maintenance requirements, minimizing forced outages, and enabling more reliable switching operations. It also reduces lifecycle costs through improved reliability, manufacturer supportability, and lower corrective maintenance requirements.
Net benefits accruing to customers	The project provides customers with improved reliability and reduced outage risk by replacing obsolete, unsupported equipment. Benefits include fewer and shorter interruptions, enhanced system safety, reduced maintenance costs, and improved long-term service continuity through more reliable and supportable switchgear infrastructure.
Impact of Investment on reliability performance (including on the frequency and duration of outages)	The replacement of aging switchgear and circuit breakers reduces the risk of equipment failure that could result in forced outages and extended restoration times. Modern switchgear improves fault interruption performance, operational reliability, and switching capability, thereby reducing both the frequency and duration of outages. Improved maintainability and long-term manufacturer support further reduce the likelihood of prolonged outages associated with delayed repairs or
Scheduling Alternatives	The Kitchener 6TS Switchgear Replacement project is driven by asset condition, safety, and increasing maintenance requirements, which limits flexibility in deferring execution without increasing operational risk. While minor adjustments to the construction schedule may be accommodated through coordination with station operations, contractors, and equipment suppliers, overall timing is constrained by outage requirements and procurement lead times. Deferral of the project would extend reliance on aging equipment, increasing the risk of forced outages, higher maintenance costs, and potential operational restrictions. Enova evaluates scheduling options to balance system reliability risk, safety considerations, and cost impacts, with the objective of executing the project in the most efficient and least disruptive timeframe.
Ownership and/or Funding Alternatives	The transformer station assets associated with this project will remain solely owned and operated by Enova. There are no ownership or funding alternatives associated with this investment.

Safety

The replacement transformer infrastructure will be designed and constructed in accordance with applicable CSA standards, IEEE standards, IEC standards, utility engineering practices, and transmitter and IESO requirements. The replacement of aging station assets improves worker safety by reducing the risks associated with equipment deterioration, equipment failure, and operation of obsolete infrastructure. Modern transformer equipment also incorporates updated protection, monitoring, and operational features that improve the safe operation and maintenance of the station.

Cyber-security, Privacy

The project involves replacement of primary station switchgear and does not introduce customer data collection or privacy impacts. Any associated protection, control, and monitoring systems will be implemented in accordance with Enova's cyber security policies and applicable utility standards to ensure secure and reliable operation of station assets.

Co-ordination, Interoperability

Coordination with utilities, regional planning and/or links with 3rd parties (where applicable)	Enova will coordinate the Kitchener 6TS Switchgear Replacement project with the supplying transmitter, the IESO, and affected internal operational groups to ensure alignment with system outage requirements, protection coordination, and regional planning needs. Coordination with equipment manufacturers and vendors is ongoing to confirm technical specifications, manufacturing schedules, and lead times for switchgear and breakers. Construction and commissioning activities will be planned in collaboration with contractors and station operations to minimize system impacts and ensure safe, reliable execution of the work.
Enabling of future technological functionality or addressing of future operational requirements	The new switchgear increases station short-circuit capability, improving operational flexibility and enabling potential future generation interconnections and system expansion. The upgraded equipment also supports modern protection and control schemes, enhancing compatibility with evolving operational and monitoring requirements within the transmission-connected station environment.

Environmental Benefits

Not Applicable

Non-Wires Solutions Consideration

Enova's consideration of non-wires solutions for this program is documented in accordance with the NWS Guidelines (EB-2024-0118) and the BCA Framework. See details below.

Benefit-Cost Analysis Framework (5.4.2.2.)

Not Applicable (below $2M threshold)

Kitchener 7TS Switchgear Replacement

General Information on the project/program (5.4.2.1.A)

Project Name Kitchener 7TS Switchgear Replacement
Program Code R-SE
OEB Investment Category System Renewal

Project Description

The Kitchener 7TS Switchgear Replacement project involves the replacement of aging switchgear and circuit breakers identified through Enova's ACA program as approaching end-of-life. The existing equipment is obsolete and no longer supported by the manufacturer, with replacement parts and repair services no longer available, significantly increasing operational risk and the potential for extended outages.

The project will replace the existing equipment with modern switchgear and circuit breakers that provide improved reliability, reduced maintenance requirements, enhanced operational flexibility, and higher short-circuit interrupting ratings. The replacement eliminates obsolete, unsupported equipment and restores long-term manufacturer supportability, improving maintainability and reducing the risk of prolonged outages associated with equipment failures. The upgraded infrastructure will improve long-term station performance while supporting future system requirements, including additional load growth and potential generation interconnections.

Detailed SubProjects

The following individual projects are covered by this project category:

EnovaProject	Sub Project	Project Name	Total
R-SE		Kitchener 7TS Switchgear Replacement	$949,905
		Total	$949,905

Capital Investment

Total Capital **$949,905**

O&M Costs (if applicable) **$0** Not Applicable

Capital Contributions to a Transmitter

CCRA Contribution $0

Customer Attachments/Load (kVA)

Customer Attachments (#): 13656
Customer Load (peak kVA) 38000

Project Timing

Start Date June 1, 2027
End Date May 31, 2029

Expected In-Service Date December 31, 2028

Expenditure Timing

2027	100%	$949,905

Schedule Risk and Risk Mitigation

Switchgear replacement projects require coordination with the transmitter, outage planning groups, contractors, and station operations to schedule outages and construction activities while maintaining system reliability. The switchgear and breaker equipment has procurement lead times of approximately 12–16 months, requiring early engagement with manufacturers and ongoing communication regarding production schedules and supply chain risks. Project risks are mitigated through advance equipment procurement, detailed outage planning, coordination with external stakeholders, and regular vendor communication to minimize the potential impacts of global supply chain disruptions and changing market conditions.

Comparative Information

Comparable investments in previous years are as follows:

2020:	$2,622,384
2021:	$2,066,593
2022:	$2,339,449
2023:	$5,920,502
2024:	$7,232,120
2025:	$6,773,375
2026 (Bridge)	$5,769,460

Total Capital & OM&A Costs Associated with REG Investments

Not Applicable

Leave to Construct Approval

Not Applicable

Evaluation Criteria and information requirements for each project/program (5.4.2.1.B)

Efficiency, Customer Value, Reliability

Main Driver	The main driver for the Kitchener 7TS Switchgear Replacement Program is the replacement of aging switchgear and circuit breakers identified through Enova's ACA program as approaching end-of-life.
Related Objectives/Performance Targets	Enova Strategic Objectives: Grid Resiliency, Reliability Performance (SAIDI/SAIFI), Asset Renewal, Operational Sustainability, and Health, Safety and Environment, as identified in the DSP. The project also supports long-term system reliability and operational flexibility through the replacement of obsolete station equipment with modern switchgear technology designed to current utility and industry standards.
Source and Nature of the Information Used to Justify the Investment	The investment is justified through Enova's ACA program, station asset condition assessments, maintenance history, manufacturer support, equipment failure risk analysis, and engineering evaluations identifying the existing switchgear and breakers as approaching end-of-life.
Secondary Driver(s)	Secondary drivers include restoring long-term manufacturer supportability by replacing obsolete switchgear, reducing maintenance requirements, increasing short-circuit interrupting capability, improving operational flexibility, and supporting future load growth and potential generation interconnections.
Good Utility Practice	The switchgear replacement project is designed and executed in accordance with applicable CSA, IEEE, and IEC standards, utility engineering best practices, and transmitter and IESO requirements. The new switchgear and breaker equipment will be installed, tested, and commissioned in accordance with manufacturer specifications and industry-accepted practices to ensure safe and reliable operation. Modern protection, control, grounding, and arc-resistant design features improve worker safety, operational reliability, and long-term maintainability while supporting continued compliance with utility operational and system performance requirements.
Investment Priority	System Access investments are ranked as top priority, as they are mandated by regulation or code. System Renewal assets are prioritized by the health condition of the assets developed through Enova's ACA program. Assets found at risk of imminent failure or high public safety risk are prioritized for immediate replacement. Enova utilizes METSCO's Asset Analysis, Prioritization, and Optimization Methodology to aid in prioritizing Station asset replacement. Assets flagged for replacement are geospatially grouped to create constructible projects. Projects are ranked by taking into account their overall health condition, customer impact, alignment with Enova's Strategic Objectives such as reliability, safety, financial or environmental risk and additional drivers and benefits. The greater the customer impact or the more drivers or benefits that are attributed to a project the higher its priority. Investments in System Service and General Plant categories are prioritized in a similar fashion. Analysis of impact on customers and consideration of impact of project deferral are also considered. The compiled list of projects is reviewed and prioritized by Enova Engineering, Operations, and Finance staff. Based on the outcome of this process, this program ranks 6 out of 25. Refer to the DSP prioritization table for further details.
Analysis of the Project and Project Alternatives	a) Do Nothing – This option would retain aging switchgear and circuit breakers that are approaching end-of-life and would continue to require increasing maintenance effort and cost. This option is not considered viable due to rising operational risk, reduced reliability, and increased likelihood of equipment failure over time. b) Continue Maintenance of Existing Equipment – Continued operation with ongoing maintenance and procurement of available spare parts was evaluated. While parts remain available, the equipment is increasingly costly to maintain and does not address underlying obsolescence, aging insulation systems, or long-term reliability concerns. This option does not provide a sustainable long-term solution. c) Refurbishment/Retrofit of Existing Switchgear – Refurbishment was considered; however, this option would not increase short-circuit interrupting ratings, would not fully address end-of-life insulation conditions, and would retain legacy equipment within the switchgear structure, limiting long-term performance and safety improvements. d) Full Replacement with Modern Switchgear (Preferred Option) – Replacement with modern switchgear and breakers provides improved reliability, enhanced worker safety, reduced maintenance requirements, and increased short-circuit capability. This option also ensures long-term supportability and improves operational flexibility, while better aligning with future system growth requirements including load increases and potential generation interconnections. e) Non-Wires Solutions – Enova reviewed and determined Non-Wires Solutions to be unsuitable for addressing the core issues, which relate to equipment condition, safety, and end of life asset replacement. As such, this option was not considered viable.
Effect on system operation efficiency and cost effectiveness	The replacement of obsolete switchgear with modern equipment will improve operational efficiency by reducing maintenance requirements, minimizing forced outages, and enabling more reliable switching operations. It also reduces lifecycle costs through improved reliability, manufacturer supportability, and lower corrective maintenance requirements.
Net benefits accruing to customers	The project provides customers with improved reliability and reduced outage risk by replacing obsolete, unsupported equipment. Benefits include fewer and shorter interruptions, enhanced system safety, reduced maintenance costs, and improved long-term service continuity through more reliable and supportable switchgear infrastructure.
Impact of Investment on reliability performance (including on the frequency and duration of outages)	The replacement of aging switchgear and circuit breakers reduces the risk of equipment failure that could result in forced outages and extended restoration times. Modern switchgear improves fault interruption performance, operational reliability, and switching capability, thereby reducing both the frequency and duration of outages. Improved maintainability and long-term manufacturer support further reduce the likelihood of prolonged outages associated with delayed repairs or unavailable replacement parts.
Scheduling Alternatives	The Kitchener 7TS Switchgear Replacement project is driven by asset condition, obsolescence, and increasing maintenance requirements, which limits flexibility in deferring execution without increasing operational risk. While minor adjustments to the construction schedule may be accommodated through coordination with station operations, contractors, and equipment suppliers, overall timing is constrained by outage requirements and procurement lead times. Deferral of the project would extend reliance on aging equipment, increasing the risk of forced outages, higher maintenance costs, and potential operational restrictions. Enova evaluates scheduling options to balance system reliability risk, safety considerations, and cost impacts, with the objective of executing the project in the most efficient and least disruptive timeframe.
Ownership and/or Funding Alternatives	The transformer station assets associated with this project will remain solely owned and operated by Enova. There are no ownership or funding alternatives associated with this investment.

Safety

The replacement transformer infrastructure will be designed and constructed in accordance with applicable CSA standards, IEEE standards, IEC standards, utility engineering practices, and transmitter and IESO requirements. The replacement of aging station assets improves worker safety by reducing the risks associated with equipment deterioration, equipment failure, and operation of obsolete infrastructure. Modern transformer equipment also incorporates updated protection, monitoring, and operational features that improve the safe operation and maintenance of the station.

Cyber-security, Privacy

The project involves replacement of primary station switchgear and does not introduce customer data collection or privacy impacts. Any associated protection, control, and monitoring systems will be implemented in accordance with Enova's cyber security policies and applicable utility standards to ensure secure and reliable operation of station assets.

Co-ordination, Interoperability

Coordination with utilities, regional planning and/or links with 3rd parties (where applicable)	Enova will coordinate the Kitchener 7TS Switchgear Replacement project with the supplying transmitter, the IESO, and affected internal operational groups to ensure alignment with system outage requirements, protection coordination, and regional planning needs. Coordination with equipment manufacturers and vendors is ongoing to confirm technical specifications, manufacturing schedules, and lead times for switchgear and breakers. Construction and commissioning activities will be planned in collaboration with contractors and station operations to minimize system impacts and ensure safe, reliable execution of the work.
Enabling of future technological functionality or addressing of future operational requirements	The new switchgear increases station short-circuit capability, improving operational flexibility and enabling potential future generation interconnections and system expansion. The upgraded equipment also supports modern protection and control schemes, enhancing compatibility with evolving operational and monitoring requirements within the transmission-connected station environment.

Environmental Benefits

Not Applicable

Non-Wires Solutions Consideration

Enova's consideration of non-wires solutions for this program is documented in accordance with the NWS Guidelines (EB-2024-0118) and the BCA Framework. See details below.

Benefit-Cost Analysis Framework (5.4.2.2.)

Not Applicable (below $2M threshold)

General Information on the project/program (5.4.2.1.A)

Project Name Kitchener 1TS Relay & RTU Replacement
Program Code R-SE
OEB Investment Category System Renewal

Project Description

The Kitchener 1TS Relay and RTU Replacement project involves the replacement of existing protection relays and remote terminal unit (RTU) identified through Enova's ACA program as end-of-life, with limited to no manufacturer support and reliance on Enova-managed spare parts for continued operation. The current protection and control systems present increasing operational and maintenance risk due to aging technology and reduced supportability.

The project will replace the existing relays and RTU with modern digital protection, control, and communication equipment to improve system reliability, safety, and operational performance. Upgraded systems will enhance situational awareness for the control room, improve protection accuracy and fault response, and strengthen worker and public safety. The new equipment will also support future load growth, enable easier DER integration, and improve interoperability with advanced distribution management systems, including FLISR functionality.

Detailed SubProjects

The following individual projects are covered by this project category:

Enova Project	Sub Project	Project Name	Total
R-SE		Kitchener 1TS Relay and RTU Replacements	**$1,269,994**
		Total	**$1,269,994**

Capital Investment

Total Capital **$1,269,994**

O&M Costs (if applicable) **$0** Not Applicable

Capital Contributions to a Transmitter

CCRA Contribution $0

Customer Attachments/Load (kVA)

Customer Attachments (#): 3855
Customer Load (peak kVA) 29000

Project Timing

Start Date November 1, 2026 Engineering & Procurement
End Date December 31, 2027 Construction

Expected In-Service Date December 31, 2027

Expenditure Timing

2027	100%	$1,269,994

Schedule Risk and Risk Mitigation

Relay and RTU replacement projects require coordination with station operations, outage planning groups, the transmitter, and contractors to schedule outages and commissioning activities while maintaining system reliability. Protection relays and RTU equipment currently have typical procurement lead times of approximately two months, with panel fabrication requiring approximately four months. However, supply chain disruptions and semiconductor shortages have previously resulted in significantly extended delivery timelines. Project risks are mitigated through early equipment procurement, ongoing communication with manufacturers and panel builders, advance outage coordination, and detailed construction and commissioning planning to minimize schedule impacts and operational risk.

Comparative Information

Comparable investments in previous years are as follows:

2020:	$2,622,384
2021:	$2,066,593
2022:	$2,339,449
2023:	$5,920,502
2024:	$7,232,120
2025:	$6,773,375
2026 (Bridge):	$5,769,460

Total Capital & OM&A Costs Associated with REG Investments

Not Applicable

Leave to Construct Approval

Not Applicable

Evaluation Criteria and information requirements for each project/program (5.4.2.1.B)

Efficiency, Customer Value, Reliability

Main Driver	The main driver for the Kitchener 1TS Relay and RTU Replacement project is the replacement of aging protection relays and RTU equipment identified through Enova's ACA program as approaching end-of-life.
Related Objectives/Performance Targets	Enova Strategic Objectives: Asset Renewal, Reliability Performance (SAIDI/SAIFI), Grid Resiliency, Operational Sustainability, and Health, Safety and Environment, as identified in the DSP.
Source and Nature of the Information Used to Justify the Investment	The source of the information used to justify this investment includes Enova's ACA program, protection system condition assessments, asset maintenance history, engineering evaluations, equipment age, manufacturer supportability, spare parts availability, and operational risk assessments. The project was identified through Enova's asset management process as the existing protection relays and RTU equipment are approaching end-of-life and present an increasing risk to the reliable operation of the station.
Secondary Driver(s)	Secondary drivers include replacing aging equipment with modern protection relays and RTU equipment that address equipment obsolescence and limited manufacturer support, improve interoperability with Enova's DMS applications including FLISR, enhance control room situational awareness, reduce maintenance requirements, improve worker safety, and provide a standardized platform that supports future system automation, load growth, and DER integration.
Good Utility Practice	The relay and RTU replacement project is designed and executed in accordance with applicable standards, utility engineering best practices, and transmitter and IESO requirements. The new protection, control, and communication equipment will be configured, tested, and commissioned in accordance with manufacturer specifications and industry-accepted protection and control practices to ensure safe and reliable operation. Modern digital relays and RTU systems improve system monitoring, protection coordination, fault response, and interoperability with existing operational systems while supporting current cybersecurity, operational, and reliability requirements for transmission-connected station infrastructure.
Investment Priority	System Access investments are ranked as top priority, as they are mandated by regulation or code. System Renewal assets are prioritized by the health condition of the assets developed through Enova's ACA program. Assets found at risk of imminent failure or high public safety risk are prioritized for immediate replacement. Enova utilizes METSCO's Asset Analysis, Prioritization, and Optimization Methodology to aid in prioritizing Station asset replacement. Assets flagged for replacement are geospatially grouped to create constructible projects. Projects are ranked by taking into account their overall health condition, customer impact, alignment with Enova's Strategic Objectives such as reliability, safety, financial or environmental risk and additional drivers and benefits. The greater the customer impact or the more drivers or benefits that are attributed to a project the higher its priority. Investments in System Service and General Plant categories are prioritized in a similar fashion. Analysis of impact on customers and consideration of impact of project deferral are also considered. The compiled list of projects is reviewed and prioritized by Enova Engineering, Operations, and Finance staff. Based on the outcome of this process, this program ranks 6 out of 25. Refer to the DSP prioritization table for further details.
Analysis of the Project and Project Alternatives	Enova considered the following alternatives for the Kitchener 1TS Relay and RTU Replacement project: a) Do Nothing – This option would retain aging protection relays and RTU equipment with limited manufacturer support, increasing the risk of equipment failure, reduced system visibility, and operational limitations. This option was not considered acceptable due to increasing reliability and maintenance risks. b) Continue Maintenance of Existing Equipment – Continued operation using Enova-managed spare inventory was evaluated, however, this approach relies on aging technology with declining long-term supportability and increasing operational risk. c) Full Replacement with Modern Digital Protection and Control Equipment (Preferred Option) – Replacement with modern relays and RTU equipment improves reliability, protection performance, situational awareness, interoperability with DMS applications including FLISR, worker safety, and long-term supportability while supporting future load growth and DER integration requirements.
Effect on system operation efficiency and cost effectiveness	Modern digital relays and RTU equipment will improve operational efficiency through enhanced system monitoring, faster fault identification, improved protection performance, and better interoperability with DMS applications. The project also reduces maintenance requirements and operational risk associated with aging and unsupported protection and control equipment.
Net benefits accruing to customers	The project provides customers with improved reliability, faster fault response, enhanced system monitoring, and reduced outage risk through modernized protection and control systems. Additional benefits include improved operational flexibility, enhanced safety, reduced maintenance requirements, and better support for future load growth and DER integration.
Impact of Investment on reliability performance (including on the frequency and duration of outages)	Modern protection relays and RTU equipment improve fault detection, protection coordination, and system visibility, reducing the likelihood of protection failures and improving outage response times. Enhanced monitoring and interoperability with DMS applications support faster restoration efforts, reducing both the frequency and duration of customer outages.
Scheduling Alternatives	The Kitchener 1TS Relay and RTU Replacement project requires coordination with station operations, engineering, the transmitter, and outage planning groups to align installation and commissioning activities with available outage windows. While schedule adjustments may be accommodated, overall project timing is constrained by protection system integration requirements, testing sequences, and equipment procurement and panel fabrication lead times. Deferral of the project would extend reliance on aging, end-of-life protection and control systems, increasing operational risk, reducing system visibility, and limiting flexibility in managing system disturbances. Enova evaluates scheduling alternatives to balance system reliability risk, safety requirements, and implementation constraints, ensuring timely and effective project execution.
Ownership and/or Funding Alternatives	The transformer station assets associated with this project will remain solely owned and operated by Enova. There are no ownership or funding alternatives associated with this investment.

Safety

The replacement of aging protection relays and RTU equipment improves worker and public safety by reducing the risk of protection misoperation, equipment failure, and delayed fault clearance associated with obsolete systems. Modern digital relays provide enhanced protection accuracy, diagnostics, and monitoring capabilities, improving safe operation of the station. The upgraded RTU improves real-time system visibility for operators, supporting safer decision-making. Installation and commissioning will be completed in accordance with applicable CSA standards and utility safety practices.

Cyber-security, Privacy

The project involves replacement of protection relays and RTU equipment and does not introduce any customer data collection or privacy impacts. New digital relays and RTU systems will be implemented in accordance with Enova's cyber security policies and applicable utility and industry standards to ensure secure communication, controlled access, and protection of critical infrastructure systems.

Co-ordination, Interoperability

Coordination with utilities, regional planning and/or links with 3rd parties (where applicable)	Enova will coordinate the Kitchener 1TS Relay and RTU Replacement project with the supplying transmitter, the IESO, internal engineering teams, and operations staff to ensure alignment with system outage requirements, protection coordination, and commissioning activities. Coordination with equipment manufacturers and panel builders is ongoing to confirm technical specifications, fabrication requirements, and delivery schedules. Construction and commissioning activities will be planned in collaboration with engineering and station operations to minimize system impacts and ensure safe, reliable execution of the work.
Enabling of future technological functionality or addressing of future operational requirements	The upgraded relays and RTU improve system flexibility and support future operational requirements, including enhanced SCADA integration, improved protection schemes, and interoperability with DMS applications such as FLISR. The modernization also supports increased load growth and potential DER integration through improved system visibility and control capabilities.

Environmental Benefits

Not Applicable

Non-Wires Solutions Consideration

Enova's consideration of non-wires solutions for this program is documented in accordance with the NWS Guidelines (EB-2024-0118) and the BCA Framework. See details below.

Benefit-Cost Analysis Framework (5.4.2.2.)

Not Applicable (below $2M threshold)

General Information on the project/program (5.4.2.1.A)

Project Name Station Equipment - Expansion
Program Code E-SE
OEB Investment Category System Access

Project Description

The Enova 11TS project involves the construction of a new 150 MVA Transformer Station to provide transformation capacity for a significant customer-driven load expansion. The project is required to meet the customer's forecasted electrical demand, which exceeds the available capacity on the existing distribution system and cannot be accommodated by existing station infrastructure.

The overall project includes the construction of a new transformer station complete with power transformers, HV circuit breakers, MV switchgear, protection and control systems, communications, station service equipment, and associated station infrastructure.

The 2027 investment is focused on the procurement of long lead-time equipment, specifically the power transformers and HV circuit breakers, to support the planned construction schedule and ensure the station can be commissioned within the required customer in-service timeline. The remaining station infrastructure will be procured and constructed in subsequent years as part of the overall project.

Detailed SubProjects

The following individual projects are covered by this project category:

Enova Project	Sub Project	Project Name	Total
R-SE		Enova 11TS Expansion - Equipment	**$2,279,916**
		Total	**$2,279,916**

Capital Investment

Total Capital **$2,279,916**

O&M Costs (if applicable) **$0** Not Applicable

Capital Contributions to a Transmitter

CCRA Contribution $0

Customer Attachments/Load (kVA)

Customer Attachments (#): 8
Customer Load (peak kVA) 150000

Project Timing

Start Date January 1, 2027
End Date December 31, 2031

Expected In-Service Date December 31, 2031

Expenditure Timing

2027	100%	$2,279,916

Schedule Risk and Risk Mitigation

The Enova 11TS project is dependent on the timely procurement of long lead-time equipment, particularly the power transformers and HV circuit breakers, which are critical path items for the overall station construction schedule. Current procurement lead times for large power transformers are approximately four years, while high-voltage circuit breakers have lead times of approximately three years. Delays in securing manufacturing capacity or equipment delivery could significantly impact the overall project schedule and the ability to meet the customer's required in-service date.

Schedule risks are mitigated by initiating procurement of these long lead-time assets well in advance of station construction, allowing manufacturers to reserve production capacity and ensuring equipment delivery aligns with the planned construction schedule. Enova will continue to actively monitor procurement activities, maintain regular communication with equipment manufacturers, and coordinate engineering and construction activities to minimize schedule risk and support timely project completion.

Comparative Information

Comparable investments in previous years are as follows:

2020:	N/A
2021:	N/A
2022:	N/A
2023:	N/A
2024:	N/A
2025:	N/A
2026 (Bridge):	N/A

Total Capital & OM&A Costs Associated with REG Investments Not Applicable

Leave to Construct Approval Not Applicable

Evaluation Criteria and information requirements for each project/program (5.4.2.1.B)

Efficiency, Customer Value, Reliability

Main Driver	The main driver for the Enova 11TS project is Enova's obligation under the OEB Act, the Distribution System Code, and Enova's Conditions of Service to provide distribution service to a customer requesting connection where existing infrastructure cannot accommodate the requested electrical demand.
Related Objectives/Performance Targets	Enova Strategic Objectives: Customer Service, Capacity for Growth, Grid Resiliency, Reliability Performance (SAIDI/SAIFI), and Health, Safety and Environment, as identified in the DSP.
Source and Nature of the Information Used to Justify the Investment	The source of the information used to justify this investment is the customer's request for electrical service, supported by customer load forecasts, distribution system planning studies, and engineering assessments confirming that the requested demand cannot be accommodated by the existing distribution system. Project scope and timing are driven by the customer's required in-service date and applicable regulatory requirements, including the OEB Act, the DSC, and Enova's Conditions of Service.
Secondary Driver(s)	Secondary drivers include maintaining compliance with Enova's planning criteria, preserving the reliability and operational performance of the existing distribution system, increasing transformation capacity, improving operational flexibility, and providing infrastructure capable of supporting future customer growth and evolving system requirements.
Good Utility Practice	The Enova 11TS project will be designed and constructed in accordance with Good Utility Practice, applicable CSA, IEEE, and IEC standards, Hydro One transmission connection requirements, IESO requirements, and Enova's engineering standards. The new transformer station will incorporate modern standardized equipment, protection and control systems, and communications infrastructure designed to provide safe, reliable, and maintainable operation throughout the asset's service life. All major equipment will be manufactured, tested, and commissioned in accordance with applicable industry standards and manufacturer specifications.
Investment Priority	System Access investments are ranked as top priority, as they are mandated by regulation or code. System Renewal assets are prioritized by the health condition of the assets developed through Enova's ACA program. Assets found at risk of imminent failure or high public safety risk are prioritized for immediate replacement. Enova utilizes METSCO's Asset Analysis, Prioritization, and Optimization Methodology to aid in prioritizing Station asset replacement. Assets flagged for replacement are geospatially grouped to create constructible projects. Projects are ranked by taking into account their overall health condition, customer impact, alignment with Enova's Strategic Objectives such as reliability, safety, financial or environmental risk and additional drivers and benefits. The greater the customer impact or the more drivers or benefits that are attributed to a project the higher its priority. Investments in System Service and General Plant categories are prioritized in a similar fashion. Analysis of impact on customers and consideration of impact of project deferral are also considered. The compiled list of projects is reviewed and prioritized by Enova Engineering, Operations, and Finance staff. Based on the outcome of this process, this program ranks 1 out of 25. Refer to the DSP prioritization table for further details.
Analysis of the Project and Project Alternatives	System Access investments are driven by Enova's obligation under the Ontario Energy Board Act, the Distribution System Code, and Enova's Conditions of Service to provide distribution service when a customer requests connection and the applicable requirements are met. While the obligation to provide service is established through regulation, Enova evaluates alternative technical solutions to determine the most appropriate and cost-effective means of meeting the customer's service requirements. For the Enova 11TS project, Enova assessed the capability of the existing distribution system to accommodate the requested load, including opportunities to utilize or expand existing station capacity. Engineering assessments determined that the customer's requested demand could not be accommodated by the existing distribution system while maintaining compliance with Enova's planning criteria. Accordingly, construction of a new transformer station was identified as the preferred technical solution. The 2027 investment specifically supports the procurement of long lead-time power transformers and high-voltage circuit breakers required to maintain the overall project schedule and meet the customer's required in-service date.
Effect on system operation efficiency and cost effectiveness	The Enova 11TS project will improve system operating efficiency by providing dedicated transformation capacity to serve a significant customer-driven load expansion while maintaining the loading of existing transformer stations within planning limits. The new station will incorporate modern, standardized equipment that improves operational flexibility, reduces long-term maintenance requirements, and enhances asset reliability. Procuring long lead-time equipment in advance of construction also supports cost-effective project delivery by reducing schedule risk and helping to avoid delays associated with extended manufacturing lead times.
Net benefits accruing to customers	The project provides customers with the transformation capacity required to support significant customer-driven load growth while maintaining the reliability and performance of the existing distribution system. Additional benefits include increased system capacity, improved operational flexibility, enhanced long-term reliability through modern station infrastructure, and the ability to accommodate future growth while maintaining compliance with Enova's planning criteria.
Impact of Investment on reliability performance (including on the frequency and duration of outages)	The project is expected to maintain the reliability performance of Enova's distribution system as customer demand increases by providing sufficient transformation capacity to serve new load without adversely affecting existing customers. The additional station capacity and modern station infrastructure will improve operational flexibility and system resilience, supporting planned and unplanned system operations while helping to maintain current reliability performance over the long term.
Scheduling Alternatives	The Enova 11TS project schedule is driven by the customer's required in-service date and the extended procurement lead times for major station equipment. Power transformers and HV circuit breakers are critical path items with current lead times of approximately four years and three years, respectively. As a result, procurement of these assets must occur well in advance of station construction to maintain the overall project schedule. Deferring the procurement of these long lead-time components would delay the overall project schedule, increase the risk of missing the customer's required in-service date, and could result in additional costs associated with extended project timelines and changing market conditions. Enova has evaluated scheduling alternatives and determined that early procurement of critical equipment, combined with coordinated engineering, transmission connection activities, and construction planning, represents the most effective approach to minimize schedule risk and support timely project delivery.
Ownership and/or Funding Alternatives	The transformer station assets associated with this project will be owned, operated, and maintained by Enova as part of its regulated distribution system. In accordance with Enova's Conditions of Service and applicable Ontario regulatory requirements, the connecting customer will provide a capital contribution toward the station expansion. During the planning process, Enova worked collaboratively with the customer and Hydro One to evaluate both distribution-connected and transmission-connected service options. Hydro One identified that a direct transmission connection was a feasible alternative; however, this option would have required the customer to assume the responsibilities associated with being a transmission-connected market participant. Following this evaluation, the customer elected to pursue a distribution connection. The customer's development plans were subsequently refined to align with the approximately 150 MVA of transformation capacity that can be provided through Enova's distribution system. Although the project was originally planned to serve a single large customer load, the customer may elect to allocate portions of its 150 MVA capacity allocation to other development within the project area, such as commercial or residential uses, provided the total demand remains within the overall station allocation. Ownership alternatives were considered during the planning process. A transmission-connected solution owned by Hydro One was identified as a feasible alternative. However, based on Enova's existing distribution infrastructure, available property, and known costs associated with expanding its distribution system, Enova determined that a transmission-connected solution owned and operated by Enova represented the preferred approach to meet the customer's service requirements. The transformer station assets will therefore be owned, operated, and maintained by Enova as part of its regulated distribution system.

Safety

The Enova 11TS project will improve worker and public safety through the construction of a new transformer station designed in accordance with Good Utility Practice and applicable industry standards. The station will incorporate modern equipment, protection and control systems, and engineered safety features that reduce operational risk and support the safe operation and maintenance of the facility throughout its service life.

Modern station design will include appropriate equipment clearances, grounding systems, arc-resistant equipment where applicable, physical security measures, and protection systems designed to rapidly detect and isolate faults. All equipment will undergo factory and site acceptance testing prior to being placed into service, and construction and commissioning activities will be completed in accordance with Enova's safety procedures and applicable utility standards and practices.

Cyber-security, Privacy

The Enova 11TS project includes the implementation of modern protection, control, communications, telemetry, and Dynamic Data Reporting (DDR) systems to satisfy applicable Hydro One and IESO connection and operational requirements. The project does not introduce any new customer privacy impacts beyond the collection and transmission of operational data required for the safe and reliable operation of the electrical system.

The station's operational technology systems will be designed and implemented in accordance with Enova's cybersecurity policies, applicable industry standards, and utility best practices. Appropriate cybersecurity controls, including secure network architecture, controlled system access, network segmentation, authentication, and system hardening, will be incorporated to protect critical infrastructure and ensure the secure exchange of operational data throughout the asset's service life.

Co-ordination, Interoperability

Coordination with utilities, regional planning and/or links with 3rd parties (where applicable)	Enova will coordinate the Enova 11TS project with the connecting customer, Hydro One, the IESO, internal engineering and operations teams, and other stakeholders throughout the planning, design, procurement, construction, and commissioning phases. Coordination activities include transmission connection planning, protection and telecommunications requirements, DDR implementation, system studies, and the development of construction and energization plans. Enova will also work closely with equipment manufacturers, engineering consultants, and construction contractors to confirm technical specifications, manufacturing schedules, and delivery of long lead-time equipment. Ongoing coordination will ensure the project remains aligned with customer in-service requirements, transmission connection requirements, and the overall project schedule while supporting the safe and reliable integration of the new transformer station into the distribution system.
Enabling of future technological functionality or addressing of future operational requirements	The Enova 11TS project will incorporate modern protection, control, automation, communications, and telemetry systems designed to support current and future operational requirements. The station will be fully integrated with Enova's SCADA and operational systems and will satisfy applicable Hydro One and IESO operational and DDR requirements. The station has been designed to accommodate the customer's anticipated long-term load growth while providing a scalable platform for future system enhancements, including additional monitoring, automation, and evolving grid operational requirements. The use of standardized modern station equipment will also support long-term maintainability, interoperability, and future technology upgrades throughout the asset's service life.

Environmental Benefits

Not Applicable

Non-Wires Solutions Consideration

Enova's consideration of non-wires solutions for this program is documented in accordance with the NWS Guidelines (EB-2024-0118) and the BCA Framework. See details below.

Benefit-Cost Analysis Framework (5.4.2.2.)

In accordance with the OEB's Benefit-Cost Analysis Framework (May 2024), Enova completed a screening assessment of Non-Wires Solution (NWS) viability for this project. The screening concluded that an NWS is not a viable alternative because the project is required to provide new transformation capacity to accommodate a significant customer-driven load expansion. The magnitude of the required capacity and the customer's required in-service timeline cannot be practically or reliably addressed through non-wires alternatives. Refer to the NWS Screening Assessment appendix of this DSP for additional details.

Relocations - Special Projects

General Information on the project/program (5.4.2.1.A)

Project Name Relocations - Special Projects
Program Code E-SP
OEB Investment Category System Access

Project Description

This category represents capital expenditures required to comply with statutory obligations related to the relocation of overhead and underground facilities installed within municipal or provincial road allowances. Unlike projects that fall under the Public Service Works on Highways Act (PSWHA), this program includes projects where an alternative cost arrangement is followed. The road authority may request Enova to replace aged overhead plant with underground, the road authority funds the cost difference between overhead and underground systems, typically between 75%-85% of total project cost, otherwise the cost recovery reaches up to 100%.

Detailed SubProjects

The following individual projects are covered by this project category:

Enova Project	Sub Project	Project Name	Total
E-SP		Pioneer Tower Rd - Baxter Pl to Pioneer Ridge Dr	$606,288
E-SP		Grand River Crossing @ Lookout Lane Construction	$299,253
E-SP		Lancaster St - Bridgeport Rd to Bridge St W	$612,696
E-SP		Lancaster St - Elizabeth St to Wellington St	$683,392
E-SP		Queens Blvd - Belmont Ave to Westmount Rd	$351,880
E-SP		Spadina Rd W - Belmont Ave to Patricia Ave	$35,901
E-SP		Barnswallow Dr - Church St to First St	$376,029
E-SP		East Side Trunk Sewer - Lookout Lane DB	$165,814
		Total	$3,131,253

Capital Investment

Total Capital **$3,131,253**

O&M Costs (if applicable) **$0** Not Applicable

Capital Contributions to a Transmitter

CCRA Contribution $0

Customer Attachments/Load (kVA)

Customer Attachments (#): 7508
Customer Load (peak kVA) 32083

Project Timing

Start Date January 1, 2027 Engineering
End Date December 31, 2027 Construction

Expected In-Service Date December 1, 2027

Expenditure Timing

2027 Q1	20%	$626,251
2027 Q2	30%	$939,376
2027 Q3	30%	$939,376
2027 Q4	20%	$626,251

Schedule Risk and Risk Mitigation

Relocation projects under this program are driven by municipal construction schedules that are outside of Enova's control. The timing of Enova's work must align with the municipality's construction schedule. Delays in municipal road construction can result in the deferral of associated electrical relocation work to subsequent years.

Enova coordinates with the area Utility Coordinating Council and municipal staff to exchange project details and align construction timing.

Comparative Information

Comparable investments in previous years are as follows:

2020:	$0
2021:	$2,946
2022:	$0
2023:	$0
2024:	$0
2025:	$0
2026 (Bridge):	$3,322,237

Total Capital & OM&A Costs Associated with REG Investments

Not Applicable

Leave to Construct Approval

Not Applicable

Evaluation Criteria and information requirements for each project/program (5.4.2.1.B)

Efficiency, Customer Value, Reliability

Main Driver	The main driver for this program is the statutory obligation to relocate distribution facilities when directed by municipal road authorities.
Related Objectives/Performance Targets	Enova Strategic Priorities: Grid Resiliency (SAIDI/SAIFI targets) and Health, Safety and Environment, as identified in the DSP.
Source and Nature of the Information Used to Justify the Investment	The source of the information used to justify this investment is the external requests from municipal road authorities, developers, or customers that trigger the obligation to undertake this work. Project scope and timing are determined by the external party's construction schedule and applicable regulatory requirements (PSWHA, DSC, Conditions of Service).
Secondary Driver(s)	Not Applicable
Good Utility Practice	Enova utilizes Utility Standards Forum (USF) design standards. Construction is performed in accordance with applicable CSA, ESA, and OEB requirements. Enova coordinates with municipal authorities and other utilities through the Utility Coordinating Council process.
Investment Priority	System Access investments are ranked as top priority, as they are mandated by regulation or code. This program ranks 1 out of 25. Refer to the DSP prioritization table for further details.
Analysis of the Project and Project Alternatives	System Access investments are driven by statutory, regulatory or other obligations. Enova is obligated to undertake this work when directed by the applicable authority or when a customer connection request is received. Alternatives are limited to the technical design of the required infrastructure. Where applicable, Enova evaluates the most cost-effective design approach including the choice of overhead versus underground construction, conductor sizing, and equipment selection.
Effect on system operation efficiency and cost effectiveness	System Access investments comply with statutory obligations and do not directly target system efficiency improvements. However, new infrastructure is built to current standards which may provide incremental operational benefits.
Net benefits accruing to customers	The renewal of this infrastructure will have the following benefits: the aversion of potentially adverse effects on reliability and safety, avoidance of an increase to maintenance costs, and where applicable, provide for increased flexibility of the system via harmonization of distribution voltages, a decrease in line losses, and an increase in capacity for connection of DERs.
Impact of Investment on reliability performance (including on the frequency and duration of outages)	These projects ensure the elimination of safety hazards and that reliability is maintained. Additionally, the standards to which assets must be built today compared to the existing assets ensures they are able to withstand more adverse weather conditions and increases the clearances around the conductors to assist in reducing both the frequency and duration of outages.
Scheduling Alternatives	System Renewal investments are instrumental in reducing the risk of critical asset failures, maintaining reliability and safety performance measures and keeping expensive reactive maintenance activities to a minimum. Scheduling changes within the calendar year due to weather, coordination with third parties and resource constraints can usually be accommodated for smaller projects. Rescheduling larger projects can increase costs due to the reassignment of labour and materials and the risk of asset failure. Enova evaluates the risk and cost of rescheduling any project to achieve the most cost effective outcome.
Ownership and/or Funding Alternatives	These projects are constructed in the public right-of-way and will consist solely of Enova's assets. There are no ownership or funding alternatives.

Safety

New construction is built to current CSA and ESA safety standards, which provide improved public and worker safety compared to the legacy infrastructure being replaced or modified.

Cyber-security, Privacy

Not Applicable

Co-ordination, Interoperability

Coordination with utilities, regional planning and/or links with 3rd parties (where applicable)	Enova will meet with the area Utility Coordinating Council and municipal staff (where applicable) as well as third party stakeholders to exchange project details to coordinate construction. This coordination typically occurs in Q3-Q4 of the year preceding construction.
Enabling of future technological functionality or addressing of future operational requirements	New infrastructure is built to current standards which facilitate the future incorporation of grid modernization equipment, DER connections, and smart grid devices.

Environmental Benefits

Not Applicable

Non-Wires Solutions Consideration

Enova's consideration of non-wires solutions for this program is documented in accordance with the NWS Guidelines (EB-2024-0118) and the BCA Framework. See details below.

Benefit-Cost Analysis Framework (5.4.2.2.)

In accordance with the OEB's BCA Framework (May 2024), Enova conducted a pre-assessment of non-wires solution (NWS) viability for this program. The pre-assessment concluded that NWS is not a viable alternative because the system need is driven by asset condition, not capacity constraint. Refer to the NWS Pre-Assessment appendix of this DSP for details.

General Information on the project/program (5.4.2.1.A)

Project Name Relocations - Routine Projects
Program Code E-RP
OEB Investment Category System Access

Project Description

This category represents capital expenditures required to comply with statutory obligations related to the relocation of overhead and underground facilities installed within municipal or provincial road allowances. Based on a legislated cost sharing formula under the Public Service Works on Highways Act (PSWHA), road authority contributes 50% of labour and labour saving devices.

Detailed SubProjects

The following individual projects are covered by this project category:

Enova Project	Sub Project	Project Name	Total
E-RP		Reidel Dr - New Dundee Rd to Stauffler Pl	$200,639
E-RP		River Rd Extension - Chandaria Pl to Wabanaki Dr	$199,402
E-RP		University Ave E - Weber St N to Albert St	$327,180
		Total	$727,221

Capital Investment

Total Capital **$727,221**

O&M Costs (if applicable) **$0** Not Applicable

Capital Contributions to a Transmitter

CCRA Contribution $0

Customer Attachments/Load (kVA)

Customer Attachments (#): 1050
Customer Load (peak kVA) 4645

Project Timing

Start Date January 1, 2027
End Date December 31, 2027

Expected In-Service Date December 1, 2027

Expenditure Timing

2027 Q1	20%	$145,444
2027 Q2	30%	$218,166
2027 Q3	30%	$218,166
2027 Q4	20%	$145,444

Schedule Risk and Risk Mitigation

PSWHA relocation projects are driven by municipal road authority construction schedules. Enova's work must be coordinated with the road authority's construction timeline. The primary scheduling risk is changes to the municipal construction schedule, which can result in either acceleration or deferral of electrical relocation work.

Enova coordinates with the Region of Waterloo and local municipal and township staff through the Utility Coordinating Council process.

Comparative Information

Comparable investments in previous years are as follows:

2020:	$3,758,854
2021:	$2,303,049
2022:	$2,498,884
2023:	$597,495
2024:	$2,394,508
2025:	$3,511,107
2026 (Bridge):	$1,387,675

Total Capital & OM&A Costs Associated with REG Investments

Not Applicable

Leave to Construct Approval

Not Applicable

Evaluation Criteria and information requirements for each project/program (5.4.2.1.B)

Efficiency, Customer Value, Reliability

Main Driver	The main driver for this program is the statutory obligation to relocate distribution facilities under the Public Service Works on Highways Act (PSWHA).
Related Objectives/Performance Targets	Enova Strategic Objectives: Grid Resiliency (SAIDI/SAIFI targets) and Health, Safety and Environment, as identified in the DSP.
Source and Nature of the Information Used to Justify the Investment	The source of the information used to justify this investment is the external requests from municipal road authorities, developers, or customers that trigger the obligation to undertake this work. Project scope and timing are determined by the external party's construction schedule and applicable regulatory requirements (PSWHA, DSC, Conditions of Service).
Secondary Driver(s)	Not Applicable
Good Utility Practice	Enova utilizes Utility Standards Forum (USF) design standards. Construction is performed in accordance with applicable CSA, ESA, and OEB requirements. Enova coordinates with municipal authorities and other utilities through the Utility Coordinating Council process.
Investment Priority	System Access investments are ranked as top priority, as they are mandated by regulation or code. This program ranks 1 out of 25. Refer to the DSP prioritization table for further details.
Analysis of the Project and Project Alternatives	System Access investments are driven by statutory, regulatory or other obligations. Enova is obligated to undertake this work when directed by the applicable authority or when a customer connection request is received. Alternatives are limited to the technical design of the required infrastructure. Where applicable, Enova evaluates the most cost-effective design approach including the choice of overhead versus underground construction, conductor sizing, and equipment selection.
Effect on system operation efficiency and cost effectiveness	System Access investments comply with statutory obligations and do not directly target system efficiency improvements. However, new infrastructure is built to current standards which may provide incremental operational benefits.
Net benefits accruing to customers	The renewal of this infrastructure will have the following benefits: the aversion of potentially adverse effects on reliability and safety, avoidance of an increase to maintenance costs, and where applicable, provide for increased flexibility of the system via harmonization of distribution voltages, a decrease in line losses, and an increase in capacity for connection of DERs.
Impact of Investment on reliability performance (including on the frequency and duration of outages)	These projects ensure the elimination of safety hazards and that reliability is maintained. Additionally, the standards to which assets must be built today compared to the existing assets ensures they are able to withstand more adverse weather conditions and increases the clearances around the conductors to assist in reducing both the frequency and duration of outages.
Scheduling Alternatives	System Renewal investments are instrumental in reducing the risk of critical asset failures, maintaining reliability and safety performance measures and keeping expensive reactive maintenance activities to a minimum. Scheduling changes within the calendar year due to weather, coordination with third parties and resource constraints can usually be accommodated for smaller projects. Rescheduling larger projects can increase costs due to the reassignment of labour and materials and the risk of asset failure. Enova evaluates the risk and cost of rescheduling any project to achieve the most cost effective outcome.
Ownership and/or Funding Alternatives	These projects are constructed in the public right-of-way and will consist solely of Enova's assets. There are no ownership or funding alternatives.

Safety

New construction is built to current CSA and ESA safety standards, which provide improved public and worker safety compared to the legacy infrastructure being replaced or modified.

Cyber-security, Privacy

Not Applicable

Co-ordination, Interoperability

Coordination with utilities, regional planning and/or links with 3rd parties (where applicable)	Enova will meet with the area Utility Coordinating Council and municipal staff (where applicable) as well as third party stakeholders to exchange project details to coordinate construction. This coordination typically occurs in Q3-Q4 of the year preceding construction.
Enabling of future technological functionality or addressing of future operational requirements	New infrastructure is built to current standards which facilitate the future incorporation of grid modernization equipment, DER connections, and smart grid devices.

Environmental Benefits

Not Applicable

Non-Wires Solutions Consideration

Enova's consideration of non-wires solutions for this program is documented in accordance with the NWS Guidelines (EB-2024-0118) and the BCA Framework. See details below.

Benefit-Cost Analysis Framework (5.4.2.2.)

Not Applicable (below $2M threshold)

General Information on the project/program (5.4.2.1.A)

Project Name OH Line Expansions
Program Code E-OL
OEB Investment Category System Access

Project Description

This program covers the expansion of the overhead distribution system to serve new load or to extend service to areas not currently reached by the existing overhead network. Projects include new overhead line extensions, additional feeder circuits, and system reinforcement where existing overhead capacity is insufficient to serve approved new connections.

Overhead expansion projects are driven by customer connection requests, municipal planning approvals, and the need to maintain adequate system capacity in growing areas of the service territory.

Detailed SubProjects

The following individual projects are covered by this project category:

Project	Sub Project	Project Name	Total
E-OL		Lundy Rd - Katherine St to Halm Rd	$699,316
E-OL		Strasburg Rd - Robert Ferrie Dr to New Dundee Rd	$29,205
		Total	$728,522

Capital Investment

Total Capital **$728,522**

O&M Costs (if applicable) **$0** Not Applicable

Capital Contributions to a Transmitter

CCRA Contribution $0

Customer Attachments/Load (kVA)

Customer Attachments (#): 0
Customer Load (peak kVA) 0

Project Timing

Start Date January 1, 2027 Engineering
End Date December 31, 2027 Construction

Expected In-Service Date December 1, 2027

Expenditure Timing

2027 Q1	20%	$145,704
2027 Q2	30%	$218,556
2027 Q3	30%	$218,556
2027 Q4	20%	$145,704

Schedule Risk and Risk Mitigation

Overhead expansion projects are generally driven by customer connection requests and must be completed within the timelines specified in the Distribution System Code. The primary scheduling risk is the coordination of right-of-way approvals and construction permits with municipal authorities.

Comparative Information

Comparable investments in previous years are as follows:

2020:	$1,456,157
2021:	$764,075
2022:	$607,728
2023:	$970,599
2024:	$638,364
2025:	$3,816,719
2026 (Bridge):	$976,434

Total Capital & OM&A Costs Associated with REG Investments Not Applicable

Leave to Construct Approval Not Applicable

Evaluation Criteria and information requirements for each project/program (5.4.2.1.B)

Efficiency, Customer Value, Reliability

Main Driver	The main driver for this program is the obligation to extend distribution service to customers requesting connection within Enova's licensed service territory.
Related Objectives/Performance Targets	Enova Strategic Objectives: Grid Resiliency (SAIDI/SAIFI targets) and Health, Safety and Environment, as identified in the DSP.
Source and Nature of the Information Used to Justify the Investment	The source of the information used to justify this investment is the external requests from municipal road authorities, developers, or customers that trigger the obligation to undertake this work. Project scope and timing are determined by the external party's construction schedule and applicable regulatory requirements (PSWHA, DSC, Conditions of Service).
Secondary Driver(s)	Not Applicable
Good Utility Practice	Enova utilizes Utility Standards Forum (USF) design standards. These standards are based on CSA C22.3 No 1-15 Overhead Systems Heavy Weather Loading design standards. Newer construction standards and materials provide for more weather resilient assets to help maintain safety and reliability. Enova overhead designs facilitate the future incorporation of grid modernization equipment and renewable energy generation. Enova conducts annual inspection and testing programs, evaluates the results and reprioritizes the replacement of assets if required. Although pole condition is normally the main driver for overhead renewal projects, other assets such as transformers, insulators, wire, and arrestors are also replaced as part of pole line rebuild. These assets are nearing end of life and would not normally survive a second life cycle. Replacing these assets all at the same time is more cost effective and less disruptive than waiting until individual assets fail or reach end of life.
Investment Priority	System Access investments are ranked as top priority, as they are mandated by regulation or code. This program ranks 1 out of 25. Refer to the DSP prioritization table for further details.
Analysis of the Project and Project Alternatives	System Access investments are driven by statutory, regulatory or other obligations. Enova is obligated to undertake this work when directed by the applicable authority or when a customer connection request is received. Alternatives are limited to the technical design of the required infrastructure. Where applicable, Enova evaluates the most cost-effective design approach including the choice of overhead versus underground construction, conductor sizing, and equipment selection.
Effect on system operation efficiency and cost effectiveness	System Access investments comply with statutory obligations and do not directly target system efficiency improvements. However, new infrastructure is built to current standards which may provide incremental operational benefits.
Net benefits accruing to customers	The renewal of this infrastructure will have the following benefits: the aversion of potentially adverse effects on reliability and safety, avoidance of an increase to maintenance costs, and where applicable, provide for increased flexibility of the system via harmonization of distribution voltages, a decrease in line losses, and an increase in capacity for connection of DERs.
Impact of Investment on reliability performance (including on the frequency and duration of outages)	These projects ensure the elimination of safety hazards and that reliability is maintained. Additionally, the standards to which assets must be built today compared to the existing assets ensures they are able to withstand more adverse weather conditions and increases the clearances around the conductors to assist in reducing both the frequency and duration of outages.
Scheduling Alternatives	System Renewal investments are instrumental in reducing the risk of critical asset failures, maintaining reliability and safety performance measures and keeping expensive reactive maintenance activities to a minimum. Scheduling changes within the calendar year due to weather, coordination with third parties and resource constraints can usually be accommodated for smaller projects. Rescheduling larger projects can increase costs due to the reassignment of labour and materials and the risk of asset failure. Enova evaluates the risk and cost of rescheduling any project to achieve the most cost effective outcome.
Ownership and/or Funding Alternatives	These projects are constructed in the public right-of-way and will consist solely of Enova's assets. There are no ownership or funding alternatives.

Safety

The new construction standards make work on pole lines much safer for all workers due to increased separation of high voltage conductors between themselves as well as from low voltage conductors. The replacement also minimizes the risk of unexpected pole failures in these areas, decreasing risk to the public.

Cyber-security, Privacy

Not Applicable

Co-ordination, Interoperability

Coordination with utilities, regional planning and/or links with 3rd parties (where applicable)	Enova will meet with the area Utility Coordinating Council and municipal staff (where applicable) as well as third party stakeholders to exchange project details to coordinate construction. This coordination typically occurs in Q3-Q4 of the year preceding construction.
Enabling of future technological functionality or addressing of future operational requirements	New lines generally incorporate larger conductor, increased strength, and where available, higher voltages. As a result, the system is better able to withstand poor weather conditions; provide increased capacity and siting options for the connection of renewable energy generation, electric vehicles, energy storage; provide increased physical space for third party communications and smart grid devices; and reduce power quality issues and losses.

Environmental Benefits

Not Applicable

Non-Wires Solutions Consideration

Enova's consideration of non-wires solutions for this program is documented in accordance with the NWS Guidelines (EB-2024-0118) and the BCA Framework. See details below.

Benefit-Cost Analysis Framework (5.4.2.2.)

Not Applicable (below $2M threshold)

General Information on the project/program (5.4.2.1.A)

Project Name Customer Connections - Loads
Program Code E-CC-L
OEB Investment Category System Access

Project Description

This program encompasses capital expenditures for customer connection activities across Enova's service territory, including overhead and underground new service installations, service rebuilds and upgrades.

Customer Service Connections: Enova is obligated under the Ontario Energy Board Act and the Distribution System Code (DSC) to connect customers who request service within its licensed territory. New service connection requests are processed through Enova's Conditions of Service. The program includes new overhead services, new underground services, and the rebuild of existing services where the existing service infrastructure has reached end of life or is inadequate for the customer's current requirements.

Detailed SubProjects

The following individual projects are covered by this project category:

Enova Project	Sub Project	Project Name	Total
E-CC-L		New OH Services - VS	$1,286,521
E-CC-L		New OH Services - CS	$721,196
E-CC-L		New UG Services - VS	$3,866,099
E-CC-L		New UG Services - CS	$2,153,411
		Total	$8,027,227

Capital Investment

Total Capital **$8,027,227**

O&M Costs (if applicable) **$0** Not Applicable

Capital Contributions to a Transmitter

CCRA Contribution $0

Customer Attachments/Load (kVA)

Customer Attachments (#): 0
Customer Load (peak kVA) 0

Project Timing

Start Date January 1, 2027 Engineering
End Date December 31, 2027 Construction

Expected In-Service Date December 1, 2027

Expenditure Timing

2027 Q1	20%	$1,605,445
2027 Q2	30%	$2,408,168
2027 Q3	30%	$2,408,168
2027 Q4	20%	$1,605,445

Schedule Risk and Risk Mitigation

Customer service connection requests are processed on a first-come, first-served basis in accordance with Enova's Conditions of Service and the timelines prescribed by the Distribution System Code. The volume of new service connection requests is driven by regional construction activity and is inherently variable from year to year. Enova's 2027 budget is based on a five-year historical data of service connection volumes, adjusted for known development activity.

Underground service connections for new residential subdivisions are coordinated with the developer's lot servicing schedule. A specific risk factor for the 2027 program is the Region of Waterloo's water servicing capacity constraints, which may delay the issuance of municipal servicing permits for new developments. If the Region restricts development approvals, the associated service connection work may be deferred. Similairly, if water capacity opens up, Enova may see a higher than normal level of activity as developers catch up on deferred projects from prior years.

Comparative Information

Comparable investments in previous years are as follows:

2020:	$5,074,034
2021:	$5,375,634
2022:	$5,958,977
2023:	$5,904,945
2024:	$5,950,002
2025:	$6,858,248
2026 (Bridge):	$8,552,696

Total Capital & OM&A Costs Associated with REG Investments

Not Applicable

Leave to Construct Approval

Not Applicable

Evaluation Criteria and information requirements for each project/program (5.4.2.1.B)

Efficiency, Customer Value, Reliability

Main Driver	The main driver for this program is Enova's statutory obligation under the OEB Act and the Distribution System Code to connect customers requesting electrical service within its licensed territory. New service connection requests are non-discretionary: Enova must provide service within the timelines prescribed by the DSC once a valid connection request is received. Service rebuild requests are driven by the deteriorated condition of existing service cables or the need to upgrade service capacity for customers with increased load requirements (e.g., EV charging, heat pump installations, panel upgrades).
Related Objectives/Performance Targets	Enova Strategic Objectives: Customer Service Excellence and Grid Resiliency. Customer connection activities directly support Enova's customer service obligations and contribute to regional economic development by enabling new residential, commercial, and industrial construction.
Source and Nature of the Information Used to Justify the Investment	The source of the information used to justify this investment is the external requests from municipal road authorities, developers, or customers that trigger the obligation to undertake this work. Project scope and timing are determined by the external party's construction schedule and applicable regulatory requirements (PSWHA, DSC, Conditions of Service).
Secondary Driver(s)	For new service connections in areas with high DER adoption (rooftop solar, EV chargers, battery storage), Enova designs new services to accommodate bidirectional power flow and higher-amperage panel requirements. This supports the Province's electrification objectives under the Integrated Energy Plan (IEP) Directive and reduces the need for future service upgrades as customers adopt distributed energy resources.
Good Utility Practice	Enova utilizes Utility Standards Forum (USF) design standards. Construction is performed in accordance with applicable CSA, ESA, and OEB requirements. Enova coordinates with municipal authorities and other utilities through the Utility Coordinating Council process.
Investment Priority	System Access investments are ranked as top priority, as they are mandated by regulation or code. This program ranks 1 out of 25. Refer to the DSP prioritization table for further details.
Analysis of the Project and Project Alternatives	System Access investments are driven by statutory, regulatory, or other obligations. Enova is obligated to provide service connections when a valid customer request is received under the DSC and Enova's Conditions of Service. Alternatives are limited to the technical design of the service installation. For new service connections, Enova evaluates the most cost-effective design approach: a) Overhead vs. Underground - for new subdivisions, underground is the standard per municipal requirements. For infill and rural connections, overhead is typically the lower-cost option. b) Service sizing - Enova sizes services based on the customer's declared load, with consideration for future electrification load growth (EV, heat pump) where the customer indicates intent. c) Transformer sharing - where feasible, new services share existing distribution transformers to minimize cost. Non-wires solutions are not applicable to customer service connections, as the physical service cable and metering infrastructure must be installed to provide electrical service to the customer's premises.
Effect on system operation efficiency and cost effectiveness	System Access investments comply with statutory obligations and do not directly target system efficiency improvements. However, new infrastructure is built to current standards which may provide incremental operational benefits.
Net benefits accruing to customers	The renewal of this infrastructure will have the following benefits: the aversion of potentially adverse effects on reliability and safety, avoidance of an increase to maintenance costs, and where applicable, provide for increased flexibility of the system via harmonization of distribution voltages, a decrease in line losses, and an increase in capacity for connection of DERs.
Impact of Investment on reliability performance (including on the frequency and duration of outages)	These projects ensure the elimination of safety hazards and that reliability is maintained. Additionally, the standards to which assets must be built today compared to the existing assets ensures they are able to withstand more adverse weather conditions and increases the clearances around the conductors to assist in reducing both the frequency and duration of outages.
Scheduling Alternatives	System Renewal investments are instrumental in reducing the risk of critical asset failures, maintaining reliability and safety performance measures and keeping expensive reactive maintenance activities to a minimum. Scheduling changes within the calendar year due to weather, coordination with third parties and resource constraints can usually be accommodated for smaller projects. Rescheduling larger projects can increase costs due to the reassignment of labour and materials and the risk of asset failure. Enova evaluates the risk and cost of rescheduling any project to achieve the most cost effective outcome.
Ownership and/or Funding Alternatives	These projects are constructed in the public right-of-way and will consist solely of Enova's assets. There are no ownership or funding alternatives.

Safety

New construction is built to current CSA and ESA safety standards, which provide improved public and worker safety compared to the legacy infrastructure being replaced or modified.

Cyber-security, Privacy

Not Applicable

Co-ordination, Interoperability

Coordination with utilities, regional planning and/or links with 3rd parties (where applicable)	Enova coordinates with municipal building departments, the Electrical Safety Authority, and development site contractors to schedule service installations. For underground services in new subdivisions, Enova coordinates with the developer's civil contractor to ensure electrical duct installation occurs at the appropriate stage of lot servicing.
Enabling of future technological functionality or addressing of future operational requirements	New infrastructure is built to current standards which facilitate the future incorporation of grid modernization equipment, DER connections, and smart grid devices.

Environmental Benefits

Not Applicable

Non-Wires Solutions Consideration

Enova's consideration of non-wires solutions for this program is documented in accordance with the NWS Guidelines (EB-2024-0118) and the BCA Framework. See details below.

Benefit-Cost Analysis Framework (5.4.2.2.)

In accordance with the OEB's BCA Framework (May 2024), NWA is not applicable as it is external driven.

UG Line Expansions - Feeders

General Information on the project/program (5.4.2.1.A)

Project Name UG Line Expansions - Feeders
Program Code E-UL-F
OEB Investment Category System Access

Project Description

This program encompasses underground feeder-level distribution infrastructure work driven by a combination of customer-requested connections, externally-driven relocations (road works, municipal infrastructure projects), and system expansion to serve new commercial and institutional developments. These investments are triggered by external requests and obligations rather than by Enova's own system planning priorities.

The program scope includes primary feeder cable installation, duct bank construction, switchgear installation, transformer pad installation, and associated civil works.

Detailed SubProjects

The following individual projects are covered by this project category:

Enova Project	Sub Project	Project Name	Total
E-UL-F		321 Courtland Ave [Expansion] - Electrical	**$445,662**
E-UL-F		720 Erbsville Rd [170 town lots]	**$1,072,054**
E-UL-F		Bridgeport / Regina OH to UG (70 King St N)	**$7,873**
E-UL-F		Customer Driven Projects - Underground Feeders - VS	**$700,708**
E-UL-F		Customer Driven Projects - Underground Feeder - CS	**$568,125**
		Total	**$2,794,422**

Capital Investment

Total Capital **$2,794,422**

O&M Costs (if applicable) **$0** Not Applicable

Capital Contributions to a Transmitter

CCRA Contribution $0

Customer Attachments/Load (kVA)

Customer Attachments (#): 0
Customer Load (peak kVA) 0

Project Timing

Start Date January 1, 2027 Engineering
End Date December 31, 2027 Construction

Expected In-Service Date December 1, 2027

Expenditure Timing

2027 Q1	20%	$558,884
2027 Q2	30%	$838,326
2027 Q3	30%	$838,326
2027 Q4	20%	$558,884

Schedule Risk and Risk Mitigation

Underground feeder expansion projects are driven by external customer and municipal timelines. Road works relocation projects must be coordinated with the municipal road authority's construction schedule. Customer connection projects must meet DSC timeline requirements.

The primary scheduling risk is changes to external construction schedules and potential conflicts with other underground utilities during construction.

Comparative Information

Comparable investments in previous years are as follows:

2020:	$1,201,326
2021:	$1,995,211
2022:	$2,547,709
2023:	$2,212,887
2024:	$1,252,143
2025:	$650,442
2026 (Bridge):	$1,055,335

Total Capital & OM&A Costs Associated with REG Investments

Not Applicable

Leave to Construct Approval

Not Applicable

Evaluation Criteria and information requirements for each project/program (5.4.2.1.B)

Efficiency, Customer Value, Reliability

Main Driver	The main driver for this program is Enova's obligation under Section 28 of the OEB Act and the Distribution System Code to connect customers requesting service within its licensed territory.
Related Objectives/Performance Targets	Enova Strategic Objectives: Grid Resiliency (SAIDI/SAIFI targets) and Health, Safety and Environment, as identified in the DSP.
Source and Nature of the Information Used to Justify the Investment	The source of the information used to justify this investment is the external requests from municipal road authorities, developers, or customers that trigger the obligation to undertake this work. Project scope and timing are determined by the external party's construction schedule and applicable regulatory requirements (PSWHA, DSC, Conditions of Service).
Secondary Driver(s)	Not Applicable
Good Utility Practice	Enova utilizes Utility Standards Forum (USF) and internal design standards for underground construction. Underground cable selection, installation, and testing follow CSA and IEEE standards. Underground renewal projects are designed to current standards including improved duct bank configurations, modern cable types, and enhanced vault drainage to extend asset service life and reduce future maintenance costs.
Investment Priority	System Access investments are ranked as top priority, as they are mandated by regulation or code. This program ranks 1 out of 25. Refer to the DSP prioritization table for further details.
Analysis of the Project and Project Alternatives	System Access investments are driven by statutory, regulatory or other obligations. Enova is obligated to undertake this work when directed by the applicable authority or when a customer connection request is received. Alternatives are limited to the technical design of the required infrastructure. Where applicable, Enova evaluates the most cost-effective design approach including the choice of overhead versus underground construction, conductor sizing, and equipment selection.
Effect on system operation efficiency and cost effectiveness	System Access investments comply with statutory obligations and do not directly target system efficiency improvements. However, new infrastructure is built to current standards which may provide incremental operational benefits.
Net benefits accruing to customers	The renewal of this infrastructure will have the following benefits: the aversion of potentially adverse effects on reliability and safety, avoidance of an increase to maintenance costs, and where applicable, provide for increased flexibility of the system via harmonization of distribution voltages, a decrease in line losses, and an increase in capacity for connection of DERs.
Impact of Investment on reliability performance (including on the frequency and duration of outages)	These projects ensure the elimination of safety hazards and that reliability is maintained. Additionally, the standards to which assets must be built today compared to the existing assets ensures they are able to withstand more adverse weather conditions and increases the clearances around the conductors to assist in reducing both the frequency and duration of outages.
Scheduling Alternatives	System Renewal investments are instrumental in reducing the risk of critical asset failures, maintaining reliability and safety performance measures and keeping expensive reactive maintenance activities to a minimum. Scheduling changes within the calendar year due to weather, coordination with third parties and resource constraints can usually be accommodated for smaller projects. Rescheduling larger projects can increase costs due to the reassignment of labour and materials and the risk of asset failure. Enova evaluates the risk and cost of rescheduling any project to achieve the most cost effective outcome.
Ownership and/or Funding Alternatives	These projects are constructed in the public right-of-way and will consist solely of Enova's assets. There are no ownership or funding alternatives.

Safety

Underground renewal eliminates the risk of cable faults which can present safety hazards including arc flash, ground potential rise, and manhole events. Modern cable and equipment designs incorporate improved safety features and fault containment capability.

Cyber-security, Privacy

Not Applicable

Co-ordination, Interoperability

Coordination with utilities, regional planning and/or links with 3rd parties (where applicable)	Enova will meet with the area Utility Coordinating Council and municipal staff (where applicable) as well as third party stakeholders to exchange project details to coordinate construction. This coordination typically occurs in Q3-Q4 of the year preceding construction.
Enabling of future technological functionality or addressing of future operational requirements	New underground cable systems incorporate modern insulation materials and duct configurations that provide improved performance and longer service life. Where applicable, conduit spare capacity is provided to facilitate future cable additions without additional civil construction. Modern switchgear incorporates provisions for SCADA communication and automated switching capability.

Environmental Benefits

Not Applicable

Non-Wires Solutions Consideration

Enova's consideration of non-wires solutions for this program is documented in accordance with the NWS Guidelines (EB-2024-0118) and the BCA Framework. See details below.

Benefit-Cost Analysis Framework (5.4.2.2.)

In accordance with the OEB's BCA Framework (May 2024), NWA is not applicable as it is external driven.

UG Line Expansions - Subdivisions

General Information on the project/program (5.4.2.1.A)

Project Name UG Line Expansions - Subdivisions
Program Code E-UL-S
OEB Investment Category System Access

Project Description

This program encompasses underground distribution infrastructure construction required to provide electrical service to new residential subdivision developments within Enova's service territory. Under Distribution System Code, Enova has an obligation to connect customers who request service within its licensed service territory.

The timing and scope of subdivision expansion work is determined by the pace of residential development as approved by the municipalities within Enova's service area. Capital contributions from developers offset a portion of project costs in accordance with the DSC's economic evaluation methodology.

Detailed SubProjects

The following individual projects are covered by this project category:

Enova Project	Sub Project	Project Name	Total
E-UL-S		33 Anvil St [32 towns]	$152,525
E-UL-S		665 Erbsville Rd [130 town lots]	$820,059
E-UL-S		7 Morrison [32 towns]	$334,640
E-UL-S		Conservation Drive @ Beaver Creek [350 lots]	$1,576,222
E-UL-S		Huron Woods Stage 5B Subdivision	$215,203
E-UL-S		1000 New Dundee Rd [127 units TOWNHOMES]	$796,473
E-UL-S		Strovhest	$270,358
		Total	$4,165,479

Capital Investment

Total Capital **$4,165,479**

O&M Costs (if applicable) **$0** Not Applicable

Capital Contributions to a Transmitter

CCRA Contribution $0

Customer Attachments/Load (kVA)

Customer Attachments (#): 0
Customer Load (peak kVA) 0

Project Timing

Start Date January 1, 2027 Engineering
End Date December 31, 2027 Construction

Expected In-Service Date December 1, 2027

Expenditure Timing

2027 Q1	20%	$833,096
2027 Q2	30%	$1,249,644
2027 Q3	30%	$1,249,644
2027 Q4	20%	$833,096

Schedule Risk and Risk Mitigation

Underground subdivision expansion projects are driven by developer construction schedules and municipal planning approvals. The timing of Enova's electrical infrastructure installation must align with the developer's lot servicing and road construction schedule.

A specific risk factor for the 2027 program is the Region of Waterloo's water servicing capacity constraints, which may delay the issuance of municipal servicing permits for new residential subdivision developments. If the Region restricts new development approvals due to water capacity limitations, the associated electrical infrastructure projects in this program may be deferred to subsequent years. Enova monitors municipal development approval status and adjusts its capital program accordingly.

Capital contributions from developers offset a portion of project costs; deferral of developer-driven projects therefore also defers the associated capital expenditure, resulting in a neutral impact on Enova's capital spending plan.

Comparative Information

Comparable investments in previous years are as follows:

2020:	$3,478,496
2021:	$2,964,763
2022:	$3,434,338
2023:	$3,521,142
2024:	$4,143,390
2025:	$4,450,187
2026 (Bridge):	$5,852,426

Total Capital & OM&A Costs Associated with REG Investments

Not Applicable

Leave to Construct Approval

Not Applicable

Evaluation Criteria and information requirements for each project/program (5.4.2.1.B)

Efficiency, Customer Value, Reliability

Main Driver	The main driver for this program is Enova's obligation under OEB Act and the Distribution System Code to connect customers requesting service within its licensed territory.
Related Objectives/Performance Targets	Enova Strategic Priorities: Grid Resiliency (SAIDI/SAIFI targets) and Health, Safety and Environment, as identified in the DSP.
Source and Nature of the Information Used to Justify the Investment	The source of the information used to justify this investment is the external requests from municipal road authorities, developers, or customers that trigger the obligation to undertake this work. Project scope and timing are determined by the external party's construction schedule and applicable regulatory requirements (PSWHA, DSC, Conditions of Service).
Secondary Driver(s)	Not Applicable
Good Utility Practice	Enova utilizes Utility Standards Forum (USF) and internal design standards for underground construction. Underground cable selection, installation, and testing follow CSA and IEEE standards. Underground renewal projects are designed to current standards including improved duct bank configurations, modern cable types, and enhanced vault drainage to extend asset service life and reduce future maintenance costs.
Investment Priority	System Access investments are ranked as top priority, as they are mandated by regulation or code. This program ranks 1 out of 25. Refer to the DSP prioritization table for further details.
Analysis of the Project and Project Alternatives	System Access investments are driven by statutory, regulatory or other obligations. Enova is obligated to undertake this work when directed by the applicable authority or when a customer connection request is received. Alternatives are limited to the technical design of the required infrastructure. Where applicable, Enova evaluates the most cost-effective design approach including the choice of overhead versus underground construction, conductor sizing, and equipment selection.
Effect on system operation efficiency and cost effectiveness	System Access investments comply with statutory obligations and do not directly target system efficiency improvements. However, new infrastructure is built to current standards which may provide incremental operational benefits.
Net benefits accruing to customers	The renewal of this infrastructure will have the following benefits: the aversion of potentially adverse effects on reliability and safety, avoidance of an increase to maintenance costs, and where applicable, provide for increased flexibility of the system via harmonization of distribution voltages, a decrease in line losses, and an increase in capacity for connection of DERs.
Impact of Investment on reliability performance (including on the frequency and duration of outages)	These projects ensure the elimination of safety hazards and that reliability is maintained. Additionally, the standards to which assets must be built today compared to the existing assets ensures they are able to withstand more adverse weather conditions and increases the clearances around the conductors to assist in reducing both the frequency and duration of outages.
Scheduling Alternatives	System Renewal investments are instrumental in reducing the risk of critical asset failures, maintaining reliability and safety performance measures and keeping expensive reactive maintenance activities to a minimum. Scheduling changes within the calendar year due to weather, coordination with third parties and resource constraints can usually be accommodated for smaller projects. Rescheduling larger projects can increase costs due to the reassignment of labour and materials and the risk of asset failure. Enova evaluates the risk and cost of rescheduling any project to achieve the most cost effective outcome.
Ownership and/or Funding Alternatives	These projects are constructed in the public right-of-way and will consist solely of Enova's assets. There are no ownership or funding alternatives.

Safety

Underground renewal eliminates the risk of cable faults which can present safety hazards including arc flash, ground potential rise, and manhole events. Modern cable and equipment designs incorporate improved safety features and fault containment capability.

Cyber-security, Privacy

Not Applicable

Co-ordination, Interoperability

Coordination with utilities, regional planning and/or links with 3rd parties (where applicable)	Enova will meet with the area Utility Coordinating Council and municipal staff (where applicable) as well as third party stakeholders to exchange project details to coordinate construction. This coordination typically occurs in Q3-Q4 of the year preceding construction.
Enabling of future technological functionality or addressing of future operational requirements	New underground cable systems incorporate modern insulation materials and duct configurations that provide improved performance and longer service life. Where applicable, conduit spare capacity is provided to facilitate future cable additions without additional civil construction. Modern switchgear incorporates provisions for SCADA communication and automated switching capability.

Environmental Benefits

Not Applicable

Non-Wires Solutions Consideration

Enova's consideration of non-wires solutions for this program is documented in accordance with the NWS Guidelines (EB-2024-0118) and the BCA Framework. See details below.

Benefit-Cost Analysis Framework (5.4.2.2.)

In accordance with the OEB's BCA Framework (May 2024), NWA is not applicable as it is external driven.

General Information on the project/program (5.4.2.1.A)

Project Name Meters – Retail
Program Code E-ME-R
OEB Investment Category System Access

Project Description

This program includes the installation, replacement, and maintenance of Enova Power's metering assets in compliance with Measurement Canada (MC) standards and the Distribution System Code (DSC). The work includes inspection and replacement of defective meters, procurement, testing, and installation of meters for new or upgraded residential and commercial services, and required supporting infrastructure to measure, record, and transfer electricity consumption data.

The program also encompasses metering asset management activities including delta/wye transformer upgrades, current transformer (CT) and potential transformer (PT) replacements, 2.5 ELM (Element) meter upgrades under a planned 7-year compliance program, and AMI communication system upgrades. Planning activities for AMI 2.0 are also included to support the future evolution of Enova's metering infrastructure.

Detailed SubProjects

The following individual projects are covered by this project category:

Enova Project	Sub Project	Project Name	Total
E-ME-R	1	New 1-Phase Services	**$399,548**
E-ME-R	2	New GS<50kW Services	**$146,282**
E-ME-R	3	New GS>50kW Services	**$344,216**
E-ME-R	4	New Wholesale Metering Installations/Equipment	**$63,657**
E-ME-R	5	Defective Meter Replacements	**$201,922**
E-ME-R	6	Delta/Wye Upgrades – Asset Management, Ongoing Program	**$69,407**
E-ME-R	7	2.5 ELM Upgrades – 7 Year Program	**$42,727**
E-ME-R	8	CT/PT Upgrades – Asset Management, Ongoing Program	**$39,535**
E-ME-R	9	Meter Communications – Upgrades	**$100,000**
E-ME-R	10	AMI 2.0 – Planning	**$19,352**
		Total	**$1,426,646**

Capital Investment

Total Capital **$1,426,646**

O&M Costs (if applicable) **$0** Not Applicable

Capital Contributions to a Transmitter

CCRA Contribution $0

Customer Attachments/Load (kVA)

Customer Attachments (#): Various – demand driven
Customer Load (peak kVA) Various – demand driven

Project Timing

Start Date January 2027

Expected In-Service Date December 2027

Expenditure Timing

2027 Q1	25%	$356,662
2027 Q2	25%	$356,662
2027 Q3	25%	$356,662
2027 Q4	25%	$356,662

Schedule Risk and Risk Mitigation

This work is routine for Enova Power and covered by well-established processes which mitigate issues around customer or developer-driven timing risks. Timelines are strictly monitored and enforced to ensure obligations set forth in the DSC are met and that customer satisfaction is maintained.

For new service metering, installation timelines are coordinated with the service connection program (E-CC-L) to ensure meters are available and installed concurrently with new service energization. For meter replacements, scheduling is managed through Enova's meter sample testing and reverification program in accordance with Measurement Canada regulations.

AMI 2.0 planning activities in 2027 carry minimal schedule risk as they are limited to planning and assessment work. Capital deployment for AMI 2.0 infrastructure is anticipated in subsequent DSP years.

Comparative Information

Comparable investments in previous years are as follows:

2020:	$1,183,526
2021:	$1,035,605
2022:	$1,008,411
2023:	$1,120,082
2024:	$1,004,029
2025:	$1,742,777
2026 (Bridge):	$1,362,989

Total Capital & OM&A Costs Associated with REG Investments Not Applicable

Leave to Construct Approval Not Applicable

Evaluation Criteria and information requirements for each project/program (5.4.2.1.B)

Efficiency, Customer Value, Reliability

Main Driver	These projects are mandatory. For new or upgraded services, scope and timelines are based on the requirements put forth by customers and obligations set forth for connecting customers in the DSC. For replacement of existing meters, scope of work and timelines are based on the regulatory requirements established by Measurement Canada and the DSC.
Related Objectives/Performance Targets	Enova Strategic Priority: Customer Service Excellence, as identified in the DSP.
Source and Nature of the Information Used to Justify the Investment	Request for service and obligations set forth in the DSC and Measurement Canada regulations.
Secondary Driver(s)	Not Applicable
Good Utility Practice	Enova Power utilizes the Sensus FlexNet metering and communication network as its Advanced Metering Infrastructure (AMI) solution. The Sensus AMI system is used for reading residential, commercial and industrial, and MIST meters. The meters that Enova deploys are equipped with basic power quality monitoring, configurable alarms, and encrypted communications. These additional features provide key data points for managing outages and reliability metrics as follows: a) Integrating power outage/restore messages with the Outage Management System (OMS); b) Integrating power outage/restore messages with FLISR for automated switching operations and reduced outage time; c) Integrating power outage/restore messages with Enova's online outage map; d) Integrating smart meter data into Enova's distribution planning systems, load flow software, and transformer load analysis; e) Remote interrogation of meters (via pinging) for diagnosing power-related issues.
Investment Priority	System Access investments are ranked as top priority, as they are mandated by regulation or code. This program ranks 1 out of 25. Refer to the DSP prioritization table for further details.
Analysis of the Project and Project Alternatives	Customer connection metering projects are driven by customer requests and the specific requirements of the customer. Design and methodology for such projects are standardized through Enova's policies and practices and in line with Enova's Conditions of Service. Alternatives are limited as metering options are standardized, but if alternatives exist, they are normally the choice of the customer. Management of existing metering assets is governed by Measurement Canada regulations. Enova uses meter sample testing and reverification programs to ensure billing accuracy and compliance with MC regulations. Metering equipment is typically replaced on a like-for-like basis. This is the preferred option as it allows for rapid replacement with minimal disruption to the customer and continuity of billing services.
Effect on system operation efficiency and cost effectiveness	Smart interval meters with remote communications are now the standard installation for Enova, and facilitate the following: a) Eliminates manual meter reading; b) Eliminates scheduled appointments to read difficult-to-access meters; c) Reduces outage time by integrating meter alarm messages with the OMS and GIS systems to improve situational awareness; d) Improved load monitoring capabilities for distribution transformers and system analysis. Refer to the AMI section of the DSP for further detail.
Net benefits accruing to customers	Meter alarm monitoring and data analytics allow Enova to respond to malfunctioning meters and power quality issues in a timely and efficient manner. Making interval data available to the customer facilitates customer awareness of electricity consumption and aids in managing energy to reduce or shift demand to off-peak periods. Future initiatives include providing customers with notifications for power outages, power restores, high consumption, and low consumption alerts.
Impact of Investment on reliability performance (including on the frequency and duration of outages)	The metering program is expected to help reduce the duration of outages on Enova's distribution system. This is accomplished through the collection of meter alarms and integrating the data with the utility's Outage Management System (OMS). Enova's AMI system supports two-way communications. This feature allows system operators to remotely interrogate power quality information from the meters and perform basic troubleshooting without dispatching crews. Refer to the AMI section of the DSP for further detail.
Scheduling Alternatives	These projects are mandatory. Scope and timelines are based on requirements put forth by customers and obligations set forth in the DSC and Measurement Canada codes and regulations.
Ownership and/or Funding Alternatives	These projects will consist solely of Enova's assets. There are no ownership or funding alternatives.

Safety

These projects are not intended to address existing safety concerns, but are expected to have safety-related added benefits. This metering program leverages meter alarm functionality to identify potentially hazardous conditions including fire hazards, situations involving theft of power, and loss of power conditions.

Cyber-security, Privacy

Enova's smart meter and related AMI infrastructure have been procured through Sensus. Sensus' system supports a multi-layered security approach including access control, authorization, authentication, and data integrity protocols. It also includes robust AES-256-based encryption. As part of its continuous improvement model, Enova collaborates with other Ontario Sensus customers to perform periodic security assessments and identify opportunities for enhanced system hardening.

Co-ordination, Interoperability

Coordination with utilities, regional planning and/or links with 3rd parties (where applicable)	Coordination with utilities and regional planning is not required. Enova coordinates with customers, contractors, and the Electrical Safety Authority as required based on the scope of work for each project.
Enabling of future technological functionality or addressing of future operational requirements	A component of this program supports the capital investments required for the ongoing operation, maintenance, and evolution of the AMI. The 2027 program includes AMI 2.0 planning activities to assess next-generation metering infrastructure requirements including Wi-SUN FAN network technology, enhanced meter data management, and integration with Enova's grid modernization roadmap. Refer to the AMI section of the DSP for further detail.

Environmental Benefits

The smart meter infrastructure supports Time-of-Use billing and the Province's conservation objectives. The AMI system also provides environmental benefits by reducing vehicle run time associated with manual meter reading.

Non-Wires Solutions Consideration

Enova's consideration of non-wires solutions for this program is documented in accordance with the NWS Guidelines (EB-2024-0118) and the BCA Framework. See details below.

Benefit-Cost Analysis Framework (5.4.2.2.)

Not Applicable (below $2M threshold)

General Information on the project/program (5.4.2.1.A)

Project Name Grid Improvements - Connectivity
Program Code U-GI-C
OEB Investment Category System Service

Project Description

This program involves the installation of new overhead tie-line connections between distribution feeders to improve system connectivity, operational flexibility, and outage restoration capability. Enhanced connectivity allows Enova to transfer customer load between feeders during planned outages and emergency conditions, reducing the frequency and duration of sustained interruptions.

A key objective of this program is to enable a more optimal distribution of available station capacity across the system. By establishing new tie points between feeders served by different stations, Enova can rebalance load from more heavily loaded stations to stations with available headroom, deferring the need for station capacity additions while improving the utilization of existing infrastructure. This load rebalancing capability also improves system resilience by providing alternative supply paths when a station transformer is out of service for maintenance or during contingency conditions.

Projects in this program are identified through system planning studies that evaluate station loading, feeder capacity, switching capability, and restoration options. Additional conductor and switching equipment is installed to create new tie points between adjacent feeders, with priority given to connections that provide the greatest load transfer capability and contingency support.

Detailed SubProjects

The following individual projects are covered by this project category:

Enova Project	Sub Project	Project Name	Total
U-GI-C		Strange St - Victoria to Glasgow + Park St - Glasgow to Union	$835,105
U-GI-C		Park St & William St Intersection	$93,395
		Total	$928,500

Capital Investment

Total Capital **$928,500**

O&M Costs (if applicable) **$0** Not Applicable

Capital Contributions to a Transmitter

CCRA Contribution $0

Customer Attachments/Load (kVA)

Customer Attachments (#): 0
Customer Load (peak kVA) 0

Project Timing

Start Date January 1, 2027 Engineering
End Date December 31, 2027 Construction

Expected In-Service Date December 1, 2027

Expenditure Timing

2027 Q1	20%	$185,700
2027 Q2	30%	$278,550
2027 Q3	30%	$278,550
2027 Q4	20%	$185,700

Schedule Risk and Risk Mitigation

Grid connectivity projects require coordination with Enova's Operations group to schedule switching operations and outages on both the source and receiving feeders. Projects involving new tie points in urban areas require municipal road occupancy permits and traffic management plans.

Comparative Information

Comparable investments in previous years are as follows:

2020:	$99,055
2021:	$303,763
2022:	$363,009
2023:	$0
2024:	$2,245
2025:	$0
2026 (Bridge):	$63,794

Total Capital & OM&A Costs Associated with REG Investments Not Applicable

Leave to Construct Approval Not Applicable

Evaluation Criteria and information requirements for each project/program (5.4.2.1.B)

Efficiency, Customer Value, Reliability

Main Driver	The main driver for this program is the improvement of system reliability and operational flexibility to meet Enova's SAIDI/SAIFI reliability targets. Also, optimization of station capacity utilization across Enova's system, enabling load transfer from stations approaching capacity thresholds to stations with available headroom.
Related Objectives/Performance Targets	Enova Strategic Objectives: Grid Resiliency (SAIDI/SAIFI targets) and Health, Safety and Environment, as identified in the DSP.
Source and Nature of the Information Used to Justify the Investment	The source of the information used to justify this investment is Enova's system planning studies, including feeder loading analysis, switching capability assessment, and reliability performance data. Projects are identified and prioritized based on their expected contribution to SAIDI/SAIFI improvement.
Secondary Driver(s)	Secondary drivers include improved switching capability for planned maintenance, reduced customer-hours-of-interruption during system restoration, and enhanced grid capacity for DER integration.
Good Utility Practice	Enova utilizes Utility Standards Forum (USF) design standards. Construction is performed in accordance with applicable CSA, ESA, and OEB requirements. Enova coordinates with municipal authorities and other utilities through the Utility Coordinating Council process.
Investment Priority	System Access investments are ranked as top priority, as they are mandated by regulation or code. Under the System Service category, Enova identifies project opportunities to address service level issues based on a detailed review of the Distribution System Reliability Report, expected or known system constraints, post-mortem analysis of large outages, and the introduction of functionality to address operational objectives or system performance issues, and then develops a list of solutions. The solutions that can be implemented quickly and/or inexpensively are prioritized for faster execution. To prioritize the remaining projects in this category, Enova considers alignment with Enova's Strategic Objectives, customer impact, and any additional drivers or benefits for each project. These include criticality of assets, safety issues, health index of asset(s), improved condition assessments, system loss reduction (voltage conversion), alignment with Enova's long term distribution system plan, relocation requirements (Enova or municipally driven), or replacement for regulatory compliance. The greater the alignment with Enova's Strategic Objectives, the greater the customer impact or the more drivers or benefits are attributed to a solution, the higher the priority. Investments in System Renewal and General Plant categories are prioritized in a similar fashion. Analysis of the impact on customers and consideration of the impact of project deferral are also considered. The compiled list of projects is reviewed and prioritized by Senior Engineering, Operations, IT and Finance staff. Based on the outcome of this process, this project ranks 9 out of 25. Refer to the DSP Prioritization Table for further details.
Analysis of the Project and Project Alternatives	Enova considered the following alternatives: a) Do Nothing - this option does not address the identified system reliability or capacity deficiency and is not considered appropriate. b) Traditional Infrastructure (poles and wires) - this is the preferred option for the projects identified in this program, as they involve physical installation of switching equipment and line extensions. c) Non-Wires Solutions - Enova considered whether DER-based solutions could address the system need. For the projects in this program, the system need requires physical installation of switching or connection infrastructure that cannot be substituted by NWS.
Effect on system operation efficiency and cost effectiveness	The installation of automated switching equipment and enhanced connectivity will improve operational efficiency by reducing restoration times and enabling remote switching operations that currently require crew dispatch.
Net benefits accruing to customers	The renewal of this infrastructure will have the following benefits: the aversion of potentially adverse effects on reliability and safety, avoidance of an increase to maintenance costs, and where applicable, provide for increased flexibility of the system via harmonization of distribution voltages, a decrease in line losses, and an increase in capacity for connection of DERs.
Impact of Investment on reliability performance (including on the frequency and duration of outages)	These projects ensure the elimination of safety hazards and that reliability is maintained. Additionally, the standards to which assets must be built today compared to the existing assets ensures they are able to withstand more adverse weather conditions and increases the clearances around the conductors to assist in reducing both the frequency and duration of outages.
Scheduling Alternatives	System Renewal investments are instrumental in reducing the risk of critical asset failures, maintaining reliability and safety performance measures and keeping expensive reactive maintenance activities to a minimum. Scheduling changes within the calendar year due to weather, coordination with third parties and resource constraints can usually be accommodated for smaller projects. Rescheduling larger projects can increase costs due to the reassignment of labour and materials and the risk of asset failure. Enova evaluates the risk and cost of rescheduling any project to achieve the most cost effective outcome.
Ownership and/or Funding Alternatives	These projects are constructed in the public right-of-way and will consist solely of Enova's assets. There are no ownership or funding alternatives.

Safety

New construction is built to current CSA and ESA safety standards, which provide improved public and worker safety compared to the legacy infrastructure being replaced or modified.

Cyber-security, Privacy

Not Applicable

Co-ordination, Interoperability

Coordination with utilities, regional planning and/or links with 3rd parties (where applicable)	Enova will meet with the area Utility Coordinating Council and municipal staff (where applicable) as well as third party stakeholders to exchange project details to coordinate construction. This coordination typically occurs in Q3-Q4 of the year preceding construction.
Enabling of future technological functionality or addressing of future operational requirements	Grid improvement investments directly enable the deployment of advanced grid capabilities including FLISR, Volt-VAR optimization, and enhanced DER monitoring and control. These capabilities support the transition to a more dynamic and resilient distribution system.

Environmental Benefits

Not Applicable

Non-Wires Solutions Consideration

Enova's consideration of non-wires solutions for this program is documented in accordance with the NWS Guidelines (EB-2024-0118) and the BCA Framework. See details below.

Benefit-Cost Analysis Framework (5.4.2.2.)

Not Applicable (below $2M threshold)

General Information on the project/program (5.4.2.1.A)

Project Name Grid Improvements - Automation
Program Code U-GI-A
OEB Investment Category System Service

Project Description

This program involves the installation and upgrade of automated switching equipment (reclosers with SCADA capability) on the distribution system. Reclosers equipped with SCADA communication and control enable Fault Location, Isolation and Service Restoration (FLISR) functionality, which allows Enova's control room to remotely locate faults, isolate affected sections, and restore service to unaffected customers within minutes rather than hours.

The recloser program is a key component of Enova's grid modernization strategy and directly supports the achievement of SAIDI and SAIFI reliability targets.

Detailed SubProjects

The following individual projects are covered by this project category:

Enova Project	Sub Project	Project Name	Total
U-GI-A		Recloser Program - Enova	$614,680
		Total	$614,680

Capital Investment

Total Capital **$614,680**

O&M Costs (if applicable) **$0** Not Applicable

Capital Contributions to a Transmitter

CCRA Contribution $0

Customer Attachments/Load (kVA)

Customer Attachments (#): N/A
Customer Load (peak kVA) N/A

Project Timing

Start Date January 1, 2027 Engineering
End Date December 31, 2027 Construction

Expected In-Service Date December 1, 2027

Expenditure Timing

2027 Q1	20%	$122,936
2027 Q2	30%	$184,404
2027 Q3	30%	$184,404
2027 Q4	20%	$122,936

Schedule Risk and Risk Mitigation

Recloser installation projects require coordination with Enova's SCADA/Communications group to ensure communication infrastructure is in place prior to recloser commissioning. The primary scheduling risk is the lead time for recloser procurement and the availability of SCADA commissioning resources.

Comparative Information

Comparable investments in previous years are as follows:

2020:	$1,926,066
2021:	$1,599,706
2022:	$635,834
2023:	$131,993
2024:	$303,608
2025:	$474,904
2026 (Bridge):	$432,697

Total Capital & OM&A Costs Associated with REG Investments

Not Applicable

Leave to Construct Approval

Not Applicable

Evaluation Criteria and information requirements for each project/program (5.4.2.1.B)

Efficiency, Customer Value, Reliability

Main Driver	The main driver for this program is the improvement of system reliability and operational flexibility to meet Enova's SAIDI/SAIFI reliability targets.
Related Objectives/Performance Targets	Enova Strategic Objectives: Grid Resiliency (SAIDI/SAIFI targets) and Health, Safety and Environment, as identified in the DSP.
Source and Nature of the Information Used to Justify the Investment	The source of the information used to justify this investment is Enova's system planning studies, including feeder loading analysis, switching capability assessment, and reliability performance data. Projects are identified and prioritized based on their expected contribution to SAIDI/SAIFI improvement.
Secondary Driver(s)	Secondary drivers include improved switching capability for planned maintenance, reduced customer-hours-of-interruption during system restoration, and enhanced grid capacity for DER integration.
Good Utility Practice	Enova utilizes Utility Standards Forum (USF) design standards. Construction is performed in accordance with applicable CSA, ESA, and OEB requirements. Enova coordinates with municipal authorities and other utilities through the Utility Coordinating Council process.
Investment Priority	System Access investments are ranked as top priority, as they are mandated by regulation or code. Under the System Service category, Enova identifies project opportunities to address service level issues based on a detailed review of the Distribution System Reliability Report, expected or known system constraints, post-mortem analysis of large outages, and the introduction of functionality to address operational objectives or system performance issues, and then develops a list of solutions. The solutions that can be implemented quickly and/or inexpensively are prioritized for faster execution. To prioritize the remaining projects in this category, Enova considers alignment with Enova's Strategic Objectives, customer impact, and any additional drivers or benefits for each project. These include criticality of assets, safety issues, health index of asset(s), improved condition assessments, system loss reduction (voltage conversion), alignment with Enova's long term distribution system plan, relocation requirements (Enova or municipally driven), or replacement for regulatory compliance. The greater the alignment with Enova's Strategic Objectives, the greater the customer impact or the more drivers or benefits are attributed to a solution, the higher the priority. Investments in System Renewal and General Plant categories are prioritized in a similar fashion. Analysis of the impact on customers and consideration of the impact of project deferral are also considered. The compiled list of projects is reviewed and prioritized by Senior Engineering, Operations, IT and Finance staff. Based on the outcome of this process, this project ranks 21 out of 25. Refer to the DSP Prioritization Table for further details.
Analysis of the Project and Project Alternatives	Enova considered the following alternatives: a) Do Nothing - this option does not address the identified system reliability or capacity deficiency and is not considered appropriate. b) Traditional Infrastructure (poles and wires) - this is the preferred option for the projects identified in this program, as they involve physical installation of switching equipment and line extensions. c) Non-Wires Solutions - Enova considered whether DER-based solutions could address the system need. For the projects in this program, the system need requires physical installation of switching or connection infrastructure that cannot be substituted by NWS.
Effect on system operation efficiency and cost effectiveness	The installation of automated switching equipment and enhanced connectivity will improve operational efficiency by reducing restoration times and enabling remote switching operations that currently require crew dispatch.
Net benefits accruing to customers	The renewal of this infrastructure will have the following benefits: the aversion of potentially adverse effects on reliability and safety, avoidance of an increase to maintenance costs, and where applicable, provide for increased flexibility of the system via harmonization of distribution voltages, a decrease in line losses, and an increase in capacity for connection of DERs.
Impact of Investment on reliability performance (including on the frequency and duration of outages)	These projects ensure the elimination of safety hazards and that reliability is maintained. Additionally, the standards to which assets must be built today compared to the existing assets ensures they are able to withstand more adverse weather conditions and increases the clearances around the conductors to assist in reducing both the frequency and duration of outages.
Scheduling Alternatives	System Renewal investments are instrumental in reducing the risk of critical asset failures, maintaining reliability and safety performance measures and keeping expensive reactive maintenance activities to a minimum. Scheduling changes within the calendar year due to weather, coordination with third parties and resource constraints can usually be accommodated for smaller projects. Rescheduling larger projects can increase costs due to the reassignment of labour and materials and the risk of asset failure. Enova evaluates the risk and cost of rescheduling any project to achieve the most cost effective outcome.
Ownership and/or Funding Alternatives	These projects are constructed in the public right-of-way and will consist solely of Enova's assets. There are no ownership or funding alternatives.

Safety

New construction is built to current CSA and ESA safety standards, which provide improved public and worker safety compared to the legacy infrastructure being replaced or modified.

Cyber-security, Privacy

Not Applicable

Co-ordination, Interoperability

Coordination with utilities, regional planning and/or links with 3rd parties (where applicable)	Enova will meet with the area Utility Coordinating Council and municipal staff (where applicable) as well as third party stakeholders to exchange project details to coordinate construction. This coordination typically occurs in Q3-Q4 of the year preceding construction.
Enabling of future technological functionality or addressing of future operational requirements	Grid improvement investments directly enable the deployment of advanced grid capabilities including FLISR, Volt-VAR optimization, and enhanced DER monitoring and control. These capabilities support the transition to a more dynamic and resilient distribution system.

Environmental Benefits

Not Applicable

Non-Wires Solutions Consideration

Enova's consideration of non-wires solutions for this program is documented in accordance with the NWS Guidelines (EB-2024-0118) and the BCA Framework. See details below.

Benefit-Cost Analysis Framework (5.4.2.2.)

Not Applicable (below $2M threshold)

Fleet Replacement Program

General Information on the project/program (5.4.2.1.A)

Project Name Fleet Replacement Program
Program Code G-FL
OEB Investment Category General Plant

Project Description

This program provides for the condition-based replacement of Enova Power's fleet of vehicles, trucks, trailers, and specialized equipment used to construct, maintain, and operate the electricity distribution system. The 2027 program encompasses four categories of fleet assets:

Large Trucks: Replacement of large specialized utility vehicles including a new digger derrick for the Cambridge Service area (CS), a new material handler / 55' single bucket truck for CS, and service trucks for the Waterloo Service area (VS). These vehicles are essential for overhead line construction, maintenance, and emergency restoration work.

Medium Trucks: Replacement of medium-sized utility vehicles including a new cable pulling truck for VS and a new box truck for the construction department. These vehicles support underground cable installation, material transport, and construction crew operations.

Small Vehicles: Replacement of light-duty vehicles used by field staff, supervisors, and technical personnel for daily operational activities including inspections, customer site visits, and project oversight.

Equipment and Trailers: Replacement of specialized equipment and trailers including a new wood chipper for VS, a scrubber sweeper for CS, and four new trailers used to transport equipment and materials to job sites.

All vehicles and equipment identified for replacement have been assessed by Enova's fleet mechanics as being in poor condition, with increasing breakdown frequency, escalating maintenance costs, and declining reliability that impacts crew productivity and operational effectiveness.

Detailed SubProjects

The following individual projects are covered by this project category:

Enova Project	Sub Project	Project Name	Total
G-FL		Replacement of Large Trucks	$1,550,000
G-FL		Replacement of Medium Trucks	$930,000
G-FL		Replacement of Small Vehicles	$295,000
G-FL		Replacement of Equipment and Trailers	$540,000
		Total	$3,315,000

Capital Investment

Total Capital **$3,315,000**

O&M Costs (if applicable) **$0** Not Applicable

Capital Contributions to a Transmitter

CCRA Contribution $0

Customer Attachments/Load (kVA)

Customer Attachments (#): NA
Customer Load (peak kVA) NA

Project Timing

Start Date January 1, 2027 Engineering & Procurement
End Date December 31, 2027 Construction

Expected In-Service Date December 1, 2027

Expenditure Timing

2027	5%	$3,315,000

Schedule Risk and Risk Mitigation

The timing of vehicle and equipment deliveries can be disrupted by supply chain issues, particularly for large specialized utility trucks (digger derricks, bucket trucks, cable pullers) which have extended manufacturing lead times. To mitigate this risk, Enova places orders well in advance of the planned delivery date. All large and medium trucks in the 2027 program were ordered in advance and are currently on schedule for delivery.

For trailers and equipment, orders are placed before year-end to secure production slots and mitigate supply chain disruption. Small vehicle replacements are sourced through fleet dealer networks with shorter lead times and carry lower scheduling risk.

Deferral of fleet replacement is not recommended as it increases the frequency of vehicle breakdowns, reduces crew availability for planned and emergency distribution work, escalates maintenance costs, and may compromise worker safety.

Comparative Information

Comparable investments in previous years are as follows:

2020:	$1,093,947
2021:	$1,492,907
2022:	$1,794,058
2023:	$2,011,257
2024:	$1,955,370
2025:	$3,475,699
2026 (Bridge):	
2027:	$3,315,000

Total Capital & OM&A Costs Associated with REG Investments

Not Applicable

Leave to Construct Approval

Not Applicable

Evaluation Criteria and information requirements for each project/program (5.4.2.1.B)

Efficiency, Customer Value, Reliability

Main Driver	The main driver for this program is that the condition of the vehicles, trucks, trailers, and equipment has been assessed as poor by Enova's fleet mechanics. The operating and maintenance costs to keep the aging fleet operational are escalating, and reliability concerns require replacement. The units are breaking down more frequently, resulting in increased downtime and reduced crew availability for planned and emergency distribution work. All assets identified for replacement have been individually assessed through Enova's condition-based fleet assessment program.
Related Objectives/Performance Targets	Enova Strategic Objectives: Asset Renewal and Health, Safety & Environment, with an indirect contribution to Reliability Performance through crew availability and restoration responsiveness, as identified in the DSP.
Source and Nature of the Information Used to Justify the Investment	The investment is justified through Enova's fleet replacement program. Fleet mechanics perform condition assessments on all vehicles and equipment, evaluating mechanical condition, safety compliance, maintenance cost trends, and remaining useful life. Vehicles assessed as poor condition with escalating maintenance costs and increasing breakdown frequency are recommended for replacement.
Secondary Driver(s)	Improve crew efficiency by providing more reliable and modern vehicles and equipment to execute planned and emergency distribution work. Newer vehicles also incorporate updated safety features and improved ergonomics that support employee well-being.
Good Utility Practice	It is good utility practice to operate a condition-based fleet replacement program that retires assets at end of useful life before failure rates and maintenance costs escalate, maintaining crew availability and safety. Enova's fleet replacement program is informed by manufacturer-recommended service life guidelines, actual condition assessments performed by qualified mechanics, and maintenance cost trend analysis.
Investment Priority	System Access investments are ranked as top priority, as they are mandated by regulation or code. Under the General Plant category, Enova identifies underperforming assets or processes based on feedback received from customers, vendors, staff, tracking of performance, operating and maintenance costs. Enova also identifies opportunities for improvement in its ability to meet the Enova Strategic Objectives and compiles a complete list of projects for this category. Projects that are driven by regulatory compliance or policy responsiveness are prioritized for immediate execution. To prioritize the execution of the remaining projects, Enova takes into account the criticality of the impacted assets as well as additional drivers or benefits of completing the project. This typically includes improvements in: customer experience, worker safety, security, ability to continue to provide services to customers, opportunity for cost reduction, increase in productivity, operating efficiency, ability to operate and maintain systems, ability to adapt to future needs, and regulatory compliance. The greater the alignment with Enova Strategic Objectives, the greater the customer impact or the more drivers or benefits are attributed to a project, the higher its priority. Investments in System Service and System Renewal categories are prioritized in a similar fashion. Analysis of the impact on customers and consideration of the impact of project deferral are also considered. The compiled list of projects is reviewed and prioritized by Senior Enova Engineering, Operations, IT and Finance
Analysis of the Project and Project Alternatives	The following alternatives were considered: a) Do Nothing / Defer Replacement – Delaying replacement would increase vehicle downtime, reduce crew availability, escalate maintenance costs, and potentially compromise worker safety. Not appropriate for vehicles assessed as poor condition. b) Lease Instead of Purchase – Not practical for specialized utility trucks (digger derricks, bucket trucks, cable pullers) as these are custom-built and not available through standard fleet leasing programs. c) Purchase Replacement Vehicles (Preferred) – Replacement vehicles are specified to meet operational requirements and procured through competitive processes. Like-for-like replacement is the standard approach.
Effect on system operation efficiency and cost effectiveness	The operational impact will be to improve the efficiency of work performed by distribution crews through more reliable equipment with reduced breakdown frequency. Newer vehicles also provide improved fuel efficiency and reduced maintenance costs compared to the aging units being retired.
Net benefits accruing to customers	Reduces the cost of ongoing distribution capital and maintenance projects by ensuring crew availability with reliable equipment. Reliable fleet assets support timely execution of planned capital work and rapid response to emergency outage restoration, both of which directly benefit customer service and reliability.
Impact of Investment on reliability performance (including on the frequency and duration of outages)	Reliable fleet equipment ensures that crews can perform repairs and installation of new equipment with minimal delays caused by vehicle breakdowns. Large trucks (digger derricks, bucket trucks) are critical for overhead emergency restoration; medium trucks (cable pullers) are essential for underground fault repair. Equipment reliability directly affects the duration of sustained outages.
Scheduling Alternatives	Not Applicable
Ownership and/or Funding Alternatives	Not Applicable

Safety

The replacement of aging fleet assets improves safety for crews as they operate vehicles with the latest safety technology and equipment that is less prone to mechanical failure. Modern utility trucks incorporate updated operator safety features, improved hydraulic system controls, and current compliance with Transport Canada and MTO regulations.

Cyber-security, Privacy

Not Applicable

Co-ordination, Interoperability

Coordination with utilities, regional planning and/or links with 3rd parties (where applicable)	Not Applicable
Enabling of future technological functionality or addressing of future operational requirements	Not Applicable

Environmental Benefits

Not Applicable

Non-Wires Solutions Consideration

Enova's consideration of non-wires solutions for this program is documented in accordance with the NWS Guidelines (EB-2024-0118) and the BCA Framework. See details below.

Benefit-Cost Analysis Framework (5.4.2.2.)

Not Applicable — The Benefit-Cost Analysis Framework (Section 5.4.2.2) applies to electricity distribution system investments where non-wires or system alternatives can be evaluated. This is a General Plant (Fleet) program assessed on asset condition and operational necessity. General Plant investments are explicitly excluded from the BCA Framework's scope per the NWS Guidelines (Section 3.2), which states the requirement applies to "electricity system needs with an expected capital cost of $2 million or more, excluding general plant investments."

Customer Information System (CIS) Major Release Upgrade

General Information on the project/program (5.4.2.1.A)

Project Name Customer Information System (CIS) Major Release Upgrade
Program Code G-SW-IT
OEB Investment Category General Plant

Project Description Perform technical upgrade of CIS system (Oracle's CC&B) from current release version (2.7.3) to a version that will continue to receive support.
Detailed SubProjects The following individual projects are covered by this project category:

Enova Project	Sub Project	Project Name	Total
CIS Upgrade		G-SW-IT Software	**$3,533,333**
		Total	**$3,533,333**

Capital Investment
Total Capital **$3,533,333**
O&M Costs (if applicable) **$0** Not Applicable

Capital Contributions to a Transmitter CCRA Contribution $0

Customer Attachments/Load (kVA)
Customer Attachments (#): NA
Customer Load (peak kVA) NA

Project Timing
Start Date January 1, 2027 Research and Design
End Date December 31, 2027 Post Go-Live Activities

Expected In-Service Date December 1, 2027

Expenditure Timing

2027	100%	$3,533,333

Schedule Risk and Risk Mitigation Major CIS upgrades require coordination across multiple business units and contractors including but not limited to: Finance, Regulatory, Billing, Customer Service, Collections, Metering, Information Technology and Engineering. In addition, due to the complexity of these systems and their interactions with external parties, several market activities must be carefully coordinated with parties such as: Provincial MDM/R, retailer market transactions, customer portals, Ontario Energy Board reporting, financial institutions, and customer-facing systems. Project risks are mitigated through careful procurement, resource planning and the use of external consultants for high-complexity work.

Comparative Information Comparable investments in previous years are as follows:

2020:	$0
2021:	$0
2022:	$0
2023:	$0
2024:	$680,000
2025:	$0
2026 (Bridge):	$1,500,000

Total Capital & OM&A Costs Associated with REG Investments Not Applicable

Leave to Construct Approval Not Applicable

Evaluation Criteria and information requirements for each project/program (5.4.2.1.B)

Efficiency, Customer Value, Reliability

Main Driver	Standard support for this product ended on September 2023 with an option to extend until September 2026. After September 2026 there are no support options from Oracle for this product and an upgrade is required to continue to have product support for this business application.
Related Objectives/Performance Targets	Enova Strategic Objectives: Asset Renewal, Customer-Centric Services and Cyber-Security, as identified in the DSP. This project primarily affects Customer Service continuity and Cyber-Security.
Source and Nature of the Information Used to Justify the Investment	This investment is justified through Enova's Digital Strategy and cyber-security practices.
Secondary Driver(s)	Improve customer experience and support staff efficiency through the use of identified features available in the next product version.
Good Utility Practice	It is good practice to maintain software systems and avoid running versions beyond their end of life.
Investment Priority	System Access investments are ranked as top priority, as they are mandated by regulation or code. Under the General Plant category, Enova identifies underperforming assets or processes based on feedback received from customers, vendors, staff, tracking of performance, operating and maintenance costs. Enova also identifies opportunities for improvement in its ability to meet the Enova Strategic Objectives and compiles a complete list of projects for this category. Projects that are driven by regulatory compliance or policy responsiveness are prioritized for immediate execution. To prioritize the execution of the remaining projects, Enova takes into account the criticality of the impacted assets as well as additional drivers or benefits of completing the project. This typically includes improvements in: customer experience, worker safety, security, ability to continue to provide services to customers, opportunity for cost reduction, increase in productivity, operating efficiency, ability to operate and maintain systems, ability to adapt to future needs, and regulatory compliance. The greater the alignment with Enova Strategic Objectives, the greater the customer impact or the more drivers or benefits are attributed to a project, the higher its priority. Investments in System Service and System Renewal categories are prioritized in a similar fashion. Analysis of the impact on customers and consideration of the impact of project deferral are also considered. The compiled list of projects is reviewed and prioritized by Senior Enova Engineering, Operations, IT and Finance staff. Based on the outcome of this process, this program ranks 10 out of 25. Refer to the DSP prioritization table for further details.
Analysis of the Project and Project Alternatives	Alternatives available are either much more costly (Switch to a different CIS system) or pose too great a risk (run without vendor support).
Effect on system operation efficiency and cost effectiveness	Operational effieiency is not a driver of this project. However, it is expected that there will be mild improvements based on new features available in the next version.
Net benefits accruing to customers	Continued accurate customer service and billing.
Impact of Investment on reliability performance (including on the frequency and duration of outages)	This project is not expected to impact supply or reliability.
Scheduling Alternatives	There are no scheduling alternatives as this upgrade will already run past the version end of life date of September 2026.
Ownership and/or Funding Alternatives	No alternative ownership models are available for this system that comply with market regulations.

Safety

It is not expected that Enova staff or customer physical safety will be affected by this upgrade.

Cyber-security, Privacy

This upgrade will have a significant impact on cyber-security as many application dependencies required by the current version (2.7.3) carry significant known risks.

Co-ordination, Interoperability

Coordination with utilities, regional planning and/or links with 3rd parties (where applicable)	This upgrade requires co-ordination with customers and several integration 3rd parties.
Enabling of future technological functionality or addressing of future operational requirements	This upgrade will enable a higher level of technical agility making it possible for future customer facing technology to be implemented or better implemented than without the upgrade.

Environmental Benefits

Not Applicable

Non-Wires Solutions Consideration

Enova's consideration of non-wires solutions for this program is documented in accordance with the NWS Guidelines (EB-2024-0118) and the BCA Framework. See details below.

Benefit-Cost Analysis Framework (5.4.2.2.)

Not Applicable — on substance. The Benefit-Cost Analysis Framework (5.4.2.2) applies to engineering / distribution-system investments where non-wires or system alternatives can be evaluated. This is a General Plant (IT software) program assessed on vendor support, lifecycle/asset condition and cyber-security, so the BCA Framework does not apply on substance.

General Information on the project/program (5.4.2.1.A)

Project Name Customer Information System (CIS) Major Systems
Program Code G-SW-IT
OEB Investment Category General Plant

Project Description
Perform annual work required to maintain a healthy CIS system. This includes but is not limited to projects to meet regulatory market needs, enhancements to business process flow to improve staff efficiency as well as customer experience

Detailed SubProjects
The following individual projects are covered by this project category:

Enova Project	Sub Project	Project Name	Total
Major Systems	CIS - Technical	G-SW-IT Software	**$300,000**
Major Systems	CIS - Business Improvem	G-SW-IT Software	**$950,000**
Major Systems	CIS - Regulatory	G-SW-IT Software	**$300,000**
		Total	**$1,550,000**

Capital Investment
Total Capital **$1,550,000**
O&M Costs (if applicable) **$0** Not Applicable

Capital Contributions to a Transmitter
CCRA Contribution $0

Customer Attachments/Load (kVA)
Customer Attachments (#): NA
Customer Load (peak kVA) NA

Project Timing
Start Date January 1, 2027 Research and Design
End Date December 31, 2027 Post Go-Live Activities

Expected In-Service Date December 1, 2027

Expenditure Timing
2027 100% $1,550,000

Schedule Risk and Risk Mitigation
This project was identified through planning the overall program for all major systems and is designed to avoid the risk of allowing systems to atrophy. Project risks are mitigated through careful procurement, resource planning and the use of external consultants for high complexity work

Comparative Information
Comparable investments in previous years are as follows:
2020: $0
2021: $0
2022: $0
2023: $400,000
2024: $1,175,000
2025: $1,034,000
2026 (Bridge): $900,000

Total Capital & OM&A Costs Associated with REG Investments
Not Applicable

Leave to Construct Approval
Not Applicable

Evaluation Criteria and information requirements for each project/program (5.4.2.1.B)

Efficiency, Customer Value, Reliability

Main Driver	The primary driver of this program is to extend the useful life of this asset by maintaining system health.
Related Objectives/Performance Targets	Enova Strategic Objectives: Asset Renewal, Regulatory Compliance and Customer-Centric Services, as identified in the DSP.
Source and Nature of the Information Used to Justify the Investment	This investment is justified through Enova's Digital Strategy and cyber-security practices.
Secondary Driver(s)	Maintain regulatory compliance, Improve customer experience and support staff efficiency by reducing technical debt and increasing the efficient use of technology. In addition as well as extending business capability and keeping the technical frameworks current.
Good Utility Practice	Maintaining an "evergreen program" for critical business systems is a good practice within utilities.
Investment Priority	System Access investments are ranked as top priority, as they are mandated by regulation or code. Under the General Plant category, Enova identifies underperforming assets or processes based on feedback received from customers, vendors, staff, tracking of performance, operating and maintenance costs. Enova also identifies opportunities for improvement in its ability to meet the Enova Strategic Objectives and compiles a complete list of projects for this category. Projects that are driven by regulatory compliance or policy responsiveness are prioritized for immediate execution. To prioritize the execution of the remaining projects, Enova takes into account the criticality of the impacted assets as well as additional drivers or benefits of completing the project. This typically includes improvements in: customer experience, worker safety, security, ability to continue to provide services to customers, opportunity for cost reduction, increase in productivity, operating efficiency, ability to operate and maintain systems, ability to adapt to future needs, and regulatory compliance. The greater the alignment with Enova Strategic Objectives, the greater the customer impact or the more drivers or benefits are attributed to a project, the higher its priority. Investments in System Service and System Renewal categories are prioritized in a similar fashion. Analysis of the impact on customers and consideration of the impact of project deferral are also considered. The compiled list of projects is reviewed and prioritized by Senior Enova Engineering, Operations, IT and Finance staff. Based on the outcome of this process, this program ranks 10 out of 25. Refer to the DSP prioritization table for further details.
Analysis of the Project and Project Alternatives	This is an essential project for continued business operation.
Effect on system operation efficiency and cost effectiveness	Over time these improvements are expected to reduce OM&A spending on external support for this system.
Net benefits accruing to customers	Incremental improvements on customer experience related to billing and customer service.
Impact of Investment on reliability performance (including on the frequency and duration of outages)	This project is not expected to impact supply or reliability.
Scheduling Alternatives	There are no scheduling alternatives as major business systems require regular investment and often have new regulatory requirements
Ownership and/or Funding Alternatives	No alternative ownership models are available for this system that comply with market regulations

Safety

It is not expected that Enova staff or customer physical safety will be affected by this upgrade

Cyber-security, Privacy

These improvements will have incremental upgrades to this system's cyber security posture through introduction of further automation, platform excellence and internal staff knowledge

Co-ordination, Interoperability

Coordination with utilities, regional planning and/or links with 3rd parties (where applicable)	This project requires co-ordination with customers and several integration 3rd parties.
Enabling of future technological functionality or addressing of future operational requirements	This upgrade will enable a higher level of technical agility making it possible for future customer facing technology to be implemented or better implemented than without the upgrade.

Environmental Benefits

Not Applicable

Non-Wires Solutions Consideration

Enova's consideration of non-wires solutions for this program is documented in accordance with the NWS Guidelines (EB-2024-0118) and the BCA Framework. See details below.

Benefit-Cost Analysis Framework (5.4.2.2.)

Not Applicable — on substance. The Benefit-Cost Analysis Framework (5.4.2.2) applies to engineering / distribution-system investments where non-wires or system alternatives can be evaluated. This is a General Plant (IT software) program assessed on vendor support, lifecycle/asset condition and cyber-security, so the BCA Framework does not apply on substance.

General Information on the project/program (5.4.2.1.A)

Project Name Facility Renovation – Victoria Street Property
Program Code G-BL (Buildings)
OEB Investment Category General Plant

Project Description

This project involves the renovation of Enova Power's Victoria Street Property located at 301 Victoria Street South, Kitchener, Ontario. The Victoria Street Property serves as Enova Power's head office and primary operations centre, originally built in 1982 with subsequent additions in 1987 and 2003. The property comprises approximately 112,483 square feet (10,450 m²) of commercially zoned land including main office, south office spaces, warehouse, and vehicle garage.

The Facility Renovation addresses three critical requirements:

1. HVAC System Replacement: The existing HVAC system was installed 41 years ago and has significantly exceeded its estimated useful life of 20 to 25 years. The system is increasingly incapable of delivering consistent temperature control, with documented instances of temperatures outside acceptable ranges. Advancements in HVAC technology have rendered the equipment outdated in terms of energy efficiency and performance. Most critically, the age and condition of the current system create a heightened risk of catastrophic failure that could disable the facility's ability to operate. The replacement involves installation of an Air Source Variable Refrigerant Flow (VRF) and Dedicated Outside Air System with Energy Recovery in the main and south offices, and conversion of the warehouse and garage heating from natural gas-fired radiant tube heaters to overhead electric radiant heating.

2. Interior Renovations: The Victoria Street Property's interior design and infrastructure no longer meet the demands of a modern utility workplace. The office was originally designed to support a smaller workforce with different operational requirements. Outdated building systems including lighting, HVAC, and IT/communications cabling undermine operational efficiency and employee experience. The renovation will modernize the workspace to support Enova Power's current and future operational needs.

3. Customer Service Centre Accessibility: The existing customer service centre requires significant remodelling to improve accessibility in compliance with the Accessibility for Ontarians with Disabilities Act (AODA). The current layout requires customers with mobility challenges to navigate an accessible ramp, a small foyer, and then use an elevator to reach the main floor, creating barriers that do not meet contemporary accessibility standards. The renovation includes a new accessible main customer entrance at grade with the parking lot, eliminating the need for ramp and elevator access and providing an approximately 1,500 square foot expansion of the customer service area.

The information presented here contains the full project scope, including 2026 and 2027 components and costs.

Detailed SubProjects

The following components are covered by this project:

Enova Project	Sub Project	Project Name	Total
G-BL	Additions	Customer Service Centre Accessibility Expansion (1,500 sq. ft.)	**$1,779,323**
G-BL	Renovations	Interior Renovations – Office Modernization	**$6,611,242**
G-BL	Mechanical	HVAC System Replacement (VRF + Radiant Heating)	**$4,567,008**
		Total (Full Project)	**$12,957,573**

Capital Investment

Total Capital **$12,957,573**

O&M Costs (if applicable) **$0**

Capital Contributions to a Transmitter

CCRA Contribution $0

Customer Attachments/Load (kVA)

Customer Attachments (#): N/A
Customer Load (peak kVA) N/A

Project Timing

Start Date Q2 2026
Expected In-Service Date Q2 2027

Expenditure Timing Expecting the project to be completed by 2027 Q2

Schedule Risk and Risk Mitigation

The primary schedule risk for this project is coordinating the renovation of the temporary space for relocated employees before construction activities begin. This decision was made to reduce the total construction cost and timeline by providing an empty building for construction. Enova Power's customer service needed to be relocated to another location on the property over one weekend to remain operational throughout the renovation period. Customers needed to find the new entrance and employees needed to pivot to a new customer entrance to continue providing in-person customer service for dozens of customers per day.

Supply chain risks related to VRF equipment lead times have been identified and are being mitigated through early procurement engagement with equipment suppliers. The general contractor selection process will incorporate supply chain assurance requirements.

The customer service centre accessibility expansion involves minor structural work (new entrance at grade) which must be coordinated with the interior renovation schedule. Enova Power will establish a temporary customer service location at the opposite side of the property for the duration of the construction period.

Comparative Information

Comparable investments in previous years are as follows:

2020: N/A
2021: N/A
2022: N/A
2023: N/A
2024: N/A
2025: N/A
2026: N/A
2027: $12,978,250

Total Capital & OM&A Costs Associated with REG Investments Not Applicable

Leave to Construct Approval Not Applicable

Evaluation Criteria and information requirements for each project/program (5.4.2.1.B)

Efficiency, Customer Value, Reliability

Main Driver	The main driver for this project is the critical condition of the HVAC system at Enova Power's Victoria Street Property. The existing system was installed 41 years ago and has significantly exceeded its estimated useful life of 20 to 25 years. The system is increasingly incapable of delivering consistent temperature control, and the age and condition create a heightened risk of catastrophic failure that could render the facility inoperable. A full HVAC failure during extreme weather conditions would disrupt utility operations, including the control room, dispatch, engineering, and customer service functions that are essential to the safe and reliable operation of the distribution system. Secondary drivers include: (a) the need to modernize interior workspace to support operational effectiveness and staff retention, and (b) to improve accessibility, functionality, and overall customer experience anf the requirement to bring the customer service centre into compliance with contemporary accessibility standards
Related Objectives/Performance Targets	Enova Strategic Objectives: Health, Safety and Environment (HVAC failure risk mitigation, GHG reduction through electrification); Organizational Culture (modern workplace supporting staff retention and recruitment); Customer Centric Services (accessible customer service centre compliant with AODA requirements).
Source and Nature of the Information Used to Justify the Investment	The source of the information used to justify this investment includes: HVAC Assessment: Enova Power commissioned Walter-Fedy, a recognized engineering consulting firm, to produce a Level 2 Energy Audit for the Victoria Street Property. The audit identified and analyzed alternative HVAC system retrofit options ranging from targeted replacements to comprehensive building electrification. The audit confirmed that the existing system has exceeded its useful life and recommended the Air Source VRF system as the most cost-effective electrification option. Space Planning: A Space Planning Audit was performed to evaluate departmental requirements and identify the optimal layout for the renovated facility. The audit assessed current and projected staffing levels, operational workflows, and workplace design standards. Benchmarking: Enova Power completed a benchmarking scan comparing the proposed renovation to facility investments approved by the OEB for other Ontario electricity distributors, including Centre Wellington Hydro (EB-2024-0012), Milton Hydro (EB-2022-0049), Essex Powerlines (EB-2024-0022), and others.
Secondary Driver(s)	Workforce modernization: The highly dated interior finishes, furniture, and overall design are out of step with contemporary office standards. Employees expect a modern, professional work environment. The renovation supports staff retention and recruitment in a competitive labour market. Electrification and GHG reduction: The HVAC upgrade converts the facility from natural gas-fired heating to electric air-source VRF, achieving an estimated 76.9% reduction in total GHG emissions and 99.8% reduction in natural gas consumption. Annual utility costs are projected to decrease by approximately $19,200.
Good Utility Practice	Enova Power engaged qualified professional consultants (Walter-Fedy for the Level 2 Energy Audit and space planning) to assess facility conditions and evaluate alternatives. The options analysis considered five distinct alternatives ranging from do-nothing to comprehensive renovation, with the preferred option (Option 3) selected as the most cost-effective solution that addresses all identified requirements. The benchmarking analysis demonstrates that facility renovation investments have been approved by the OEB for comparable Ontario electricity distributors under both Cost of Service and ICM frameworks. The project cost on a per-square-foot basis is within the range of approved precedents.
Investment Priority	System Access investments are ranked as top priority, as they are mandated by regulation or code. Under the General Plant category, Enova identifies underperforming assets or processes based on feedback received from customers, vendors, staff, tracking of performance, operating and maintenance costs. Enova also identifies opportunities for improvement in its ability to meet the Enova Strategic Priorities and compiles a complete list of projects for this category. Projects that are driven by regulatory compliance or policy responsiveness are prioritized for immediate execution. To prioritize the execution of the remaining projects, Enova takes into account the criticality of the impacted assets as well as additional drivers or benefits of completing the project. This typically includes improvements in: customer experience, worker safety, security, ability to continue to provide services to customers, opportunity for cost reduction, increase in productivity, operating efficiency, ability to operate and maintain systems, ability to adapt to future needs, and regulatory compliance. The greater the alignment with Enova Strategic Objectives, the greater the customer impact or the more drivers or benefits are attributed to a project, the higher its priority. Investments in System Service and System Renewal categories are prioritized in a similar fashion. Analysis of the impact on customers and consideration of the impact of project deferral are also considered. The compiled list of projects is reviewed and prioritized by Senior Enova Engineering, Operations, IT and Finance staff. Based on the outcome of this process, this program ranks 16 out of 25. Refer to the DSP prioritization table for further details.
Analysis of the Project and Project Alternatives	Enova Power completed a detailed options analysis evaluating five alternatives: a) Option 1: Do Nothing – No improvements or changes. Maintains and increases the risk of HVAC system failure, compromises workplace conditions, and does not address accessibility deficiencies. 2027 Capital: $0. This option is not considered appropriate due to the heightened risk of catastrophic HVAC failure. b) Option 2: HVAC Upgrade Only (Air-source VRF) – Replaces the HVAC system without interior renovations or accessibility improvements. 2027 Capital: $4.7M. NPV of revenue requirement (40 years): $11.3M. This option was not selected as it does not address interior condition or accessibility requirements. c) Option 3: HVAC Upgrade + Interior Renovations + Accessibility Expansion (1,500 sq. ft.) [PREFERRED] – Replaces the HVAC system, modernizes the interior, and provides an accessible grade-level customer entrance with 1,500 sq. ft. expansion. 2027 Capital: $12.9M NPV of revenue requirement (40 years): $22.1M. This is the preferred option as it addresses all identified requirements at the most cost-effective scale. d) Option 4: HVAC + Renovations + Larger Accessibility Expansion (3,000 sq. ft.) – Same as Option 3 but with a larger 3,000 sq. ft. expansion. 2027 Capital: $20.5M. NPV: $31.9M. Not selected due to the incremental cost not being justified by the additional space. e) Option 5: Comprehensive HVAC + Renovations + Larger Expansion – Includes the Walter-Fedy "Comprehensive" HVAC cluster (domestic hot water, upgraded LED lighting, envelope improvements). 2027 Capital: $34.1M. NPV: $43.4M. Not selected due to the significantly higher capital cost ($34.1M for the Comprehensive HVAC cluster alone). Additionally, Enova Power considered and dismissed: (i) consolidating all staff into one existing building (infeasible due to space constraints), and (ii) selling both legacy properties and acquiring a new facility (dismissed on the basis of cost).
Effect on system operation efficiency and cost effectiveness	The HVAC electrification is projected to reduce annual utility costs by approximately $19,200 (from $218,544 to $199,345 per year). The modernized workspace will improve operational efficiency through better lighting, IT/communications infrastructure, and workspace design. The renovation is expected to reduce ongoing maintenance costs associated with the legacy HVAC system.
Net benefits accruing to customers	The Facility Renovation provides the following benefits to customers: (a) elimination of the risk of catastrophic HVAC failure that could disrupt utility operations including control room, dispatch, and customer service; (b) a modern, accessible customer service centre that meets AODA standards and provides an improved in-person customer experience; (c) GHG reduction of 76.9% supporting Ontario's electrification objectives; and (d) improved employee retention and productivity supporting the utility's ability to deliver reliable service.
Impact of Investment on reliability performance (including on the frequency and duration of outages)	The Facility Renovation is a General Plant investment and does not directly impact distribution system reliability metrics (SAIDI/SAIFI). However, the HVAC system replacement mitigates the risk of facility disruption that could affect control room and dispatch operations, which are critical to outage management and system restoration.

Scheduling Alternatives	The HVAC system replacement is the most time-critical component due to the risk of catastrophic failure. Deferral increases the probability of an uncontrolled failure during extreme weather, which could force emergency procurement at significantly higher cost and with extended lead times. Enova Power has determined that the renovation should proceed as planned to manage this risk. The interior renovation and accessibility components could theoretically be deferred, but combining them with the HVAC replacement achieves construction efficiencies (single mobilization, coordinated phasing, reduced total disruption period) that would be lost if the components were executed separately.
Ownership and/or Funding Alternatives	The Victoria Street Property is owned by Enova Power. The Facility Renovation will be funded through the OEB's Incremental Capital Module framework, with the incremental revenue requirement recovered through ICM rate riders applied to Enova Power's Kitchener-Wilmot and Waterloo North rate zones. The annual incremental revenue requirement is $1.3M, resulting in residential bill impacts of $0.40/month (KWRZ) and $0.39/month (WNRZ), representing approximately 0.32% and 0.28% of the total bill respectively.

Safety

The HVAC system replacement addresses employee health and safety risks associated with inconsistent temperature control and the potential for catastrophic system failure. The interior renovation will incorporate modern fire safety systems, improved lighting, and ergonomic workstation design. The customer service accessibility improvements will eliminate physical barriers for customers with mobility challenges, improving public safety and compliance with AODA requirements.

Cyber-security, Privacy

Not Applicable

Co-ordination, Interoperability

Coordination with utilities, regional planning and/or links with 3rd parties (where applicable)	The Facility Renovation is an internal project at Enova Power's owned property. Coordination with the City of Kitchener is required for building permit approvals and any site plan amendments associated with the customer service centre expansion. Enova Power will coordinate with the Electrical Safety Authority for any electrical work associated with the HVAC electrification.
Enabling of future technological functionality or addressing of future operational requirements	The interior renovation will incorporate modern IT and communications infrastructure, including structured cabling and network capacity to support future operational technology requirements. The HVAC electrification aligns with the Province's electrification objectives and eliminates Enova Power's reliance on natural gas for space heating at its primary facility.

Environmental Benefits

The HVAC electrification achieves an estimated 76.9% reduction in total facility GHG emissions and a 99.8% reduction in natural gas consumption. Utility electricity consumption is projected to decrease by approximately 17% through the efficiency gains of the VRF system compared to the legacy equipment. These environmental benefits support Ontario's broader electrification and decarbonization objectives.

Non-Wires Solutions Consideration

Enova's consideration of non-wires solutions for this program is documented in accordance with the NWS Guidelines (EB-2024-0118) and the BCA Framework. See details below.

Benefit-Cost Analysis Framework (5.4.2.2.)

Not Applicable — on substance. The Benefit-Cost Analysis Framework (5.4.2.2) applies to engineering / distribution-system investments where non-wires or system alternatives can be evaluated. This is a General Plant (Facility) program, so the BCA Framework does not apply on substance.

APPENDIX B-1

Asset Condition Assessment (ACA) Report

DISTRIBUTION ASSETS CONDITION ASSESSMENT REPORT (ACA)



June 30, 2026

TABLE OF CONTENTS

TABLE OF CONTENTS ..... **ii**

LIST OF TABLES ..... **v**

LIST OF FIGURES ..... **viii**

1 INTRODUCTION **1**

1.1 Assets Under Study 2

1.2 Asset Condition Assessment Methodology 3

1.3 Asset Management Policy 6

2 ASSET CONDITION ASSESSMENTS **7**

2.1 STATION (TS) SWITCHYARD EQUIPMENT 8

2.1.1 Asset Demographics 8

2.1.2 Condition Assessment Criteria 9

2.1.3 Condition Assessments 9

2.1.4 Data Availability Indicator 11

2.1.5 Analysis of Results 11

2.2 STATION (TS) SWITCHES / CIRCUIT SWITCHERS 12

2.2.1 Asset Demographics 12

2.2.2 Condition Assessment Criteria 13

2.2.3 Condition Assessments 15

2.2.4 Data Availability Indicator 16

2.2.5 Analysis of Results 16

2.3 STATION (TS) TRANSFORMERS 18

2.3.1 Asset Demographics 18

2.3.2 Condition Assessment Criteria 20

2.3.3 Condition Assessments 21

2.3.4 Data Availability Indicator 22

2.3.5 Analysis of Results 22

2.4 STATION (TS) SWITCHGEAR 24

2.4.1 Asset Demographics 24

2.4.2 Condition Assessment Criteria 26

2.4.3 Condition Assessments 27

2.4.4 Data Availability Indicator 28

2.4.5 Analysis of Results 28

2.5 STATION (TS & DS) CIRCUIT BREAKERS 30

2.5.1 Asset Demographics 30

2.5.2 Condition Assessment Criteria 31

2.5.3 Condition Assessments 33
2.5.4 Data Availability Indicator 34
2.5.5 Analysis of Results 34
2.6 STATION (TS) FEEDER CABLES 36
2.6.1 Asset Demographics 36
2.6.2 Condition Assessment Criteria 37
2.6.3 Condition Assessments 39
2.6.4 Data Availability Indicator 39
2.6.5 Analysis of Results 39
2.7 STATION (TS) PROTECTION RELAYS 41
2.7.1 Asset Demographics 41
2.7.2 Condition Assessment Criteria 42
2.7.3 Condition Assessments 43
2.7.4 Data Availability Indicator 46
2.7.5 Analysis of Results 46
2.8 DISTRIBUTION STATION (DS) TRANSFORMERS 47
2.8.1 Asset Demographics 47
2.8.2 Condition Assessment Criteria 47
2.8.3 Condition Assessments 48
2.8.4 Data Availability Indicator (DAI) 49
2.8.5 Analysis of Results 49
2.9 POLES 51
2.9.1 Asset Demographics 51
2.9.2 Condition Assessment Criteria 52
2.9.3 Condition Assessments 53
2.9.4 Data Availability Indicator (DAI) 57
2.9.5 Analysis of Results 57
2.10 PRIMARY UNDERGROUND DISTRIBUTION CABLES 59
2.10.1 Asset Demographics 59
2.10.2 Condition Assessment Criteria 63
2.10.3 Condition Assessments 65
2.10.4 Data Availability Indicator (DAI) 66
2.10.5 Analysis of Results 67
2.11 DISTRIBUTION TRANSFORMERS 69
2.11.1 Asset Demographics 69
2.11.2 Condition Assessment Criteria 72
2.11.3 Condition Assessments 75

2.11.4 Data Availability Indicator (DAI) 76
2.11.5 Analysis of Results 76
2.12 REVENUE METERING 78
2.12.1 Asset Demographics 78
2.12.2 Condition Assessment Criteria 81
2.12.3 Condition Assessments 83
2.12.4 Data Availability Indicator (DAI) 85
2.12.5 Analysis of Results 85
3 SUMMARY 88

LIST OF TABLES

Table 1-1: Assets Under Study 2
Table 1-2: Asset Condition based on Health Index 5
Table 2-1: TS Station Switchyards 9
Table 2-2: Station Switchyard Equipment TUL 9
Table 2-3: TS Station Switchyard Equipment Condition Assessments 11
Table 2-4: TS HV Switches / Circuit Switchers 12
Table 2-5: TS HV Circuit Switches / Circuit Switchers (TUL) 13
Table 2-6: Station HV Circuit Switches Condition Assessment Criteria 14
Table 2-7a: Station HV Switches / Circuit Switches Condition Assessments 15
Table 2-7b: Station HV Switches / Circuit Switches Condition Assessments 15
Table 2-8: TS Large Power Transformers (In-service) 18
Table 2-9: TS Step Up / Step Down Transformer Demographics 19
Table 2-10: TS Station Transformer (TUL) 20
Table 2-11: TS Transformer Condition Assessment Criteria 20
Table 2-12: TS Transformer Health Condition Assessments 21
Table 2-13: TS Switchgear Demographics 24
Table 2-14: TS Switchgear (TUL) 26
Table 2-15: Station Switchgear Condition Assessment Criteria 26
Table 2-16: TS Switchgear Condition Assessments 27
Table 2-17: Breaker Demographics 30
Table 2-18: Station Circuit Breaker (TUL) 31
Table 2-19: Station Breaker Condition Assessment Criteria 32
Table 2-20: Breaker Condition Assessments by Station 33
Table 2-21: Feeder Cable Demographics 36
Table 2-22: Feeder Cable Age by Cable Type 36
Table 2-23: Station Feeder Cables (TUL) 38
Table 2-24: TS Feeder Cables Assessment Criteria 38
Table 2-25: Station Cable Condition Assessments 39
Table 2-26: Station Cable Replacement Plan 40
Table 2-27: TS Protection Systems Demographics 41

Table 2-28: TS Protection Systems (TUL) 42
Table 2-29: Protection Relay Condition Assessment Criteria 43
Table 2-30a: Protection Relay Condition 43
Table 2-30b: Protection Relay Condition (Continued) 44
Table 2-30c: Protection Relay Condition (Continued) 45
Table 2-31: DS Transformer Demographics 47
Table 2-32: DS Transformers (TUL) 47
Table 2-33: DS Transformers Condition Assessment Criteria 48
Table 2-34: DS Transformers Health Condition Assessments 48
Table 2-35: Pole Population by Type 51
Table 2-36: Pole Utilization 51
Table 2-37: Poles (TUL) 52
Table 2-38: Recommended Health Index Assessment Criteria 53
Table 2-39: Poles past TUL 53
Table 2-40: Health Index Distribution 55
Table 2-41: Pole Health Index by Pole Type 55
Table 2-42: Pole Health Index Distribution by Number of Circuits 57
Table 2-43: Pole Replacement Recommendations 58
Table 2-44: Cable Population Approaching or Past TUL 61
Table 2-45: Cable Population by Installation Method 62
Table 2-46: Cable Population by Operating Voltage 62
Table 2-47: Cable TUL 63
Table 2-48: Enova Cable Assessment Criteria 64
Table 2-49: Condition Assessment Results 65
Table 2-50: XLPE Cable > TUL by Cable Size 66
Table 2-51: Distribution Cable Replacement Plan 68
Table 2-52: Distribution Transformer Population by Type 69
Table 2-53: Distribution Transformer Average Age by Type 69
Table 2-54: Distribution Transformer Loading by Type 71
Table 2-55: Distribution Transformer Average Loading above 100% 71
Table 2-56: Distribution Transformer TUL's 72

Table 2-57: Recommended Health Index Assessment Criteria 73
Table 2-58: PCB Transformers 74
Table 2-59: Distribution Transformer HI 75
Table 2-60: Distribution Transformer HI by Type 75
Table 2-61: Distribution Transformer Replacement Plan 77
Table 2-62: Metering Assets 78
Table 2-63: Meters by Age 79
Table 2-64: Metering Asset TUL 81
Table 2-65: Meter Condition Assessment Criteria 82
Table 2-66: Meter Installation Condition Assessment Criteria 83
Table 2-67: Meter Condition Assessments 83
Table 3-1: Health Index Distribution (%) 88
Table 3-2: Enova Asset Replacement Plan 90

LIST OF FIGURES

Figure 2-1: TS HV Switches / Circuit Switches Age Profile 13
Figure 2-2: TS HV Switches / Circuit Switches Condition Profile 16
Figure 2-3: TS Transformer Age Profile 19
Figure 2-4: TS Transformer Condition Profile 22
Figure 2-5: TS Switchgear Age Profile 25
Figure 2-6: TS Switchgear Condition Profile 28
Figure 2-7: Station Circuit Breaker Age Profile 31
Figure 2-8: Station Circuit Breaker Condition Profile 34
Figure 2-9: Station Cable Age Profile 37
Figure 2-10: Protection Relays Age Profile 42
Figure 2-11: Protection Relays Health Profile 45
Figure 2-12: Distribution Station Transformer Health Profile 49
Figure 2-13: Enova Pole Population Age Profile 52
Figure 2-14: Enova Wood Pole Remaining Strength Profile 54
Figure 2-15: Enova Pole Population HI Distribution 56
Figure 2-16: Cable Population Age Profile 60
Figure 2-17: Cable Population Age by Cable Type 61
Figure 2-18: Cable Population Condition 66
Figure 2-19: Distribution Transformer Age Profile 70
Figure 2-20: Distribution Transformer Population Loading Profile 70
Figure 2-21: Meter Installations Age Profile 80
Figure 2-22: Meter Installations Age Profile by Type 81
Figure 2-23: Metering Installations' Condition Profile 85
Figure 3-1: Health Index Distribution 89

GLOSSARY

1) AAC - All-Aluminum Conductor
2) ACA - Asset Condition Assessment
3) ACSR – Aluminum Conductor Steel-Reinforced
4) AM – Asset Management
5) AMI – Advanced Metering Infrastructure
6) AMP – Asset Management Process
7) BIL – Basic Impulse Level
8) CPAF - Condition Parameter Availability Factor
9) CSA – Canadian Standards Association
10) CT – Current Transformer
11) DG – Distributed Generation
12) DGA – Dissolved Gas Analysis
13) DAI – Data Availability Indicator
14) DS – Distribution Station
15) DSC – Distribution System Code
16) DSP – Distribution System Plan
17) EII - Engineered Intelligence Inc. (formally METSCO Energy Solutions Inc.)
18) Enova – Enova Power Corporation Inc.
19) EOL – End of Life
20) ESA – Electrical Safety Authority
21) FLISR – Fault Location, Isolation and Service Restoration
22) GATR – Guelph Area Transmission Reinforcement
23) GIS – Geographic Information System
24) GS – General Service
25) HI - Health Index
26) HONI – Hydro One Networks Inc.
27) IESO – Independent Electricity System Operator
28) IT – Information Technology
29) KPI – Key Performance Indicator

30) kW - kilowatt
31) KWCG – Kitchener – Waterloo – Cambridge – Guelph
32) KWH – Kitchener-Wilmot Hydro Inc.
33) LDC – Local Distribution Company
34) LDG – Load Displacement Generation
35) LOS – Loss of Supply
36) LTLT – Long Term Load Transfer
37) LTR – Limited Time Rating
38) MC – Measurement Canada
39) MDM/R - Meter Data Management/Repository
40) NWA - Non-wires alternatives
41) O/H or OH - Overhead
42) O&M – Operation & Maintenance
43) OM&A – Operation, Maintenance & Administration
44) ONAN - Oil Natural Air Natural
45) ONAF - Oil Natural Air Forced
46) ODS – Operational Data Store
47) OEB – Ontario Energy Board
48) OMS – Outage Management System
49) OPA – Ontario Power Authority
50) ORTAC – Ontario Resource and Transmission Assessment Criteria
51) OT – Operation Technology
52) PT – Potential Transformer
53) REG – Renewable Energy Generation
54) RIP – Regional Infrastructure Planning
55) ROE – Return on Equity
56) RRFE – Renewed Regulatory Framework for Electricity Distributors
57) RTU – Remote Terminal Units
58) SCADA – Supervisory Control and Data Acquisition
59) the Board – Ontario Energy Board
60) City(K) – City of Kitchener

61) City(W) – City of Waterloo
62) RHIF - Recommended Health Index Formulation
63) RHIP - Recommended Health Index Parameters
64) Region – Region of Waterloo
65) TPSS – Traction Power Substations
66) TRXLPE – Tree-Retardant Cross-Linked Polyethylene
67) TUL – Typical Useful Life
68) TS – Transmission Station or Transformer Station
69) U/G or UG – Underground
70) ULTC – Under-Load Tap Changing
71) URD – Underground Residential Distribution
72) USF – Utilities Standards Forum
73) WNHI / WNH – Waterloo North Hydro Inc.
74) XFMR – Transformer
75) XLPE – Cross-Linked Polyethylene

1 INTRODUCTION

Enova Power Corporation (Enova) is an electrical Local Distribution Company (LDC) licensed by the Ontario Energy Board (OEB) in accordance with its Distribution License ED-2022-0006. Enova was formed on September 1, 2022, by the merger of Waterloo North Hydro Holding Corporation (WNHHC) and Kitchener Power Corporation (KPC) and subsequently Waterloo North Hydro Inc. (WNH) with Kitchener-Wilmot Hydro Inc. (KWH).

With a service area of approximately 1,108 sq. km, Enova provides electricity distribution services to approximately 165,000 business and residential customers in the City of Kitchener, the City of Waterloo, the Township of Wellesley, the Township of Wilmot and the Township of Woolwich, all of which are located within the Regional Municipality of Waterloo. As a result of past service area amendments, Enova also provides regulated electricity distribution services to approximately 142 customers in the bordering counties of Wellington, Perth, Oxford and the City of Cambridge.

This Asset Condition Assessment (ACA) report was prepared by Enova to provide a consolidated view of the condition of Enova's key station and distribution assets; and is in support of Enova's first consolidated Distribution System Plan (DSP). References are made in this report to the legacy corporations to provide clarity and context to the information provided. They will be denoted as follows;

- WNH - Country Squire Rd. (CS)
- KWH - Victoria Street (VS)

This report also informs the senior executive team (Executive) at Enova in developing Enova's overall investment plans for the years 2026 to 2031 inclusive and supports Enova's 2026 ICM application.

Unless otherwise stated, the findings this report are based on data collected up to and including December 31, 2024.

1.1 Assets Under Study

The scope of the assets covered in this ACA is outlined in **Table 1-1**.

Table 1-1: Assets Under Study

Assets Under Study	
	Grid-Connected Transformer Stations (115 kV & 230 kV)
1	Station (TS) Switchyard Equipment
2	Station (TS) Switches / Circuit Switchers
3	Station (TS) Transformers
4	Station (TS) Switchgear
5	Station (TS & DS) Circuit Breakers
6	Station (TS) Feeder Cables
7	Station (TS) Protection Relays
	Distribution Stations (<50 kV)
8	Distribution Station (DS) Transformers
	Distribution System
9	Poles
10	Primary Underground Distribution Cables
11	Distribution Transformers
12	Revenue Metering

Fleet, Information Technology and Facilities assets are addressed in their own ACA Reports and are not included within the scope of this report. They can be found in the following DSP Appendices;

- **Appendix H - Information Technology Management Plan**
- **Appendix I - Facilities Management Plan**
- **Appendix J - Fleet Management Plan**

1.2 Asset Condition Assessment Methodology

Enova's Asset Condition Assessment methodology consists of a data-driven evaluation process that informs Enova's asset maintenance, refurbishment, and replacement programs. This involves the continuous collection of asset condition data from inspection, testing and maintenance programs to provide condition assessments for its major distribution system assets. End-Of-Life Criteria are developed by understanding the degradation and failure processes for each asset and quantifying typical-useful-life (TUL) and maximum-useful-life (MUL) parameters. Enova has relied on results of the Kinectrics Inc. Report No: K-418033-RA-001-R000, April 28, 2010, Kinectrics Inc. (Kinectrics Report) in this report.

Analysis of performance and/or condition data against end-of-life (EOL) criteria is accomplished with the aid of Health Index Frameworks. Within the Framework, health data is measured against weighted degradation criteria as not all factors contribute equally to an asset's end-of-life. Degradation criteria are benchmarks used to measure and evaluate how each asset type deteriorates in condition, performance and ultimately fails.

A normalized sum from each weighted degradation factor is calculated resulting in a quantitative Health Index Score (HI) for each asset. An asset's HI is an indicator of asset remaining life and helps identify and rank assets at greatest risk.

For the analysis of poles, underground cable and distribution transformers, Enova utilized ENGIN, an Asset Analysis, Prioritization and Optimization software application developed by Engineered Intelligence Inc. (EII).

For the remainder of the assets under study, the asset condition assessments were aided by Health Index Frameworks developed by METSCO Energy Solutions Inc (METSCO). These frameworks were informed by Enova's own:

- Internal Knowledge: Understanding of key asset classes and sub-classes with specialized characteristics that result in elevated failure probabilities that must be captured as part of health index formulation;

- Inspection and Maintenance Practices: In-field inspection data captured from current maintenance practices to support health index quantification;
- Subject Matter Experts (SMEs): These experts represent a key component in the development and validation of the HI formulation and include equipment manufacturers' recommendations, Enova's expertise, judgement and experience.
- Consultant Experience: Industry-defined degradation parameters can be produced where current-state data remains limited. Enova has utilized both the Kinectrics report and METSCO's Health Index Frameworks as the basis of developing its own frameworks as presented in this report.

In addition to asset condition data, Enova's Asset Registry information includes demographic information such as asset types, features, ratings, age distribution, quantities, and average data availability indicators (DAI) for each of the asset classes under study.

Asset condition, which is represented by the asset's Health Index Score, is an indicator of asset remaining life. Health Scores are classified into one of five asset condition categories: Very Good, Good, Fair, Poor, or Very Poor.

Table 1-2 provides a summary of the health index score ranges, categories and the corresponding asset condition.

Table 1-2: Asset Condition based on Health Index

Health Index Score	Condition Category	Description	Recommended Action
85 < 100	Very Good	Some ageing or minor deterioration of a limited number of components	Normal maintenance
70 < 85	Good	Significant deterioration of some components	Normal maintenance
50 < 70	Fair	Widespread significant deterioration or serious deterioration of specific components	Increase diagnostic testing; possible remedial work or replacement needed depending on criticality
30 < 50	Poor	Widespread serious deterioration	Start planning process to replace or rehabilitate considering risk and consequences of failure
0 < 30	Very Poor	Extensive serious deterioration	Asset has reached its end-of-life; immediately assess risk; replace or refurbish based on assessment

Commonly, the following guidelines are used to determine asset replacement.

- Assets in service and identified as in immediate danger of failure are assigned to Enova's Reactive Renewal Program. Depending on the condition, assets are planned for replacement anywhere from next day to 6 months. In severe cases assets may be required to be removed from service until repairs or replacement can be made.
- Assets in service and in Very Poor or Poor condition are assigned to Enova's System Proactive Renewal Program. Depending on the condition and risk assessments, assets are normally replaced anywhere from 6 months to 2 years.
- Assets in Fair condition are monitored and may be revaluated in the upcoming 2 to 5 years to determine their near-term rate of degradation. This may require additional inspection/testing and may require replacement under Enova's System Proactive Renewal Program within the forecast period.
- Assets evaluated in Good and Very Good condition generally fall outside the current 5-year renewal plan.

All assets are revaluated as new inspection, testing, performance and financial data become available. Factors affecting replacement timelines include availability of suitable

replacements, long delivery times, quantity of assets to be replaced, failure rates, and re-engineering required for replacement assets.

1.3 Asset Management Policy

Responsibility for asset management is held from the CEO to the Vice Presidents.

It is the responsibility of the President & CEO to ensure there are established roles, responsibilities, authorities and controls to achieve the asset management policy, strategy, objectives and plans.

The VP of Grid Transformation and Chief Distribution Officer has the overall responsibility for:

- Reviewing this policy periodically and update if required.
- Overseeing the development, implementation, and performance of Enova's asset management system (policies, strategies, and plans).
- Ensuring alignment across Innovation & Energy Management, Station & Grid Intelligence, Engineering, and Operations functions.

A copy of Enova's complete Asset Management Policy can be found in **Appendix B-2**.

2 ASSET CONDITION ASSESSMENTS

Each asset condition assessment outlined in this report includes the following sections:

1. Asset Demographics – includes a description of the assets in each asset group, quantities, age, ratings,
2. Condition Assessment Criteria – the degradation factors and measures by which asset Health Indices are calculated. Degradation factors are weighted according to their particular impact on the health of the asset.
3. Typical Useful Life – used to provide age demographics and inform the asset condition assessments. Reference in this report is made frequently to Kinectrics Inc. Report No: K-418033-RA-001-R000, April 28, 2010, Kinectrics Inc. (Kinectrics Report).
4. Health Index Scoring – the numerical total of all evaluated degradation factors multiplied by their individual weighting.
5. Health Index Condition Categories – the categorization of Health Index scoring into five categories from Very Good to Very Poor.
6. Data Availability Indicator - is a measure of the completeness of the data set required to calculate the Health Indices and assess the overall condition of the asset group. The DAI is a weighted average of the quantity of asset data used for the HI calculations and the relative evaluation weighting of data, expressed as a percent of the maximum.
7. Analysis of Results – provides an overview of the asset condition assessments and assets flagged for action.

2.1 STATION (TS) SWITCHYARD EQUIPMENT

2.1.1 Asset Demographics

Transformer station switchyards contain a number of key elements that are critical to the delivery of power from the HONI 115 kV and 230 kV transmission systems to the HV transformers as well as the safety and security of the transformer stations as a whole. Three of these elements are addressed in this section of Enova's ACA.

1) Ridged Bus & Conductors
   - This asset class includes the current carrying bus in the station, station post insulators, and connections to the Hydro One Transmission system. The buses can be constructed from rigid tubular pipe or bare aluminum based multi-strand wire such as ACSR or AAC.

2) Support Structures
   - There are a number of different types of structures at transformers stations for supporting buses and equipment. The predominant types are galvanized steel, either lattice or hollow sections supported by concrete pier foundations.

3) Security Fencing
   - Station security fencing involves installing robust, heavy-gauge galvanized steel chain link material topped with barbed wire to prevent trespassing, vandalism, and theft at utility sites.

Table 2.1 provides a listing of Enova's 12 HV grid-connected transformer stations. Each station is constructed with two separate HV buses connecting Enova's TS transformers to the HONI transmission lines. HV insulators support the energized conductors which need to be able to carry the full station load. As these conductors are not insulated, support structures are required to keep energized equipment safely above ground and separated from other equipment.

Each station employs security fencing around the site to prevent trespassing, vandalism, theft and acts as a safety barrier for unauthorized persons.

Table 2-1: TS Station Switchyards

#	Transformer Stations	Tx HV Rating (kV)	Year in Service	Age	% TUL
1	HMSTS 'A'	230	1969	56	112%
2	HMSTS 'B'	230	1985	40	80%
3	MTS #3	230	2001	24	48%
4	ERTS	115	1995	30	60%
5	1TS	115	1998	27	54%
6	3TS	115	1996	29	58%
7	4TS	115	1986	39	78%
8	5TS	115	1997	28	56%
9	6TS	230	1990	35	70%
10	7TS	230 x 115	1994	31	62%
11	8TS	230	2004	21	42%
12	9TS	230	2010	15	30%
	Avg.			31.3	63%

2.1.2 Condition Assessment Criteria

Table 2-2 provides a listing of the major components in Enova switchyards and their TUL.

Table 2-2: Station Switchyard Equipment TUL

	KINECTRICS REPORT			Enova
Asset Type	**Min UL**	**TUL**	**Max UL**	**TUL**
Steel Structures	35	50	90	50
Rigid Busbars	30	55	60	50
Security Fencing	25	N/A	60	40
Station Grounding	N/A	N/A	N/A	N/A
Surface Granular Material	N/A	N/A	N/A	N/A
Building	50	N/A	75	N/A

2.1.3 Condition Assessments

The condition of the buildings, steel structures, rigid busbars, HV conductors, insulators, lightning arrestors, and fencing are assessed through regular inspection processes. Supplementing this are annual thermographic surveys of any energized current-carrying equipment. Fencing, grounding and granular surfaces are assessed through regular inspections. In addition, grounding is assessed through periodic electrical ground grid testing.

Degradation of busbars or overhead wires can result from environmentally induced chemical corrosion, electrical overheating or mechanical damage. Temperature variations, plus wind and ice loadings lead to changes in conductor tension. Station insulators have similar degradation modes including damage from electrical flashover due to lightning or animal interference.

Reduction in the strength of steel structures can result from corrosion, structural fatigue, or gradual deterioration of foundation components. Structural fatigue can also result from repeated structural loading and unloading of support members.

Typically, foundations are cylindrical steel reinforced concrete structures with anchor bolts connecting the structure to its base. Key degradation mechanisms include reinforcement steel corrosion, carbonation, sulfate attack, and freeze-thaw cycles, which lead to cracking, spalling, and loss of strength.

Common security fence degradation mechanisms include chain-link fabric, barbed wire and support post deterioration due to physical and environmental factors. Grounding and fence integrity are frequently inspected due to vandalism.

Switchyard assets are inspected on a monthly basis. In-field inspection data is captured and recorded with repair/replacement priorities set by the severity of the defect. Development of HI scores are based on equipment manufacturers' recommendations, Enova's expertise, judgement and experience. Development of condition assessments is still a manual process as Enova has yet to quantify and digitize testing and inspection data. Work in this area is ongoing as Enova continues to make efforts to harmonize data and information systems post-merger.

Table 2-3: TS Station Switchyard Equipment Condition Assessments

#	Station	HV Connection	Max Score	Score	% HI	Condition Rating
1	HMSTS A	D6V	600	355	59%	Fair
2	HMSTS B	D7V	600	445	74%	Good
3	MTS#3	D6V	600	490	82%	Good
4	ERTS	D10H	600	490	82%	Good
5	1TS	D12K	600	435	73%	Good
6	3TS	D9F	600	425	71%	Good
7	4TS	D12K	600	375	63%	Fair
8	5TS	F11C	600	480	80%	Good
9	6TS	M20D	600	440	73%	Good
10	7TS	D9F	600	435	73%	Good
11	8TS	M20D	600	485	81%	Good
12	9TS	D5W	600	535	89%	Very Good
	Avg.				75%	Good

2.1.4 Data Availability Indicator

Enova's DAI for TS switchyard equipment condition assessment data is 100%.

2.1.5 Analysis of Results

The results of Enova's annual Stations Inspection and Maintenance program informs Enova's annual investment planning. Deficiencies are rectified either through maintenance or capital programs, whichever is appropriate.

The following are condition based deficiencies that have been documented and capital expenditures planned between 2026 and 2031.

1) TS building repairs, 4TS, 5TS and 8TS (2026)
2) TS building repairs, HMSTS "A" (2027)

All of these projects are below the level of materiality.

2.2 STATION (TS) SWITCHES / CIRCUIT SWITCHERS

2.2.1 Asset Demographics

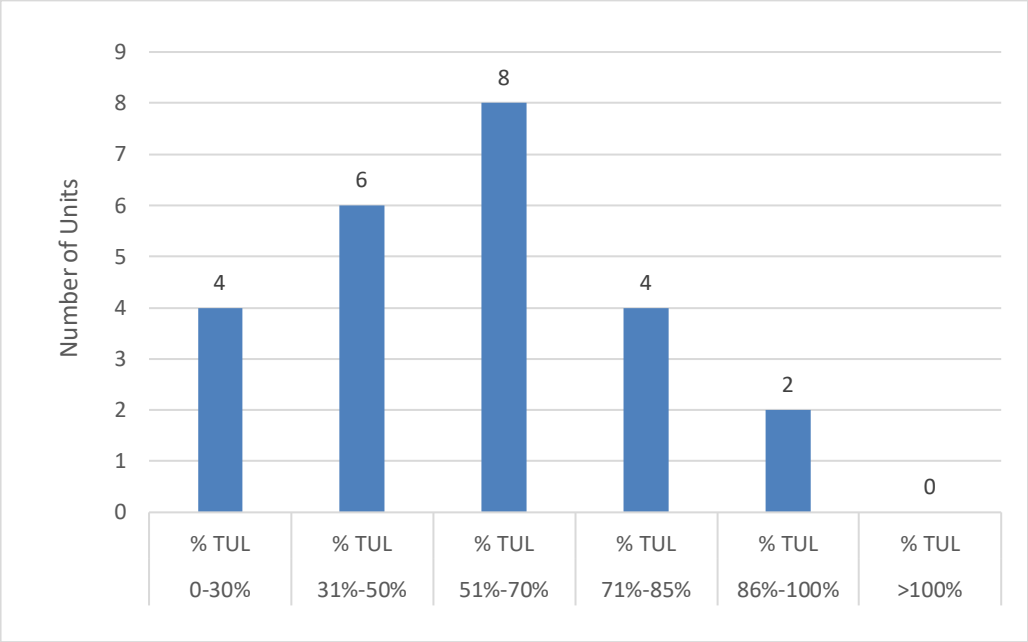
This asset group is made up of 24 outdoor high voltage air break switches and SF6/Vacuum interrupter circuit switchers. These devices are used to separate and isolate the main station power transformers from the HONI 115 kV and 230 kV transmission systems. **Table 2-4** provides a listing of assets in this group and their ages. The average age of the assets is 22.5 years which is 56.1% of their TUL.

Table 2-4: TS HV Switches / Circuit Switchers

Station	Switch ID	Year in Service	Age	% TUL	Type
HMSTS A	T1	2006	18	45%	Air Break
HMSTS A	T2	2006	18	45%	Air Break
HMSTS B	T3	1986	38	95%	Air Break
HMSTS B	T4	1988	36	90%	Air Break
MTS#3	T1	2001	23	58%	Circuit Switcher
MTS#3	T2	2001	23	58%	Circuit Switcher
ERTS	T1	2010	14	30%	Circuit Switcher
ERTS	T2	2010	14	30%	Circuit Switcher
1TS	K1T1-D12K	1998	26	65%	Circuit Switcher
1TS	K1T2-D11K	1998	26	65%	Circuit Switcher
3TS	K3T5-D9F	1996	28	70%	Circuit Switcher
3TS	K3T6-D7F	1996	28	70%	Circuit Switcher
4TS	K4T7-D12K	2023	1	3%	Circuit Switcher
4TS	K4T8-D11K	2025	0	0%	Circuit Switcher
5TS	K5T9-F12C	1997	27	68%	Circuit Switcher
5TS	K5T10-F11C	1997	27	68%	Circuit Switcher
6TS	K6T11-M21D	1990	34	85%	Circuit Switcher
6TS	K6T12-M20D	1990	34	85%	Circuit Switcher
7TS	K7T13-D7F	1994	30	75%	Circuit Switcher
7TS	K7T14-D9F	1994	30	75%	Circuit Switcher
8TS	K8T15-M21D	2004	20	50%	Circuit Switcher
8TS	K8T16-M20D	2004	20	50%	Circuit Switcher
9TS	K9T17-D4W	2010	14	35%	Circuit Switcher
9TS	K9T18-D5W	2010	14	35%	Circuit Switcher
AVG.			22.5	56.1%	
TOTAL	24				

Figure 2-1 provides an age profile of these assets.

Figure 2-1: TS HV Switches / Circuit Switches Age Profile



2.2.2 Condition Assessment Criteria

Enova has adopted a TUL of 40 years for these assets. This is consistent with the Kinectrics Report and Enova's own experience.

Table 2-5: TS HV Circuit Switches / Circuit Switchers (TUL)

KINECTRICS REPORT			Enova
Min UL	TUL	Max UL	TUL
30	45	60	40

Table 2-6 provides a summary of the asset assessment criteria used to calculate the Health Indices for Enova's station switches.

Table 2-6: Station HV Circuit Switches Condition Assessment Criteria

Degradation Factor	Type	Weight	Ranking	Numerical Grade	Max Grade	AB	SF6/Vac
Age	All	8	A,B,C,D,E	4,3,2,1,0	32	32	32
Timing/Travel Tests	All	3	A,B,C,D,E	4,3,2,1,0	12	12	12
Visual Inspection	All	8	A,B,C,D,E	4,3,2,1,0	32	32	32
Disconnect - Live Parts*	All	3	A,B,C,D,E	4,3,2,1,0	12	12	12
Contact Resistance	All	3	A,B,C,D,E	4,3,2,1,0	12	12	12
Infrared Scan (IR)	All	6	A,C,E	4,2,0	24	24	24
Vacuum Loss	SS	6	A,B,C,D,E	4,3,2,1,0	24	N/A	24
SF6 Leaks and their severity	SS	6	A,B,C,D,E	4,3,2,1,0	24	N/A	24
Total Max Score						124	172

**Note: Disconnect condition only applies if there is an integrated disconnect in the circuit switcher assembly.*

2.2.3 Condition Assessments

Tables 2-7(a, b) provide age and Health Index scores for Enova's TS high voltage station switches.

Table 2-7a: Station HV Switches / Circuit Switches Condition Assessments

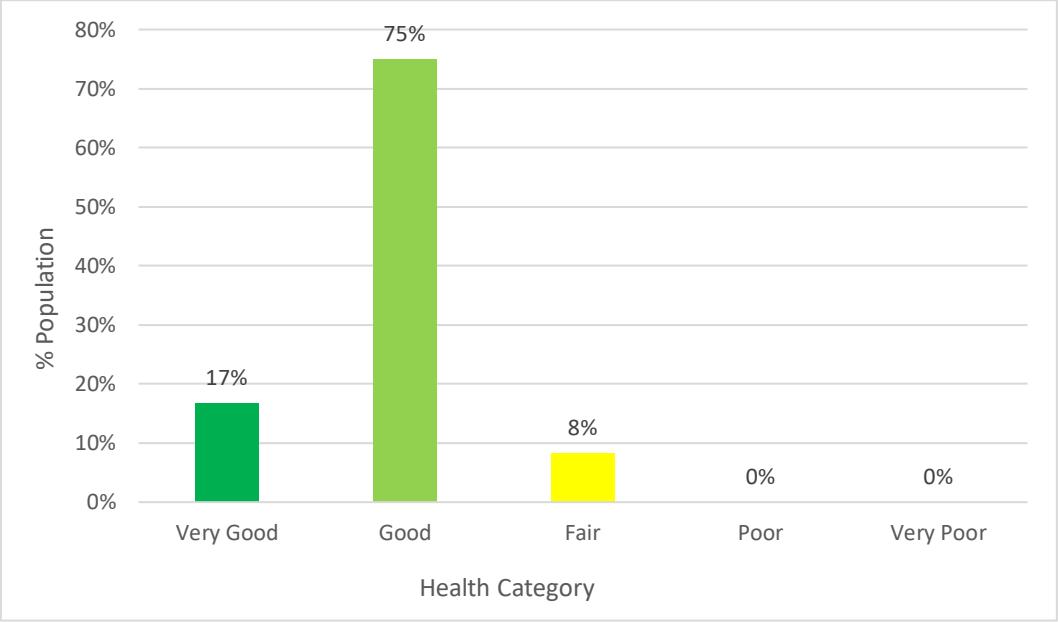
Station	Switch ID	% TUL	Health Score	Max Score	% HI	Condition Rating	Type
HMSTS A	T1	45%	99	124	80%	Good	Air Break
HMSTS A	T2	45%	102	124	82%	Good	Air Break
HMSTS B	T3	95%	92	124	74%	Good	Air Break
HMSTS B	T4	90%	89	124	72%	Good	Air Break
MTS#3	T1	58%	115	172	67%	Fair	Circuit Switcher
MTS#3	T2	58%	115	172	67%	Fair	Circuit Switcher
ERTS	T1	30%	123	172	72%	Good	Circuit Switcher
ERTS	T2	30%	123	172	72%	Good	Circuit Switcher
1TS	K1T1-D12K	65%	128	172	74%	Good	Circuit Switcher
1TS	K1T2-D11K	65%	128	172	74%	Good	Circuit Switcher
3TS	K3T5-D9F	70%	136	172	79%	Good	Circuit Switcher
3TS	K3T6-D7F	70%	136	172	79%	Good	Circuit Switcher
4TS	K4T7-D12K	3%	172	172	100%	Very Good	Circuit Switcher
4TS	K4T8-D11K	0%	172	172	100%	Very Good	Circuit Switcher
5TS	K5T9-F12C	68%	136	172	79%	Good	Circuit Switcher
5TS	K5T10-F11C	68%	136	172	79%	Good	Circuit Switcher

Table 2-7b: Station HV Switches / Circuit Switches Condition Assessments

Station	Switch ID	% TUL	Health Score	Max Score	% HI	Condition Rating	Type
6TS	K6T11-M21D	85%	128	172	74%	Good	Circuit Switcher
6TS	K6T12-M20D	85%	128	172	74%	Good	Circuit Switcher
7TS	K7T13-D7F	75%	128	172	74%	Good	Circuit Switcher
7TS	K7T14-D9F	75%	128	172	74%	Good	Circuit Switcher
8TS	K8T15-M21D	50%	136	172	79%	Good	Circuit Switcher
8TS	K8T16-M20D	50%	136	172	79%	Good	Circuit Switcher
9TS	K9T17-D4W	35%	150	172	87%	Very Good	Circuit Switcher
9TS	K9T18-D5W	35%	150	172	87%	Very Good	Circuit Switcher
TOTAL	24						
AVG.		56.1%			78.3%	Good	

Figure 2-2 provides a condition profile of these assets.

Figure 2-2: TS HV Switches / Circuit Switches Condition Profile



2.2.4 Data Availability Indicator

Enova's DAI for TS high voltage station switches condition assessment data is 100%.

2.2.5 Analysis of Results

With an overall health score of 78.3%, 92% of Enova's transformer station HV switches are rated in Good to Very Good condition with the exception of two switches at MTS #3 which are rated as Fair.

Increased fault current contributions from existing connected embedded generation, Hydro One's transmission system upgrade as part of the Guelph Area Transmission Reinforcement (GATR) project, and transmission-connected REGs have over time contributed to the increase in available short circuit levels on the HONI D6V/D7V 230 kV transmission circuits that supply MTS #3. Now approaching the maximum interrupting ratings of these circuit switchers, Enova is planning the replacement of these switches with higher rated circuit breakers. Design work is expected to begin in 2031 with in-service

expected in 2033 and 2034.

There are no switches with a health condition of Poor or Very Poor. There are no replacements forecast prior to 2031.

2.3 STATION (TS) TRANSFORMERS

2.3.1 Asset Demographics

Enova owns a fleet of 27 large high voltage power transformers (**Table 2-8**) located at 12 grid-connected transformer stations. Of these transformers, 24 are in-service and connected to the HONI 115 kV and 230 kV transmission systems and 3 are spare power transformers.

With an average age of 25.7 years, approximately 95% of Enova's total electrical supply flows through these assets.

Table 2-8: TS Large Power Transformers (In-service)

Transformer Stations	HONI Tx Line	Tx HV Rating (kV)	LV (kV)	Tx ID	Tx ONAN Rating (MVA)	Tx ONAF Rating (MVA)	Summer LTR (MVA)	Install Date	Age	% TUL
HMSTS 'A'	D6V	230	13.8	T1	30	50	69	1969	55	138%
	D7V	230	13.8	T2	30	50	69	1969	55	138%
HMSTS 'B'	D7V	230	13.8	T3	50	83	110	1988	36	90%
	D6V	230	13.8	T4	50	83	110	1988	36	90%
MTS #3	D6V	230	27.6	T1	40	66.7	85	2010	14	35%
	D7V	230	27.6	T2	40	66.7	85	2010	14	35%
ERTS	D10H	115	13.8	T1	30	50	75	2000	24	60%
	D8S	115	13.8	T2	30	50	75	2000	24	60%
1TS	D12K	115	13.8	T1	30	50	60	1998	26	65%
	D11K	115	13.8	T2	30	50	60	1998	26	65%
3TS	D9F	115	13.8	T5	60	100	120	2011	13	33%
	D7F	115	13.8	T6	60	100	120	1996	28	70%
4TS	D12K	115	13.8	T7	50	83	102	1997	27	68%
	D11K	115	13.8	T8	50	83	102	1986	38	95%
5TS	F12C	115	13.8	T9	60	100	120	2025	0	0%
	F11C	115	13.8	T10	60	100	120	2024	0	0%
6TS	M21D	230	13.8	T11	50	83	102	1990	0	0%
	M20D	230	13.8	T12	50	83	102	1990	30	75%
7TS	D7F	230 x 115	13.8	T13	30	50	61	1994	34	85%
	D9F	230 x 115	13.8	T14	30	50	61	1993	34	85%
8TS	M21D	230	13.8	T15	30	50	60	2003	30	75%
	M20D	230	13.8	T16	30	50	60	2003	31	78%
9TS	D4W	230	27.6	T17	50	83	100	2010	21	53%
	D5W	230	27.6	T18	50	83	100	2010	21	53%
3TS	Spare Tx #1	115	14.2	T98	45	75		1984	14	35%
5TS	Spare Tx #2	230 x 115	14.2	T99	30	50		1994	14	35%
9TS	Spare Tx #3	28.4	14.2	T97	30	50		2013	11	28%
Total Units									27	
Avg.									25.7	61%

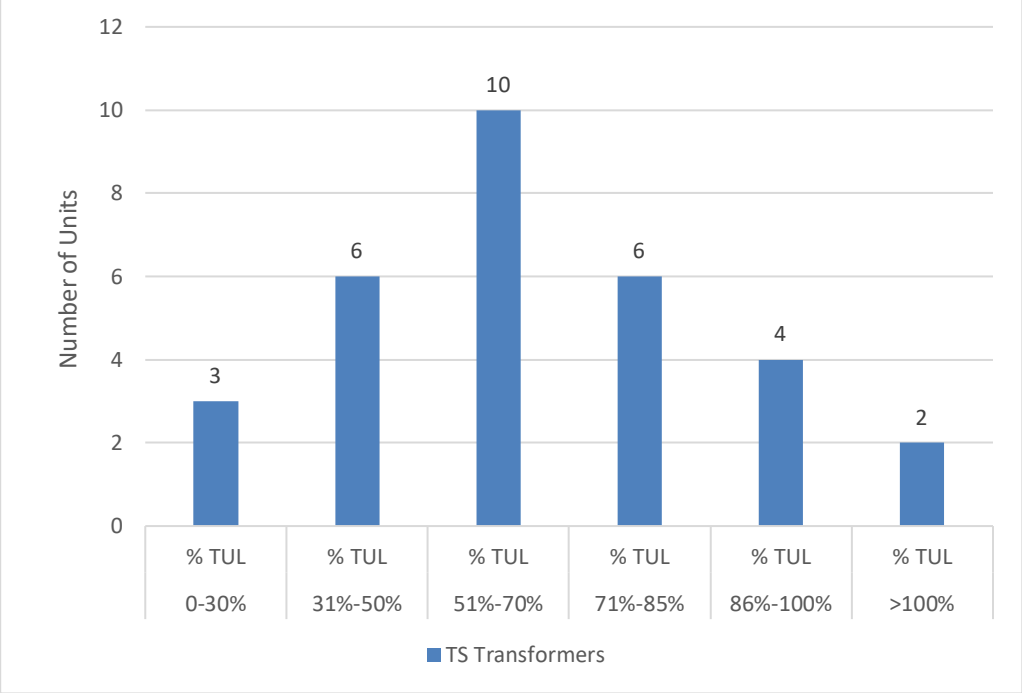
Enova also owns 4 step-up/down transformers (**Table 2-9**). These units are located at the transformer stations and allow Enova to interconnect 4 feeders between the 13.8 kV and 27.6 kV stations. These transformers allow for greater utilization and flexibility of station capacity during regular operations and loss of power events.

Table 2-9: TS Step Up / Step Down Transformer Demographics

Transformer Stations	Supplied by	LINE HV (kV)	LV (kV)	Tx ID	Tx ONAN Rating (MVA)	Tx ONAF Rating (MVA)	AGE	% TUL
HMSTS 'B'	HS19	13.8	27.6	T5	20	33	28	70%
	HS26	13.8	27.6	T6	20	33	28	70%
MTS #3	3F62 (3F50)	27.6	13.8	T3	12	16	19	48%
	3F67 (3F51)	27.6	13.8	T4	12	16	19	48%
Total Units							4	
Avg. Age							23.5	59%

Figure 2-3 provides an age profile of these assets.

Figure 2-3: TS Transformer Age Profile



2.3.2 Condition Assessment Criteria

Enova has adopted a TUL of 40 years for its large station power transformers and step up/down transformers. This is consistent with the Kinectrics Report and Enova's own experience.

Table 2-10: TS Station Transformer (TUL)

Relay Type	KINECTRICS REPORT			Enova
	Min UL	TUL	Max UL	
Transformer	30	45	60	40
Bushings	10	20	30	40
Tap changer	20	30	60	40

Table 2-11 provides a summary of the asset assessment criteria used to calculate the Heath Indices for Enova's station transformers.

Table 2-11: TS Transformer Condition Assessment Criteria

#	Degradation Factor	Weight	Ranking	Numeric al Grade	Max Grade	Max Grade Tx's with OLTC	Max Grade Tx's without OLTC
1	Age	10	A,B,C,D,E	4,3,2,1,0	40	40	40
2	Dissolved Gas Analysis*	10	A,B,C,D,E	4,3,2,1,0	40	40	40
3	Load History	10	A,B,C,D,E	4,3,2,1,0	40	40	40
4	Insulation Power Factor*	10	A,B,C,D,E	4,3,2,1,0	40	40	40
5	Oil Quality	6	A,C,E	4,2,0	24	24	24
6	Degree of Polymerization (or Service Age)	10	A,B,C,D,E	4,3,2,1,0	40	40	40
7	Turns Ratio	5	A,B,C,D,E	4,3,2,1,0	20	20	20
8	Winding Resistance	6	A,B,C,D,E	4,3,2,1,0	24	24	24
9	Tap Changer DGA (if applicable)	6	A,B,C,D,E	4,3,2,1,0	24	24	N / A
10	Tap Changer Oil Quality (if applicable)	3	A,B,C,D,E	4,3,2,1,0	12	12	N / A
11	Tap Changer Operations	5	A,B,C,D,E	4,3,2,1,0	20	20	N / A
12	HV Bushing Capacitance	2	A,B,C,D,E	4,3,2,1,0	8	8	N / A
13	HV Bushing Power Factor	2	A,B,C,D,E	4,3,2,1,0	8	8	N / A
14	Overall, Bushings	2	A,B,C,D,E	4,3,2,1,0	8	8	8
15	Infrared Scan (IR)*	10	A,B,C,D,E	4,3,2,1,0	40	40	40
16	Overall Inspection Condition	8	A,B,C,D,E	4,3,2,1,0	32	32	32
17	Overall LTC (if applicable)	5	A,B,C,D,E	4,3,2,1,0	20	20	N / A
	Total Score					440	348
	*Note: If conditions are E, divide the overall Health Index by 2.						

2.3.3 Condition Assessments

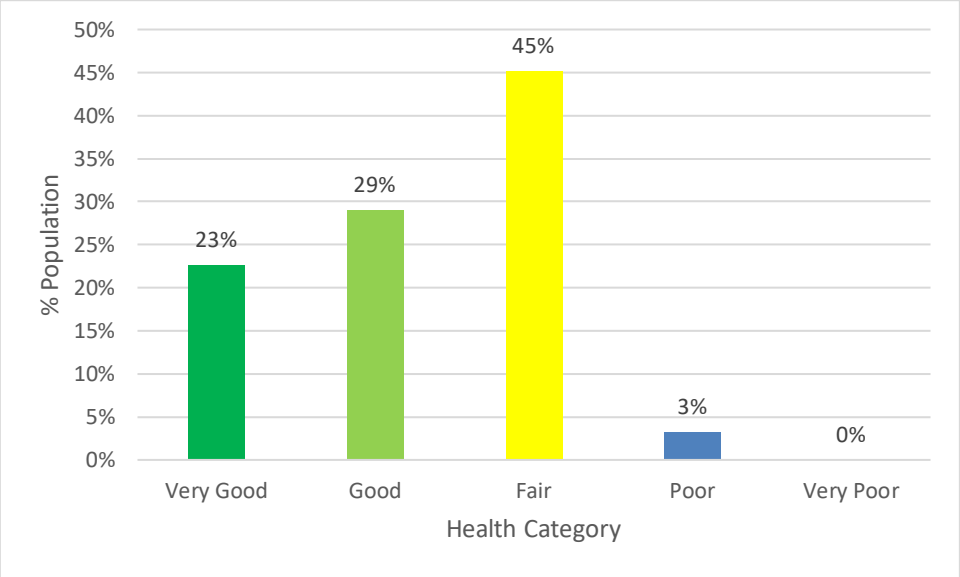
Table 2-12 provides the age and Health Index scores for all Enova TS transformers. With a health score of 71.6%, the transformer population has an overall rating of Good.

Table 2-12: TS Transformer Health Condition Assessments

STATION	TRANSFORMER	TOTAL HI SCORE	MAX HI SCORE	HI % SCORE	HEALTH CONDITION
HMSTS A	T1	221	440	50%	Fair
HMSTS A	T2	245	440	56%	Fair
HMSTS B	T3	215	440	49%	Poor
HMSTS B	T4	243	440	55%	Fair
ERTS	T1	349	440	79%	Good
ERTS	T2	396	440	90%	Very Good
MTS#3	T1	325	440	74%	Good
MTS#3	T2	365	440	83%	Good
1TS	T1	273	440	62%	Fair
1TS	T2	297	440	68%	Fair
3TS	T5	393	440	89%	Very Good
3TS	T6	307	440	70%	Fair
3TS	T98	261	440	59%	Fair
4TS	T7	248	440	56%	Fair
4TS	T8	232	440	53%	Fair
5TS	T9	430	440	98%	Very Good
5TS	T10	430	440	98%	Very Good
5TS	T99	290	440	66%	Fair
6TS	T11	274	440	62%	Fair
6TS	T12	260	440	59%	Fair
7TS	T13	263	440	60%	Fair
7TS	T14	265	440	60%	Fair
8TS	T15	323	440	73%	Good
8TS	T16	311	440	71%	Good
9TS	T17	393	440	89%	Very Good
9TS	T18	393	440	89%	Very Good
9TS	T97	307	348	88%	Very Good
HMSTS	T5	280	348	80%	Good
HMSTS	T6	265	348	76%	Good
MTS#3	T3	290	348	83%	Good
MTS#3	T4	252	348	72%	Good
	Overall Score			71.6%	Good

Figure 2-4 provides a condition profile of these assets.

Figure 2-4: TS Transformer Condition Profile



2.3.4 Data Availability Indicator

Enova's DAI for substation transformer condition assessment data is 95% for transformers with on-load tap changers and 100% for station transformers without on-load tap changers. Incomplete dissolved gas analysis records were discovered during the harmonization of WNH & KWH records. This data will be acquired during the next scheduled DGA sampling cycle.

2.3.5 Analysis of Results

Due to their importance, asset condition is frequently monitored and assessed. These are high-value capital assets and Enova invests in comprehensive inspection and maintenance programs to ensure their useful lives are maximized.

With an overall health score of 72%, 52% of Enova's station transformers are rated to be in Good to Very Good condition while 45% are rated as Fair. HMSTS B T3 is the only unit with a health condition of Poor.

The following projects are planned for the 2026 – 2031 timeframe.

1. HMSTS"A" T1 and T2 have been evaluated to have a Health Index of 50% and 56% respectively. Although still in Fair condition, the evaluations are just above a Poor rating. The transformers are also 55 years of age or 138% of their TUL. These transformers have been thoroughly inspected and tested and as a result, are expected to be in Poor condition over the forecast period. There is no cost effective option for the rehabilitation of these units. Replacement of these transformers is forecast to begin in 2031 with an in-service date of 2033 and 2034 at which time they will be between 64-65 years of age (160% – 162% of their TUL). Enova will use the replacement of these transformers as a cost-effective opportunity to increase transformer size and station capacity.

2. HMSTS"B" T3 and T4 have been evaluated to have a Health Index of 49% (Poor) and 55% (Fair) respectively. These transformers are just 36 years of age or 90% of their TUL, however, they are deteriorating at a rate faster than expected and at a rate faster than other transformers in Enova's fleet. Inspection and testing has found that there is no cost-effective option for the rehabilitation of these units. Replacement of these transformers is forecast to begin in 2026 with an in-service date of 2029 and 2030 at which time they will be between 41-42 years of age (103% – 105% of their TUL). Enova will use the replacement of these transformers as a cost-effective opportunity to increase transformer size and station capacity.

3. 4TS, T7 and T8 transformers have been evaluated to have a Health Index of 56% (Fair) and 53% (Fair) respectively. These transformers are at 68% and 95% of their TUL and also appear to be degrading faster than expected. These transformers are candidates for rehabilitation. Work on T7 and T8 is scheduled for 2026 and 2027 and is expected to improve the condition of the transformers and maintain their Fair rating.

The remainder of the fleet are in Fair to Very Good condition with an average Health Score of 83%. There are no other HV transformer replacements planned for the current forecast period.

2.4 STATION (TS) SWITCHGEAR

2.4.1 Asset Demographics

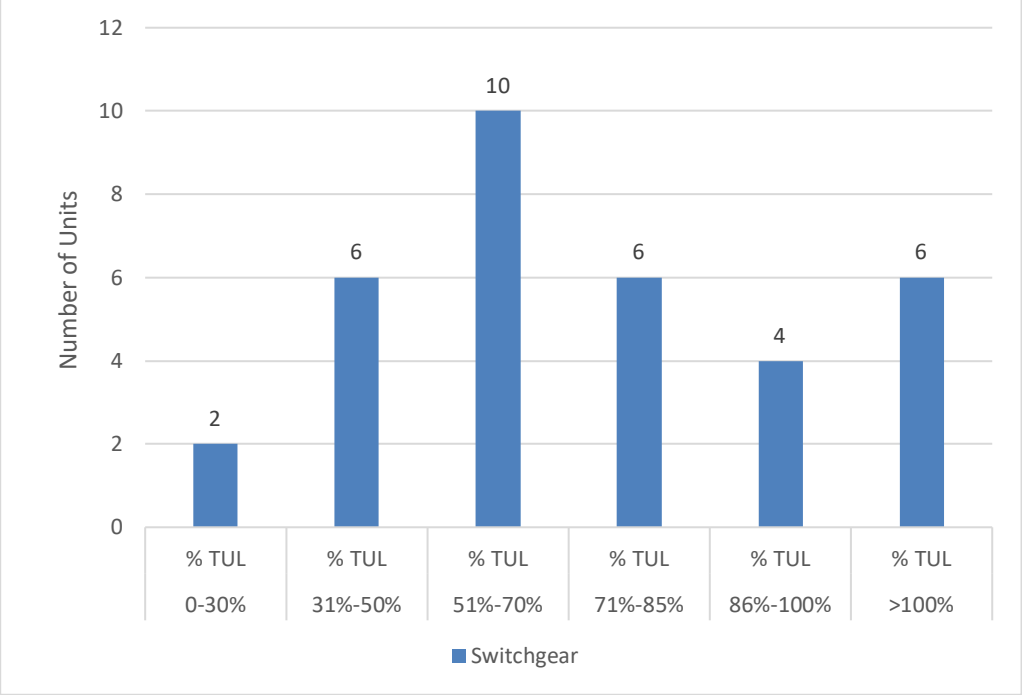
Enova maintains 30 lineups of air-insulated metalclad switchgear and 4 lineups of SF6 gas insulated switchgear at its grid-connected transformer stations.

Table 2-13: TS Switchgear Demographics

Stations	Bus Configuration	Bus ID	Switchgear Rating (A)	Voltage Rating (kV)	Age (yrs.)	%TUL	Busbar Insulation
HMSTS "A"	Jones	B	3000	15	55	110%	Air
HMSTS "A"	Jones	Y	3000	15	55	110%	Air
HMSTS "B"	Bermondsey	H	2500	15	38	76%	Air
HMSTS "B"	Bermondsey	J	2500	15	38	76%	Air
HMSTS "B"	Bermondsey	Q	2500	15	38	76%	Air
HMSTS "B"	Bermondsey	T	2500	15	38	76%	Air
ERTS	Jones	B1	3000	15	58	56%	Air
ERTS	Jones	B2	3000	15	58	56%	Air
MTS #3	Jones	B1	2400	36	23	46%	SF6
MTS #3	Jones	B2	2500	36	23	46%	SF6
1TS	Jones	T1B	3000	15	26	52%	Air
1TS	Jones	T2B	3000	15	26	52%	Air
3TS	Bermondsey	T51B	2500	15	37	74%	Air
3TS	Bermondsey	T52B	3000	15	22	44%	Air
3TS	Bermondsey	T61B	2500	15	37	74%	Air
3TS	Bermondsey	T62B	3000	15	22	44%	Air
4TS	Bermondsey	T71B	2500	15	52	104%	Air
4TS	Bermondsey	T72B	2500	15	52	104%	Air
4TS	Bermondsey	T81B	2500	15	52	104%	Air
4TS	Bermondsey	T82B	2500	15	52	104%	Air
5TS	Bermondsey	T91B	2500	15	45	90%	Air
5TS	Bermondsey	T92B	2500	15	45	90%	Air
5TS	Bermondsey	T101B	2500	15	45	90%	Air
5TS	Bermondsey	T102B	2500	15	45	90%	Air
6TS	Bermondsey	T111B	2500	15	35	70%	Air
6TS	Bermondsey	T112B	2500	15	35	70%	Air
6TS	Bermondsey	T121B	2500	15	35	70%	Air
6TS	Bermondsey	T122B	2500	15	35	70%	Air
7TS	Jones	T13B	3000	15	30	60%	Air
7TS	Jones	T14B	3000	15	30	60%	Air
8TS	Jones	T15B	3000	15	20	40%	Air
8TS	Jones	T16B	3000	15	20	40%	Air
9TS	Jones	T17B	2500	36	15	30%	SF6
9TS	Jones	T18B	2500	36	15	30%	SF6

Of the 12 transformer stations owned by Enova, 7 are constructed in a standard “Jones” configuration having one switchgear lineup per transformer with a connecting tie breaker in between. The remaining 5 stations are constructed in a “Bermondsey” configuration with dual secondary windings on the power transformers. Each winding is connected to one of four buses with each bus pair having a connecting tie breaker.

Figure 2-5: TS Switchgear Age Profile



The average age of Enova’s switchgear assets is 35.1 years (70% TUL).

2.4.2 Condition Assessment Criteria

Enova has adopted a TUL of 50 years for its TS metalclad switchgear. This is consistent with the Kinectrics Report and Enova's own experience.

Table 2-14: TS Switchgear (TUL)

	KINECTRICS REPORT		Enova
Min UL	TUL	Max UL	TUL
30	40	60	50

Table 2-15 provides a summary of the asset assessment criteria used to calculate the Heath indices for Enova's station switchgear.

Table 2-15: Station Switchgear Condition Assessment Criteria

Degradation Factor	Type	Weight	Ranking	Numerical Grade	Max Score
Service Age	All	10	A,B,C,D,E	4,3,2,1,0	40
Insulation Resistance Tests	All	20	A,C,E	4,2,0	80
SF6 Gas Tests	SF6 only	20	A,E	4,2,0	80
Metal Clad Cubicle and Components	All	10	A,B,C,D,E	4,3,2,1,0	40
Control & Operating Mechanism Components	All	10	A,B,C,D,E	4,3,2,1,0	40
Overall Physical Condition	All	20	A,B,C,D,E	4,3,2,1,0	80
SF6 Leaks	SF6 only	20	A,B,C,D,E	4,3,2,1,0	80
Total Score				Air	280
				SF6	440

2.4.3 Condition Assessments

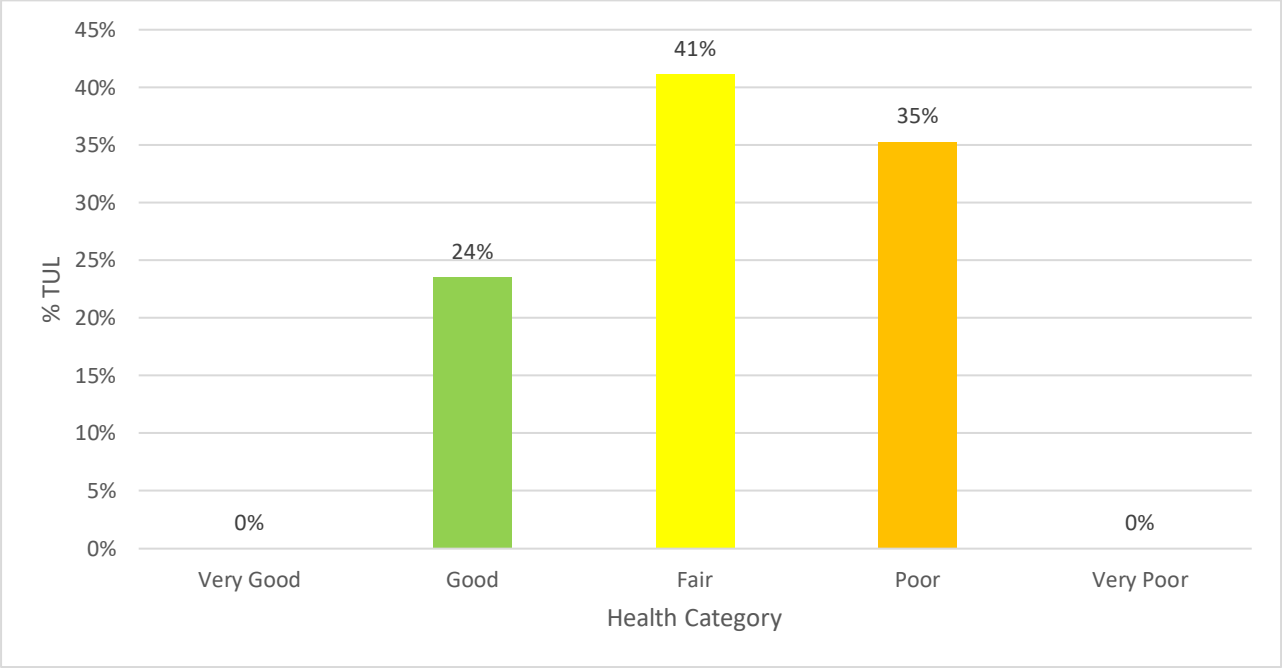
Table 2-16 provides the age and Health index scores for all Enova TS switchgear.

Table 2-16: TS Switchgear Condition Assessments

Station	Bus	Max Score	Actual Score	HI % Score	Condition Rating
HMSTS A	Bus B	280	190	68%	Fair
HMSTS A	Bus Y	280	190	68%	Fair
HMSTS B	Bus H	280	210	75%	Good
HMSTS B	Bus J	280	210	75%	Good
HMSTS B	Bus Q	280	210	75%	Good
HMSTS B	Bus T	280	210	75%	Good
ERTS	Bus B1	280	220	79%	Good
ERTS	Bus B2	280	220	79%	Good
MTS#3	Bus B1	440	340	77%	Good
MTS#3	Bus B2	440	340	77%	Good
1TS	T1B	280	140	50%	Fair
1TS	T2B	280	140	50%	Fair
3TS	T51B	280	140	50%	Fair
3TS	T52B	280	140	50%	Fair
3TS	T61B	280	140	50%	Fair
3TS	T62B	280	140	50%	Fair
4TS	T71B	280	120	43%	Poor
4TS	T72B	280	120	43%	Poor
4TS	T81B	280	120	43%	Poor
4TS	T82B	280	120	43%	Poor
5TS	T91B	280	120	43%	Poor
5TS	T92B	280	120	43%	Poor
5TS	T101B	280	120	43%	Poor
5TS	T102B	280	120	43%	Poor
6TS	T111B	280	130	46%	Poor
6TS	T112B	280	130	46%	Poor
6TS	T121B	280	130	46%	Poor
6TS	T122B	280	130	46%	Poor
7TS	T13B	280	140	50%	Fair
7TS	T14B	280	140	50%	Fair
8TS	T15B	280	150	54%	Fair
8TS	T16B	280	150	54%	Fair
9TS	T17B	440	270	61%	Fair
9TS	T18B	440	270	61%	Fair

Figure 2-6 provides a condition profile of these assets.

Figure 2-6: TS Switchgear Condition Profile



2.4.4 Data Availability Indicator

Enova's DAI for TS switchgear data is 100%.

2.4.5 Analysis of Results

The four switchgear buses at 6TS switchgear have been rated in Poor condition with a Health Index score of 46% and a % TUL of 70%. The switchgear does not have an arc-proof rating, meaning there is a higher risk to personnel safety when working in and around the energized equipment, as well as a greater risk of an arcing electrical fault escalating into a multi-feeder outage. Replacement of these buses is forecast to begin in 2026 with an in-service date of 2027 to 2029.

The two switchgear buses at 7TS switchgear have been rated in Fair condition with a Health

Index score of 50% and a % TUL of 60%. The vendor has stated that the circuit breakers are obsolete with spare parts and support no longer offered. This switchgear is scheduled to be replaced over the 2028-2029 time period.

The four switchgear buses at HMSTS B switchgear have been rated in Good condition with a Health Index score of 75% and a % TUL of 76%. The switchgear does not have an arc-proof rating, meaning there is a higher risk to personnel safety when working in and around the energized equipment as well as a greater risk of an arcing electrical fault escalating into a multi-feeder outage. The vendor has stated that the circuit breakers are obsolete, with spare parts and support no longer offered. Replacement of the HMSTS B switchgear is planned for the 2030 – 2033 timeframe.

Switchgears at 4TS and 5TS are currently rated in Poor condition; however, they pose a lesser risk due to their arc proof rating. In 2026 and 2027, Enova will reevaluate rehabilitation/replacement options for these assets and bring forward a plan before the end of the forecast period.

2.5 STATION (TS & DS) CIRCUIT BREAKERS

2.5.1 Asset Demographics

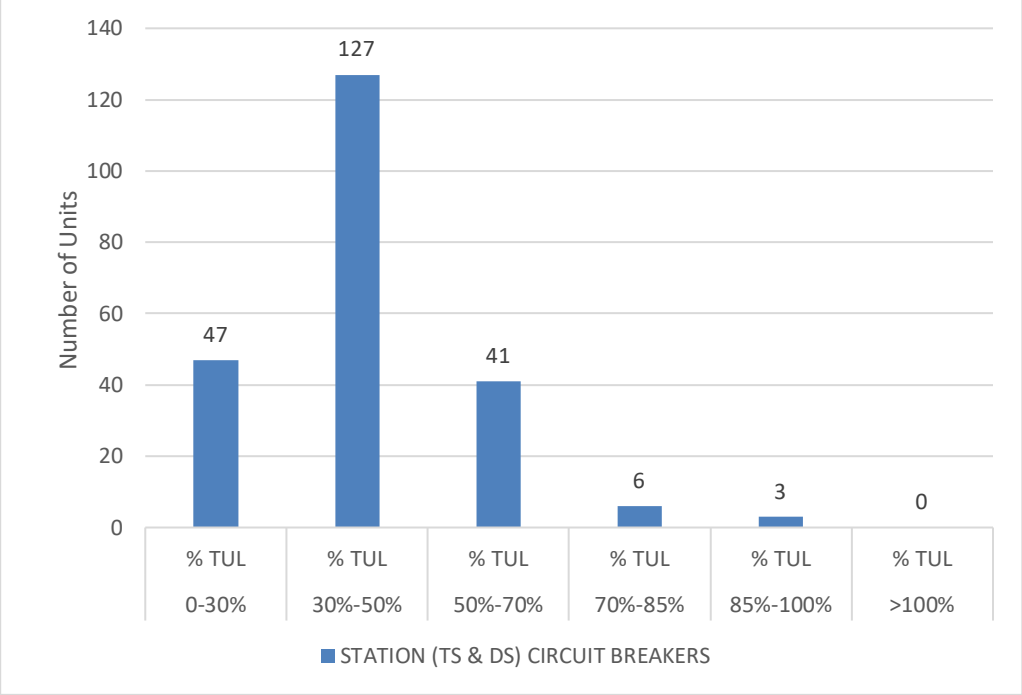
Enova maintains a population of 224 medium voltage circuit breakers, of which 209 are in service and the remainder are retained as spare units. Three of the in-service breakers are located at a rural DS, with the remainder being in service at grid-connected transformer stations.

The breakers are divided into two categories; main bank/tie breakers and feeder breakers and further divided into several vintages of breakers including air insulated, air insulated with vacuum interrupters, air insulated with SF6 interrupters and SF6 insulated with vacuum interrupters.

Table 2-17: Breaker Demographics

Station	# Breakers	Average Age (Yrs)	% TUL
HMSTS A	13	8	16%
HMSTS B	29	31	62%
MTS#3	15	21	42%
ERTS	13	28	56%
1TS	13	26	52%
3TS	26	25	50%
4TS	24	22	33%
5TS	25	16	57%
6TS	22	23	45%
7TS	13	29	58%
8TS	15	20	40%
9TS	13	16	32%
6DS	3	43	143%
AVG.	224	23	46%

Figure 2-7: Station Circuit Breaker Age Profile



2.5.2 Condition Assessment Criteria

Enova has adopted a TUL of 50 years for its TS and DS circuit breakers. This is consistent with the Kinectrics Report.

Table 2-18: Station Circuit Breaker (TUL)

	KINECTRICS REPORT		Enova
Min UL	TUL	Max UL	TUL
30	40	60	50

Table 2-19 provides a summary of the assessment criteria used to evaluate the health of Enova's medium voltage circuit breakers.

Table 2-19: Station Breaker Condition Assessment Criteria

						HSA, ERTS, 1TS, 3TS, 4TS, 5TS, 6TS, 8TS	HSB, 7TS, 3TS	MTS #3	6DS
Degradation Factor	**Type**	**Weight**	**Ranking**	**Numerical Grade**	**Max Grade**	**Metalclad Vacuum Breaker**	**Metal Clad SF6 Breaker**	**GIS Vacuum Breaker**	**Air Magnetic Breaker**
Service Age (indoor circuit breaker)	Air, Vacuum, SF6	4	A,B,C,D,E	4,3,2,1,0	16	16	16	16	16
Timing / Travel Tests	Air, Vacuum, SF6	2	A,B,C,D,E	4,3,2,1,0	8	8	8	8	8
Insulation resistance test (Closed Contacts)	Air, Vacuum, SF6	4	A,B,C,D,E	4,3,2,1,0	16	16	16	16	16
Insulation resistance test (Open Contacts)	Air, Vacuum, SF6	4	A,B,C,D,E	4,3,2,1,0	16	16	16	16	16
Vacuum Bottle Integrity	Vacuum	4	A,E	4,0	16	16	16	16	NA
Contact Resistance Tests	Air, Vacuum, SF6	2	A,B,C,D,E	4,3,2,1,0	8	8	8	8	8
Control & Operating Mechanism Components	Air, Vacuum, SF6	4	A,B,C,D,E	4,3,2,1,0	16	16	16	16	16
Overall Condition	Air, Vacuum, SF6	4	A,B,C,D,E	4,3,2,1,0	16	16	16	16	16
Total Score					112	112	112	112	96

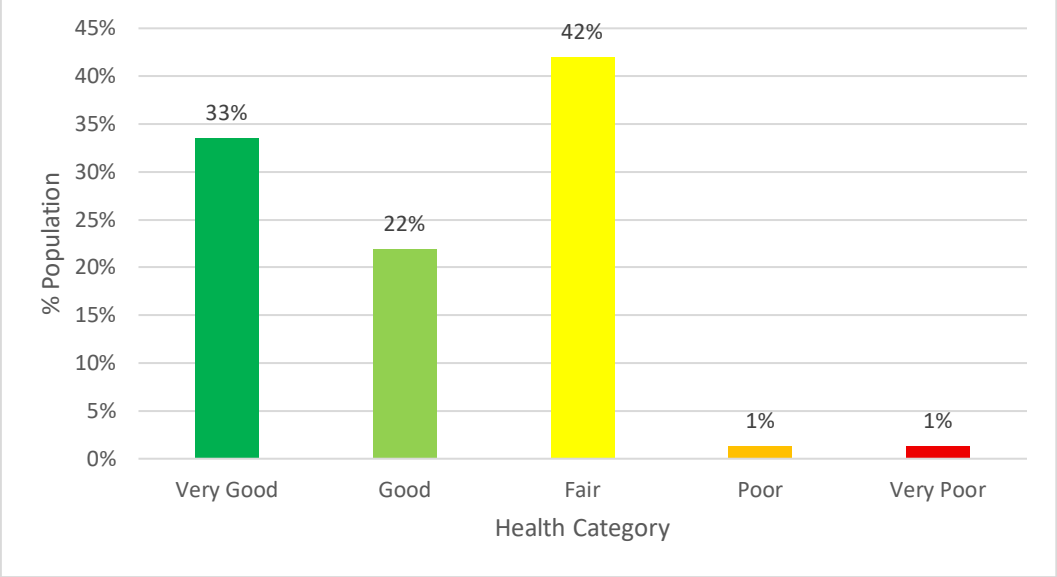
2.5.3 Condition Assessments

Table 2-20 provides a summary of the health conditions of Enova's medium voltage circuit breakers.

Table 2-20: Breaker Condition Assessments by Station

Station	# Breakers	HI % Score	Overall Condition
HMSTS A	13	96%	Very Good
HMSTS B	29	89%	Very Good
MTS#3	15	91%	Very Good
ERTS	13	84%	Good
1TS	13	66%	Fair
3TS	26	63%	Fair
4TS	24	66%	Fair
5TS	25	84%	Good
6TS	22	71%	Good
7TS	13	53%	Fair
8TS	15	63%	Fair
9TS	13	95%	Very Good
6DS	3	38%	Poor
Total	224	75%	Good

Figure 2-8: Station Circuit Breaker Condition Profile



2.5.4 Data Availability Indicator

Enova's DAI for station circuit breaker condition assessment data is 100%.

2.5.5 Analysis of Results

With an overall health score of 75%, Enova's circuit breaker population is in Good condition. Two breakers at 3TS and one at 7TS are in Very Poor condition, out of service and scheduled for repairs.

Three circuit breakers in Poor condition are located at 6DS, a 27.6 kV to 8.32 kV distribution station. Enova does not plan to invest in replacements due to the anticipated retirement of the station. Enhanced inspection and maintenance will be performed until the station is retired.

There are 94 breakers in Fair condition comprising 42% of the total population. Enova has identified 60 breakers in declining health that will need to be addressed.

1. 3TS breakers - 11 units with an average health score of 54.6% are scheduled for replacement in 2026.

2. 6TS breakers - 27 units with an average health score of 56.5% are scheduled for replacement in 2028 - 2029.

3. 7TS breakers - 13 units with an average health score of 56.5% are scheduled for replacement in 2028 - 2029.

4. ERTS breakers – 9 units with an average health score of 84.3% are scheduled for replacement in 2026 due to short circuit interrupting capacity being exceeded.

The remainder of the population have a health score above 60% and are not expected to be replaced over the forecast period.

2.6 STATION (TS) FEEDER CABLES

2.6.1 Asset Demographics

Feeder cables are a subset of Enova's underground cable population and are managed separately due to the criticality of these assets in overall system reliability. These cables deliver station loads out into the distribution system thereby having the highest load and customer impact of all underground cables.

There are 168 sets of three phase feeder cables comprised of various ages and circuit lengths. The feeder cable population is comprised of older EPR, PILC, XLPE cable and the newer TRXLPE cable. With total installed cable length of approximately 181 km, the breakdown of the population is provided in the following figures and tables.

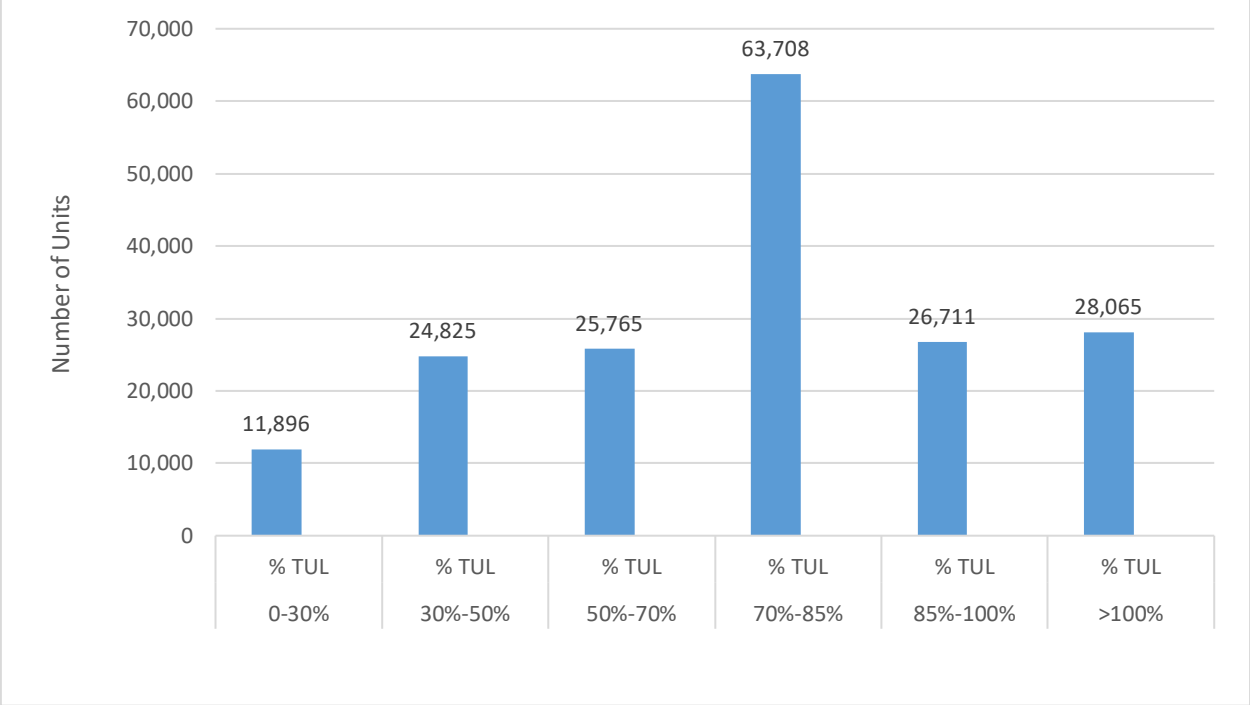
Table 2-21: Feeder Cable Demographics

Total Cable Lengths (m) by Voltage & System Voltage					
CABLE TYPE	**8.32kV**	**13.8kV**	**27.6kv**	**Total**	**% of Total**
EPR		5,124		5,124	2.8%
PILC		30,762		30,762	17.0%
XLPE	1,200	102,632	12,963	116,795	64.5%
TRXLPE		19,403	8,887	28,290	15.6%
	1,200	157,921	21,850	180,970	100.0%
% by System Voltage	1%	87%	12%	100%	

Table 2-22: Feeder Cable Age by Cable Type

CABLE TYPE	Total Length	Avg Age (Yrs)	TUL (Yrs)	%TUL
EPR	5,124	25	35	71.4%
PILC	30,762	54	65	83.1%
XLPE	116,795	29	35	82.9%
TRXLPE	28,289	18	40	45.0%
	180,970			

Figure 2-9: Station Cable Age Profile



	Age Demographics						
Asset Category	**0-30%**	**30%-50%**	**50%-70%**	**70%-85%**	**85%-100%**	**>100%**	**Total**
	% TUL	**% TUL**	**% TUL**	**% TUL**	**% TUL**	**% TUL**	
Cable Length (m)	11,896	24,825	25,765	63,708	26,711	28,065	180,970
% of Total	6.6%	13.7%	14.2%	35.2%	14.8%	15.5%	100.0%

At the 15 kV operating level, older feeder cable insulation levels are 15 kV, 100% and 133% while the newer cables are 28 kV, 100%. The higher insulation level is expected to provide longer cable life for these critical assets.

At the 27.6 kV level, feeder cable insulation levels are 28 kV, 100% and 133%.

2.6.2 Condition Assessment Criteria

Table 2-23 provides a summary of the TULs for Enova station cables. Enova's adoption of a 40 year TUL for XLPE cable exceeds the TUL and Max UL published in the Kinectrics Report.

Enova's current XLPE cable population with a maximum age of 54 with an average age of

41 years. Given its own experience with XLPE cable, Enova felt that the 40 year TUL is more representative of this cable's performance.

Table 2-23: Station Feeder Cables (TUL)

	KINECTRICS REPORT			Enova
Cable Type	**Min UL**	**TUL**	**Max UL**	**TUL**
EPR	20	25	25	25
PILC	60	65	70	60
XLPE (Duct)	20	25	30	40
TRXLPE	35	40	55	40

Table 2-24 provides a summary of the assessment criteria used to evaluate the health of Enova's station feeder cables.

Table 2-24: TS Feeder Cables Assessment Criteria

Degradation Factor	Weight	Ranking	Numerical Grade	Max Grade
Service Age	5	A,B,C,D,E	4,3,2,1,0	20
Insulation Rating	7	A,B,C,D,E	4,3,2,1,0	28
Loading History	2	A,B,C,D,E	4,3,2,1,0	8
Failure Rates	5	A,B,C,D,E	4,3,2,1,0	20
Field Tests - Insulation Resistance	5	A,B,C,D,E	4,3,2,1,0	20
Field Tests - Polarization Index	5	A,B,C,D,E	4,3,2,1,0	20
Condition of Concentric Neutral / Taped Shield	3	A,C,D,E	4,2,1,0	12
Visual Inspection of Cable Terminators & Splices	1	A,C,E	4,2,0	4
Total Score			Max	132

2.6.3 Condition Assessments

Table 2-25 provides a summary of the health conditions of Enova's station feeder cables.

Table 2-25: Station Cable Condition Assessments

	Health Index Distribution (%)					
Asset Category	**Very Good**	**Good**	**Fair**	**Poor**	**Very Poor**	**Total**
Cable Length (m)	18,381	21,878	23,246	89,625	27,840	180,970
% of Total	10%	12%	13%	50%	15%	100%

2.6.4 Data Availability Indicator

Enova's DAI for TS feeder cables data is 100%.

2.6.5 Analysis of Results

Overall, 65% of Enova's station cables are considered to be in Poor or Very Poor Condition with another 13% in Fair condition.

The cables in Very Poor condition have an average Health Score of 23% and TUL of 132%. The approximately 27.8 km of cable in this category is made up entirely of XLPE type cable. These cables have started to exhibit insulation failures. In addition, the cables' taped shields are corroding, overheating and burning away, causing damage to the cable insulation. These cables will be scheduled for replacement over the forecast period.

The cables in Poor condition have an average Health Score of 42% and TUL of 76%. The approximately 94.3 km of cable in this category are comprised of XLPE (58.4 km), ERP (5.1 km) and PILC (30.8 km). Some of the XLPE cables in this group are starting to exhibit the same degradation as noted with the group in Very Poor condition. Further work is required to segment out the poorest of these cables so that they may be prioritised for replacement over the forecast period along with the Very Poor cables. The replacement for the remaining

cables in this group is expected to be beyond 2031.

Approximately 23.2 km of cable are in Fair condition have an average Health Score of 61% and TUL of 63%. There are no replacement plans for this group of cables during the forecast period.

The remaining station feeder cables are in Good or Very Good condition and no action is planned for this group of cables over the forecast period.

As part of Enova's System Renewal program, the replacement of station switchgear is planned at 6TS, and 7TS over the forecast period. The replacement of various feeder cables at these stations will be coordinated to facilitate this stations capital work.

Table 2-26 provides a summary of Enova's station cable replacement program.

Table 2-26: Station Cable Replacement Plan

Size	Conductor	Cable Type	km	Installation Method	Area	Age	% HI	2026	2027	2028	2029	2030	2031	Total (km)
600	CU	XLPE	14.0	Duct	5TS (2)	46	23%	14.0						14.0
600	CU	XLPE	15.0	Duct	6TS (1)	30	42%			8.9	6.1			15.0
600	CU	XLPE	7.8	Duct	7TS (1)	30	41%			3.9	3.9			7.8
600	CU	XLPE	11.2	Duct	4TS (2)	52	23%					6.0	5.2	11.2
Total			48			49		14.0	0.0	12.8	10.0	6.0	5.2	48.0

Note: (1) Cable in Poor and Very Poor condition. Replacement to be coordinated with station switchgear replacement.

(2) Cable in Very Poor condition. Replacement is independent of any station work.

2.7 STATION (TS) PROTECTION RELAYS

2.7.1 Asset Demographics

Table 2-27: TS Protection Systems Demographics

Transformer Stations	Line Protections	Transformer Protection	Bus Protections	Feeder Protections	Ave Age	TUL (yrs)	% TUL	Relay Type
HMSTS 'A'	2009	2009	2009	2009	15	15	100%	Digital
HMSTS 'B'	2015	2014	2014	2011	13	15	87%	Digital
MTS #3	2019	2019	2019	2015	3	15	20%	Digital
ERTS	2012	2012	2012	2012	12	15	80%	Digital
1TS	2005	2005	1997/2005	1997	23	15	153%	Digital / Electronic
3TS	2000	2000	2000/2019	2000/2006	22	15	147%	Digital / Electronic
4TS	2008	2008	2008	2008	16	15	107%	Digital
5TS	2017	2017	2017	2017	7	15	47%	Digital
6TS	2022	2022	2022	2022	2	15	13%	Digital
7TS	2011	1995	1995	1995	29	25	116%	Digital / Electronic / Mech
8TS	2004	2004	2004	2004	20	15	133%	Digital
9TS	2010	2010	2010	2010	14	15	93%	Digital

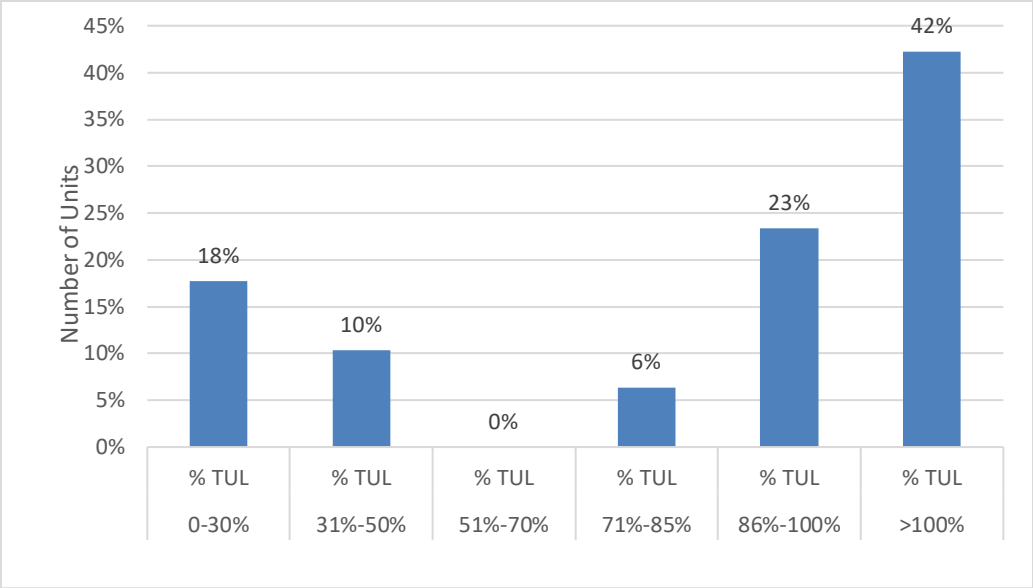
Enova has a total of 407 protective relays at its grid-connected transformer stations. These devices protect high value station assets and coordinate power outages during fault occurrences to minimize the extent and duration of customer outages on downstream distribution feeders. Some relays also help minimize the impact on transmission outages from faults on Enova's grid-connected equipment.

Older versions of digital, electronic and electromechanical relays are not able to support Enova's grid programs such as Feeder Fault Detection, Isolation and Restoration (FLISR). Currently FLISR is deployed at 4 transformer stations on 56 feeders. As the older protection relays are updated over time, this functionality will be rolled out to the remaining stations and feeders. Older versions of protective relays also do not have the capabilities to deal with the requirements of modern distribution systems such as the connection of DERs.

The average age of Enova's protective relay population is 14.1 years (94% TUL) with 42%

of the population past their TUL. **Figure 2-10** provides a breakdown of the population by age.

Figure 2-10: Protection Relays Age Profile



2.7.2 Condition Assessment Criteria

Table 2-28 provides the TUL for protection relays based on Enova's experience with electromechanical, electronic and programmable microprocessor-based protection relays.

Table 2-28: TS Protection Systems (TUL)

	KINECTRICS REPORT			Enova
Vintage	**Min UL**	**TUL**	**Max UL**	**TUL**
Electromechanical	25	35	50	25
Electronic / Solid State	10	30	45	25
Digital / Programable	15	20	20	15

In addition to on-board health diagnostics, the accuracy and functionality of these assets are reverified every 2 – 4 years depending on the protection group. Enova's assessment criteria for the reverification of protective relays comes in part from the Transmitter (HONI),

the IESO (Transmission System Code), vendor recommendations and Enova's experience and expertise. Any relay that fails to meet a performance or non-performance requirement, or that possesses a defect which could affect its ability to meet specified requirements, is removed from service.

Table 2-29 provides summary of degradation factors Enova considers when assessing the overall condition of the relays.

Table 2-29: Protection Relay Condition Assessment Criteria

Degradation Factor	Weight	Ranking	Numerical Grade	Max Grade
Service Age	4	A,B,C,D,E	4,3,2,1,0	16
Defect and Test Reports	2	A,B,C,D,E	4,3,2,1,0	8
Mean Time Between Failures	5	A,B,C,D,E	4,3,2,1,0	20
Visual Inspections	3	A,B,C,D,E	4,3,2,1,0	12
Non-Discretionary Obsolescence	5	A,E	4,0	20
Discretionary Obsolescence	1	A,B,C,D,E	4,3,2,1,0	4
Total Score				80

2.7.3 Condition Assessments

Enova has found that the microprocessor-based protection relays do not experience declining health in the same manner as other assets. They tend to operate within functional and accuracy standards and then fail. Some relay types are modular with replaceable components while others must be returned to the manufacture for repair. Obsolescence of software and hardware is the main driver forcing most protective relays into end-of-life.

Tables 2-30 a, b, c provide a breakdown of relay condition by station bus. The overall health score of the relay population is 63% or Fair.

Table 2-30a: Protection Relay Condition

Station	Bus	Age	% TUL	% HI	Condition Rating
HMSTS A	T1	15	100%	59%	Fair
HMSTS A	T2	15	100%	59%	Fair
HMSTS A	Bus B	15	100%	59%	Fair
HMSTS A	Bus Y	15	100%	59%	Fair

Table 2-30b: Protection Relay Condition (Continued)

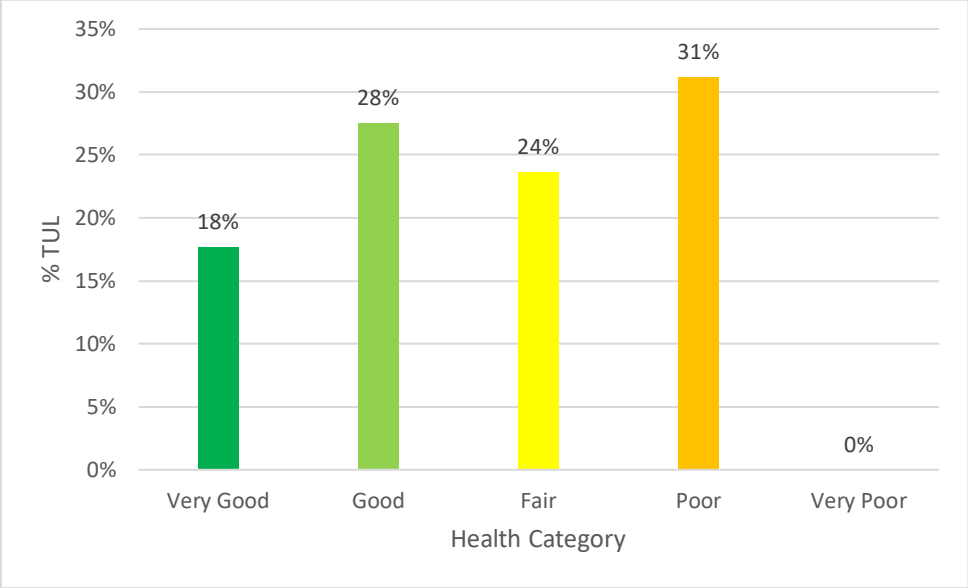
Station	Bus	Age	% TUL	% HI	Condition Rating
HMSTS B	T3	11	73%	71%	Good
HMSTS B	T4	11	73%	71%	Good
HMSTS B	Bus H	13	87%	71%	Good
HMSTS B	Bus J	13	87%	71%	Good
HMSTS B	Bus Q	13	87%	71%	Good
HMSTS B	Bus T	13	87%	71%	Good
ERTS	T1	12	80%	71%	Good
ERTS	T2	12	80%	71%	Good
ERTS	Bus B1	12	80%	71%	Good
ERTS	Bus B2	12	80%	71%	Good
MTS#3	T1	5	33%	84%	Good
MTS#3	T2	4	27%	89%	Very Good
MTS#3	Bus B1	2	13%	95%	Very Good
MTS#3	Bus B2	1	7%	100%	Very Good
1TS	Bus B1	27	180%	41%	Poor
1TS	Bus B2	27	180%	41%	Poor
1TS	Tx 1	19	127%	41%	Poor
1TS	Tx 2	19	127%	41%	Poor
3TS	Bus B51	18	120%	40%	Poor
3TS	Bus B61	18	120%	40%	Poor
3TS	Bus B52	24	160%	40%	Poor
3TS	Bus B62	24	160%	40%	Poor
3TS	Tx 5	24	160%	40%	Poor
3TS	Tx 6	24	160%	40%	Poor
4TS	Bus B71	16	107%	65%	Fair
4TS	Bus B81	16	107%	65%	Fair
4TS	Bus B72	16	107%	65%	Fair
4TS	Bus B82	16	107%	65%	Fair
4TS	Tx 7	16	107%	65%	Fair
4TS	Tx 8	16	107%	65%	Fair
5TS	Bus B91	7	47%	76%	Good
5TS	Bus B101	7	47%	76%	Good
5TS	Bus B92	7	47%	76%	Good
5TS	Bus B102	7	47%	76%	Good
5TS	Tx 9	7	47%	76%	Good
5TS	Tx 10	7	47%	76%	Good
6TS	Bus B111	2	13%	83%	Good
6TS	Bus B121	2	13%	83%	Good
6TS	Bus B112	2	13%	83%	Good
6TS	Bus B122	2	13%	83%	Good
6TS	Tx 11	2	13%	83%	Good
6TS	Tx 12	2	13%	83%	Good

Table 2-30c: Protection Relay Condition (Continued)

Station	Bus	Age	% TUL	% HI	Condition Rating
7TS	Bus B13	29	193%	40%	Poor
7TS	Bus B14	29	193%	40%	Poor
7TS	Tx 13	29	193%	40%	Poor
7TS	Tx 14	29	193%	40%	Poor
8TS	Bus B15	20	133%	40%	Poor
8TS	Bus B16	20	133%	40%	Poor
8TS	Tx 15	20	133%	40%	Poor
8TS	Tx 16	20	133%	40%	Poor
9TS	Bus B17	14	93%	66%	Fair
9TS	Bus B18	14	93%	66%	Fair
9TS	Tx 17	14	93%	66%	Fair
9TS	Tx 18	14	93%	66%	Fair

Figure 2-11 illustrates that 31% of the population has been assessed as in Poor condition.

Figure 2-11: Protection Relays Health Profile



	Health Index Distribution (%)					
Asset Category	Very Good	Good	Fair	Poor	Very Poor	Count
Protection Relays	72	112	96	127	0	407
% Total	18%	28%	24%	31%	0%	100%

2.7.4 Data Availability Indicator

Enova's DAI for TS protection relays condition evaluation data is 100%.

2.7.5 Analysis of Results

Protection relays at four of Enova's grid-connected transformer stations (1TS, 3TS, 7TS and 8TS) have been evaluated as in Poor Condition with an average Health Score of 40%. This represents 31% of the of the protection relay population. These relays also have an average age of 23.3 years or 156% of their TUL.

In addition to not being able to support smart Grid technologies, older versions of digital relays are suffering from component failure and obsolescence.

Hardware support has ended for most of these relays. Enova has managed this population of relays through scavenging failed relays and component replacements; however, not all components are supported in all relays.

Software support has also ended for most of these relays. They cannot be reprogrammed or the old software will not run on newer computers. The lack of reprogramming capability limits the ability to connect REGs and to deploy FLISR.

In 2020, Enova began a replacement plan that has seen 72 relays replaced at MTS #3 and 6TS. This plan will continue with replacements at 1TS (26), 3TS (47), 7TS (26), 8TS (26) and HMSTS A (24) scheduled over the forecast period.

2.8 DISTRIBUTION STATION (DS) TRANSFORMERS

2.8.1 Asset Demographics

Enova has 10 remaining distribution stations < 50 kV operating throughout the rural areas of its service area. This group of assets is being phased out over time as Enova's System Renewal investments replace 8.32 kV lines in poor condition and with new lines operating at 27.6 kV.

Table 2-31: DS Transformer Demographics

#	DS	BASE RATING (MVA)	MAX COOLED RATING (MVA)	HV (kV)	LV (kV)	In Service	Age (2024)
1	DS#27	5.0	5.0	27.6	8.32	1990	34
2	DS#28	5.0	6.7	27.6	8.32	1996	28
3	DS#30	5.0	5.0	44.0	8.32	1976	48
4	DS#31	5.0	6.7	27.6	8.32	1980	44
5	1DS	5.0	5.0	27.6	8.32	1987	37
6	2DS	5.0	5.0	27.6	8.32	1970	54
7	3DS	5.0	5.0	27.6	8.32	1967	57
8	6DS	5.0	6.7	27.6	8.32	1982	42
9	7DS	5.0	5.0	27.6	8.32	1991	33
10	8DS	5.0	6.7	27.6	8.32	1995	29
		50.0	56.7			Avg	41

2.8.2 Condition Assessment Criteria

Enova has adopted 40 years as the TUL for its DS transformers. This is consistent with the Kinectrics Report and Enova's own experience.

Table 2-32: DS Transformers (TUL)

	KINECTRICS REPORT		Enova
Min UL	TUL	Max UL	TUL
30	45	60	40

Table 2-33: DS Transformers Condition Assessment Criteria

#	Degradation Factor	Weight	Ranking	Numerical Grade	Max Grade	Tx's with OLTC	Tx's without OLTC
1	Service Age	10	A,B,C,D,E	4,3,2,1,0	40	40	40
2	Dissolved Gas Analysis*	10	A,B,C,D,E	4,3,2,1,0	40	40	40
3	Load History	10	A,B,C,D,E	4,3,2,1,0	40	40	40
4	Insulation Power Factor*	10	A,B,C,D,E	4,3,2,1,0	40	40	40
5	Oil Quality	6	A,C,E	4,2,0	24	24	24
6	Degree of Polymerization (or Service Age)	10	A,B,C,D,E	4,3,2,1,0	40	40	40
7	Turns Ratio	5	A,B,C,D,E	4,3,2,1,0	20	20	20
8	Winding Resistance	6	A,B,C,D,E	4,3,2,1,0	24	24	24
9	Tap Changer DGA (if applicable)	6	A,B,C,D,E	4,3,2,1,0	24	24	N / A
10	Tap Changer Oil Quality (if applicable)	3	A,B,C,D,E	4,3,2,1,0	12	12	N / A
11	Tap Changer Operations	5	A,B,C,D,E	4,3,2,1,0	20	20	N / A
12	Overall, Bushings	2	A,B,C,D,E	4,3,2,1,0	8	8	8
13	Infrared Scan (IR)*	10	A,B,C,D,E	4,3,2,1,0	40	40	40
14	Overall Inspection Condition	8	A,B,C,D,E	4,3,2,1,0	32	32	32
15	Overall LTC (if applicable)	5	A,B,C,D,E	4,3,2,1,0	20	20	N / A
	Total Score					424	348
	*Note: If conditions are E, divide the overall Health index by 2.						

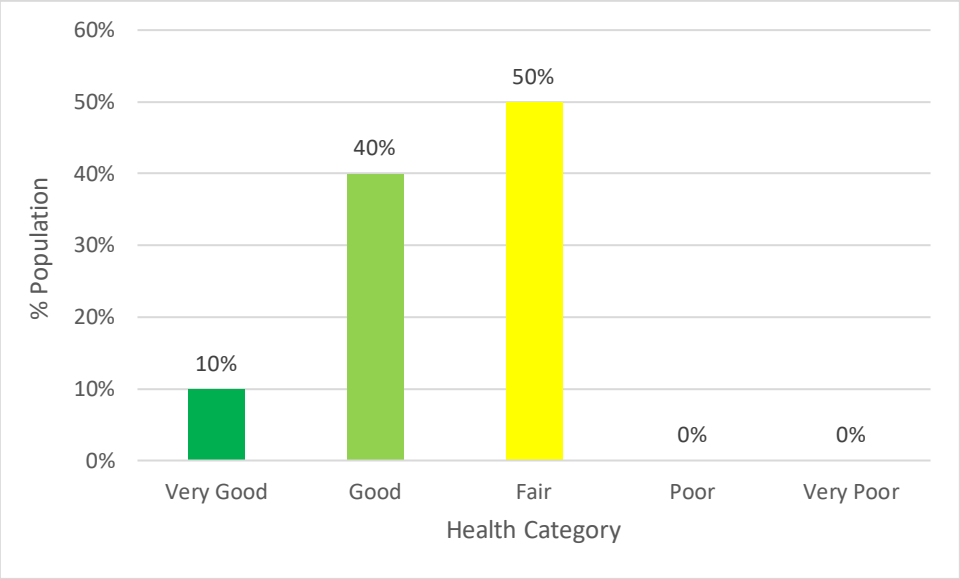
2.8.3 Condition Assessments

Table 2-34 provides age and Health index scores for all DS transformers. Ranging from a HI of 58% to 89%, the overall fleet of transformers has a rating of 70% (Fair).

Table 2-34: DS Transformers Health Condition Assessments

DS	Tx ID	TOTAL HI SCORE	MAX HI SCORE	HI % SCORE	CONDITION	Age (2024)	%TUL
DS#27	T1	376	424	89%	Very Good	34	85%
DS#28	T1	285	348	82%	Good	48	70%
DS#30	T1	332	424	78%	Good	44	120%
DS#31	T1	275	424	65%	Fair	28	110%
1DS	T1	215	348	62%	Fair	37	93%
2DS	T1	215	348	62%	Fair	54	135%
3DS	T1	201	348	58%	Fair	57	143%
6DS	T1	205	348	59%	Fair	42	105%
7DS	T1	246	348	71%	Good	33	83%
8DS	T1	245	348	70%	Good	29	73%
	Avg			70%	Fair	41	102%

Figure 2-12: Distribution Station Transformer Health Profile



2.8.4 Data Availability Indicator (DAI)

Enova's DAI for DS transformers condition evaluation data is 100%.

2.8.5 Analysis of Results

This is a mature asset group of 10 station transformers with an average age of 41 years and a maximum age of 57 years. The condition assessments reveal transformers ranging from Fair to Very Good condition with an overall Health Score of 70%.

Enova's System Renewal programs in overhead lines have allowed for a gradual shift in load from 8.32 kV to 27.6 kV resulting in the retirement of 4 stations since 2020. It has also allowed Enova to manage the loads of the remaining 10 stations avoiding the need to invest in distribution station capacity upgrades on its 8.32 kV system.

Although 5 of the 10 transformers have exceeded their TUL, it is expected that their condition and loading will allow them to remain in service until their ultimate retirement due to Enova's contingency planning.

Due to the ultimate elimination of its 8.32 kV system, Enova has taken measures to avoid the recapitalization of DS assets and to mitigate the increasing risk associated with transformer age and condition.

1. Enova owns and maintains a two mobile unit substation (MUS) to provide temporary supply to any 8.32 kV station within 4 hours.

2. Enova maintains spare 44 kV and 27.6 kV transformers that can be pressed into service in case of an in-service failure.

3. Enova salvages serviceable equipment from retired stations to maintain operability.

Enova is planning to retire 3DS in the 2025-2026 timeframe. There are no other stations planned for retirement before 2031.

2.9 POLES

2.9.1 Asset Demographics

Enova has a population of approximately 45,800 poles, 84% of which are wood. **Table 2-35** provides a breakdown of Enova's pole population by pole type.

Table 2-35: Pole Population by Type

Pole Type	Number of Poles	% Pop	Avg. Age
Wood	38,471	84%	25.6
Concrete	7,086	15%	31.6
Steel	253	0.6%	24.5
Composite	4	0.01%	16.0
Total	45,814	100%	26.5

Wood, and more specifically fully treated pine poles, have become the major pole type used at Enova. Western Red Cedar poles tend to be used in applications where their lighter weight is an advantage such as in tall pole line or rear lot applications.

Enova has a smaller population of concrete poles which are only used sparingly in urban areas. Their higher cost, greater weight and greater susceptibility to salt damage makes them candidates only where aesthetics are prioritized.

Enova also has a minor population of steel poles which are on the decline. Steel poles have become uneconomical in recent years and are no longer used for new construction.

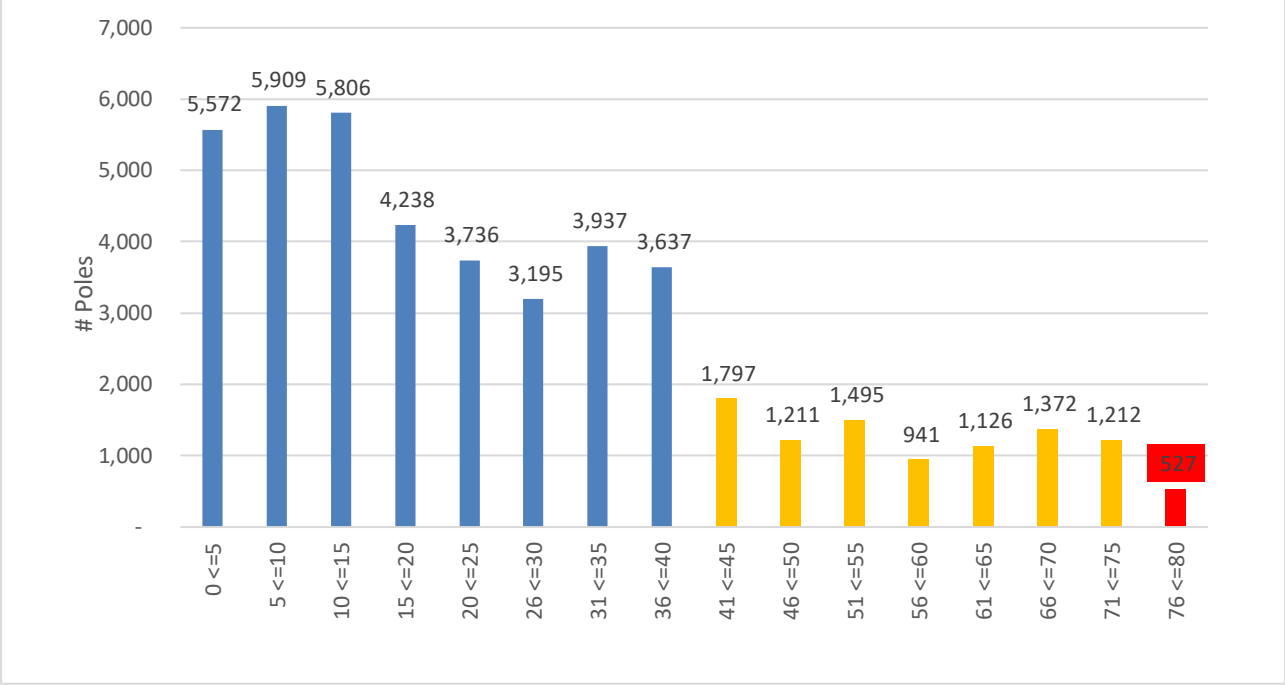
Table 2-36 provides a breakdown of the pole population by function in the distribution system.

Table 2-36: Pole Utilization

Pole Type	# Poles	% Pop
Primary Distribution Poles	37,847	83%
Secondary Distribution Poles	5,070	11%
Support Poles (guying)	2,897	6%
Total	45,814	100%

Figure 2-13 provides an age profile of Enova's pole population. Poles past 75 years of age are highlighted in red as these poles exceed the maximum useful life as outlined in the Kinectrics Report. Currently there are 527 poles past the maximum useful life. Without intervention, another 1,212 poles will reach that state within the next 5 years. There are approximately 103 poles where the age has not yet been determined.

Figure 2-13: Enova Pole Population Age Profile



2.9.2 Condition Assessment Criteria

Table 2-37 provides a summary of the TUL's Enova has adopted for all of its pole types.

Table 2-37: Poles (TUL)

	KINECTRICS Report			Enova
Pole Type	**Min UL**	**TUL**	**Max UL**	**TUL**
Wood Poles	35	45	75	40
Concrete Poles	50	60	80	40
Steel Poles	60	60	80	40
Composite Poles	N/A	N/A	N/A	40

Table 2-38 provides a summary of the main asset management criteria used to calculate the Health Indices for Enova's pole population.

Table 2-38: Recommended Health Index Assessment Criteria

Degradation Factor	Weight	Ranking	Numerical Grade	Max Grade
Service Age	15	A,B,C,D,E	4,3,2,1,0	60
Pole Treatment	5	A,C,E	4,2,0	20
Remaining Strength*, **	20	A,B,C,D,E	4,3,2,1,0	80
Crossarm Condition	1	A,C,E	4,2,0	4
Pole Top Condition*	1	A,C,D,E	4,2,1,0	4
Shell Condition and Environment	7	A,C,D,E	4,2,1,0	28
Total Score	Pole	196	Pole < 25 years	116
* Note: If conditions are E, divide the overall Health Index by 2. Off Ramp for RFS < 50%				
** Only applicable for poles subject to Enova pole testing (> 25 years old).				

2.9.3 Condition Assessments

Condition assessments are developed through Enova's Pole Inspection and Testing program. Enova uses EII's ENGIN analytical software to develop Health Indices for its pole population and develop recommended pole replacement programs.

Table 2-39 summarizes, by age, the number of poles that are currently past TUL and those that will exceed their TUL by 2031.

Although Enova's replacement program for poles is based on condition, age is still an important indicator of asset lifecycle behaviour.

Table 2-39: Poles past TUL

Category	# Poles	% of Pop
Past TUL	9,784	21%
Approaching TUL during forecast period	3,637	8%
Total	13,421	29%
Not Near TUL	32,393	71%
Total Population	45,814	

For wood poles, Remaining Fibre Strength (RFS) is a key degradation factor in determining a Pole's HI. Enova's pole testing program targets poles greater than 25 years of age and currently 11,087 or 72% of this group has been tested. Enova also tests pole less than 25 years of age if they are deemed to be vulnerable or high impact.

Enova's criteria for minimum wood pole remaining fibre strength (RFS) is 50%. Poles with a RFS of less than 50% are considered to be in Very Poor condition and scheduled for replacement in 1 – 3 years. Currently, of the 11,087 wood poles tested, there are 1,164 poles have a RFS value of < 50%.

Figure 2-14 provides a profile of the RFS profile for the tested population.

Figure 2-14: Enova Wood Pole Remaining Strength Profile

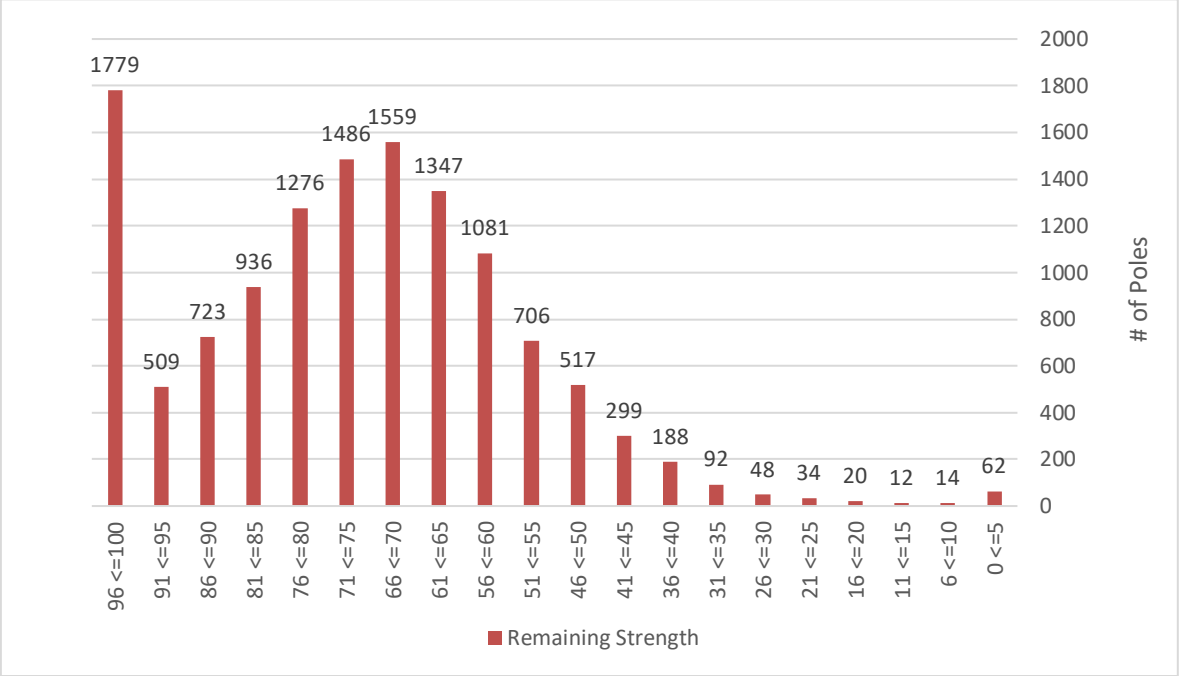


Table 2-40 provides a summary of the condition assessment results. Approximately 82% of Enova's pole population is in Fair condition or above with 18% of the population in Poor or Very poor condition. The average RFS of Enova's wood pole population is 72.2%. There are 116 poles that have insufficient data; a deficiency that will be corrected by Enova as part

of the 2026 inspection and pole testing program.

Table 2-40: Health Index Distribution

HEALTH INDICIES	# Poles	% of Pop	Avg. Age	% Remaining Strength
Very Poor	3,725	8.1%	54.4	44.8
Poor	4,505	9.8%	56.9	63.9
Fair	8,420	18.4%	40.2	75.5
Good	13,228	28.9%	20.8	86.2
Very Good	15,820	34.5%	9.3	96.5
Total Poles Under Evaluation	45,698	99.7%	26.8	72.2
Poles with no HI data	116	0.3%		
Total Poles	45,814	100.0%		

Currently Enova has approximately 9,784 poles past their TUL which represents 21% of the population. Of these poles, 7,206 or 15.7% of the population has been evaluated to be in Very Poor or Poor Condition. Many of the poles that are currently in Poor condition are expected to degrade to Very Poor condition over the forecast period.

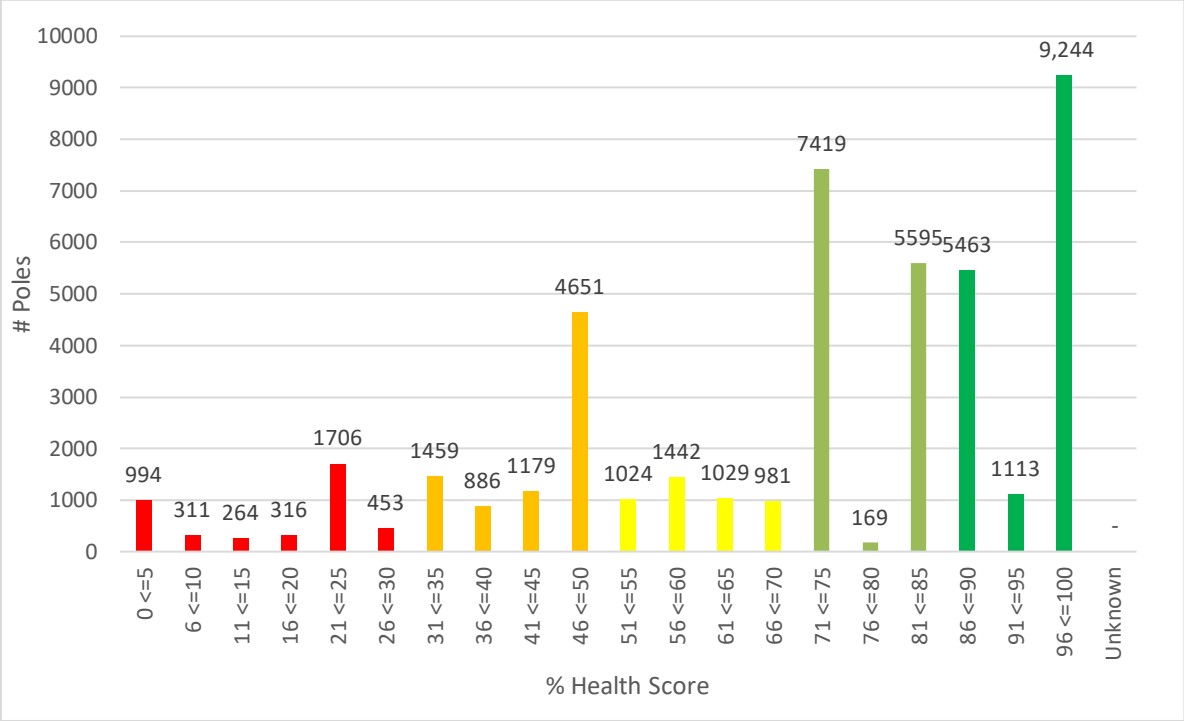
Table 2-41 provides a summary of the condition assessment results based on pole type.

Table 2-41: Pole Health Index by Pole Type

Pole Type	Number of Poles	% Pop	Avg. Age	Avg HI	HI Category
Wood	38,471	84.0%	25.8	73.2%	Good
Concrete	7,086	15.5%	32.4	55.9%	Fair
Steel	253	0.6%	24.5	74.1%	Good
Composite	4	0.01%	16.0	75.0%	Good
Total	45,814	100.0%	26.8	70.5%	Good

Figure 2-15 illustrates Enova's pole population Health Index distribution. The average HI of Enova's pole population is 70.5% or rated in Good condition

Figure 2-15: Enova Pole Population HI Distribution



		Health Index Distribution (%)					
Asset Category	**Count**	**Very Good**	**Good**	**Fair**	**Poor**	**Very Poor**	**Total**
Wood Poles	38,471	15,439	10,062	6,093	4,505	2,372	38,471
Wood Poles	100%	40%	26%	16%	12%	6%	100%
Concrete Poles	7,086	380	2,920	2,317	0	1,469	7,086
Concrete Poles	100%	5%	41%	33%	0%	21%	100%

Table 2-42 breaks out the Health Indices of Enova's pole population by number of circuits they impact. In Enova's investment prioritization process, multi-circuit lines which have larger customer impact are weighted more heavily for replacement than single phase lines.

Table 2-42: Pole Health Index Distribution by Number of Circuits

# Circuits	# Poles	Average HI	HI Category
Support Poles, No Circuits	4,119	71.7%	Good
Single Circuit, Single Phase	5,242	68.7%	Fair
Single Circuit, Multi Phase	8,591	77.1%	Good
Two Circuit, Multi Phase	3,603	79.8%	Good
Three Circuit, Multi Phase	697	80.6%	Good
Four Circuit, Multi Phase	67	75.5%	Good
Unidentified	23,495	66.6%	Fair
All poles	45,814	70.5%	Good

2.9.4 Data Availability Indicator (DAI)

Enova's DAI for pole condition assessment data is 85.4% for poles greater than 25 years of age. Poles less than the age of 25 are not tested for remaining strength, therefore this data is not available. All poles undergo visual inspections on a 3 year or 6 year inspection cycle.

2.9.5 Analysis of Results

Over the historic period, Enova replaced approximately 930 poles per year due to condition and approximately 200 poles per year due to non-condition related reasons such as relocations, motor vehicle accidents, service upgrades and storm damage.

Currently, there are approximately 3,725 poles with a Health Index of Very Poor that present a high risk of failure. This represents approximately 8% of the population. These poles are recommended for replacement over the next 1 to 3 years.

There are also another 4,505 poles currently with a Health Index of Poor. This represents approximately 10% of the population. Recommended for replacement are approximately 2,364 of these poles with a HI of < 40%. To pace the pole replacement program,

replacement is recommended in the next 3-6 years or prior to 2031.

In addition, the poles in Fair condition with the lowest health scores are planned to be closely monitored for transition into the Poor or Very Poor categories.

In addition to condition based replacements, additional poles are often required due to height, spacing or offset changes required in the new construction. Poles in a line section may also not be uniform in their condition; however, it is normally more efficient to replace all the poles in a line section even though all do not meet the replacement criteria. Pole replacements also occur due to road widening requests from the municipalities, motor vehicle accidents, and weather related damage.

Table 2-43 provides a summary of the recommended pole replacements between 2026 and 2031.

Table 2-43: Pole Replacement Recommendations

Annual Avg. Pole Replacements	Total	2026	2027	2028	2029	2030	2031	Avg.
Very Poor - Remaining Strength < 50%	1,164	956	208	-	-	-	-	194
Very Poor - Other Degradation Factors	2,561	69	842	1,000	650	-	-	427
Poor - HI < 40%	2,364	-	-	-	345	985	1,034	394
Infill replacement poles required to facilitate Constructable Projects (20%)	1,218	205	210	200	199	197	207	203
Other Pole replacements (weather, MVAs, road widenings)	1,200	200	200	200	200	200	200	200
Annual Replacement Total	8,507	1,430	1,460	1,400	1,394	1,382	1,441	1,418

Based on the ACA results, Enova is forecasting a need to replace approximately 1,400 poles per year between 2026 and 2031.

2.10 PRIMARY UNDERGROUND DISTRIBUTION CABLES

2.10.1 Asset Demographics

Enova's total underground distribution system consists of approximately 3,587 km of medium voltage cable, the majority of which is found in residential subdivisions and services. The cable population is segmented into two cable types (XLPE and TRXLPE) and two installation types (direct buried and ducted).

CS's current population of XLPE cable was installed between 1965 and 1993, after which CS transitioned to TRXLPE cable. VS's current population of XLPE cable was installed between 1961 and 1996, after which VS also transitioned to TRXLPE cable.

Cross Linked Polyethylene Cable (XLPE)

These cables were constructed with copper conductor, copper neutrals, polymeric insulation (XLPE), and for the most part, polyvinyl chloride (PVC) jacketing. There may still be a small population of unjacketed cable direct buried cable in the oldest parts of the distribution system: however, most has been replaced.

Water treeing is the most significant degradation process for polymeric cables. By today's standards, the designs of these earlier XLPE cables were poor, allowing water ingress between the jacket and the insulation and into the interstices of the conductor. In the presence of electric fields, water migration results in the formation of water trees, partial discharge in the insulation and ultimately electrical breakdown. The rate of growth of water trees is dependent on the quality of the polymeric insulation and the manufacturing process.

Earlier XLPE manufacturing processes, especially those before 1980, were not as robust as today. Contamination, voids and deformities in the insulation were more prevalent, leading to more sites for partial discharge to begin and faster degradation.

Tree Retardant Cross-Linked Polyethylene Cable (TRXLPE)

Enova's TRXLPE cables come with a number of features which make it superior to previous XLPE cables and it is expected to result in longer life. With water treeing being the most

significant degradation process for polymeric cables, a cable insulation with greater resistance to water treeing is the most significant feature. Enova also specifies its cable with strand blocking technology to significantly reduce water ingress into the cable. Also included is an encapsulated polyethylene jacket which is mechanically stronger and more impervious to water ingress and mechanical damage during installation. Lastly, improved cable manufacturing in recent years has reduced contaminants and imperfections in the cable insulation extruding process making it less susceptible to partial discharge failure.

Enova has 11 legacy cable sizes inherited from its predecessor LDC's. Enova has now standardized on the use of 600A copper conductor, TRXLPE cable on main trunk distribution feeder cable and 200A aluminum conductor, TRXLPE cable on its 200A underground residential distribution (URD) for System Expansion and System Renewal projects

Figure 2-16 provides an age profile of Enova's current cable population.

Figure 2-16: Cable Population Age Profile

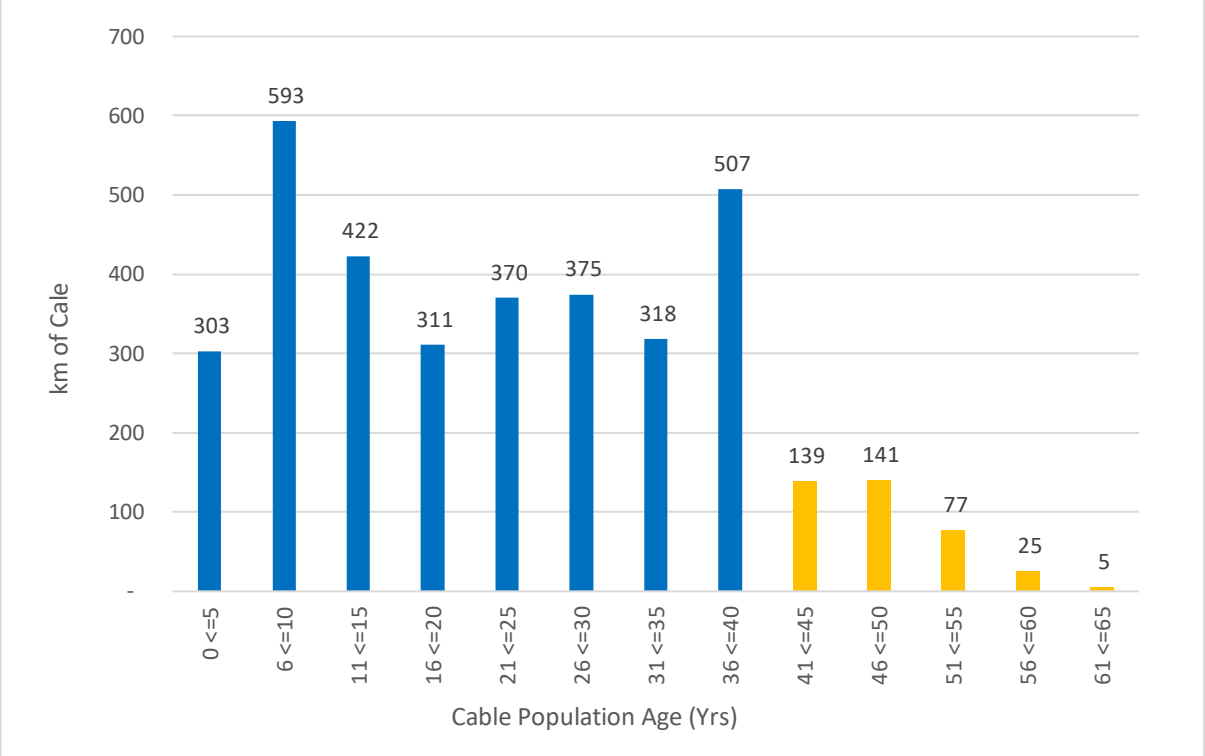


Figure 2-17 provides an age profile of Enova's current cable population by cable type.

Figure 2-17: Cable Population Age by Cable Type

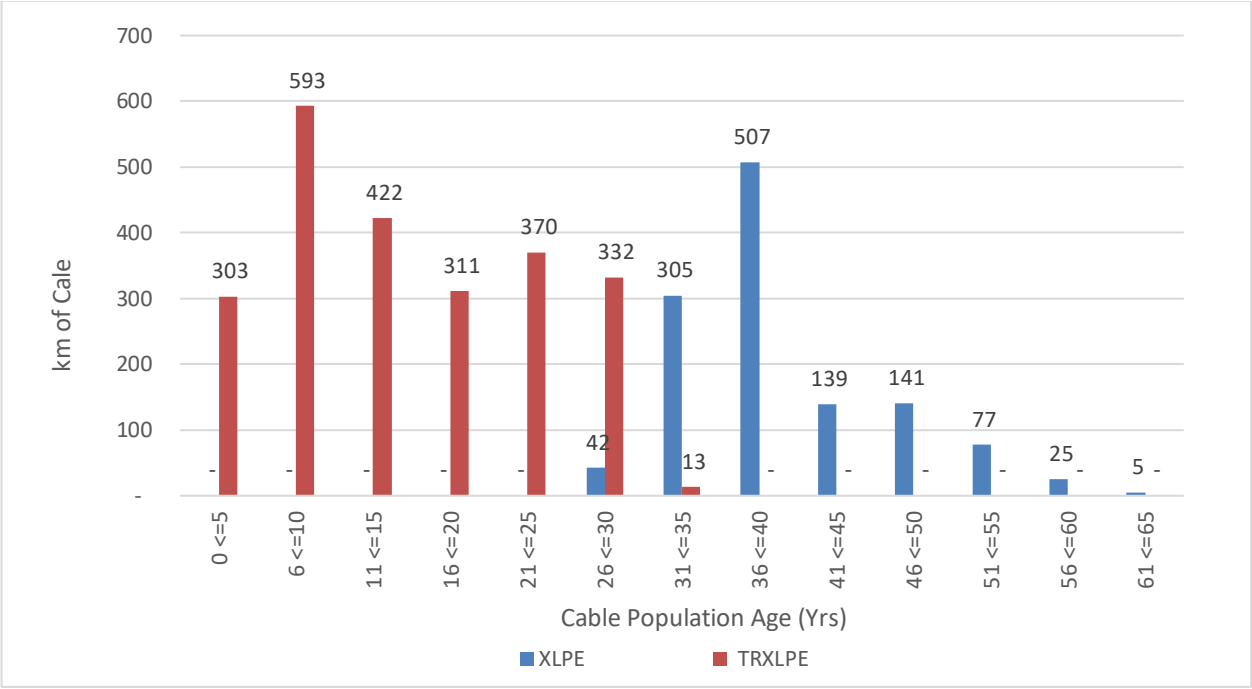


Table 2-44 provides a breakdown of Enova's cable population relevant to the cable's TUL. Of significance is the amount of direct buried XLPE cable in Enova's distribution system and the amount that will reach or exceed 40 years of age before the end of the current forecast period. Approximately 387 km of XLPE cable is past TUL with another 507 km reaching TUL within the next 5 years. Together, these two groups represent 25% of the total cable population.

Table 2-44: Cable Population Approaching or Past TUL

Age Criteria	XLPE	TRXLPE	Total	% Pop
Past TUL (> 40 YRS)	387	0	387	10.8%
Approaching TUL (5 year)	507	0	507	14.1%
Not Near TUL	348	2,345	2,693	75.1%
Total Under Evaluation	1,242	2,345	3,587	100.0%

Table 2-45 provides a breakdown of cable population by type and installation method. It can be seen that 35% of the cable population consists of XLPE and 65% consists of TRXLPE cable. It can also be seen that 83% of the cable population is installed in duct. The transition from direct buried to duct installation came about in 1988-1990 for most underground distribution.

Table 2-45: Cable Population by Installation Method

INSTALLATION METHOD	XLPE (km)	TRXLPE (km)	Total (km)	% Pop
Direct Buried	610	0	610	17%
Ducted	632	2,345	2,977	83%
Total	1,242	2,345	3,587	100%
% Pop	35%	65%		

Table 2-46 provides breakdown of cable population by system voltage.

Table 2-46: Cable Population by Operating Voltage

OPERATING VOLTAGE	XLPE	TRXLPE	Total	% Pop
4.8 KV	29	40	69	1.9%
8 kV	441	613	1,054	29.4%
8.32 kV	28	10	38	1.1%
13.8 kV	726	1,161	1,887	52.6%
16.0 kV	7	250	257	7.2%
27.6 kV	11	271	282	7.9%
Total Cable (km)	1,242	2,345	3,587	100.0%

As part of past System Renewal investments, Enova has completely retired its 4.16 kV distribution system.

2.10.2 Condition Assessment Criteria

Table 2-47 provides a breakdown of TUL's by cable type.

Table 2-47: Cable TUL

Cable Type	KINECTRICS REPORT			Enova
	Min UL	TUL	Max UL	TUL
Primary XLPE Cables - Direct Buried	20	25	30	40
Primary XLPE Cables - In Duct	20	25	30	40
Primary TRXLPE Cables - Direct Buried	25	30	35	40
Primary TRXLPE Cables - In Duct	35	40	55	40

Enova's adoption of a 40 year TUL for XLPE cable exceeds the TUL and Max UL published in the Kinectrics Report. Enova's current XLPE cable population has a minimum age of 31 and a maximum age of 63 with an average age of 38.6 years. Given the performance of its own XLPE cables, Enova determined that the 40 year TUL is more representative of its XLPE population.

TRXLPE cables now make up 65% of Enova's total cable population and is the type of cable installed by Enova since the mid 1990's. Enova's current TRXLPE cable population has a maximum age of 31 and an average age of 15.5 years. Constructed to a higher standard and fully ducted, Enova has seen very few cable failures in this population. At this time, Enova has adopted a TUL of 40 years for this population as it believes the population will have the at least the same performance than the XLPE population. Enova will monitor its TRXLPE cable population to see if its performance warrants an increase in its TUL.

Table 2-48 provides a summary of the degradation criteria Enova plans to employ to develop the Health Indices for Enova's cable population. Currently only service age is utilized in the HI calculation. Enova has used field testing of distribution cables in the past and found the results to be inconclusive for the purposes of developing a HI. In 2026, Enova plans to move to a different field testing method whose results can be quantified and utilized within the ENGIN framework.

Regular infrared thermography and visual inspections are conducted as part Enova's inspection and maintenance programs. Cables found in poor condition are repaired or replaced depending on the severity of the defect.

Resulting inspection information has not yet been fully digitized and correlated to allow for a more fulsome assessment of the asset population in the ENGIN framework. Work in this area is ongoing as Enova continues to make efforts to harmonize data and information systems post-merger.

Table 2-48: Enova Cable Assessment Criteria

Degradation Factor	Weight	Ranking	Numerical Grade	Max Grade
Service Age (XLPE)	5	A,B,C,D,E	4,3,2,1,0	20
Service Age (TRXLPE)	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
Failure Rates	5	A,B,C,D,E	4,3,2,1,0	20
Field Tests	5	A,C,E	4,2,0	20
Condition of Concentric Neutral	4	A,C,D,E	4,2,1,0	16
Visual Inspection of splices or terminations and elbows	1	A,C,E	4,2,0	4
Total Score				88

2.10.3 Condition Assessments

Enova has used EII's ENGIN analytical software to develop Health Indices for its cable population and develop a recommended cable replacement program for the period 2026 - 2031. **Table 2-49** provides a summary of the condition assessment results.

Table 2-49: Condition Assessment Results

Health Categories	XLPE	TRXLPE	Total
Very Poor	387		387
Poor	812	13	825
Fair	43	702	745
Good		733	733
Very Good		897	897
Total Population	1,242	2,345	3,587

Currently, 387 km of underground distribution cable has been evaluated in Very Poor condition. All of these cables are XLPE and direct buried. There are no TRXLPE cables that fall into the Very Poor category.

Figure 2-18 provides a breakdown of the cable population by HI.

Figure 2-18: Cable Population Condition

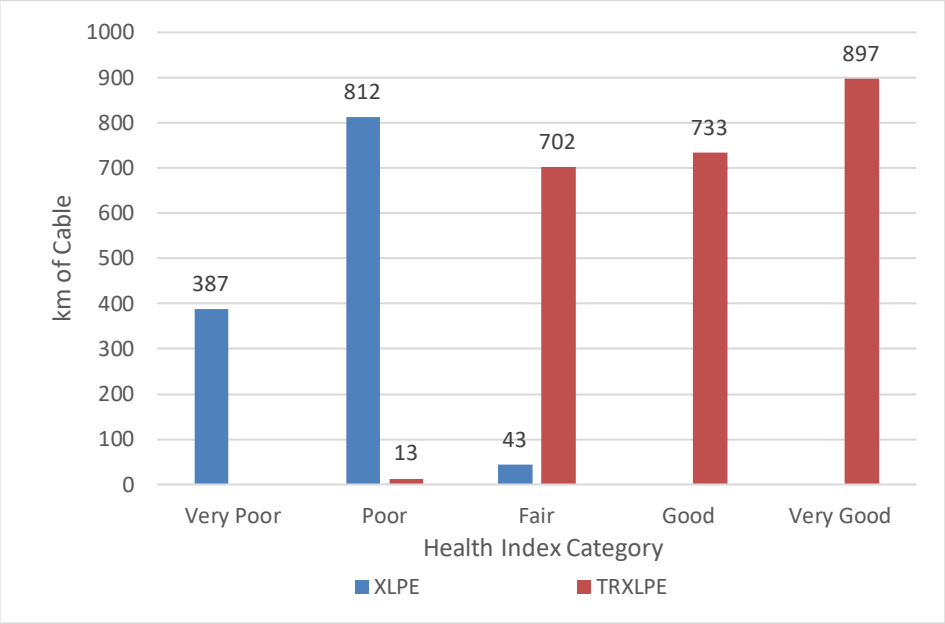


Table 2-50 illustrates that a number of cable groups are well past Enova's TUL of 40 years and Kinectrics Max UL of 30 years.

Table 2-50: XLPE Cable > TUL by Cable Size

Size	Cond	Type	km	Install	Age
#1	CU	XLPE	224.3	DB	46.9
#2	CU	XLPE	2.0	DB	52.4
1/0	CU	XLPE	47.6	DB	43.3
2/0	CU	XLPE	2.8	DB	57.0
4/0	CU	XLPE	8.7	DB	52.2
N/A	CU	XLPE	1.4	DB	46.2
Total			287		46.1

CU – Copper, AL Aluminum, DB – Direct Buried, N/A – Cable of unknown typ

2.10.4 Data Availability Indicator (DAI)

Enova's DAI for cable condition assessment data currently stands at 28%. Enova expects improvement in this value after vendor improvements in the ENGIN connectivity model are made in 2026 and further cable testing is completed and evaluated in 2026 and 2027.

2.10.5 Analysis of Results

Enova's underground distribution cable consists of 3,587 km of medium voltage cable comprised of 1,242 km of XLPE and 2,345 km of TRXLPE cable. The XLPE cables, of which 610 km are direct buried, are the oldest and of greatest concern. Of this population, 387 km of XLPE cable are considered to be in Very Poor condition with 287 of these cables being direct buried. This is Enova's oldest, most problematic underground infrastructure and is Enova's highest priority for replacement.

In addition to the distribution cable, associated concrete vaults are also in Very Poor condition having found many to be prone to flooding and particulate infiltration. There is also physical deterioration of the concrete and steel components due to salt and corrosion. Secondary cable insulation is also showing signs of embrittlement; a sign of oncoming failure. Numerous vaults are located in sidewalks and boulevards where physical deterioration can present a public safety hazard.

The replacement of these assets is logistically difficult, disruptive to customers, requires greater engineering and construction time and have higher replacement costs than ducted cable. To be cost effective, the replacement of direct buried cable is normally planned over an area rather than a cable-by-cable approach. Due to the disruptions associated with this work, individual customer contact and public information meetings are often required.

The remaining 323 km of direct buried cable will be approaching their TUL within the next 5 years.

Table 2-51 represents Enova's distribution cable replacement plan up to the end of the current forecast period. Enova has prioritized and paced the replacement of assets that present the greatest risk of failure and impact on customer interruptions. The plan balances the Enova's planning and design resources with available contractor capacity.

Table 2-51: Distribution Cable Replacement Plan

Size	Cond	Cable Type	km	Install	Age	2026	2027	2028	2029	2030	2031	Total (km)	% Replaced
#1	CU	XLPE	224	DB	46.2			13.6	19.0	22.0	25.0	79.6	36%
#2	CU	XLPE	2.0	DB	52.4	2.0						2.0	100%
1/0	CU / AL	XLPE	47.6	DB	43.3	2.2	15.4					17.6	37%
2/0	CU	XLPE	2.8	DB	57.0	2.8						2.8	100%
4/0	CU	XLPE	8.7	DB	52.2			4.7	4.0			8.7	100%
N/A	CU	XLPE	1.4	DB	49.6			1.4				1.4	100%
Total			286.5		46.1	7.0	15.4	19.7	23.0	22.0	25.0	112.1	39%

CU – Copper, AL Aluminum, DB – Direct Buried, N/A – Cable of unknown type

In 2026 and 2027 Enova will re-evaluate its replacement program and adjust the pace accordingly. Given the amount and age of direct buried cable in Enova's distribution system, it is expected that Enova will need to file for an ICM in 2027 to support this program.

2.11 DISTRIBUTION TRANSFORMERS

2.11.1 Asset Demographics

Enova has a population of approximately 18,972 distribution transformers. These are utilized in single-phase installations and three phase installations, some of which are comprised of 3 individual single-phase transformers banked together. In addition, approximately 990 transformers are in inventory at any one time, most in advance of System Renewal and System Access projects with the remainder reserved for emergency replacement stock. **Table 2-52** provides a breakdown of Enova's distribution transformer population by type.

Table 2-52: Distribution Transformer Population by Type

Transformer Population	Total	%
Polemount	8,555	45.1%
Padmount	5,627	29.7%
Submersible	4,085	21.5%
Vault	673	3.5%
Network	32	0.2%
Total Overhead	8,555	45.1%
Total Underground / Vault / Network	10,417	54.9%
Total Transformers in Service	18,972	100.0%

Table 2-53 and **Figure 2-19** provide age related information on Enova's distribution transformer population. The average age of the population is 17.7 years with 1,476 (7.8%) transformers past their TUL.

Table 2-53: Distribution Transformer Average Age by Type

Transformer Population	Total	Avg. Age	# > TUL	% of Pop
Polemount	8,555	14.6	219	1.2%
Padmount	5,627	18.7	96	0.5%
Submersible	4,085	20.7	1058	5.6%
Vault	673	30.2	103	0.5%
Network	32	6.7	0	0.0%
Total Overhead	8,555	14.6	219	1.2%
Total Underground / Vault / Network	10,417	20.2	1,257	6.6%
Total Transformers in Service	18,972	17.7	1,476	7.8%

Figure 2-19: Distribution Transformer Age Profile

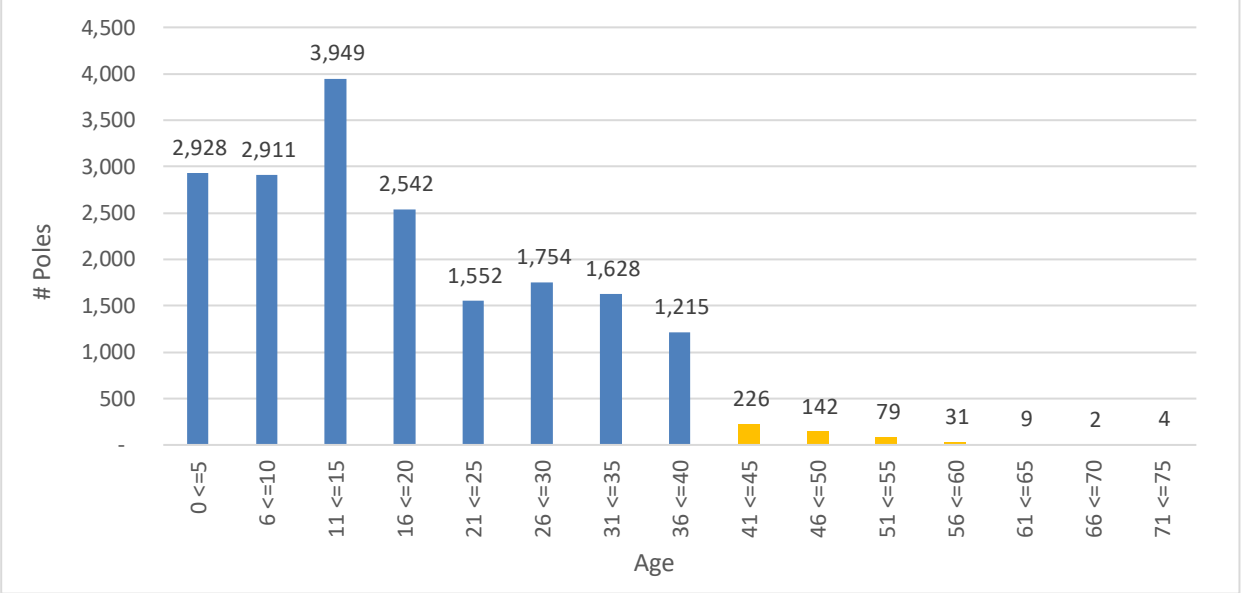


Figure 2-20 provides a loading profile for Enova's transformer population.

Figure 2-20: Distribution Transformer Population Loading Profile

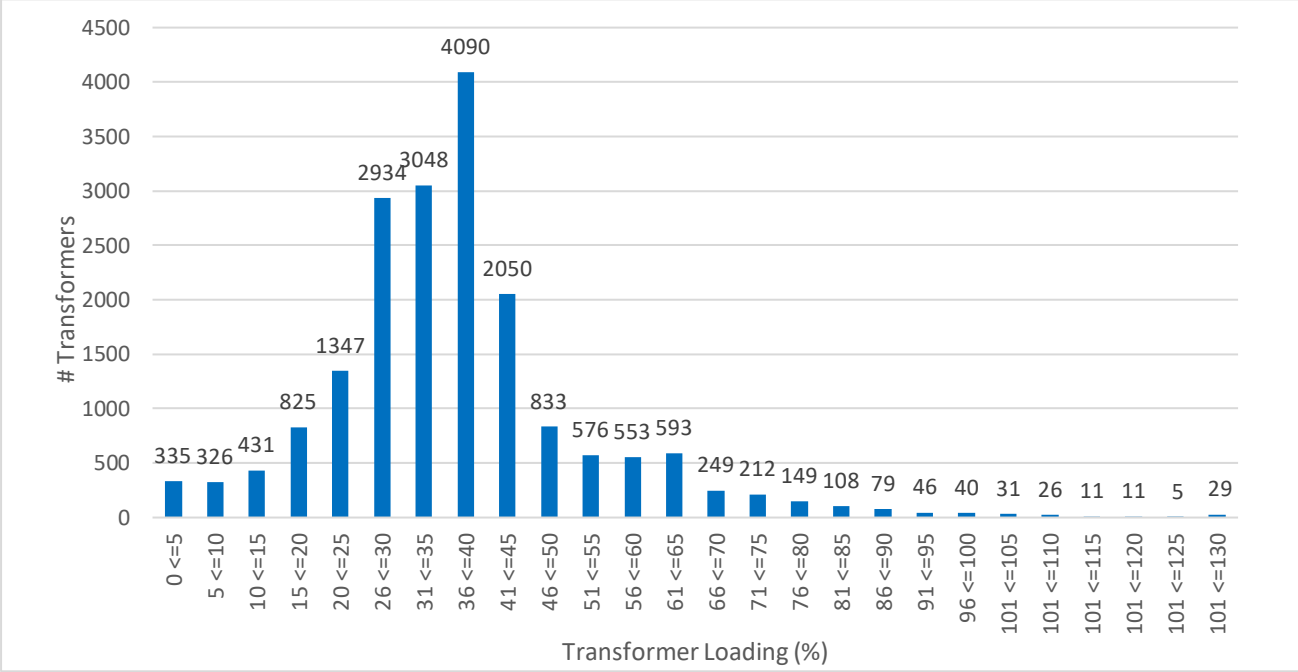


Table 2-54 provides a breakdown of Enova's distribution transformer loading by transformer type. Data gathered from Enova's AMI system indicates that the average loading over the entire distribution transformer population is approximately 35%.

Table 2-54: Distribution Transformer Loading by Type

Transformer Population	Total	% Loading
Polemount	8,555	34.2%
Padmount	5,627	37.7%
Submersible	4,085	35.6%
Vault	673	34.4%
Network	32	N/A
Total Overhead	8,555	34.2%
Total Underground / Vault / Network	10,417	35.7%
Total Transformers in Service	18,972	35.2%

Enova follows a loading policy whereby distribution transformers with a normal residential load profile can be loaded up to 150% of nominal rating. For other types of loads, 130% of nominal rating is followed. **Table 2-55** provides a breakdown of distribution transformers with an average loading above 100%.

Table 2-55: Distribution Transformer Average Loading above 100%

Loading Factor (%)	# Units
> 100%	113
> 130%	23
> 150%	9

2.11.2 Condition Assessment Criteria

Enova has adopted a TUL of 40 years for all of their transformer population except for submersible transformers which have a TUL of 30 years. **Table 2-56** provides a comparison with the Kinectrics Report.

Table 2-56: Distribution Transformer TUL's

	KINECTRICS REPORT			Enova
Transformer Type	**Min UL**	**TUL**	**Max UL**	**TUL**
Overhead (polemount & step down) & Vault Room Txs	30	40	60	40
Padmount Txs	25	40	45	40
Submersible Txs	25	35	45	30
Network	20	35	50	40

Enova has found that submersible transformers have a shorter TUL primarily due to the extensive corrosion caused by continuous exposure to high humidity and moisture in underground vaults. Underground environments often trap environmental contaminants such as salt from road and sidewalk runoff or industrial pollutants which settle on surfaces and promote galvanic corrosion more aggressively than in open-air overhead systems.

Overhead transformers generally have less exposure to corrosion due to their height above ground. The TUL for poles and overhead distribution transformers are aligned as most overhead transformers are replaced during renewal projects. They may or may not be able to be reused depending on age, condition and compliance to Ontario Reg. 22/04. The practice of using new transformers on new construction also reduces customer interruption minutes during the transfer of customer services. Otherwise, Enova's strategy is to run the transformers to failure.

The degradation factors outlined in **Table 2-57** and are noted during inspections and flagged for action.

Table 2-57: Recommended Health Index Assessment Criteria

Degradation Factor	Weight	Ranking	Numerical Grade	Max Grade	OH Tx	UG Tx
Service Age	3	A,B,C,D,E	4,3,2,1,0	12	12	12
Peak Loading	3	A,B,C,D,E	4,3,2,1,0	12	12	12
Infrared Scan (IR)	4	A,B,C,D,E	4,3,2,1,0	16	16	16
Condition of Civil Structure	4	A,C,E	4,2,0	16		16
Cabinet and/or Tank Condition	2	A,B,C,D,E	4,3,2,1,1	8	8	8
Oil Leaks	2	A,B,C,D,E	4,3,2,1,0	8	8	8
Access to Tx	2	A,C,E	4,2,0	8	8	8
Bushing	2	A,C,E	4,2,0	8	8	8
HV/LV Spade	2	A,C,E	4,2,0	8	8	8
Termination/Elbow	4	A,C,E	4,2,0	16		16
Arrestor	2	A,C,E	4,2,0	8	8	8
Lock Bolt	2	A,C,E	4,2,0	8		8
Total Score				**128**	**88**	**128**

Transformers undergo regular infrared thermography and visual inspections as part Enova's inspection and maintenance programs. Transformers found in poor condition are repaired or replaced depending on the severity of the defect. Resulting inspection information has not yet been fully digitized and correlated to allow for a more fulsome assessment of the asset population in the ENGIN framework. Work in this area is ongoing as Enova continues to make efforts to harmonize data and information systems post-merger.

2.11.2.1 PCB's

Enova maintains an active program to eliminate PCBs from all of its distribution equipment. Transformers are the last asset class known to contain PCBs at Enova.

The PCB Regulations (SOR/2008-273) came into force on September 5, 2008. The most recent amendments to the regulations came into force on January 1, 2015. The purpose of the regulations is to protect the health of Canadians and the environment by preventing the release of polychlorinated biphenyls (PCBs) to the environment, and by accelerating the

phasing out of these substances. The regulations set a deadline of December 31, 2025, to eliminate concentrations of PCB's greater than 50 ppm in electrical transformers. Enova's PCB Reduction Program has eliminated all oil filled equipment with PCB concentrations greater than 50 ppm.

The Regulations also prohibit the release of PCBs into the environment in concentrations of no more than 1 gram of PCBs from equipment in use or a liquid containing PCBs at a concentration of 2 mg/kg or more from equipment not in use (storage).

Enova's PCB Reduction Program is now focused on reducing PCB concentrations to less than 2 ppm. **Table 2-58** illustrates that 235 transformers remain with PCB concentrations greater than 2 ppm. The 68 transformers containing greater than 1 gram of PCB pose the highest environmental risk and are being prioritized for removal. The remaining 167 transformers are expected to be removed from service through normal attrition as these units are also at 130% of their TUL.

Table 2-58: PCB Transformers

PCB's (ppm)	Units	% of Tx Population	Avg. Age
ppm > 2 <= 50	235	1.24%	52
Transformers with > 1 gram of PCBs	68	0.36%	51

2.11.3 Condition Assessments

Enova is currently utilizing age and transformer loading to develop Health Indices for its distribution transformers. Inspection criteria noted in **Table 2-57** are not yet fully incorporated into the Health Condition Assessments. Distribution transformers undergo regular infrared thermography and visual inspections as part Enova's inspection and maintenance programs and any significant deficiencies are noted and remedied through Enova's maintenance program.

Tables 2-59 and **2-60** provide HI related information on Enova's distribution transformer population.

Table 2-59: Distribution Transformer HI

HEALTH CATAGORY	# of Transformers	%
Very Poor	29	0.2%
Poor	121	0.6%
Fair	4,024	21%
Good	3,358	18%
Very Good	11,440	60%
Total Under Evaluation	18,972	100%

Table 2-60: Distribution Transformer HI by Type

Transformer Population	Total	HI	Health Category
Polemount	8,555	89.7%	Very Good
Padmount	5,627	79.3%	Good
Submersible	4,085	80.3%	Good
Vault	673	70.0%	Good
Network	32	94.5%	Very Good
Total Overhead	8,555	89.7%	Very Good
Total Underground / Vault / Network	10,417	79.1%	Good
Total Transformers in Service	18,972	84%	Good

Enova's entire Tx population is rated as Good with an average HI of 84%. Less than 1% of the population is in Poor or Very Poor condition.

2.11.4 Data Availability Indicator (DAI)

Enova's overall DAI for distribution transformer condition assessment data currently sits at 60%. Enova has service age information on 100% of its transformers. There are 32 transformers with no current loading information. This is expected to be corrected during Enova's next data collection cycle.

As previously stated, the results of Enova's Inspection and Maintenance program have not yet been digitized and correlated to allow for a more fulsome assessment of this asset population in the ENGIN framework. Work in this area is ongoing as Enova continues to make efforts to harmonize data and information systems post-merger.

2.11.5 Analysis of Results

Enova's distribution transformer population has an overall HI of 84% which is in Good condition.

There are 29 transformers assessed to be in Very Poor condition with another 121 in Poor condition. Enova plans to replace these assets over the forecast period.

Enova also plans to remove from service, 235 transformers containing oil with more than 2 ppm of PCBs over the forecast period. Of these, 68 transformers contain more than 1 gram of PCBs, and due to their higher environmental risk, will be targeted to be replaced over the next 2 years. It is expected that the remaining 167 transformers will be eliminated through the normal course of work (service changes and System Renewal projects), or attrition.

There are 32 transformers which exceed Enova's loading guidelines. These transformers are planned for proactive replacement with a larger transformer or load balancing with nearby transformers if possible. There are also an additional 81 transformers with peak loads of between 100 and 130% which will be monitored regularly over the forecast period.

Over the historical period, Enova has averaged approximately 335 transformer replacements annually due to third party damage, lighting strikes, internal failures, and end of life conditions. This annual replacement rate represents approximately 1.8% of the population and remained consistent over the historical period. Enova projects similar replacement numbers over the forecast period.

Table 2-61: Distribution Transformer Replacement Plan

Replacement Driver	2026	2027	2028	2029	2030	2031	Total
Very Poor	15	14					29
Poor			30	30	30	31	121
PCB > 1 Gram	25	25	18				68
PCB > 2 PPM , <= 1 gram of PCB		25	25	40	40	37	167
Loading > 130%	32						32
Other	265	265	265	265	265	265	1,590
Annual Replacement	337	329	338	335	335	333	2,007
Annual Replacement (%)	1.8%	1.7%	1.8%	1.8%	1.8%	1.8%	10.58%

2.12 REVENUE METERING

2.12.1 Asset Demographics

Enova's meter population is divided into 3 groups:

1. Residential
2. Commercial & Industrial (C&I)
3. Wholesale

The meter population is then further subdivided into self-contained and transformer rated meters. This categorization is important due to the fact that transformer rated meters are utilized with metering installations that include additional equipment such as instrument transformers, communications and auxiliary equipment. Metering installations generally live through several generations of meters and have a longer TUL. **Table 2-62** provides a summary of Enova metering assets.

Table 2-62: Metering Assets

Asset Type	# Meters	%
Residential Meters	148,043	89.26%
C&I Meters < 50 kW	14,360	8.66%
C&I Meters >= 50 kW	1,697	1.02%
MicroFIT / FIT	1,451	0.87%
Transformer Discount	219	0.13%
Wholesale Meters	91	0.05%
Total	165,861	100.00%
Meter Installations (CTs & PTs)	4,950	
TGB / Repeaters (communications)	11	

Table 2-63 provides a breakdown of Enova's meter population by year of installation. Evident is the transition to smart metering that occurred from 2009 - 2012 for residential meters and 2012 - 2013 for C&I meters. The meters replaced during this time were forced out of service due to government regulation and not condition or performance. Since the initial conversion to smart meters, Enova's meter population has grown by approximately 1% per year.

Table 2-63: Meters by Age

Year of Installation	Total	% Total Population	Age
2009	93,635	56.5%	15
2010	38,893	23.4%	14
2011	3,950	2.4%	13
2012	5,900	3.6%	12
2013	5,353	3.2%	11
2014	1,808	1.1%	10
2015	1,744	1.1%	9
2016	1,718	1.0%	8
2017	1,618	1.0%	7
2018	1,580	1.0%	6
2019	1,581	1.0%	5
2020	1,647	1.0%	4
2021	1,608	1.0%	3
2022	1,720	1.0%	2
2023	1,506	0.9%	1
2024	1,600	1.0%	0
Total	165,861	100.0%	

Figure 2-21 provides a breakdown of Enova's meter installations by age.

Figure 2-21: Meter Installations Age Profile

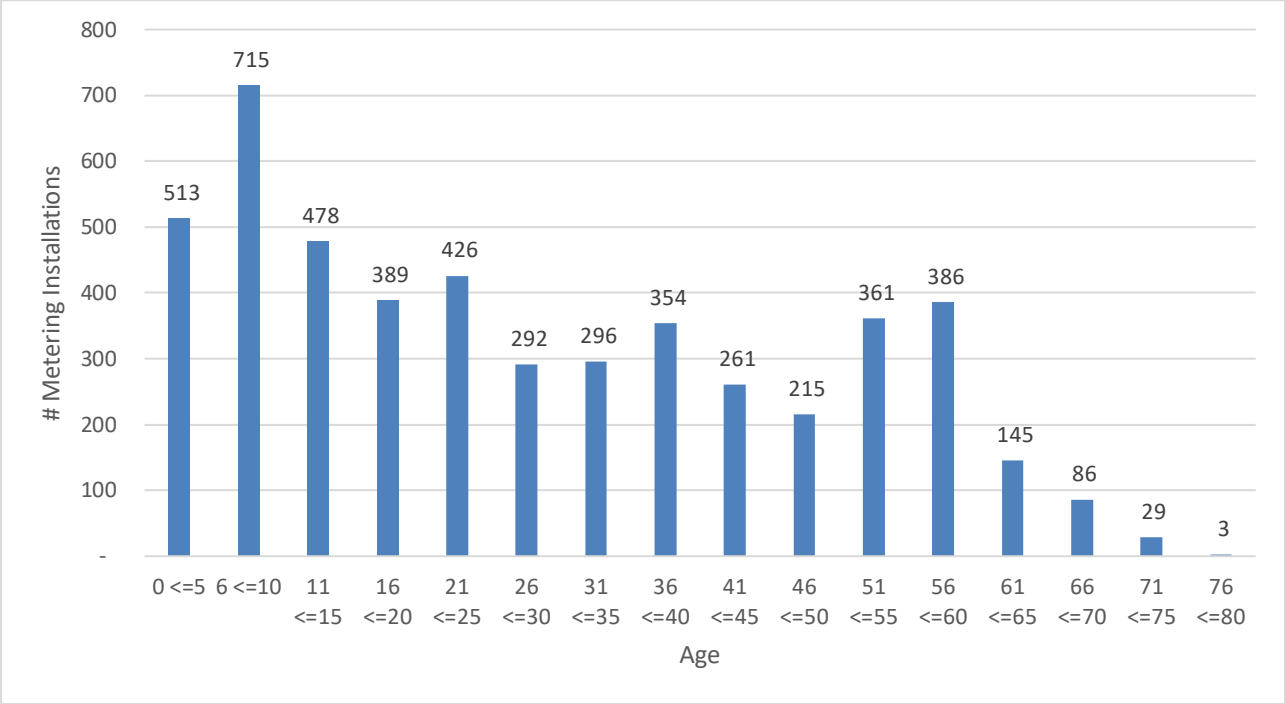
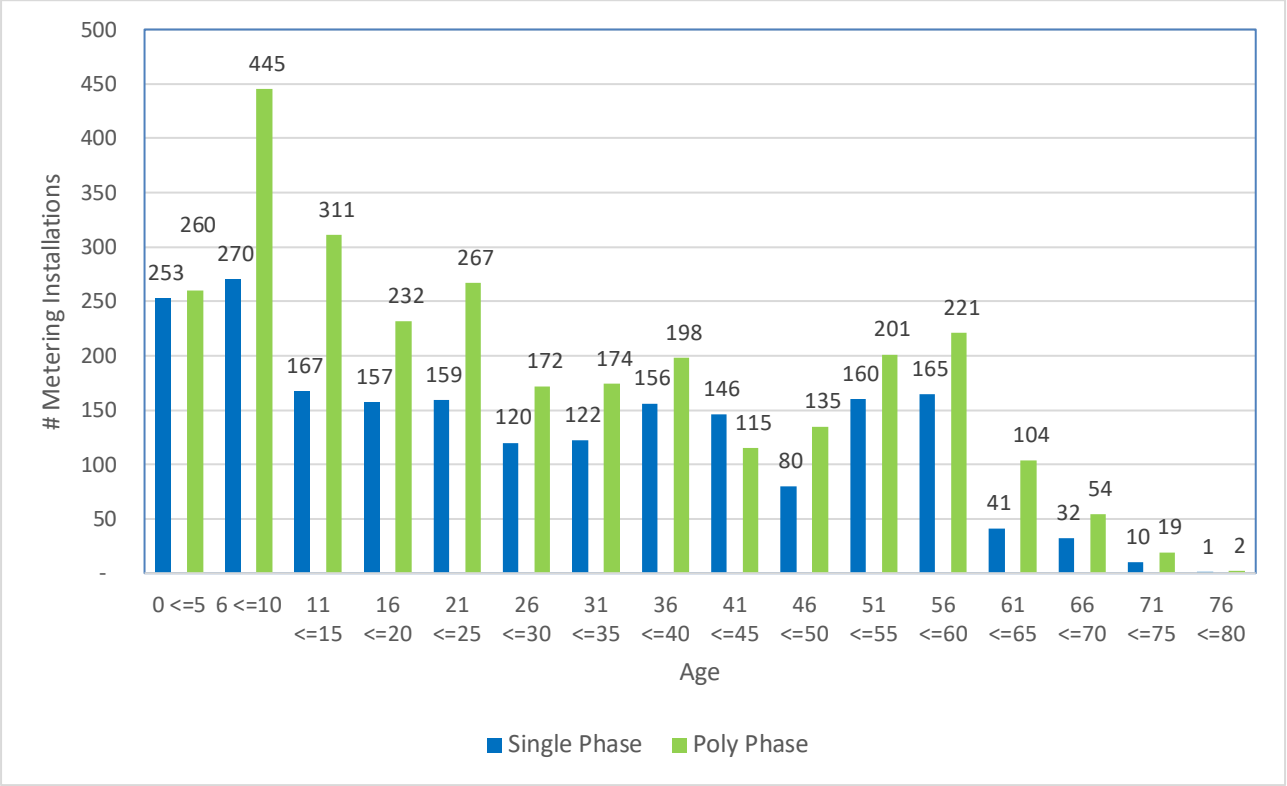


Figure 2-22 provides a breakdown of Enova's metering installations by type.

Figure 2-22: Meter Installations Age Profile by Type



2.12.2 Condition Assessment Criteria

Table 2-64 provides a listing of the TULs used by Enova for metering assets.

Table 2-64: Metering Asset TUL

Asset Type	KINECTRICS REPORT			Enova TUL
	Min UL	TUL	Max UL	
Smart Meters (Res)	5	(*)	15	15
Smart Meters (C&I)	5	(*)	15	15
Wholesale Meters	15	(*)	30	15
Metering Installations	35	(*)	50	50
TGB / Repeaters	15	(*)	20	15

(*) Not defined in Kinectrics report

Enova's meters population health assessment is based on the criteria listed in **Table 2-65**.

Table 2-65: Meter Condition Assessment Criteria

Degradation Factor	Weight	Ranking	Numerical Grade	Max Grade
Service Age	4	A,B,C,D,E	4,3,2,1,0	16
Defect and Test Reports	4	A,B,C,D,E	4,3,2,1,0	16
Mean Time Between Failures	3	A,B,C,D,E	4,3,2,1,0	12
Visual Inspections	3	A,B,C,D,E	4,3,2,1,0	12
Non-Discretionary Obsolescence	5	A,C,E	4,2,0	20
Discretionary Obsolescence	1	A,B,C,D,E	4,3,2,1,0	4
Total Score				80

Enova's condition assessment criteria for electricity meters comes in part from Measurement Canada's (MC) regulations under the *Electricity and Gas Inspection Act (the ACT)*. All electricity meters must conform to all of the performance and non-performance requirements of an approved pattern (design, features, functions, marking, etc.).

The owner of the meter remains legally responsible for ensuring the meters' compliance with the Act and related MC policies and programs. Meter owners shall also subject meters to monitoring programs established by MC. Any meter that fails to meet a performance or non-performance requirement, or that possesses a defect which could affect its ability to meet specified requirements, shall be classified as nonconforming and is removed from service. Enova ensures compliance to MC regulations by having the meters tested by a MC accredited meter verifier. In addition, Enova is registered as a Wholesale Meter Service Provider with the IESO and maintains its own wholesale meters in compliance with IESO policies and regulations. Records of meter inspection and testing are maintained and subject to Measurement Canada and/or IESO audit as the case may be.

Smart meters are subject to functional obsolescence, the most serious of which are the software and communication systems. The meter's communications are integrated into the smart meters both physically and operationally. The changing or loss of the current smart meter communications platform could trigger a wholesale upgrade of all the meters, despite their condition or measurement accuracy.

Metering installations are predominately for larger services associated with commercial / industrial customers. They are inspected for condition and tested for accuracy (cross-phased) once every 8 - 10 years. In the case of Enova's larger customers, Enova attempts to gain access to inspect and test metering installations at least once every 5 years. Any degraded installation components are normally replaced at that time.

In addition, many of the failure modes of meter or meter installation components are monitored and reported through Enova's Advanced Metering Infrastructure (AMI). Reports are monitored daily, and remediation is scheduled as soon as possible.

Table 2-66: Meter Installation Condition Assessment Criteria

Degradation Factor	Weight	Ranking	Numerical Grade	Max Grade
Service Age	16	A,B,C,D,E	4,3,2,1,0	64
Defect and Test Reports	10	A,B,C,D,E	4,3,2,1,0	40
Mean Time Between Failures	4	A,B,C,D,E	4,3,2,1,0	16
Visual Inspections	3	A,B,C,D,E	4,3,2,1,0	12
Total Score				132

2.12.3 Condition Assessments

Table 2-67: Meter Condition Assessments

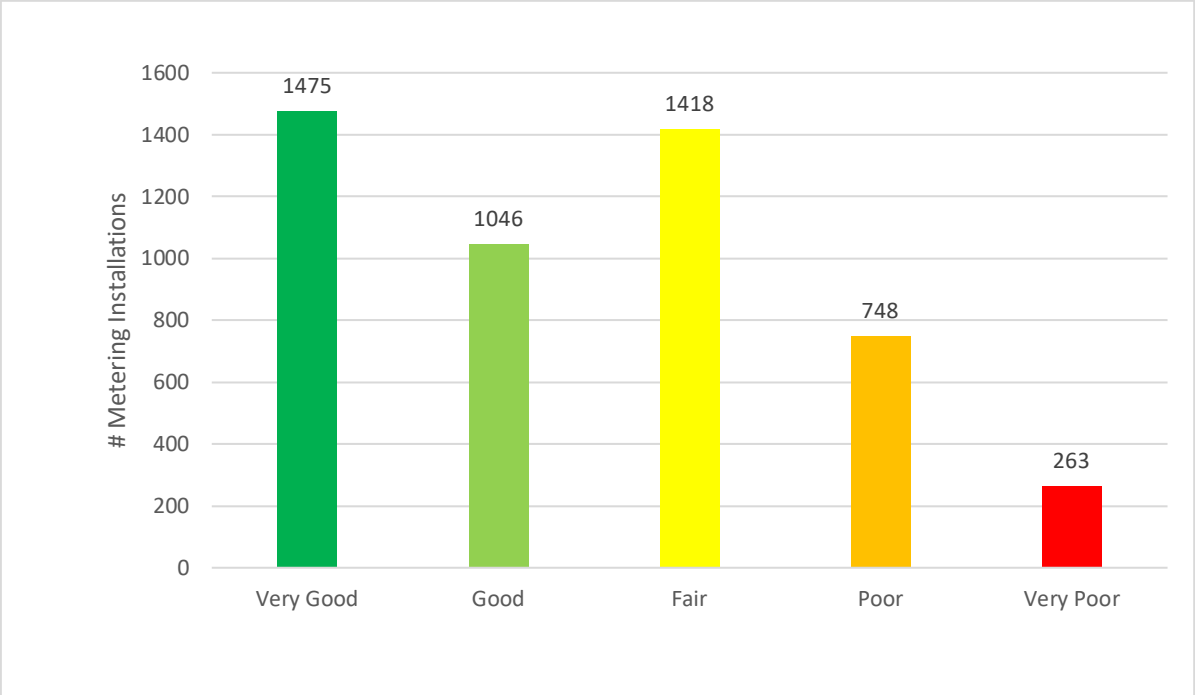
Year in Service	# Meters placed in Service	% of Population	Age	% TUL	% HI	Condition Rating
2009	93,635	56.5%	15	100%	63%	Fair
2010	38,893	23.4%	14	93%	68%	Fair
2011	3,950	2.4%	13	87%	68%	Fair
2012	5,900	3.6%	12	80%	68%	Fair
2013	5,353	3.2%	11	73%	73%	Good
2014	1,808	1.1%	10	67%	73%	Good
2015	1,744	1.1%	9	60%	73%	Good
2016	1,718	1.0%	8	53%	73%	Good
2017	1,618	1.0%	7	47%	73%	Good
2018	1,580	1.0%	6	40%	73%	Good
2019	1,581	1.0%	5	33%	78%	Good
2020	1,647	1.0%	4	27%	83%	Good
2021	1,608	1.0%	3	20%	83%	Good
2022	1,720	1.0%	2	13%	88%	Very Good
2023	1,506	0.9%	1	7%	88%	Very Good
2024	1,600	1.0%	0	0%	88%	Very Good
Total	165,861	100.0%				

Between 2009 and 2013 Enova installed approximately 148,000 smart meters with initial seal periods of 10 years. Enova has implemented a re-verification sampling plan for its first-generation smart meters. The sampling plan was developed in accordance with Measurement Canada Specifications and is used to track meter performance. The sampling plan allows for seal extensions without 100% re-verification testing of the entire meter population.

Since 2016, Enova has sample tested approximately 6,500 meters in 31 groups representing 122,200 meters. All groups sample tested have achieved test results which qualified for the maximum Level 1 (8 year) meter seal extension.

Currently, service age and accuracy audit results are the main degradation factors used in determining the HI of the metering installations. Although inspections and accuracy audits are performed, the resulting documentation has not been digitized and correlated to allow for a more fulsome assessment of the asset population. Work in this area is ongoing as Enova continues to make efforts to harmonize data and information systems post-merger.

Figure 2-23: Metering Installations' Condition Profile



2.12.4 Data Availability Indicator (DAI)

Enova has 100% data availability on its meter population. Every meter, as required by Measurement Canada, has a meter test record completed by an accredited meter verifier.

Similarly, each meter installation has an installation record maintained by Enova; however, these records have not been digitized and correlated to allow for a more fulsome assessment.

2.12.5 Analysis of Results

The first smart meters installed are now reaching the end of their TUL of 15 years. Although still in service and operating within Measurement Canada's accuracy parameters, Enova is concerned with the impending liability of this large volume of meters.

Age-related failures are at the forefront of impending issues. There has yet to be an end-of-life failure profile established for these first-generation smart meters.

Enova replaces approximately 300 smart meters (0.18%) annually due to failure. The meter's radio communications, digital displays and power supplies are the main sources of failure. This failure rate has been stable over the life of these meters; however, as the meter population exceeds its TUL, this is expected to increase.

Enova has found that the electronic meters do not experience declining functionality in a manner similar to older electromechanical meters and other assets. They tend to function within Measurement Canada compliance standards and then abruptly fail.

There is no effective maintenance or repair option for these meters. Attempts to return failed meters to the manufacturer for repair have been unsuccessful as it was found that the meters could not be repaired or the repair was costlier than the cost of replacement. The integrated nature of the meter's functionality results in a single point of failure rendering the entire meter unusable.

A high percentage of in-service meters are also showing weathered and clouded plexiglass meter covers, making them difficult for a homeowner to read. This creates a regulatory risk and supports the case for timely replacement. Meters that can't be read by the customer are non-compliant with Measurement Canada standards and necessitates replacement.

In preparation, a risk mitigation strategy for the 148,000 meters installed from 2009 to 2013 has been developed, Starting in 2029, Enova will begin its AMI 2.0 replacement program and replace approximately 20,000 meters per year over an 8-year period. The meters being replaced will be between 20 and 25 years old at the time of replacement, 5 to 10 years beyond the original estimated useful life.

These smaller staged deployments will make it easier for Enova to utilise internal resources and secure qualified contractors to assist with the replacement program. Also factoring into the plan is that with more residents working from home and insisting on scheduled appointments, meter changes are becoming more time-consuming and challenging to organize and execute.

Kinectrics stated in their Report that the Useful Life range of metering Installations (CTs & PTs) ranged from 35 to 50 years. Enova's experience has been that a significant number of its installations remain in service past this range with approximately 1,011 (20%) meter installations reaching or exceeding the 50-year mark. Observing the age profile of these assets (**Figure 2-9**) it can be seen the population drops considerably for these assets after the 60 year age mark. This population 263 (5.3%) is being targeted by Enova for replacement over the forecast period.

In addition, there are another 386 (7.8%) meter installations that will reach or exceed 60 years of age over the forecast period. These installations will be reinspected for condition, prioritized and scheduled for replacement.

3 SUMMARY

Table 3-1 and **Figure 3-1** provides a summary of the asset health condition results presented at the end of each asset section of this report.

Table 3-1: Health Index Distribution (%)

Asset Category	Population	Very Good	Good	Fair	Poor	Very Poor
Station HV Switchyards	12	8%	75%	17%	0%	0%
Station HV Switches / Circuit Switchers	24	17%	75%	8%	0%	0%
Station Transformers	31	23%	29%	45%	3%	0%
Station Switchgear	34	0%	24%	41%	35%	0%
Station Circuit Breakers	224	33%	22%	42%	1%	1%
Station Feeder Cables (km)	181	10%	12%	13%	50%	15%
Station Protection Relays	407	18%	28%	24%	31%	0%
Distribution Station Transformers	10	10%	40%	50%	0%	0%
Wood Poles	38,471	40%	26%	16%	12%	6%
Concrete Poles	7,086	5%	41%	33%	0%	21%
Primary Distribution Cables (km)	3,587	25%	20%	21%	23%	11%
OH Distribution Transformers	8,555	78%	10%	11%	1%	0%
UG Distribution Transformers	10,417	46%	24%	30%	1%	0%
Revenue Metering - Meters	165,861	3%	11%	86%	0%	0%
Revenue Metering - Installations	4,950	30%	21%	29%	15%	5%
OVERALL HEALTH CONDITION	239,850	14%	15%	66%	3%	2%

Figure 3-1: Health Index Distribution

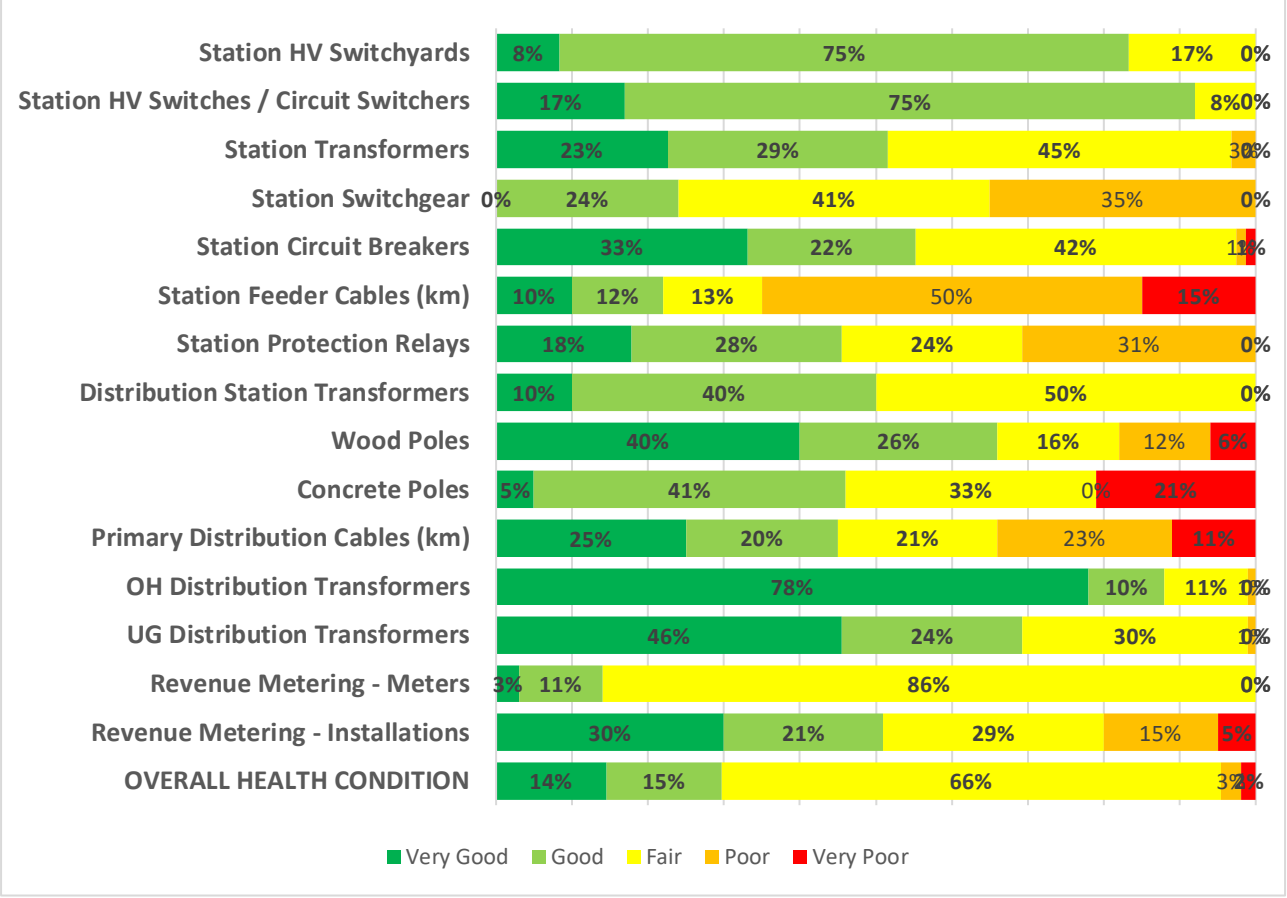


Table 3-2 summarizes the recommended number of asset replacements resulting from this ACA. The replacements outlined in **Table 3-2** are included in Enova's capital investment plan.

Table 3-2: Enova Asset Replacement Plan

#	Year	2026	2027	2028	2029	2030	2031	Total
1	Station HV Switchyard Equipment	5	1	1	0	0	0	7
2	Station HV Switches / Circuit Switchers	0	0	0	0	0	0	0
3	Station Transformers	0	0	0	1	1	0	2
4	Station Switchgear	2	0	3	3	0	0	8
5	Station Circuit Breakers	22	0	21	19	0	0	62
6	Station Feeder Cables (km)	14	0	13	10	6	5	48
7	Station Protection Relays	47	50	13	26	13	0	149
8	Distribution Station Transformers	0	0	0	0	0	0	0
9	Poles	1,430	1,460	1,400	1,394	1,382	1,441	8,507
10	Primary Distribution Cables (km)	7.0	15.4	19.7	23.0	22.0	25.0	112.1
11	Distribution Transformers	337	329	338	335	335	333	2,007
12	Revenue Meters	300	300	300	20,000	20,000	20,000	60,900
13	Revenue Metering Installations	44	44	44	44	44	44	264

APPENDIX B-2
Asset Management Policy

Asset Management – Distribution Policy

Department:	All
Prepared By:	VP Grid Transformation & Chief Distribution Officer
Approved By:	President & CEO
Issue Date (y-m-d)	2026-05-08
Review Date:	N/A – initial release
Review Frequency:	As Needed

1. Purpose

Enova Power Corp. (Enova) is committed to delivering safe, reliable, and sustainable electricity distribution services in a financially and operationally efficient manner. Enova's assets are capital-intensive with long lifecycles. Ensuring their optimal performance is critical to meeting customer expectations and regulatory obligations. This policy establishes the asset management principles guiding the company's planning and operational framework, supporting strategic alignment with Enova's business objectives and corporate plan.

2. Scope

The Asset Management Policy focuses primarily on the management of physical distribution system assets as listed below. Other assets, such as information technology, financial, building, and vehicle assets, support Enova's distribution assets and are managed under separate policies, yet they contribute to effective asset lifecycle management. The Policy provides guidelines on current and future business needs while considering risks and opportunities and making efficient use of resources.

Physical Asset Class	Description
Transmission and Distribution Stations	Power and auxiliary transformers, circuit breakers, switches, protection and control systems, infrastructure, and buildings that make up a TS and DS.
Overhead Distribution System	Wood pole and concrete pole lines, together with all their accessories such as switches, capacitors, etc.
Underground Distribution System	High- and low-voltage cables installed below grade, together with their accessories, such as switches, vaults, pull boxes, ducts, capacitors, etc.

Distribution Transformers	Overhead, underground, and network transformers.
Metering Equipment	Wholesale and retail revenue metering equipment.

3. Policy

It is Enova's policy that all assets used in the distribution system shall be planned, designed, procured, constructed, operated, maintained, renewed, and retired in an efficient manner that:

i. Supports Corporate Strategy and Regulatory Compliance
   a. Aligns with Enova's corporate goals, strategic plans, and grid transformation objectives.
   b. Supports the outcome of the OEB's Renewed Regulatory Framework for Electricity (RRFE).
   c. Integrates climate resilience and system hardening considerations as outlined in the OEB's Vulnerability Assessment and System Hardening (VASH) policies and a framework in planning and investment decisions.

ii. Promotes Safe, Reliable, and Sustainable Operation
   a. Ensures compliance with all applicable health, safety, environmental, and reliability regulations.
   b. Promotes Good Utility Practices in asset design, operation, maintenance, renewal, and retirement.

iii. Applies Risk-Based Decision-Making
   a. Employs condition assessment, risk analytics, and lifecycle cost evaluation in investment planning.
   b. Balances services levels, potential performance risk, and cost-effectiveness, leveraging asset condition data.
   c. Provides a framework for the continuous improvement of the asset management system.

iv. Aligns with Capital and Operational Planning
   a. Implements Enova's Distribution System Planning (DSP), ensuring consistency between short-term operations and long-term investment strategies.
   b. Pace and prioritizes the long-term replacement of critical assets in a balanced and measured approach that reconciles with Enova's investment strategies and financing capabilities.
   c. Effects timely corrective actions based on regular inspections, monitoring, and condition assessment of the assets.
   d. Consider, review, and prioritizes non-wires alterative (NWAs) integration where feasible.

4. Governance and Accountability

i. It is the responsibility of the President & CEO to ensure there are established roles, responsibilities, authorities, and controls to achieve the asset management policy, strategy, objectives, and plans. Responsibility for asset management is held from the CEO to the Vice Presidents.

ii. The V-P of Grid Transformation and Chief Distribution Officer has the overall responsibility for:
   a. Reviewing this policy periodically and update if required.
   b. Overseeing the development, implementation, and performance of Enova's asset management system (policies, strategies, and plans).
   c. Ensuring alignment across Innovation & Energy Management, Station & Grid Intelligence, Engineering, and Operations functions.

APPENDIX C-1

KWCG Needs Assessment Report (2024)



NEEDS ASSESSMENT REPORT

KWCG

[Date: April 09, 2024]

Needs Assessment Report

Final

KWCG

[Date: April 09, 2024]

Lead Transmitter:

Hydro One Networks Inc.

Prepared by: KWCG Technical Working Group



Page intentionally left blank

Disclaimer

This Needs Assessment (NA) Report was prepared for the purpose of identifying potential needs in the KWCG region and to recommend which needs a) do not require further regional coordination and can be directly addressed by developing a preferred plan as part of the NA phase and b) require further assessment and regional coordination. The results reported in this NA are based on the input and information provided by the Technical Working Group (TWG) for this region. Updates may be made based on best available information throughout the planning process.

The TWG participants, their respective affiliated organizations, and Hydro One Networks Inc. (collectively, "the Authors") shall not, under any circumstances whatsoever, be liable to each other, to any third party for whom the Needs Assessment Report was prepared ("the Intended Third Parties") or to any other third party reading or receiving the Needs Assessment Report ("the Other Third Parties"). The Authors, Intended Third Parties and Other Third Parties acknowledge and agree that: (a) the Authors make no representations or warranties (express, implied, statutory or otherwise) as to this document or its contents, including, without limitation, the accuracy or completeness of the information therein; (b) the Authors, Intended Third Parties and Other Third Parties and their respective employees, directors and agents (the "Representatives") shall be responsible for their respective use of the document and any conclusions derived from its contents; (c) and the Authors will not be liable for any damages resulting from or in any way related to the reliance on, acceptance or use of the document or its contents by the Authors, Intended Third Parties or Other Third Parties or their respective Representatives.

Executive Summary

REGION	**KWCG** Region (the "Region")
LEAD	Hydro One Networks Inc. ("HONI")

START DATE: December 11, 2024 **END DATE:** April 09, 2024

1. INTRODUCTION

The 2nd Regional Planning cycle for the KWCG Region was completed in December, 2021 with the publication of the Regional Infrastructure Plan ("RIP") report. This is the 3rd cycle of Regional Planning for the region.

The purpose of this Needs Assessment ("NA") is to:

a) Identify any new needs and reaffirm needs identified in the previous regional planning cycle; and,
b) Recommend which needs:
i) require further assessment and regional coordination (and hence, proceed to the next phases of regional planning); and,
ii) do not require further regional coordination (i.e., can be addressed directly between Hydro One and the impacted LDC(s) to develop a preferred plan and/or no regional investment is required at this time and the need may be reviewed during the next regional planning cycle).

The planning horizon for this NA assessment is ten years.

2. REGIONAL ISSUE/TRIGGER

In accordance with the Regional Planning process, the Regional Planning cycle should be triggered at least once every five years. Considering these timelines, the 3rd Regional Planning cycle was triggered in December 2023 for the KWCG Region.

3. SCOPE OF NEEDS ASSESSMENT

The scope of the KWCG Region NA and includes:

a) Review and reaffirm needs/plans identified in the previous regional planning cycle RIP (as applicable),
b) Identify any new needs resulting from this assessment,
c) Recommend which need(s) require further assessment and regional coordination in the next phases of the regional planning cycle; and,
d) Recommend which needs do not require further regional coordination (i.e., can be addressed directly between Hydro One and the impacted LDC(s) to develop a preferred plan and/or no regional investment is required at this time and the need may be reviewed during the next regional planning cycle).

The 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 ten (10) years.

4. REGIONAL DESCRIPTION AND CONNECTION CONFIGURATION

The KWCG Region covers the cities of Kitchener, Waterloo, Cambridge and Guelph, portions of Oxford and Wellington counties and the townships of North Dumfries, Puslinch, Woolwich, Wellesley and Wilmot. Electrical supply to the Region is provided from eleven 230 kV and thirteen 115 kV step-down transformer stations. The summer 2022 non-coincident regional loads were about 1436 MW.

5. INPUTS/DATA

The TWG comprises of representatives from Local Distribution Companies ("LDC"), the Independent Electricity System Operator ("IESO"), and Hydro One and provides input and relevant information for the KWCG Region regarding capacity needs, reliability needs, operational issues, and major high-voltage (HV) transmission assets requiring replacement over the planning horizon. The LDCs also capture input from municipalities in the development of their 10-year load forecast.

In accordance with the regional planning process, stakeholder engagement takes place during the IRRP phase.

6. ASSESSMENT METHODOLOGY

The assessment's primary objective is to identify the electrical infrastructure needs in the Region over the 10-year planning horizon. The assessment methodology includes a review of planning information such as load forecast (which factors various demand drivers and consideration of municipal energy plan(MEPs) and/or Community Energy plans (CEPs) where available), conservation and demand management ("CDM") forecast, distributed generation ("DG") forecast, system reliability and operation, and major HV transmission assets requiring replacement.

A technical assessment of needs is undertaken based on:

a) Current and future station capacity and transmission adequacy;

b) System reliability needs and operational concerns;

c) Major HV transmission equipment requiring replacement with consideration to "right-sizing"; and,

d) Sensitivity analysis to capture uncertainty in the load forecast as well as variability of demand drivers such as electrification.

7. NEEDS

I. Updates on needs identified during the previous regional planning cycle

The following needs and projects discussed in the 2nd cycle RIP report for KWCG region have been completed:

- Hanlon TS Transformers T1/ T2 Replacement (2022).

The following needs and projects discussed in the 2nd cycle RIP report for KWCG region are currently underway:

- **Burlington TS to CTS 1 Line Section:** The refurbishment of 115 kV B6C/ B6C line section from Burlington TS to Harper's Junction was completed in 2019. The refurbishment of line tap section from Harper's Junction to CTS1

is progressing slowly due to outage availability from the customer. This refurbishment work is currently forecasted to be completed in Q3/ Q4 2025 timeframe.

- **Kitchener MTS #5 – T9/T10 Transformers Replacement**: The existing 83 MVA T9/ T10 transformers are planned to be replaced with new 100 MVA units. This work is currently forecasted to be completed by Q1 2025.
- **Preston TS - T3/T4 Transformer Replacement:** Condition assessment of T3/ T4 transformers have identified these units for replacement. These units are currently planned to be replaced by the end of 2027 with similar Hydro One standard units. This replacement will also remove the existing supply capacity constraint due to a technical limitation in the existing units. The new LTR will be 180 MW

The remaining needs and projects discussed in the 2nd cycle RIP report for KWCG region are as follows:

- **Scheifele MTS - T1/T2 and T3/T4 Transformer Replacement**: These four (T1/T2/T3/T4) transformers are expected to approach end of life over the next 10 year horizon and are planned for replacement by Enova Power Corp. Enova Power Corp will continue monitoring the condition of these transformers with its maintenance program. The expected year of replacement is between 2029-2033.
- **Cedar TS - T7/ T8 Transformer Replacement**: Replacing the existing non-standard T7/T8 transformers with Hydro One standard units of higher capacity. Based on latest condition assessment of these units. These units are to be replaced beyond the study period (10 years) of this report. However, this transformer replacement may need to be advanced due to capacity needs.
- **Campbell TS - Breakers and Component replacement:** Replace breakers deemed to be approaching expected service life. This work is planned to be completed by 2032.
- **Fergus TS – T3/T4 Transformer Replacement:** Hydro One will continue monitoring the condition of these T3/T4 transformers and other components at Fergus TS. Hydro One will proceed with the replacement plan, if required. Otherwise, this need will be reassessed in the next regional planning cycle.
- **Galt TS – Breakers and Component Replacement:** Hydro One will continue monitoring the condition of these components at Galt TS and proceed with the replacement plan as required.

II. Newly identified needs in the region

Based on the new and updated information, a summary of the results of this Needs Assessment is provided below:

a. Asset Renewal for Major HV Transmission Equipment

- No new Asset Renewal Needs

b. Transformation Capacity

- The supply capacity needs at Preston TS, Energy + MTS, Cedar T7/T8 and Campbell TS (T3/T4) have been identified in the near term while the needs at Cedar TS T1/T2 DESN, Cedar T7/T8 DESN, Kitchner MTS #7, Waterloo MTS, and Rush MTS have been identified in the middle term.

c. Transmission System Capacity

- During the study period. Post contingency overload violations were observed on 230 kV M20D/M21D and 115 kV D11K/ D12K circuits for the loss of companion circuits.

d. System Reliability, Operation and Load restoration

- During the study period, post contingency voltage violations were observed on 230 kV M20D/M21D for the loss of companion circuits.
- Load restoration violations on 230 kV D6V/D7V circuits in the long term and system security and load restoration violation on the M21D/M20D circuit in the mid term and near term respectively, for a single tower contingency.

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 impact of the sensitivity analysis for the high and low growth scenarios identified the following updates to need dates and/or new station/line capacity needs: These needs will be assessed again during the next phases of this Regional Planning cycle.

Sr. no	Need Identified	Normal Growth Scenario	High Growth Scenario	Low Growth Scenario
1	Preston TS - Capacity need	2026	2026	2029
2	Galt TS- Capacity need	Reaches capacity in 2032	2030	Long term
3	Energy Inc MTS - Capacity need	2023	2023	2023
4	Rush MTS - Capacity need	2030	2029	Long term
5	Waterloo North MTS #3 - Capacity need	2030	2030	Long term
6	Campbell TS (T3/T4)- Capacity need	2026	2025	2030
7	Cedar TS (T7/T8)- Capacity need	Immediate	Immediate	Immediate
8	Cedar TS (T1/T2)- Capacity need	2031	2029	Long term
9	Kitchener #7	2031	2030	Long term
10	M20D/M21D Transmission Circuit Supply	2026	2024	2026
11	D11K/D12K- Transmission Circuit Supply	2032	2030	Long term

12	D10H - Transmission Circuit Supply	Long term	2030	Long term
13	M20D/M21D Load Security	2032	2028	Long term
14	M20D/M21D Restoration Needs	2025	2023	2025
15	D6V/D7V Restoration Needs	Long term	2030	Long term
16	Voltage change violation on M20D/M21D	2026	2025	2026

9. RECOMMENDATIONS

The TWG recommendations are as follows:

I. Needs that require further assessment and regional coordination

These needs may have broader regional impacts and require further assessment and coordination during the next phases[1] of the regional planning cycle. These needs are as follows:

a. Transmission System Capacity

- M20D/M21D post contingency violation (Galt Jct x Cambridge #1 Jct)- Near term
- D11K/D12K post contingency violation (Detweiler x Kitchener #1 & 4 Jct) – Mid Term

b. System Reliability, Operation and Load restoration

- System security violation on the M21D/M20D circuit in the Mid term
- Load restoration for M20D/M21D – Near term
- Voltage violations on M20D or M21D due to outage on companion circuit -Near term

c. Transformation Capacity Needs

- Preston TS (T3/T4) – Near term
- Energy Inc MTS (T1/T2) – Near term

Transmission system capacity and restoration needs are likely to trigger system reinforcement needs in the KWCG region.

II. Needs that do not require further regional coordination

These needs are local in nature and do not have a regional impact. They can be addressed by a straightforward transmission and/or distribution wires solution. They do not require investment in any upstream transmission facility or Leave to Construct (i.e., Section 92) approvals. These needs generally impact a limited number of LDCs and can be addressed directly between Hydro One and the LDC(s) to develop a preferred local plan. A list of these needs are as follows:

[1] Non-wires options are further considered (i.e. incremental to CDM and DG that is considered in this NA) as potential options in addressing these needs during the IRRP phase.

a. Transformation Capacity Needs

- Campbell TS (T3/T4) – Mid term
- Cedar TS (T1/T2) – Mid term
- Kitchener MTS #7 (T14/T13) – Mid term
- Cedar (T7/T8) – Near term
- Rush MTS – Mid term
- Waterloo North MTS #3 - Mid term

List of LDC(s) to be involved in further regional planning activities:

- Grandbridge Energy
- Enova Power Corp

List of LDC(s) which are not required to be involved in further regional planning phases:

- Hydro One Networks Inc. (Distribution)
- Alectra Inc.
- Center Wellington Hydro
- Halton Hills Hydro Inc.
- Wellington North Power

Table of Contents

1. INTRODUCTION 13
2. REGIONAL ISSUE/TRIGGER 14
3. SCOPE OF NEEDS ASSESSMENT 14
4. REGIONAL DESCRIPTION AND CONNECTION CONFIGURATION 15
5. INPUTS AND DATA 17
6. ASSESSMENT METHODOLOGY 18
6.1 Technical Assessments and Study Assumptions 18
6.2 Information Gathering process 19
7. NEEDS 20
7.1 Asset Renewal Needs for Major HV Transmission Equipment 23
7.2 Station Capacity Needs 25
7.3 Transmission Lines Capacity Needs 27
7.4 System Reliability, Operation and Restoration Needs 28
8. SENSITIVITY ANALYSIS 30
9. CONCLUSION AND RECOMMENDATION 33
10. REFERENCES 35
Appendix A: Extreme Summer Weather Adjusted Net Load Forecast 36
Appendix B: Lists of Step-Down Transformer Stations 40
Appendix C: Lists of Transmission Circuits 41
Appendix D: List of LDC's 41
Appendix E: List of Municipalities in the region 42
Appendix F: Acronyms 43

List of Figures

Figure 1: Regional Planning Process 13
Figure 2: Map of KWCG Regional Planning Area 16
Figure 3: KWCG Transmission Single Line Diagram 17

List of Tables

Table 1: KWCG Region TWG Participants 14
Table 2: Transmission Station and Circuits in the KWCG Region 16
Table 3: Near/Mid-term Needs Identified in Previous RIP and/or this NA 21
Table 4: Major HV Transmission Asset assessed for Replacement in the region over the next 10 years 24
Table 5: Impact of Sensitivity Analysis on Station/Line capacity needs in the region 31
Table 7: Needs which do not require regional coordination 33
Table 8: Needs which require further regional coordination 33

1. INTRODUCTION

The second cycle of the Regional Planning process for the KWCG Region was completed in [December 10, 2021] with the publication of the Regional Infrastructure Plan ("RIP") Report The RIP report included a common discussion of all the options and recommended plans and preferred plans for wire infrastructure investments to address the near- and medium-term needs.

This Needs Assessment initiates the third regional planning cycle for the KWCG Region. The purpose of this Needs Assessment ("NA") is to:

a) Identify any new needs and reaffirm needs identified in the previous regional planning cycle; and,
b) Recommend which needs:
   ii) require further assessment and regional coordination (and hence, proceed to the next phases of regional planning); and,
   ii) do not require further regional coordination (i.e., can be addressed directly between Hydro One and the impacted LDC(s) to develop a preferred plan and/or no regional investment is required at this time and the need may be reviewed during the next regional planning cycle).

The planning horizon for this NA assessment is ten years. The flow chart of the Regional Planning Process is given below in Figure 1 below.

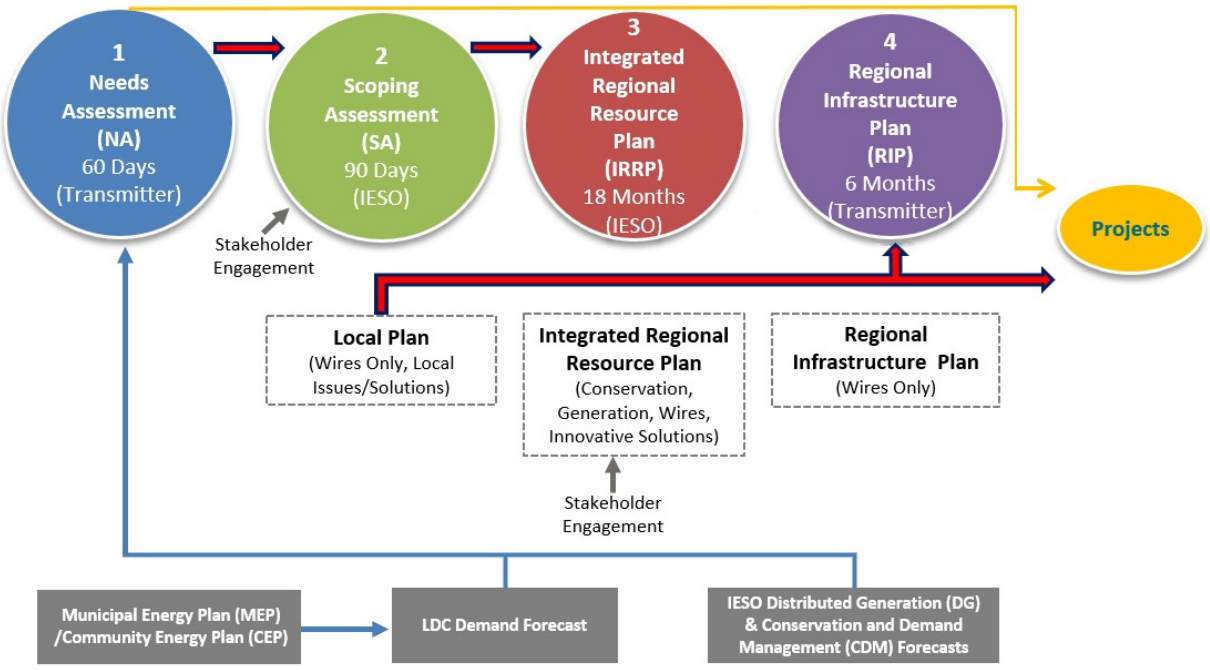


Figure 1: Regional Planning Process

This report was prepared by the KWCG Technical Working Group("TWG"), led by Hydro One Networks Inc. 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"). Participants of the TWG are listed below in Table 1.

Table 1: KWCG Region TWG Participants

Sr. no.	Name of TWG Participants
1	Hydro One Networks Inc. (Lead Transmitter)
2	Independent Electricity System Operator ("IESO")
3	Enova Power Corp.
4	Alectra Inc.
5	Grandbridge energy
6	Centre Wellington
7	Wellington North
8	Halton Hills Hydro Inc.
9	Hydro One Networks Inc. (Distribution)

2. REGIONAL ISSUE/TRIGGER

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

3. SCOPE OF NEEDS ASSESSMENT

The scope of this NA covers the KWCG region and includes:

- Review and reaffirm needs/plans identified in the previous cycle RIP (as applicable),
- Identify any new needs resulting from this assessment,
- Recommend which need(s) require further assessment and regional coordination in the next phases of the regional planning cycle; and,

- Recommend which needs do not require further regional coordination (i.e., can be addressed directly between Hydro One and the impacted LDC(s) to develop a preferred plan and/or no regional investment is required at this time and the need may be reviewed during the next 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"), Local plan (LP) and RIP, based on updated information available at that time.

The planning horizon for this NA assessment is 10 years.

4. REGIONAL DESCRIPTION AND CONNECTION CONFIGURATION

The KWCG Region covers the cities of Kitchener, Waterloo, Cambridge and Guelph, portions of Oxford and Wellington counties and the townships of North Dumfries, Puslinch, Woolwich, Wellesley and Wilmot. Electrical supply to the Region is provided from eleven 230 kV and thirteen 115 kV step-down transformer stations. The accumulative summer 2022 non-coincident loads were about 1477 MW. The approximate boundaries of the KWCG Region are shown below in Figure 1.

The main sources of electricity into the KWCG Region are from five Hydro One stations: Middleport TS, Buchanan TS, Detweiler TS, Orangeville TS and Burlington TS. At these stations electricity is transformed from 500 kV and 230 kV to 230 kV and 115 kV levels, respectively. Electricity is then delivered to the end users of LDCs and transmission connected industrial customers through 26 (supply transformer stations) step-down transformer stations. Figure 2 illustrates these stations as well as the four major regional sub-systems: Waterloo-Guelph 230 kV sub-system, Cambridge-Kitchener 230 kV sub-system, Kitchener Guelph 115 kV sub-system and South-Central Guelph 115 kV sub-system. The single line diagram of the KWCG region is shown in Figure 3 below.

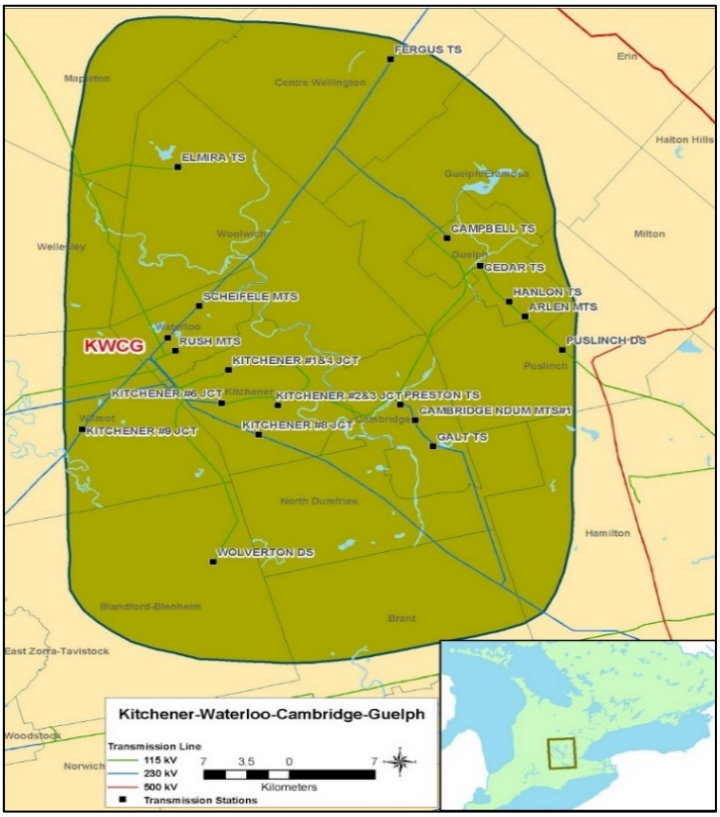


Figure 2: Map of KWCG Regional Planning Area

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

Table 2: Transmission Station and Circuits in the KWCG Region

115Kv circuits	230Kv circuits	Hydro One Transformer Stations	Generation Stations
B5C/B6C D7F/D9F F12C/F11C D11K/D12K D8S D10K	D4W/D5W D6V/D7V B22D/B23D M20D/M21D	*Detweiler TS , Fergus TS, *Cedar TS, Campbell TS, Galt TS, Elmira TS, Hanlon TS, Scheifele MTS, Waterloo North MTS#3, Energy MTS#1, Kitchener MTS #1, Kitchener MTS#3, Kitchener MTS#4, Kitchener MTS#5, Kitchener MTS#6, Kitchener MTS#7, Kitchener MTS#8, Kitchener MTS#9, Rush MTS, Wolverton DS, Puslinch DS, CTS 1, CTS 2, Preston TS*.	N/A

*Stations with Autotransformers installed

The single line diagram of the Transmission Network of KWCG region is shown in Figure 3 below.

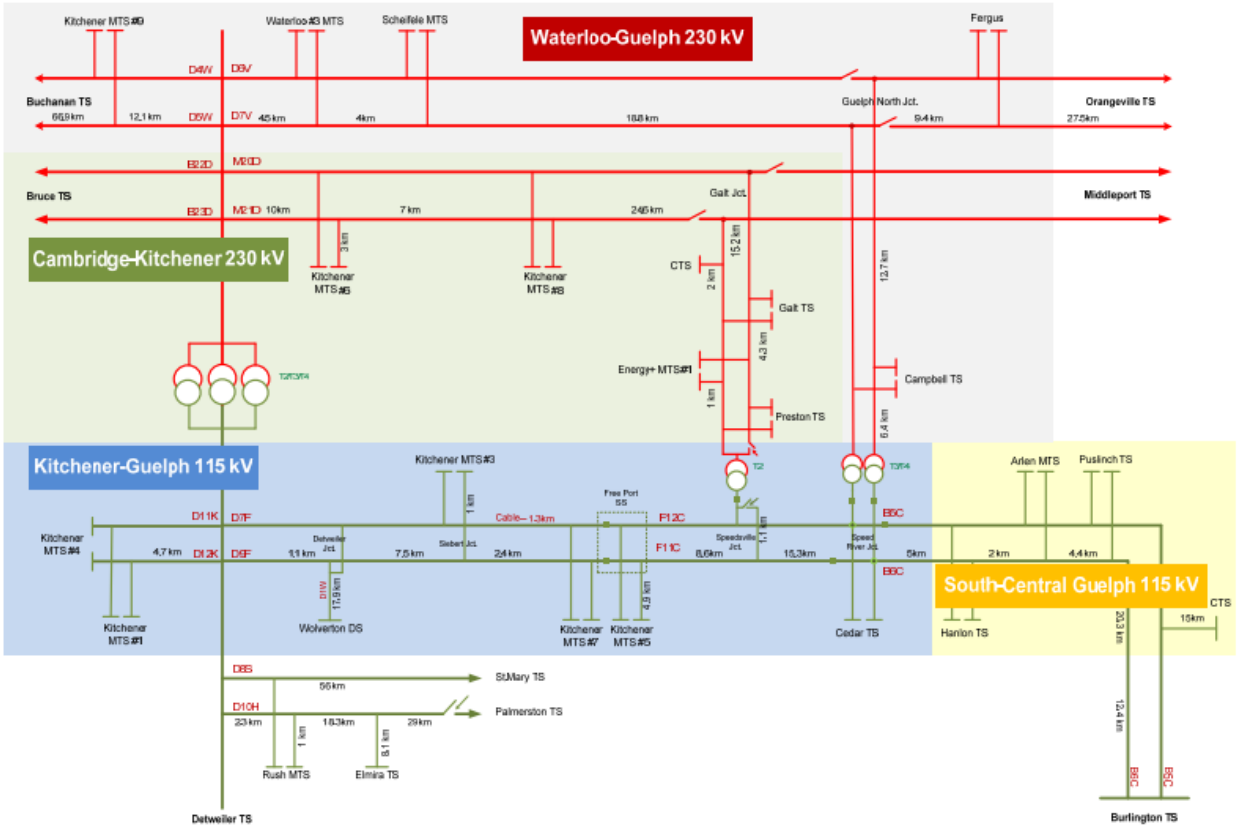


Figure 3: KWCG Transmission Single Line Diagram

5. INPUTS AND DATA

TWG participants, including representatives from LDCs, IESO, and Hydro One provided information and input for the KWCG NA. With respect to the load forecast information, the OEB Regional Planning Process Advisory Group (RPPAG) recently published a document called “Load Forecast Guideline for Ontario” in Oct. 2022. The objective of this document is to provide guidance to the TWG in the development of the load forecasts used in the various phases of the regional planning process with a focus on the NA and the IRRP. One of the inputs into the LDC’s load forecast that is called for in this guideline is information from Municipal Energy Plans (MEP) and/or Community Energy Plans (CEP). The list of all the Municipalities falling under the geographical boundaries of the region are given in Appendix-E.

The information provided includes the following:

- KWCG 10-year Load Forecast for all supply stations inclusive of the inputs provided by the municipalities (e.g. through their MEPs & CEPs),
- 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 KWCG.
- Captured 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.

6. ASSESSMENT METHODOLOGY

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

6.1 Technical Assessments and Study Assumptions

The technical assessment of needs was undertaken based on:

- Current and future station capacity and transmission adequacy;
- System reliability and operational considerations;
- Asset renewal for major high voltage transmission equipment requiring replacement with consideration to “right-sizing”; and,
- Load forecast data was requested from industrial customers in the region, and
- This assessment is based on Summer peak loads. Three load forecasts were developed i.e. Normal Growth scenario, High & low Growth scenario. The High and low Growth scenario load forecast was developed to conduct a sensitivity analysis to cover unforeseen developments such as, fuel switching, Government policies, higher-than-expected EV charging trend during peak load conditions, etc.

The following other assumptions are made in this report.

- The study period for this Needs Assessment is 2023-2032.
- The Region is summer peaking, so this assessment is based on summer peak loads.
- 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).

6.2 Information Gathering process

6.2.1. Load forecast:

The LDCs provided their load forecast for all the stations supplying their loads in the KWCG region for the 10-year study period including the inputs from the Municipalities such as MEPs and CEPs. The IESO provided a Conservation and Demand Management ("CDM") and Distributed Generation ("DG") forecast for the KWCG region. The region's extreme summer non-coincident peak gross load forecasts for each station were prepared by applying the LDC load forecast growth rates to the actual 2022 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 for the contracted projects only 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 KWCG region is given in Appendix A.

A very few of the stations have winter peaks marginally higher than summer peaks. The higher winter transformer and line ratings are adequate to accommodate the marginally higher loads. Therefore, only the Summer Assessment was carried out.

Alectra recently advised the TWG that a revised forecast, to better account for their community's decarbonization activities, will soon be available. This updated forecast will be included in later stages of the regional planning process and may impact the area's overall needs and/or may require the creation of a regional winter forecast.

6.2.2. Sensitivity Analysis:

A sensitivity analysis was undertaken by the TWG to capture uncertainty in the load forecast as well as variability of drivers such as electrification. Hence, the NA recommendations are not necessarily linked to sensitivity scenarios; but rather are used to identify any emerging needs for consideration in developing recommendations. The impact of sensitivity analysis for the high and low growth scenarios are provided in section 8 of this report.

Relevant information regarding system reliability and operational issues in the region; and

6.2.3. Asset renewal Needs for Major HV Equipment:

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. The scope of equipment considered is given in section 7.1; and

6.2.4. System Reliability and Operational Issues:

- Palmerston-to-Detweiler transfer during Hanover bank outages:
  With current load forecast, this issue does not exist.

TWG members identified the following bulk system issues in the KWCG region to be discussed outside of the RP process:

- Detweiler TS configuration and operating instruction asking for multiple equipment to be out of service during contingency
- Detweiler TS Station Service Auto-Transfer Issues
- Palmerston-to-Detweiler transfer during Hanover bank outages.

7. NEEDS

This section describes emerging new needs identified in the KWCG Region and/or updates on the previously identified needs since the completion of Previous Regional Planning cycle.

Needs that were identified and discussed in the previous regional planning cycle with associated projects that were recently completed and reaffirmed needs that are underway are briefly described below with relevant updates and will not be discussed further in the report. These projects include:

- Hanlon T1/T2 transformer replacement was completed in 2022.
- Kitchener MTS #5 project is currently underway, existing 83MVA transformers to be replaced by 100MVA units. The planned in-service date is Q3 2024 for T10 and Q1 2025 for T9.
- Preston TS: Project for like-for-like replacement of transformers T3/T4 is underway. The planned in-service date is 2027.
- B5C/B6C 115kV line section refurbishment: The Burlington TS to Harper junction line refurbishment was completed in 2019. The refurbishment of line tap from Harper junction to CTS-1 is progressing slowly due to outage availability from customer. Expected completion date is Q3/Q4 2025.
- Galt TS: The asset condition assessment identified breakers and other components needs to be replaced in long-term. Hydro One will continue to monitor the condition of these components and if required, proceed with the replacement plan.
- Campbell TS: Two feeder breakers and a bus tie breaker for T1/T2 DESN were identified for replacement. The planned in-service date is 2032.

- Scheifele MTS T1/T2/T3/T4 Transformer replacement: These four (T1/T2/T3/T4) transformers are expected to approach end of life over the next 10-year horizon and are planned for replacement by Enova Power Corp. The expected year of replacement is between 2029-2033.

Note: The planned in-service year for the above projects is tentative and is subject to change.

All near, and mid-term needs that were discussed as a part of this report are summarized in table 3 below.

Table 3: Near/Mid-term Needs Identified in Previous RIP and/or this NA

Need Description	Recommended Plan/Update	Previous RIP Report Section	NA Report Section
Asset Renewal Needs			
Cedar TS	T7/T8 Transformers Replacement	7.3.2	7.1.1
Fergus TS	T3/T4 Transformers Replacement	7.3.4	7.1.2
Galt TS	Breakers and Component Replacement	7.3.5	7.1.4
Campbell TS	Breakers and Component Replacement	7.3.6	7.1.3
Station Capacity Needs			
Preston TS	Preston T3/T4 is forecasted to exceed its supply capacity during the study period (beyond the anticipated LTR of the new transformers)	N/A	7.2.1
Energy Inc MTS	The load at Energy Inc MTS is forecasted to exceed its supply capacity in the near term.	N/A	7.2.2
Campbell TS (T3/T4)	The load at Campbell TS (T3/T4) is forecasted to exceed its supply capacity in the near term.	N/A	7.2.3
Cedar TS	Load demand at both Cedar TS T1/T2 and T7/T8 DESNs is forecasted to exceed supply capacities in the mid and near term respectively.	N/A	7.2.4
Kitchener MTS#7	The load at Kitchener MTS#7 is forecasted to exceed its supply capacity in the mid-term.	N/A	7.2.5

Waterloo North MTS #3	The load at Waterloo North MTS#3 is forecasted to exceed its supply capacity in the mid-term.	N/A	7.2.6
Rush MTS	The load at Rush MTS is forecasted to exceed its supply capacity in the mid-term.	N/A	7.2.7
Transmission Line Capacity Needs			
M20D/M21D	The 230 kV M20D/M21D circuits supply transformer stations connected between Detweiler TS and Middleport TS. Loading violations were observed on M20D/ M21D circuits starting 2026 on the sections between Galt Jct. and Cambridge Jct. .	N/A	7.3.1
D11K/D12K	D11K/D12K supplies Enova Power Corp stations, Kitchener MTS#1 and Kitchener MTS#4. Loading violations were observed on these circuits for the loss of companion circuit in the mid-term.	N/A	7.3.2
D10H	The 115 kV D10H circuit between Detweiler TS and Hanover TS supplies loads at Rush MTS, Elmira TS and Palmerston TS with a normally open motorized switch just south of Palmerston TS. During the outage of 115 kV D8S circuit, loading violations were observed on a section of 115 kV D10H circuit in the long term.	N/A	7.3.3
System Reliability, Operation and Load restoration Needs			
M20D/ M21D	For the loss of two elements M20D/M21D on the 230 kV system, the load interrupted by configuration will exceed 600MW based on the peak coincident load, resulting in violation of ORTAC security criteria in the mid-term.	N/A	7.4.1
M20D/M21D	Load restoration violations observed on the M20D/M21D 230 kV circuits	N/A	7.4.1
D6V/ D7V	Marginal load restoration violations were observed for D6V/D7V 230 kV circuits	N/A	7.4.2
Voltage Performance			

M20D/M21D	Several voltage violations were observed in the near term.	N/A	7.4.3

7.1 Asset Renewal Needs for Major HV Transmission Equipment

Hydro One and TWG has identified asset renewal needs for major high voltage transmission equipment that are expected to be replaced over the next 10 years in the **KWCG** Region. The complete list of major HV transmission equipment requiring replacement in the **KWCG** Region is provided in table 4 in this section. Hydro One and Enova Power Corp are the Transmission Asset Owners (TAO) in the Region.

Asset Replacement needs are determined by asset condition assessment. Asset condition assessment 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 major high voltage equipment information shared and discussed as part of this process is listed below:

- 230/115kV autotransformers
- 230 and 115kV load serving step down transformers
- 230 and 115kV breakers where:
  replacement of six breakers or more than 50% of station breakers, the lesser of the two
- 230 and 115kV transmission lines requiring refurbishment where:
  Leave to Construct (i.e., section 92) approval is required for any alternative to like-for-like
- 230 and 115kV underground cable requiring replacement where:
  Leave to Construct (i.e., section 92) approval is required for any alternative to like-for-like

The Asset renewal assessment considers the following options for “right sizing” the equipment:

- Maintaining the status quo
- Replacing equipment with similar equipment with *lower* ratings and built to current standards
- Replacing equipment with similar equipment with *lower* ratings and built to current standards by transferring some load to other existing facilities
- Eliminating equipment by transferring all the load to other existing facilities
- Replacing equipment with similar equipment and built to current standards (i.e., “like-for-like” replacement)
- Replacing equipment with higher ratings and built to current standards

From Hydro One’s perspective as a facility owner and operator of its transmission equipment, do nothing is generally not an option for major HV equipment due to safety and reliability risk of equipment failure. This also results in increased maintenance cost and longer duration of customer outages.

Table 4: Major HV Transmission Asset assessed for Replacement in the region over the next 10 years

Station/Circuit	Need Description	Planned ISD
Kitchener MTS #5	The existing T10 & T9 83 MVA transformers to be replaced by 100 MVA units	T10-2024 T9-2025
Preston TS	Replacement of existing T3 & T4 transformers with similar size units.	2027
B5C/B6C	Refurbishment of B5C/B6C line between Burlington TS to CTS1.	2025
Scheifele MTS	The existing four transformers are expected to approach end of service life over the next 10 years Horizon	2029-2033

7.1.1 Cedar TS (T7/T8)

Cedar TS is located in the city of Guelph supplying Alectra loads. Cedar T7/T8 is a 115/13.8 kV DESN station with an LTR of 44 MVA (40 MW @ 0.9 PF), and 40 MW of peak load in 2022. Hydro One will continue to monitor the condition of these transformers. Based on asset condition assessment, T7/T8 are expected to reach end of life beyond the 10-year planning horizon. The station capacity need at this station is discussed in Section 7.2.4 of this report.

7.1.2 Fergus TS (T3/T4)

Fergus TS is a 230 kV/ 44 kV single DESN station having two 125 MVA transformers located in the township of Fergus having a supply capacity of 154 MW and supplying 94 MW of loads. The supply capacity of this station is forecasted to be sufficient over the study period and beyond. Based on asset condition assessment, T7/T8 are expected to reach end of life beyond the 10-year planning horizon.

The TWG recommended Hydro One to keep monitoring the condition of these transformers. No further regional planning coordination is required at this time.

7.1.3 Campbell TS (T1/T2) Breakers and Components

Campbell TS is located in the city of Guelph supplying Alectra loads. Campbell TS has two 230/13.8 kV DESNs T1/T2 and T3/T4, having supply capacities of 94 MW and 56 MW respectively. The loads on these two DESNs are currently supplying about 86 MW and 47 MW of loads respectively.

In the previous regional planning RIP report, two feeder breakers and a bus tie breaker for T1/T2 DESN were identified for replacement. Based on asset condition assessment, the equipment at this station are

expected to reach end of life within 10 year planning horizon. No further regional coordination is required at this time.

7.1.4 Galt TS Breakers and Components

Galt TS is located in the city of Cambridge supplying Energy + loads in the KWCG region. Galt TS has two 230/ 28-28 kV transformers T7 and T8 of 75/100/125 MVA, currently supplying 115 MW of peak loads. The total supply capacity of Galt TS is 169 MW, expected to be more than adequate over the study period.

The T7/T8 transformers were replaced in 2010 and 2012 respectively due to technical issues with the transformers. The breakers and other component at the station are almost 50 years old. Condition assessment has identified that these older components to be replaced in the long term.

The station cannot be downsized or eliminated because there is no nearby supply station/s having surplus supply capacity for transferring loads. Hydro One will continue monitoring the condition of these components at Galt TS and if required proceed with the replacement plan as required.

7.2 Station Capacity Needs

A 'Station Capacity' assessment was performed over the study period 2023-2032 for the 230kV and 115kV Transforming stations in the KWCG Region using the non-coincident summer peak load forecasts provided by the Technical Working Group. Based on the results, the following Station capacity needs have been identified during the study period:

7.2.1 Preston TS Supply Transformers

Preston TS (DESN) is located in the city of Cambridge supplying Grandbridge energy loads. Preston TS is a single T3/T4 DESN station of 125 MVA transformers with no additional LTR capability available. This station is currently supplying loads to its supply capacity. The non-coincident loads at Preston TS are currently forecasted to reach 242 MW[2] by the end of study period. The replacement of these station supply transformers is underway and forecasted to be completed by Q2 of 2027. Upon completion, the new station LTR is expected to be in the range of 180 MW. The Preston TS loads are currently forecasted to reach this new supply capacity in the in-service timeframe of these new transformers. A near-term solution is required to address this need. The TWG recommends to further review this need in next regional planning phases.

[2] Note: Due to the load limit on M20D/M21D imposed by ORTAC's load security criteria, the coincident peak loading on M20D/M21D is limited to 600 MW forecasted to exceed in 2032.

7.2.2 Energy MTS#1

Energy + MTS#1 is located in the city of Cambridge supplying Grandbridge Energy loads in the KWCG region. This station has an LTR of 102 MW and forecasted to exceed its supply capacity near the end of the study period. The loading at this station will be monitored by Grandbridge Energy and this need will be further assessed in the next regional planning phase. Grandbridge Energy is working on measures to transfer load within the distribution system to Galt TS to address near term loading concerns. Hydro One and Grandbridge will continue to monitor load levels.

7.2.3 Campbell TS Transformer

Campbell TS is located in the city of Guelph supplying Alectra loads. Campbell TS has two 230/13.8 kV DESNs units supplying through T1/T2 and T3/T4 transformers, having supply capacities of 94 MW and 56 MW respectively. These two Campbell TS DESNs are currently supplying about 81 MW and 45 MW of loads respectively and their combined loads at Campbell TS are forecasted to exceed the total station supply capacity close to the end of the study period.

Alectra to propose measures to address capacity needs at this station, if required. Hydro One and Alectra will continue to monitor load levels. The TWG recommends that no further regional coordination is required at this time.

7.2.4 Cedar T1/T2 and T7/T8

Cedar TS is located in the city of Guelph supplying Alectra loads. Cedar TS has two 115/13.8 kV DESN stations T1/T2 and T7/T8 of 75 MVA with a LTR of 115 MVA (103 MW @ 0.9 PF) and 37 MVA with a LTR of 44 MVA (40 MW @ 0.9 PF), currently supplying 82 MW and 40 MW of peak loads respectively. The total load of both DESNs is forecasted to exceed its supply capacity in the near term.

Alectra to propose measures to address this capacity needs, if required. Hydro One and Alectra to continue monitoring load levels. The TWG recommends that no further regional coordination is required at this time.

7.2.5 Kitchener MTS #7

Kitchener MTS #7 is located in the city of Kitchener supplying Enova Power Corp loads. Kitchener MTS #7 is a 115/ 13.8 kV single T13/T14 DESN station having 50 MVA transformers and a LTR of 60 MVA (54 MW @ 0.9 PF). This station is currently supplying 37 MW of peak load. The loads at Kitchener MTS #7 are currently forecasted to grow approaching its supply capacity near the end of the study period.

Enova Power Corp to monitor the loading on this station and manage any overloading through load transfers, if required. The TWG recommends that no further regional coordination is required at this time.

7.2.6 Waterloo North MTS #3

Waterloo North MTS#3 is located in the city of Waterloo supplying Enova Power Corp. Waterloo North MTS#3 is a 230/27.6 kV single T1/T2 DESN station having an LTR of 85MVA. This station is currently supplying 48 MW of peak load. The loads at Waterloo North MTS#3 is currently forecasted to grow approaching its supply capacity near the end of the study period. Enova Power Corp to monitor the loading on this station and manage any overloading in the mid term through load transfers and a new supply station in the long term. The TWG recommends that no further regional coordination is required at this time.

7.2.7 Rush MTS

Rush MTS is located in the city of Waterloo supplying Enova Power Corp loads. Rush MTS is a 115/ 13.8 kV single T1/T2 DESN station having an LTR of 68 MW. This station is currently supplying 50 MW of peak load. The loads at Rush MTS is currently forecasted to grow approaching its supply capacity near the end of the study period. Enova Power Corp to monitor the loading on this station and manage any overloading in the mid term through load transfers and a new supply station in the long term. The TWG recommends that no further regional coordination is required at this time and will be reviewed in next regional planning cycle.

7.3 Transmission Lines Capacity Needs

All line and equipment loads shall be within their continuous ratings with all elements in service and within their long-term emergency ratings with any one element out of service. Immediately following contingencies, lines may be loaded up to their short-term emergency ratings where control actions such as re-dispatch, switching, etc. are available to reduce the loading to the long-term emergency ratings. A Transmission Lines Capacity Assessment was performed over the study period 2023-2032 for the 230kV and 115kV Transmission line circuits in the KWCG Region by assessing thermal limits of the circuit and the voltage range as per ORTAC to cater this need. Based on the results, the following line capacity needs have been identified in the during the study period:

7.3.1 M20D/M21D – 230 kV – Transmission Circuit Supply

The M20D/M21D is a 230kV double circuit line about 58 km long, supplying the following stations:

- Kitchener MTS #6
- Kitchener MTS #8
- Galt TS
- Preston TS
- Energy + Inc.
- A Customer CTS

For the loss of one of the M20D or M21D 230 kV circuits, the loading on the Galt JCT to Cambridge JCT section exceeds its rating starting in 2026 (Summer load forecast). The TWG recommends to further review this need in next regional planning phases.

7.3.2 D11K/D12K

D11K/D12K is a 115 kV line supplying Enova Power Corp stations of Kitchener MTS#1 and Kitchener MTS#4. With the current load forecast on the above stations, these D11K and D12K 115 kV circuits will be experiencing overloading for the loss of companion circuits by the end of the study period (2032). The TWG recommends to further review this need in next regional planning phases.

7.3.3 D10H

The 115 kV D10H circuit between Detweiler TS and Hanover TS supplies loads to Rush MTS and Elmira TS. The D10H circuit has a normally open point just south of Palmerston TS through a motorized disconnect switch for emergency supply to Palmerston TS. The northern section of D10H is supplied from Hanover TS radially supplying Palmerston TS loads. The southern section of D10H is supplied through Detweiler TS radially supplying Enova Power Corp's 34 MW of Elmira TS peak loads. D10H also supplies Rush MTS which has a dual supply through 115 kV D8S circuit from Detweiler TS. For any outage of 115 kV D8S circuit. The D10H line section between Detweiler and Leong Jct is approaching its supply capacity close to the end of the study period.

7.4 System Reliability, Operation and Restoration Needs

The transmission system must be planned to satisfy demand levels up to the extreme weather, median-economic forecast for an extended period with any one transmission element out of service. A study has been performed, considering the net coincident load forecast and the loss of one element over the study period 2023-2032 to cater this need**.** Based on the results, some system reliability, operating and restoring issues have been identified for this Region.

7.4.1 M20D/M21D Load Security and Restoration Needs

As per the load security criteria (ORTAC Section 7.1), with one element out of service, planned load curtailment or load rejection is permissible only to account for local generation outages; and not more than 150MW of load may be interrupted by configuration, planned load curtailment or rejection. With two elements out of service, not more than 600 MW of load may be interrupted by configuration, planned load curtailment or rejection.

As per the load restoration criteria (ORTAC Section 7.2), interrupted load must be restored within the following timelines:

- Load above 250 MW, within 30 minutes;
- Load above 150 MW, within 4 hours; and
- All load, within 8 hours.

For the loss of double 230kV circuits (M20D/M21D), a total peak coincident load of 638 MW will be interrupted in 2032 by configuration which violates ORTAC load security criteria since not more than 600 MW of load may be interrupted by configuration.

With respect to load restoration, a total of 638 MW (2032 forecast) will be interrupted by configuration, of which, 388 MW needs to be restored within 30 mins as per ORTAC criteria. For a double line fault on Galt Jct. to Preston TS section, only 210 MW (out of the 388MW required to be restored) of that load is restorable. Kitchener MTS#6 and MTS#8 load can be restored via Galt Jct in-line switches and approximately 100 MW of load can be restored at Preston TS. This can be accomplished by opening the M20/211D line disconnect switches at Preston TS and back-feed Preston TS T2 230-115 kV autotransformer to supply load at Preston TS only.

Therefore, the existing restoration capability to loads connected to M20/21D does not meet criteria for the duration of the study period. The TWG recommends to further review this need in next regional planning phases.

7.4.2 D6V/D7V Restorations Needs.

By year 2032, the total peak coincident forecasted load connected to D6V/D7V is 517 MW. Loss of this double circuit line (Tower Contingency) would result in the loss of all 517 MW which is below the ORTAC load security limit. To restore load to these stations, the 230 kV in-line switches will be utilized to isolate the problem and return to service the remaining healthy circuit sections. These switches allow for more flexibility to restore load to the affected stations in a timely fashion. Non-restorable load within 30

minutes is estimated to be about 256 MW. Hence, the load restoration criterion is substantially met. Therefore, no additional transmission restoration capability is warranted at this time, and the loading levels will be monitored.

7.4.3 Voltage Performance

M20D or M21D post contingency voltage change exceeds the 10% pre-tap and 5% post-tap limits on the low voltage side at Preston TS and Energy + Inc MTS within the near-term coincident forecast. The post contingency voltages also drop beyond the allowable voltage range. The situation is further worsened in the subsequent years.

In the midterm, the voltage change limits on the high side of Preston TS, Galt TS and Energy + Inc MTS are violated for the post-contingency loss of M20D or M21D circuits. Voltage also drops below the allowable voltage range. The TWG recommends to further review this need in next regional planning phases.

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 KWCG region to be considered in this sensitivity analysis is electric vehicle (EV) penetration and unforeseen electrification which would cause the load to increase at a faster rate than shown in the forecast; or the potential delay in some projects which could result in less demand than anticipated.

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 low growth scenario was obtained by reducing the growth rate by applying -50% growth to the annual 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 and low growth scenario identified the following updates or new Station/Line capacity needs:

Table 5: Impact of Sensitivity Analysis on Station/Line capacity needs in the region

Sr.no	Need Identified	Normal Growth Scenario	High Growth Scenario	Low Growth Scenario
1	Preston TS- Capacity need	2026	2026	2029
2	Galt TS- Capacity need	Reaches capacity in 2032	2030	Long term
3	Energy Inc MTS - Capacity need	2023	2023	2023
4	Rush MTS - Capacity need	2030	2029	Long term
5	Waterloo North MTS #3 - Capacity need	2030	2030	Long term
6	Campbell TS (T3/T4)- Capacity need	2026	2025	2030
7	Cedar TS (T7/T8)- Capacity need	2024	2024	2024
8	Cedar TS (T1/T2)- 115kV- Capacity need	2031	2029	Long term
9	Kitchener MTS#7	2031	2030	Long term
10	M20D/M21D Transmission Circuit Supply	2026	2024	2026
11	D11K/D12K- Transmission Circuit Supply	2032	2030	Long term
12	D10H - Transmission Circuit Supply	Long term	2030	Long term
13	M20D/M21D Load Security	2032	2028	Long term
14	M20D/M21D Restoration Needs	2025	2023	2025
15	D6V/D7V Restoration Needs	Long term	2030	Long term
16	Voltage change violation on M20D/M21D	2026	2025	2026

The sensitivity analysis identified the additional capacity needs towards the end of the study period and advanced the triggering date of all the needs. These needs will be assessed again during the next phases of this Regional Planning cycle.

The 2022 forecast from last year's RIP aligns with the actual 2022 loading. Therefore, the high growth scenario can be discounted for now, and monitoring the load growth is recommended.

9. CONCLUSION AND RECOMMENDATION

The Technical Working Group's recommendations to address the needs identified are as follows:

Table 7: Needs which do not require regional coordination

Sr.no.	Need	Recommendation
1	Campbell TS (T3/T4) Station Capacity	LDC to propose measures to address capacity needs, if required, Hydro One and Alectra to continue to monitor load levels.
2	Cedar TS (T1/T2) Station Capacity	LDC to propose measures to address capacity needs, if required, Hydro One and Alectra to continue to monitor load levels.
3	Kitchener MTS #7 Station Capacity	LDC to monitor load levels and manage any overloading through load transfers.
4	Cedar TS (T7/T8) Station Capacity	LDC to propose measures to address capacity needs, if required. Hydro One and Alectra to continue to monitor load levels. Advancing and upsizing Cedar transformers is also being considered as an option
5	Waterloo North MTS #3 Station Capacity	LDC to monitor the loading on this station and manage any overloading in the mid term through load transfers and a new supply station in the long term.
6	Rush MTS Station Capacity	LDC to monitor the loading on this station and manage any overloading in the mid term through load transfers and a new supply station in the long term.

Table 8: Needs which require further regional coordination

Sr.no.	Need	Recommendation
1	Preston TS Station Capacity	To be further assessed in the next RP phases. Hydro One and Grandbridge Energy to keep monitoring load levels
2	Energy Inc MTS Station Capacity	To be further assessed in the next RP phases. Grandbridge Energy to monitor load levels

3	Overload - M20D/M21D post contingency capacity violation (Galt Jct x Cambridge #1 Jct)-	To be further assessed in the next RP phases.
4	System security violation - M21D/M20D 230 kV circuits	To be further assessed in the next RP phases.
5	Voltage violations – On 230 kV M20D or M21D circuit for loss of companion circuit.	To be further assessed in the next RP phases.
6	Load restorations -M20D or M21D due to single tower outage	To be further assessed in the next RP phases.
7	Overload - D11K/D12K 115 kV circuits experience post contingency violation (Detweiler TS x Kitchener MTS#1 & #4 Jct.)	To be further assessed in the next phases. Enova Power Corp to explore load transfers between their stations. H1 and Enova Power Corp to monitor load levels.

List of LDC(s) to be involved in further regional planning activities:

- Grandbridge Energy
- Enova Power Corp.

List of LDC(s) which are not required to be involved in further regional planning phases: (if any)

- Hydro One Networks Inc. (Distribution)
- Alectra Inc.
- Center Wellington Hydro
- Halton Hills Hydro Inc.
- Wellington North Power

10. REFERENCES

[1] Independent Electricity System Operator, Ontario Resource and Transmission Assessment Criteria (issue 5.0 August 22, 2007)

[2] Ontario Energy Board, Transmission System Code (issue July 14, 2000 rev. August 2, 2023)

[3] Ontario Energy Board, Distribution system Code (issue July 14, 2000 rev. March 27, 2024)

[4] Ontario Energy Board, Load Forecast Guideline for Ontario (issue October 13, 2022)

Appendix A: Extreme Summer Weather Adjusted Net Load Forecast

Table A.1: KWCG Region – Non-Coincident- Normal Growth Net Load Forecast

Station/DESN	LTR (MW)	Historical (MW)	Summer Net Forecast (MW)									
		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Arlen MTS	45.0	35.1	34.2	17.8	20.1	21.8	22.6	23.8	24.6	26.0	27.3	28.6
Campbell TS (T1/T2)	94.1	81.2	86.1	87.3	88.3	89.1	88.8	89.2	89.2	89.5	90.0	91.0
Campbell TS (T3/T4)	56.3	45.7	46.9	54.2	56.2	56.7	56.8	57.3	57.6	58.1	58.7	59.3
Cedar TS (T1/T2)	103.3	82.5	89.0	90.7	92.0	94.8	95.8	97.6	99.1	101.3	103.5	105.4
Cedar TS (T7/T8)	39.9	40.7	45.0	46.8	48.3	50.6	51.2	52.1	52.9	54.0	55.1	56.0
Elmira TS	55.0	36.7	33.8	33.9	34.0	34.2	34.2	36.4	36.5	36.7	37.0	37.3
Energy Inc(Cam) MTS#1	101.7	115.2	125.5	130.5	135.6	141.3	146.3	152.5	158.5	164.9	172.4	179.7
Fergus TS	153.5	91.0	93.9	95.9	98.6	101.9	104.9	108.3	110.7	113.5	117.7	120.0
Galt TS	169.4	113.6	117.0	121.9	126.7	132.1	136.7	142.5	148.1	154.6	161.5	168.4
Hanlon TS	42.9	25.7	27.9	28.7	29.2	30.1	30.8	31.7	32.4	33.6	34.7	36.2
Kitchener MTS # 1	54.0	26.1	27.5	28.9	30.2	31.7	34.2	36.9	39.6	42.2	45.1	47.9
Kitchener MTS # 3	108.0	55.1	48.2	59.1	60.1	61.3	63.0	65.2	67.2	85.0	95.9	98.2
Kitchener MTS # 4	90.0	58.6	71.8	63.1	64.4	65.9	68.2	71.0	73.6	76.3	79.3	82.2
Kitchener MTS#5	79.7	72.0	58.1	77.2	78.4	80.0	91.4	94.8	97.7	100.6	98.5	102.5
Kitchener MTS#6	90.0	57.0	64.7	61.1	62.3	63.6	65.7	68.1	70.4	72.7	75.4	78.0
Kitchener MTS#7	54.0	37.4	39.8	40.6	41.7	43.0	44.9	47.2	49.4	51.6	54.1	56.5
Kitchener MTS#8	54.0	36.2	36.5	40.0	41.6	43.3	46.5	50.1	53.5	41.1	44.7	48.3
Kitchener MTS#9	90.0	32.3	20.3	28.7	29.5	30.3	37.5	38.9	40.3	41.7	43.2	44.7
Preston TS[3]	112.5	102.4	109.8	135.5	144.5	190.1	198.0	206.4	214.4	223.0	233.0	242.8
Puslinch DS	56.3	32.7	39.6	40.3	41.0	41.8	42.3	43.0	43.7	44.4	45.4	46.2
Rush MTS	67.5	50.6	54.7	55.6	56.6	57.8	58.6	62.0	65.3	69.4	73.7	78.0
Scheifele MTS (T3/T4)	99.0	83.6	89.7	91.3	92.9	94.9	96.1	101.9	107.3	114.0	113.7	110.1
Scheifele MTS (T1/T2)	62.1	50.5	54.0	55.0	56.0	57.1	57.9	61.4	64.7	58.0	54.8	58.8
Waterloo North MTS#3	76.5	48.4	52.6	53.5	54.5	55.6	56.3	59.7	62.9	77.4	86.0	90.3
Wolverton DS	54.4	18.2	18.2	18.7	19.1	19.7	20.0	20.6	21.0	21.6	22.2	22.8
CTS 1		4.2	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9
CTS 2		5.6	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3
Snyder MTS	85.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10.0	20.6

[3] Upon completion of an on-going project, the new station LTR is expected to be in the range of 180 MW.

Table A.2:KWCG Region – Coincident – Normal Growth Net Load Forecast

Station/DESN	LTR (MW)	Historical (MW)	Summer Net Forecast (MW)									
		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Arlen MTS	45.0	30.0	34.2	17.8	20.1	21.8	22.6	23.8	24.6	26.0	27.3	28.6
Campbell TS (T1/T2)	94.1	81.2	86.1	87.3	88.3	89.1	88.8	89.2	89.2	89.5	90.0	91.0
Campbell TS (T3/T4)	56.3	43.0	44.0	50.8	52.8	53.3	53.3	53.8	54.1	54.5	55.2	55.7
Cedar TS (T1/T2)	103.3	57.1	61.6	62.7	63.6	65.6	66.2	67.5	68.6	70.0	71.6	73.0
Cedar TS (T7/T8)	39.9	40.4	44.6	46.3	47.9	50.1	50.7	51.7	52.4	53.5	54.6	55.5
Elmira TS	55.0	36.7	33.6	33.7	33.8	34.0	34.0	36.2	36.3	36.5	36.8	37.1
EnergyInc(Cam) MTS#1	101.7	95.8	105.0	109.2	113.5	118.3	122.4	127.6	132.6	138.0	144.3	150.5
Fergus TS	153.5	86.2	88.1	89.9	92.5	95.6	98.5	101.6	103.9	106.5	110.6	112.9
Galt TS	169.4	83.8	91.5	95.4	99.2	103.4	107.0	111.6	116.0	121.2	126.6	132.1
Hanlon TS	42.9	24.3	26.4	27.1	27.6	28.5	29.1	30.0	30.6	31.8	32.8	34.2
Kitchener MTS # 1	54.0	25.1	26.4	27.8	29.1	30.5	32.9	35.5	38.1	40.6	43.4	46.1
Kitchener MTS # 3	108.0	51.8	45.3	55.5	56.4	57.6	59.2	61.2	63.1	79.8	90.1	92.2
Kitchener MTS # 4	90.0	53.9	66.1	58.1	59.3	60.7	62.8	65.4	67.8	70.3	73.0	75.7
Kitchener MTS#5	79.7	65.8	53.0	70.4	71.6	73.0	83.5	86.6	89.2	91.8	90.0	93.6
Kitchener MTS#6	90.0	49.5	56.2	53.0	54.0	55.2	57.0	59.1	61.1	63.2	65.5	67.7
Kitchener MTS#7	54.0	34.4	36.6	37.3	38.4	39.5	41.4	43.5	45.5	47.5	49.8	52.0
Kitchener MTS#8	54.0	32.7	32.8	36.0	37.4	39.0	41.9	45.1	48.2	37.0	40.3	43.5
Kitchener MTS#9	90.0	29.2	17.7	25.3	26.0	26.7	33.7	35.1	36.3	37.5	39.0	40.3
Preston TS[3]	112.5	98.8	108.3	133.7	142.6	187.6	195.4	203.7	211.6	220.1	229.9	239.6
Puslinch DS	56.3	32.1	38.9	39.5	40.2	41.0	41.5	42.2	42.9	43.6	44.5	45.4
Rush MTS	67.5	46.3	50.0	50.9	51.8	52.9	53.6	56.8	59.8	63.5	67.5	71.4
Scheifele MTS (T3/T4)	99.0	75.2	80.6	82.0	83.5	85.2	86.4	91.5	96.4	102.4	102.2	98.9
Scheifele MTS (T1/T2)	62.1	49.6	53.0	54.0	54.9	56.1	56.8	60.2	63.5	57.0	53.8	57.7
Waterloo North MTS#3	76.5	43.0	46.4	47.3	48.1	49.1	49.8	52.7	55.5	68.3	75.9	79.7
Wolverton DS	54.4	13.2	14.4	14.8	15.1	15.5	15.8	16.3	16.6	17.1	17.6	18.1
CTS 1		2.1	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9
CTS 2		2.9	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3
Snyder MTS	85.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10.0	20.6

[3]Upon completion of an on-going project, the new station LTR is expected to be in the range of 180 MW.

Table A.3: KWCG Region Non-Coincident – High Growth Net Load Forecast

Station/DESN	LTR (MW)	Historical (MW)	Summer Net Forecast (MW)									
		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Arlen MTS	45	35.1	34.2	17.8	21.2	23.8	25.0	26.8	28.1	30.1	32.0	34.0
Campbell TS (T1/T2)	94.1	81.2	86.1	87.3	88.7	90.0	89.6	90.1	90.2	90.5	91.3	92.9
Campbell TS (T3/T4)	56.3	45.7	46.9	54.2	57.1	58.0	58.1	58.8	59.3	60.0	61.0	61.8
Cedar TS (T1/T2)	103.3	82.5	89.0	90.7	92.7	96.8	98.3	101.1	103.3	106.6	109.9	112.8
Cedar TS (T7/T8)	39.9	40.7	45.0	46.8	49.1	52.5	53.4	54.8	55.9	57.6	59.3	60.7
Elmira TS	55	36.7	33.8	33.9	34.1	34.4	34.3	37.7	37.9	38.1	38.6	39.0
EnergyInc(Cam) MTS#1	101.7	115.2	125.5	130.5	138.2	146.8	154.2	163.5	172.5	182.1	193.3	204.4
Fergus TS	153.5	91.0	93.9	95.9	100.0	105.0	109.5	114.5	118.1	122.3	128.6	132.1
Galt TS	169.4	113.6	117.0	121.9	129.1	137.2	144.1	152.9	161.3	171.0	181.4	191.7
Hanlon TS	42.9	25.7	27.9	28.7	29.4	30.8	31.8	33.3	34.2	36.1	37.6	39.9
Kitchener MTS # 1	54	26.1	27.5	28.9	30.9	33.0	36.8	40.9	44.9	48.9	53.2	57.4
Kitchener MTS # 3	108	55.1	48.2	59.1	60.6	62.4	65.0	68.3	71.2	98.0	114.4	117.8
Kitchener MTS # 4	90	58.6	71.8	63.1	65.0	67.3	70.8	75.0	78.9	83.0	87.5	91.8
Kitchener MTS#5	79.7	72.0	58.1	77.2	79.1	81.4	98.6	103.7	107.9	112.3	109.2	115.1
Kitchener MTS#6	90	57.0	64.7	61.1	62.9	64.9	67.9	71.7	75.1	78.6	82.5	86.4
Kitchener MTS#7	54	37.4	39.8	40.6	42.3	44.2	47.1	50.6	53.8	57.2	60.9	64.4
Kitchener MTS#8	54	36.2	36.5	40.0	42.4	45.0	49.8	55.1	60.2	41.7	47.1	52.5
Kitchener MTS#9	90	32.3	20.3	28.7	29.9	31.2	41.8	44.1	46.1	48.2	50.5	52.7
Preston TS[3]	112.5	102.4	109.8	135.5	149.0	217.3	229.3	241.8	253.9	266.8	281.7	296.5
Puslinch DS	56.3	32.7	39.6	40.3	41.3	42.5	43.2	44.4	45.4	46.5	47.9	49.2
Rush MTS	67.5	50.6	54.7	55.6	57.1	58.9	60.0	65.2	70.2	76.2	82.8	89.2
Scheifele MTS (T3/T4)	99	83.6	89.7	91.3	93.7	96.7	98.6	107.1	115.3	125.3	124.9	119.5
Scheifele MTS (T1/T2)	62.1	50.5	54.0	55.0	56.5	58.2	59.4	64.5	69.5	59.6	54.7	60.7
Waterloo North MTS#3	76.5	48.4	52.6	53.5	54.9	56.6	57.8	62.8	67.6	89.3	102.2	108.7
Wolverton DS	54.4	18.2	18.2	18.7	19.4	20.2	20.7	21.5	22.2	23.0	24.0	24.9
CTS 1		4.2	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9
CTS 2		5.6	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3
Snyder MTS	85.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10	20.6

[3] Upon completion of an on-going project, the new station LTR is expected to be in the range of 180 MW.

Table A.4: KWCG Region – Coincident – High Growth Net Load Forecast

Station/DESN	LTR (MW)	Historical (MW)	Summer Net Forecast (MW)									
		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Arlen MTS	45.0	30.0	34.2	17.8	21.2	23.8	25.0	26.8	28.1	30.1	32.0	34.0
Campbell TS (T1/T2)	94.1	81.2	86.1	87.3	88.7	90.0	89.6	90.1	90.2	90.5	91.3	92.9
Campbell TS (T3/T4)	56.3	43.0	44.0	50.8	53.7	54.5	54.6	55.3	55.7	56.4	57.4	58.1
Cedar TS (T1/T2)	103.3	57.1	61.6	62.7	64.1	67.0	68.0	69.9	71.5	73.7	76.0	78.1
Cedar TS (T7/T8)	39.9	40.4	44.6	46.3	48.6	52.0	52.9	54.3	55.4	57.1	58.7	60.1
Elmira TS	55.0	36.7	33.6	33.7	33.9	34.2	34.1	37.5	37.6	37.9	38.4	38.8
EnergyInc(Cam) MTS#1	101.7	95.8	105.0	109.2	115.6	122.8	129.1	136.9	144.4	152.5	161.9	171.2
Fergus TS	153.5	86.2	88.1	89.9	93.8	98.5	102.7	107.5	110.9	114.9	121.0	124.3
Galt TS	169.4	83.8	91.5	95.4	101.0	107.4	112.9	119.7	126.3	134.1	142.3	150.4
Hanlon TS	42.9	24.3	26.4	27.1	27.8	29.2	30.1	31.4	32.3	34.1	35.6	37.7
Kitchener MTS # 1	54.0	25.1	26.4	27.8	29.7	31.8	35.4	39.4	43.2	47.1	51.2	55.2
Kitchener MTS # 3	108.0	51.8	45.3	55.5	56.9	58.6	61.0	64.1	66.9	92.0	107.4	110.6
Kitchener MTS # 4	90.0	53.9	66.1	58.1	59.9	61.9	65.2	69.1	72.7	76.4	80.5	84.5
Kitchener MTS#5	79.7	65.8	53.0	70.4	72.2	74.3	90.0	94.7	98.6	102.5	99.7	105.1
Kitchener MTS#6	90.0	49.5	56.2	53.0	54.6	56.4	59.0	62.2	65.2	68.2	71.7	75.0
Kitchener MTS#7	54.0	34.4	36.6	37.3	38.9	40.6	43.4	46.6	49.6	52.6	56.1	59.3
Kitchener MTS#8	54.0	32.7	32.8	36.0	38.2	40.5	44.9	49.7	54.3	37.5	42.5	47.3
Kitchener MTS#9	90.0	29.2	17.7	25.3	26.3	27.5	38.0	40.0	41.8	43.7	45.8	47.8
Preston TS[3]	112.5	98.8	108.3	133.7	147.0	214.5	226.3	238.6	250.6	263.3	278.0	292.6
Puslinch DS	56.3	32.1	38.9	39.5	40.5	41.7	42.4	43.6	44.6	45.6	47.0	48.3
Rush MTS	67.5	46.3	50.0	50.9	52.3	53.9	55.0	59.7	64.3	69.8	75.8	81.6
Scheifele MTS (T3/T4)	99.0	75.2	80.6	82.0	84.2	86.9	88.6	96.3	103.6	112.6	112.3	107.4
Scheifele MTS (T1/T2)	62.1	49.6	53.0	54.0	55.4	57.2	58.3	63.4	68.2	58.5	53.7	59.6
Waterloo North MTS#3	76.5	43.0	46.4	47.3	48.5	50.0	51.0	55.4	59.7	78.9	90.3	96.0
Wolverton DS	54.4	13.2	14.4	14.8	15.3	15.9	16.4	17.0	17.6	18.2	19.0	19.7
CTS 1		2.1	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9
CTS 2		2.9	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3
Snyder MTS	85.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10.0	20.6

[3]Upon completion of an on-going project, the new station LTR is expected to be in the range of 180 MW.

Appendix B: Lists of Step-Down Transformer Stations

Sr. No.	Transformer Station	Voltage (kV)	Supply Circuits
1.	Arlen MTS	115	B5C/B6C
2.	Campbell TS (T1/T2)	230	D6V/D7V
3.	Campbell TS (T3/T4)	230	D6V/D7V
4.	Cedar TS (T1/T2)	115	B5C/B6C
5.	Cedar TS (T7/T8)	115	B5C/B6C
6.	Elmira TS	115	D10H
7.	Energy+ MTS #1	230	M20D/M21D
8.	Fergus TS	230	D6V/D7V
9.	Galt TS	230	M20D/M21D
10.	Hanlon TS	115	B5C/B6C
11.	Kitchener MTS # 1	115	D11K/D12K
12.	Kitchener MTS # 3	115	D7F/D9F
13.	Kitchener MTS # 4	115	D11K/D12K
14.	Kitchener MTS #5	115	F11C/F12C
15.	Kitchener MTS #6	230	M20D/M21D
16.	Kitchener MTS #7	115	D7F/D9F
17.	Kitchener MTS #8	230	M20D/M21D
18.	Kitchener MTS #9	230	D4W/D5W
19.	Preston TS	230	M20D/M21D
20.	Puslinch DS	115	B5C/B6C
21.	Rush MTS	115	D10H/D8S
22.	Scheifele MTS	230	D6V/D7V
23.	Waterloo North MTS#3	230	D6V/D7V
24.	Wolverton DS	115	D7F/D9F
25.	CTS - 1	230	M20D/M21D
26.	CTS - 2	115	B5C/B6C

Appendix C: Lists of Transmission Circuits

Sr. No.	Connecting Stations	Circuit ID	Voltage (kV)
1.	D6V/ D7V	Detweiler TS	Orangeville TS
2.	M20D/ M21D	Detweiler TS	Middleport TS
3.	D4W/ D5W	Detweiler TS	Buchanan TS
4.	B22D/ B23D	Detweiler TS	Bruce TS
5.	D7F/ D9F	Detweiler TS	Free Port SS
6.	F11C/ F12C	Free Port SS	Cedar TS
7.	B5C/ B6C	Cedar TS	Burlington TS
8.	D11K/ D12K	Detweiler TS	Kitchener MTS #4
9.	D8S	Detweiler TS	St. Mary TS
10.	D10H	Detweiler TS	Hanover TS

Appendix D: List of LDC's

Sr. no.	Name of LDC
1	Energy + Inc
2	Alectra
3	H1 Distribution
4	Enova Power Corp
5	Centre Wellington Hydro
6	Halton Hills Hydro
7	Milton Hydro
8	Wellington North Power Inc

Appendix E: List of Municipalities in the region

Sr. no.	Name of Municipality
1	Township of Blandford-Blenheim
2	City of Cambridge
3	City of Kitchener
4	City of Waterloo
5	Regional Municipality of Waterloo
6	Township of North Dumfries
7	Township of Wellesley
8	Township of Wilmot
9	Township of Woolwich
10	Region of Waterloo
11	City of Guelph
12	County of Wellington
13	Township of Centre Wellington
14	Township of Puslinch
15	County of Perth
16	Town of St. Marys

Appendix F: 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 C-2

KWCG IRRP Scoping Assessment Outcome Report (2024)



Kitchener/Waterloo/Cambridge/ Guelph Scoping Assessment Outcome Report

July 2024

ieso
Connecting Today.
Powering Tomorrow.

Table of Contents

Table of Contents **1**

1. Introduction **3**

2. Technical Working Group **4**

3. Categories of Needs, Analysis, and Results **5**

3.1 Overview of the Region 5

3.1.1 Electricity Demand in the KWCG Region 6

3.1.2 Projects and Plans Underway 7

3.2 Needs Identified 9

3.2.1 Needs to be Addressed in Current Planning Cycle 9

3.2.2 Analysis of Needs and Identification of Region 10

3.3 Analysis of Needs 11

3.3.1 Near-Term Needs 14

3.3.2 Powering Ontario's Growth 14

3.3.3 Central-West Bulk Plan 14

4. Conclusion and Next Steps **15**

Appendix 1 – List of Acronyms **16**

Appendix 2 - Kitchener/Waterloo/Cambridge/Guelph Integrated Regional Resource Plan (IRRP) Terms of Reference **17**

1. Introduction and Background **17**

1.1 Kitchener/Waterloo/Cambridge/Guelph Region 17

1.2 Background 19

2. Objectives **20**

3. Scope **21**

3.1 Needs to be Addressed 21

3.1.1 Expansion of the needs 22
3.1.2 Near-Term Needs 22
3.1.3 Powering Ontario's Growth **Error! Bookmark not defined.**
3.1.4 Central-West Bulk Plan **Error! Bookmark not defined.**

4. Activities 22

5. Data and Assumptions 25

6. Technical Working Group 27
6.1.1 Authority and Funding 27

7. Engagement 28

8. Activities, Timeline, and Primary Accountability 29

1. Introduction

This Scoping Assessment Outcome Report is part of the Ontario Energy Board's (OEB or Board) regional planning process, as defined through the Transmission System Code, Distribution System Code, and IESO license.

This is the third cycle of planning in the Kitchener-Waterloo-Cambridge-Guelph (KWCG) region. It was initiated in December of 2023 with the Needs Assessment (NA). The NA is the first step of a regional planning cycle and was completed by the Technical Working Group (TWG) led by Hydro One Networks Inc. (Hydro One) to determine both the needs of the region and whether the needs require regional coordination. The NA was published on April 9, 2024, and identified needs that may require regional coordination. The information collected from the NA has been included in the scoping assessment to determine the nature of the planning process required to address the regional needs.

During the Scoping Assessment, the TWG reviewed the nature and timing of known needs to determine the most appropriate planning approach, as well as the best geographic grouping of the needs in order to efficiently facilitate further studies. The planning approaches considered include:

- An Integrated Regional Resource Plan (IRRP) – through which a greater range of options, including non-wires alternatives, are to be considered and/or closer coordination with communities and stakeholders is required
- A Regional Infrastructure Plan led by the transmitter – which considers more straight-forward wires only options with limited engagement
- A Local Plan undertaken by the transmitter and affected local distribution company (LDC) – for which no further regional coordination is needed

This Scoping Assessment Report:

- Lists the needs requiring more comprehensive planning, as identified in the NA 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 and/or wires planning, if required
- Establishes the composition of the Technical Working Group, if required

2. Technical Working Group

The Scoping Assessment was carried out with the following participants:

- Hydro One Networks Inc. (Transmission)
- Independent Electricity System Operator (IESO)
- Enova Power Corp.
- Alectra Inc.
- GrandBridge Energy
- Centre Wellington
- Wellington North
- Halton Hills Hydro Inc.
- Hydro One Networks Inc. (Distribution)
- Milton Hydro

3. Categories of Needs, Analysis, and Results

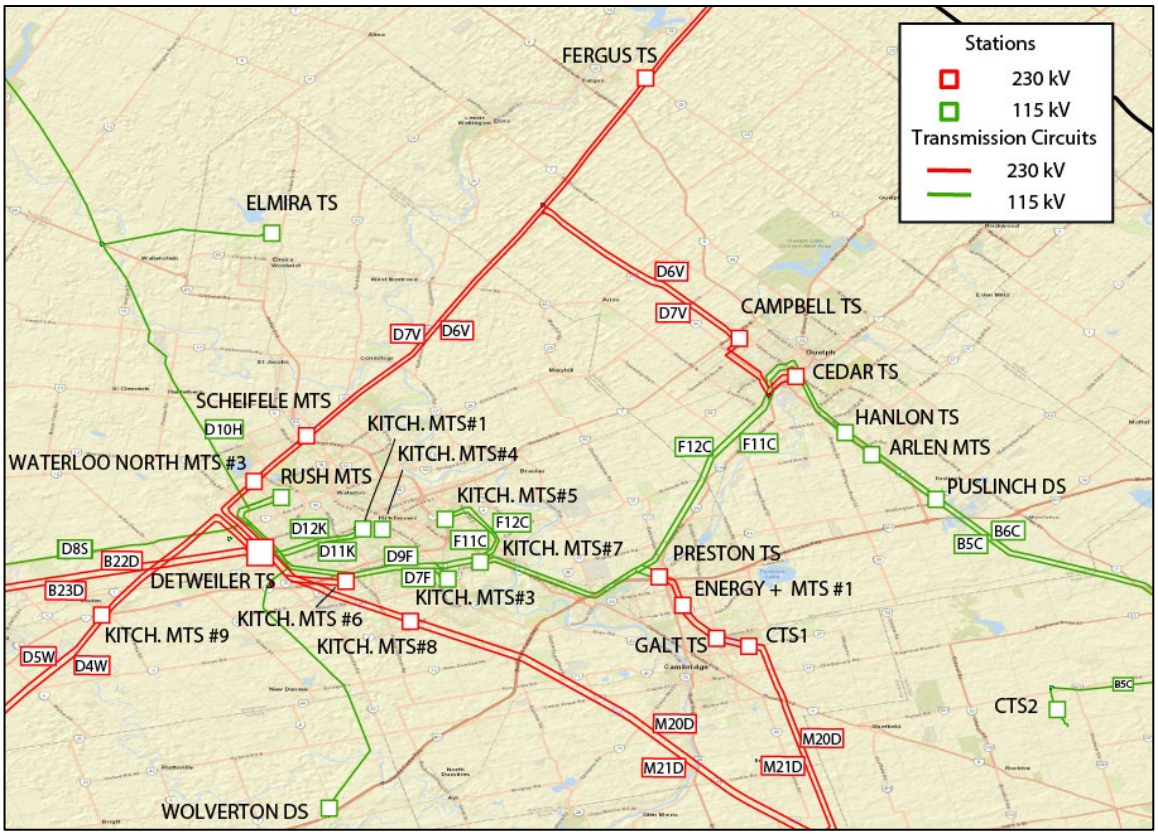
3.1 Overview of the Region

The KWCG region is in southwestern Ontario. The region includes the cities of Kitchener, Cambridge, Waterloo, and Guelph, the townships of Wellesley, Woolwich, Wilmot, North Dumfries, and portions of Oxford and Wellington counties.

The region also encompasses the Métis Nation of Ontario, Grand River Métis Council, Six Nations of the Grand River, Mississaugas of the Credit First Nation, Chiefs of Ontario, Anishinabek Nation and Association of Iroquois and Allied Indians.

The KWCG region is summer peaking and serviced electrically by 230 kV and 115 kV circuits originating from Detweiler TS and Burlington TS as well as load stations which tap double-circuit 230 kV lines connecting to Detweiler from Orangeville TS (D6V & D7V), Middleport TS (M20D & M21D), and Buchanan TS (D4W & D5W). Customers are served by numerous LDCs including Enova Power Corp., Alectra Inc., GrandBridge Energy, Centre Wellington, Wellington North, Halton Hills Hydro Inc., Milton Hydro, and Hydro One Networks Inc. Distribution. Figure 1 provides a map of the electrical infrastructure in the KWCG region.

Figure 1 | Electricity Infrastructure of the KWCG Region



3.1.1 Electricity Demand in the KWCG Region

Electricity demand in the KWCG region is driven by various factors, including population growth, industrial sector changes, intensification of the Kitchener downtown area, and rising awareness of renewable energy generation development, and conservation and demand management. The region's population and accompanying employment are expected to grow steadily, which will drive electricity demand for the next 20 years. The Region of Waterloo installed a light rail transit system between Waterloo and Kitchener with plans to extend to Cambridge, which is spurring development along the train route in both the residential and commercial sectors.

The Region of Waterloo is internationally known for its leading-edge technology and advanced manufacturing industries, innovative educational institutions, vibrant agricultural communities, and the historically significant Grand River.

The city of Cambridge is seeing a rapid increase in the electricity demand that is driven by large industrial developments in the northwest area and large data center loads. In addition to the large loads, GrandBridge Energy continues to experience a steady demand growth in the residential, commercial, and industrial developments.

The City of Kitchener is currently experiencing a conversion from being a manufacturing-oriented economy to a more diversified and balanced economy.

As directed by the OEB, Enova Power Corp is currently participating in multiple provincial renewable energy programs and conservation and demand management (CDM) programs, which help control and reduce the electricity demand. Time-of-Use is also shifting demand and conserving energy as customers manage their electricity use and control their costs.

3.1.2 Background of the Previous Planning Process

The first cycle of regional planning in the KWCG region was completed in December 2015 with the publication of the Regional Infrastructure Planning (RIP) report by Hydro One Inc. In the second cycle, completed in 2021, the TWG had decided that an IRRP was required for the region because a range of options (including non-wires alternatives) had to be considered for the needs, and engagement with communities and stakeholders was required. The IRRP identified near-, mid-, and long-term needs of the KWCG region and provided recommendations for addressing these needs. Some projects initiated in response to the second planning cycle are still underway and provide a foundation for the current planning cycle. Recommendations from the second cycle put focus on necessary End-of-Life (EOL) transformer replacements, growing capacity needs at numerous transmission stations and supply capacity needs along multiple transmission circuits.

3.1.3 Projects and Plans Underway

The previous IRRP used a 20-year demand forecast and made recommendations to monitor long-term needs in the region while providing clear direction on actions required in the near-term. Recommendations made in the IRRP and subsequent plans are summarized in the sections below.

Table 1 below summarized the needs identified in the previous regional planning cycle, recommendations made and the status of the projects implemented to address the needs identified in the previous planning cycle.

Table 1 | Needs Identified in the Previous Cycle with Implementation Plan Update

Circuit/Station	Need	Recommended Action	Status
B5C/B6C 115 kV transmission line	EOL Replacement	Line section replacement; line tap section from Harper's JCT to CTS1	Expected completion 2025
Hanlon TS (T1 & T2)	EOL Replacement	Transformer replacement	Complete
Kitchener MTS #5 (T9 & T10)	EOL Replacement	Transformer replacement	Expected completion 2025
Preston TS (T3 & T4)	EOL Replacement	Transformer replacement	Expected completion 2027
Campbell TS (T1 & T2)	EOL Replacement	Breaker replacement	Expected completion 2032
Scheifele MTS (T1, T2, T3 & T4)	EOL Replacement	Transformer replacement	Expected completion between 2029-2033
Galt TS	EOL Replacement	Breaker and component replacement	Hydro One will continue to monitor and take appropriate action
Fergus TS (T3 & T4)	EOL Replacement	Transformer replacement	Hydro One will continue to monitor and take appropriate action

Cedar TS (T7 & T8)	EOL Replacement	Transformer replacement	EOL has extended past 10 years. Transformer will continue to be monitored
Energy+ MTS #1 (T1 & T4)	Station Capacity	Load transfer to Galt TS and Preston TS	Underway
Preston TS	Station Capacity	Load transfer to Galt TS and Energy+ MTS #1	Underway
Scheifele MTS (T1+T3)/(T2+T4)	Station Capacity	Load transfer to Waterloo North Hydro MTS #3, Rush MTS, and Elmira TS	Underway
Campbell TS (T3 & T4)	Station Capacity	Load transfer to Cedar TS and Campbell TS T1/T2	Underway
Kitchener MTS #7 (T13 & T14)	Station Capacity	Load transfer to Kitchener MTS #3 or #5	Need date of 2028
Kitchener MTS #8 (T15 & T16)	Station Capacity	Load transfer to Kitchener MTS #3	Need date of 2028

The following long-term needs were identified in the previous IRRP. These needs have been monitored and will be re-evaluated as part of the IRRP.

- Supply capacity needs along the B5C and D10H circuits
- Station capacity needs at Arlen MTS, Hanlon TS, Rush MTS, Elmira TS, Kitchener MTS #1, and Waterloo North MTS #3
- Load restoration need for M20D/M21D double circuit line

3.2 Needs Identified

The most recent NA report for the KWCG region identified upcoming and currently present capacity and load security/restoration needs based on the 10-year demand forecast. The needs identified in the report are summarized in the sections below.

3.2.1 Needs to be Addressed in Current Planning Cycle

For this third cycle of regional planning, the NA report 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 KWCG region based on a 10-year station level load forecast for the region developed by the LDCs, expected transmission and distribution investments, updated asset condition information, as well as the CDM and distributed generation (DG) forecasts provided by the IESO.

The needs identified in the NA were determined to require further regional planning (See **Table 2**). These needs mainly address transmission system capacity constraints, station capacity constraints and various needs associated with the M20D/M21D double circuit.

Table 2 | Needs Identified in the Needs Assessment as Requiring Further Study

Need #	Station/Circuit	Description of Need	Timeline
1	230 kV M20D/M21D: Galt JCT to Cambridge #1 JCT	Supply Capacity Need	Near term
2	115 kV D11K/D12K: Detweiler to Kitchener #1 &#4 JCT	Supply Capacity Need	Mid term
3	230 kV M20D/M21D Circuit	Load Security Need	Mid term
4	230 kV M20D/M21D Circuit	Load Restoration Need	Near term
5	230kV M20D/M21D Circuit	Voltage Violation Need	Near term
6	Preston TS (T3 & T4)	Station Capacity Need	Near term
7	Energy+ MTS #1 (T1 & T2)	Station Capacity Need	Near term
8	Campbell TS (T3 & T4)	Station Capacity Need	Near term
9	Cedar TS (T7 & T8, T1 & T2)	Station Capacity Need	Near term,mid term
10	Kitchener MTS #7	Station Capacity Need	Mid term
11	Rush MTS	Station Capacity Need	Mid term
12	Waterloo North MTS #3	Station Capacity Need	Mid term

3.2.2 Analysis of Needs and Identification of Region

The TWG has discussed the needs in the KWCG 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
- Potential linkages between needs and their required coordination, particularly if the span LDC territories or planning regions
- Opportunity for public engagement to inform outcomes
- Potential for exploring multiple types of options to meet the needs (including non-wire alternatives)
- Potential for regional changes having implications on the upstream bulk power system

In general, the more complex a series of needs are and the greater the need for regional coordination and engagement, the more likely an IRRP will be selected. If the needs are relatively straightforward, there are few feasible alternatives to address them, and solutions 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.

The TWG agreed that numerous needs identified in the NA require regional planning, and have opportunities for integrated solutions involving both wires and non-wires solutions. Thus, the TWG agreed upon the initiation of an IRRP to address the needs in the KWCG region.

The participants agree that the IRRP for the KWCG region should not be divided into sub-regions. The needs identified are concentrated in the Cambridge area and connecting circuits, making further division unnecessary.

The needs identified in the NA directly impact GrandBridge Energy and Enova Power Corp., but additional needs may emerge during the development of the 20-year demand forecasts. For example, at the end of the NA, Alectra indicated that they will be updating their forecast to better account for their community's decarbonization activities. Thus, all LDCs in the KWCG region will contribute 20-year demand forecasts for system studies in the IRRP to refine the needs. If, after analysis of the needs, some LDCs are not affected by the regional needs, they may choose to not actively participate in further regional planning this cycle. These LDCs will be informed and invited to participate if any needs or proposed solutions may affect their facilities or customers.

3.3 Analysis of Needs

The TWG has outlined the new needs in the KWCG region and potential planning approaches to address them.

Preston TS Capacity Need

Currently at the Preston TS, a replacement of the station supply transformers is scheduled for completion in 2027. This replacement will increase the long-term rating (LTR) of the station to 180 MW. The 10-year demand forecast suggests that by the end of the study period, the demand at the Preston TS will reach 242 MW. Following the publication of the NA report, GrandBridge Energy received a large load request of 80 MW to connect near Preston TS over the next few years. Therefore, addressing the imminent capacity need at the Preston TS is a near term need that must be addressed by the TWG through the IRRP.

The TWG recommends that the capacity need at Preston TS be further reviewed in an IRRP based on the timing of the need, the opportunity for integrated solutions involving both wire and non-wire options, and the opportunity to coordinate the solution to the need.

Energy+ MTS #1 Capacity Need

The Energy+ MTS #1 has a current LTR of 102 MW. The need is imminent – historical demand for the station has already exceeded the station rating – and the load forecast shows that demand will grow beyond these levels. In response, GrandBridge Energy is preparing measures for a transfer of load from Energy+ MTS #1 to Galt TS to address the near-term need. However, Energy+ MTS #1 is near Preston TS where a potential integrated solution could address the needs at both stations.

The TWG recommends that the capacity need at Energy+ MTS #1 be further reviewed in an IRRP based on the timing of the need, the opportunity for integrated solutions involving both wire and non-wire options, and the opportunity to coordinate the solution to the need.

Campbell TS Capacity Need

Campbell TS has two sets of transformers, T1 & T2 with a LTR of 94 MW and T3 & T4 with a LTR of56 MW. These transformers currently supply 81 MW and 45 MW of load at peak, respectively. The demand forecast shows the combined load at Campbell TS exceeding the current loading capabilities.

The TWG recommends that the capacity need at Campbell TS be further reviewed in an IRRP, due to the proximity to other stations with identified needs to assess the opportunity for integrated solutions involving both wire and non-wire options, and the opportunity to coordinate the solution to the need.

Cedar TS Capacity Need

Cedar TS has two sets of transformer T1 & T2, with a LTR of 103 MW and T7 & T8 with a LTR of 40 MW. These transformers currently supply 82 MW and 40 MW of load at peak, respectively. The demand forecast shows the combined load at Cedar TS exceeding the current loading capabilities. Transformers T7 & T8 have been identified as reaching EOL in the long term, with a planned EOL replacement that will increase the capacity of station. Advancing the EOL replacement to upsize the transformers is being considered as an option.

The TWG recommends that the capacity need at Cedar TS be further reviewed in an IRRP to identify whether the full need is met over the planning timeframe and to consider the opportunity for integrated solutions involving both wire and non-wire options, and the opportunity to coordinate the solution to the need.

Kitchener MTS #7 Capacity Need

Kitchener MTS #7 supplies Enova Power Corp. loads and has a single T13 & T14 DESN with a LTR of 54 MW. The current supply at peak load is 37 MW. The demand forecast shows the load at Kitchener MTS #7 exceeding the current loading capabilities near the end of the 10-year forecast.

Enova Power Corp. will continue to monitor the station and, if required, will manage any near and mid-term overloading through load transfers to Kitchener MTS #3 or #5.

The TWG recommends that the long-term capacity need at Kitchener MTS #7 be further reviewed in an IRRP, due to the potential development of a new supply station, which requires regional planning and integration to best assess where to locate a future station based on the available transmission supply.

Rush MTS Capacity Need

Rush MTS supplies Enova Power Corp. loads and has a single T1 & T2 DESN with a LTR of 68 MW. The current supply at peak load is 50 MW. The demand forecast shows the load at Rush MTS exceeding the current loading capabilities near the end of the 10-year forecast.

The TWG recommends that the capacity need at Rush MTS be further reviewed in an IRRP to be inter-related with the previously identified supply capacity need on the 115 kV circuit, D10H, that supplies Rush MTS and Elmira TS. This, combined with the future potential of a new station in the region, should be explored through an IRRP to consider the opportunity for coordinated and integrated solutions to the various needs.

Waterloo North MTS #3 Capacity Need

Waterloo North MTS #3 supplies Enova Power Corp. loads and has a single T1 & T2 DESN with a LTR of 85 MW. The current supply at peak load is 48 MW. The demand forecast shows the load at Waterloo North MTS #3 exceeding the current loading capabilities near the end of the 10-year forecast.

The TWG recommends that the capacity need at Kitchener MTS #7 be further reviewed in an IRRP. The steep growth in demand expected at the station, paired with the long-term possibility of a new supply station in the region, indicate the need for a regionally coordinated recommendation that holistically considers the various long-term needs in the region.

D11K/D12K Detweiler to Kitchener #1 & #4 JCT – Transmission System Capacity

D11K/D12K is a 115 kV double circuit line that supplies Kitchener MTS #1 and Kitchener MTS #4. By the end of the 10-year forecast, loss of either the D11K or D12K circuit will overload the companion circuit.

The TWG recommends that the transmission circuit supply need of the D11K/D12K 115 kV double circuit line be further reviewed in an IRRP. This recommendation is based on the timing of the need, the opportunity for integrated solutions involving both wire and non-wire options, and the opportunity to coordinate the solution to the need.

M20D/M21D

The M20D/M21D circuit is a 230 kV double circuit that supplies Kitchener MTS #6, Kitchener MTS #8, Galt TS, Preston TS, Energy+ MTS #1, and a customer CTS. Three needs are identified related to the M20D/M21D circuits.

- **Circuit section from Galt JCT to Cambridge JCT - Supply Capacity Need**

By 2026, the loss of either the M20D or M21D 230 kV circuit results in the loading on the Galt JCT to Cambridge JCT section exceeding its rating.

The TWG recommends that the transmission circuit supply need of the M20D/M21D 230 kV double circuit between Galt JCT and Cambridge JCT be further reviewed in an IRRP. This recommendation is based on the timing of the need, the opportunity for integrated solutions involving both wire and non-wire options, and the opportunity to coordinate the solution to the need.

- **Load Security and Restoration Need**

In 2032, in the event of a loss of the double circuit M20D/M21D, a total peak coincident load of 638 MW will be interrupted. This interrupted load violates ORTAC load security criteria, which states that no more than 600 MW of load may be interrupted.

In addition, with a 638 MW interruption, ORTAC restoration criteria states 388 MW of the load must be restored within 30 minutes. From Galt JCT to Preston TS, only 210 MW of the interrupted load can be restored in 30 minutes.[1] This value does not meet the restoration criteria.

The TWG recommends that the load security and restoration need of the M20D/M21D 230 kV double circuit between Galt JCT to Preston TS be further reviewed in an IRRP. This recommendation is based on the timing of the need, the opportunity for integrated solutions involving both wire and non-wire options, and the opportunity to coordinate the solution to the need.

- **Voltage Violation Need**

Within the near-term forecast, the M20D/M21D post contingency voltage change on the low voltage side at Preston TS and Energy+ MTS #1 exceeds the 10% pre-underload tap changer (ULTC) action and 5% post-ULTC action allowable limits. In addition, the post contingency low voltages are below the allowable voltage range. In the midterm, on the high voltage side of Preston TS, Galt TS, and Energy+ MTS #1, the post contingency voltages also violate the allowable voltage change limit and continue to drop.

[1] The Kitchener MTS #6 and MTS #8 load can be restored with the Galt JCT. in-line switches and load can be restored at Preston TS with the back-feed through the Preston TS T2 230-115 kV autotransformer.

The TWG recommends that the voltage violations along the M20D/M21D 230 kV double circuit line be further reviewed in an IRRP. This recommendation is based on the timing of the need, the opportunity for integrated solutions involving both wire and non-wire options, and the opportunity to coordinate the solution to the need.

3.3.1 Near-Term Needs

Of the needs identified, those at Preston TS, Energy+ MTS #1, and along the Galt JCT to Cambridge section of M20D/M21D are the most pressing. This may introduce the need to use a hand-off letter to allow for the expedited initiation of projects aimed towards addressing the imminent needs. A hand-off letter, if required, confirms that these needs and the associated options were assessed by the TWG as part of the regional planning process. Any recommendations included in a hand-off letter would be captured, along with any project updates or advancements, in the final IRRP report and the subsequent RIP prepared by the transmitter.

3.3.2 Powering Ontario's Growth

On July 10, 2023, the Ministry of Energy released the Powering Ontario's Growth (POG) report, which outlines actions to support economic growth, decarbonization, and the ongoing transformation of Ontario's electricity system. The IESO's South and Central Ontario bulk planning study being initiated in 2024 will review the capability of the bulk system to support future generation connections and demand growth in key areas throughout the province, to enable a decarbonized power system in the future. This work will also consider opportunities to preserve new or expanded corridors for future transmission development. Consideration of Potential Loads for the other planning regions of interest identified in the Central-West Bulk Plan will be integrated with POG objectives in the South and Central Ontario bulk planning study to better plan for potential linkages and their cumulative impact.

3.3.3 Central-West Bulk Plan

In April 2024, the IESO published the Central-West Bulk Plan, which assessed the reliability of a large portion of the bulk transmission system in southwestern Ontario. The Plan focused on firm economic development projects in the London Area region, as well as potential economic development in five planning regions of interest, including KWCG. As part of that assessment, thermal limitations on the transmission paths between Detweiler TS and Orangeville TS, as well as the 115 kV path between Burlington TS and Detweiler TS were identified. In addition, low voltage and eventual voltage collapse at Preston TS was identified after a significant amount of load (approximately 1,110 MW) was added in the region. These two findings should be monitored and inform regional planning as well as the South and Central Ontario bulk planning study.

4. Conclusion and Next Steps

The Scoping Assessment concludes that further coordinated regional planning in the form of an IRRP is required to identify, evaluate, and recommend solutions to address needs in the KWCG region.

This IRRP will include opportunities for engagement with local communities and stakeholders, as well as include discussion of any local initiatives focused on energy, economic development, and/or reducing GHG emissions, and how the IRRP can coordinate with these initiatives. This could include reviewing economic development plans, Community Energy Plans, net-zero strategies, or similar, to understand potential impacts on the electricity demand forecast. Particular attention will be paid to opportunities for information sharing and/or coordination of goals and outcomes.

The draft Terms of Reference for the KWCG region IRRP is attached in Appendix 2.

Appendix 1 – List of Acronyms

Acronym	Definition
CDM	Conservation and Demand Management
DER	Distributed Energy Resource
DESN	Dual Element Spot Network
DG	Distributed Generation
GHG	Greenhouse Gas
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
JCT	Junction
KWCG	Kitchener-Waterloo-Cambridge-Guelph
LDC	Local Distribution Company
MW	Megawatt
OEB	Ontario Energy Board
ORTAC	Ontario Resource Transmission Assessment Criteria
TS	Transformer Station
TWG	Technical Working Group
ULTC	Underload Tap Changer

Appendix 2 - Kitchener/Waterloo/Cambridge/Guelph Integrated Regional Resource Plan (IRRP) Terms of Reference

1. Introduction and Background

Based on the near- and mid-term needs identified within the region, the forecast growth, and opportunities to consider solutions in a coordinated manner, an Integrated Regional Resource Plan (IRRP) should be undertaken for the Kitchener-Waterloo-Cambridge-Guelph (KWCG) region.

These Terms of Reference establish the objectives, scope, key assumptions, roles and responsibilities, activities, deliverables, and timelines for an IRRP of the KWCG region.

1.1 Kitchener/Waterloo/Cambridge/Guelph Region

The KWCG region is composed of the cities of Kitchener, Cambridge, Waterloo, and Guelph, the townships of Wellesley, Woolwich, Wilmot, North Dumfries, and portions of Oxford and Wellington counties.

The region also encompasses the Métis Nation of Ontario, Grand River Métis Council, Six Nations of the Grand River, Mississaugas of the Credit First Nation, Chiefs of Ontario, Anishinabek Nation and Association of Iroquois and Allied Indians.

The region is supplied by five stations: Middleport TS, Buchanan TS, Detweiler TS, Orangeville TS, and Burlington TS. These stations supply either 230 kV or 115 kV to the area, stepping down from 500 kV and 230 kV respectively. The region is supplied by numerous Local Distribution Companies (LDC): GrandBridge Energy, Enova Power Corp, Hydro One Networks Inc. (Distribution), Alectra Inc., Center Wellington Hydro Inc., Halton Hydro Inc., Wellington North Power, and Milton Hydro. The region includes 24 transmission stations as shown in Figure 2.

Electricity demand in the KWCG region is driven by various factors, including population growth, industrial sector changes, intensification of the Kitchener downtown area, and rising awareness of renewable energy generation development, and conservation and demand management. The region's population and accompanying employment are expected to grow steadily, which will drive electricity demand for the next 20 years. The Region of Waterloo installed a light rail transit system between Waterloo and Kitchener with plans to extend to Cambridge, which is spurring development along the train route in both the residential and commercial sectors.

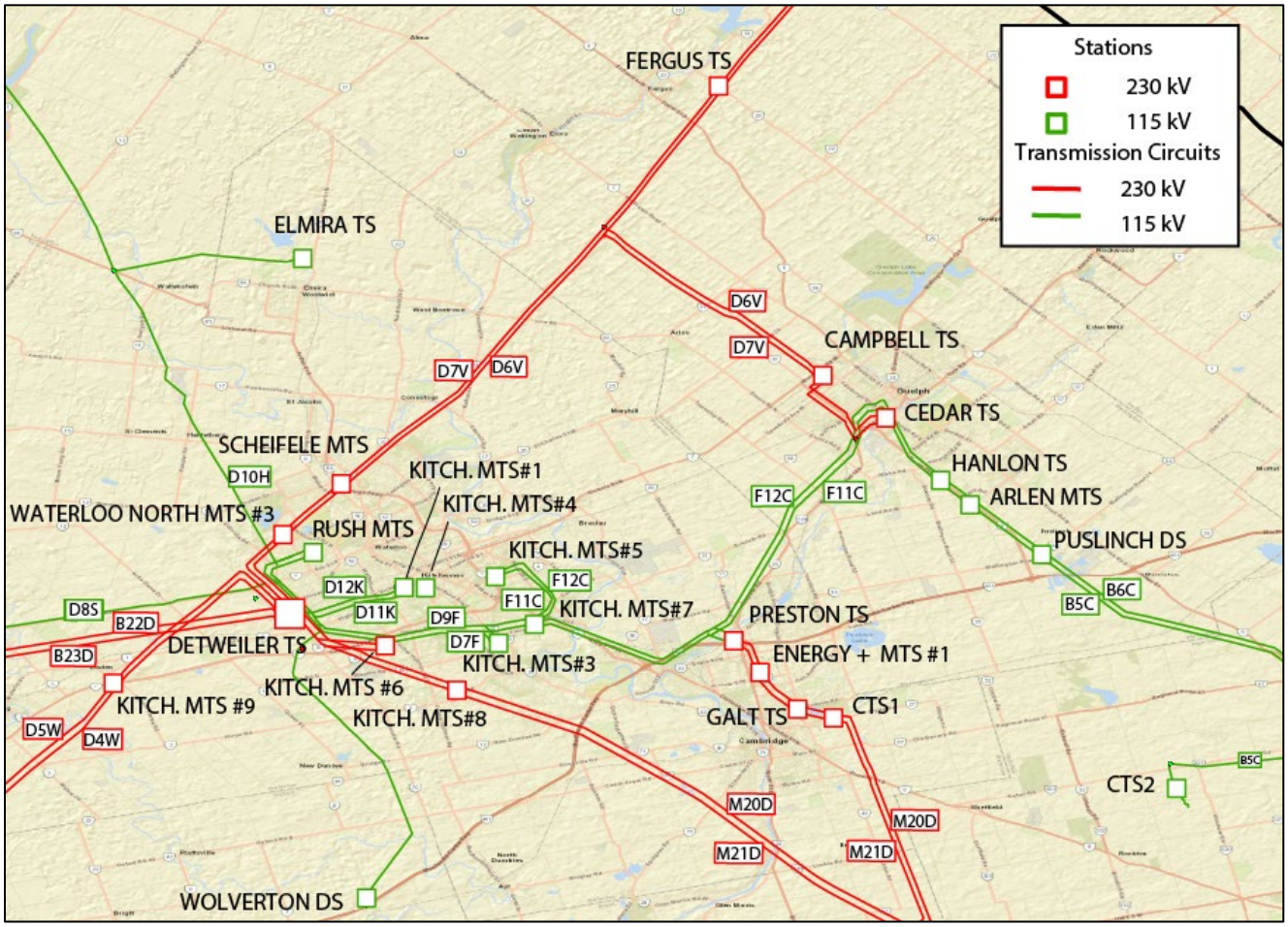
The Region of Waterloo is internationally known for its leading-edge technology and advanced manufacturing industries, innovative educational institutions, vibrant agricultural communities, and the historically significant Grand River.

The City of Kitchener is currently experiencing a conversion from being a manufacturing-oriented economy to a more diversified and balanced economy.

As directed by the OEB, Enova Power Corp is currently participating in multiple provincial renewable energy programs and conservation and demand management (CDM) programs, which help control and reduce the electricity demand. Time-of-Use is also shifting demand and conserving energy as customers manage their electricity use and control their costs.

Based on the needs of the region, no divisions are proposed that would create any sub-regions for this IRRP.

Figure 1 | Electricity Infrastructure of the KWCG Region



1.2 Background

This is the third regional planning cycle for the KWCG region. Hydro One completed the Needs Assessment (NA) report for the region in December 2023. The IESO-led SA process reviewed the results of the NA to identify a preferred planning approach for the region. An IRRP was recommended based on the nature of the regional needs; the forecast demand growth and the potential for diverse types of solutions considering both wire and non-wire possibilities.

2. Objectives

1. To assess the adequacy of the electricity supply to customers in the Kitchener-Waterloo-Cambridge-Guelph region over the next 20 years.
2. Account for major asset renewal needs, capacity needs, enhancing reliability and resilience, uncertainty in the outlook for electricity demand, and local priorities in developing a comprehensive plan.
3. Consider potential impacts of electrification targets and other policy decisions on needs identified and recommended outcomes, consistent with provincial direction.
4. Evaluate opportunities for cost effective non-wires alternatives, including conservation and demand management (CDM) and distributed energy resources (DER), as well as wires approaches for addressing the needs identified.
5. Develop an implementation plan that maintains flexibility to accommodate changes in key assumptions over time. The implementation plan should identify actions for near-term needs, preparation work for medium-term needs, and planning direction for the long term.

3. Scope

3.1 Needs to be Addressed

The IRRP will develop and recommend an integrated plan to meet the needs of the KWCG region. The plan is a joint initiative led by the IESO and completed by the members of the Technical Working Group (TWG) – Hydro One Transmission, the IESO, GrandBridge Energy, Enova Power Corp., Alectra Inc., Central Wellington Hydro, Halton Hills Hydro Inc., Hydro One Distribution, Wellington North Power, and Milton Hydro. The plan will consider the demand forecast for the region, the CDM, DER uptake, transmission, and distribution system capabilities, and align with relevant community plans, bulk system developments, and policy direction as applicable.

The KWCG IRRP aims to address the following needs identified in the Needs Assessment:

Table 4 | Needs Identified in the Needs Assessment as Requiring Further Study

Station/Circuit	Description of Need	Timeline
230 kV M20D/M21D: Galt JCT to Cambridge #1 JCT	Transmission System Capacity Need	Near term
115 kV D11K/D12K: Detweiler to Kitchener #1 &#4 JCT	Transmission System Capacity Need	Mid term
230 kV M20D/M21D Circuit	Load Security Need	Mid term
230 kV M20D/M21D Circuit	Load Restoration Need	Near term
230kV M20D/M21D Circuit	Voltage Violation Need	Near term
Preston TS (T3 & T4)	Transformer Capacity Need	Near term
Energy+ MTS #1 (T1 & T2)	Transformer Capacity Need	Near term
Campbell TS (T3 & T4)	Station Capacity Need	Near term
Cedar TS (T1 & T2)	Station Capacity Need	Mid term
Cedar TS (T7 & T8)	Station Capacity Need	Near term
Kitchener MTS #7	Station Capacity Need	Mid term
Rush MTS	Station Capacity Need	Mid term
Waterloo North MTS #3	Station Capacity Need	Mid term

3.1.1 Expansion of the needs

Each LDC in the KWCG region is required to provide a 20-year forecast. The results of this forecast may introduce more needs for the region than recognized in the 10-year forecast, especially given at the end of the NA, Alectra indicated their forecast will be updated to better account for their community's decarbonization activities. Thus, the needs studied in the IRRP may be refined to reflect the new insight provided by the 20-year demand forecasts to be completed.

3.1.2 Near-Term Needs

The following needs have been identified by the TWG as priority needs within the IRRP based on the proximity of the expected timing to the period of the IRRP study:

- Preston TS transformer capacity need
- Energy+ Inc MTS #1 transformer capacity need
- 230 kV M20D/M21D Circuit
    - Transmission capacity need
    - Voltage violation need
    - Load restoration and load security need

The solutions developed by the TWG to address the priority needs may be encompassed in a hand-off letter. This letter will allow for projects developed to address the imminent needs to be launched before the conclusion of the IRRP. This allows the needs to be addressed promptly due to the approaching nature of the expected time of the need.

3.1.3 Powering Ontario's Growth

On July 10, 2023, the Ministry of Energy released the Powering Ontario's Growth (POG) report, which outlines actions to support economic growth, decarbonization, and the ongoing transformation of Ontario's electricity system. The IESO's South and Central Ontario bulk planning study being initiated in 2024 will review the capability of the bulk system to support future generation connections and demand growth in key areas throughout the province, to enable a decarbonized power system in the future. This work will also consider opportunities to preserve new or expanded corridors for future transmission development. Consideration of Potential Loads for the other planning regions of interest identified in the Central-West Bulk Plan will be integrated with POG objectives in the South and Central Ontario bulk planning study to better plan for potential linkages and their cumulative impact.

3.1.4 Central-West Bulk Plan

In April 2024, the IESO published the Central-West Bulk Plan, which assessed the reliability of a large portion of the bulk transmission system in southwestern Ontario. The Plan focused on firm economic development projects in the London Area region, as well as potential economic development in five planning regions of interest, including KWCG. As part of that assessment, thermal limitations on the transmission paths between Detweiler TS and Orangeville TS, as well as the 115 kV path between Burlington TS and Detweiler TS were identified. In addition, low voltage and eventual voltage

collapse at Preston TS was identified after a significant amount of load (approximately 1,110 MW) was added in the region. These two findings should be monitored and inform regional planning as well as the South and Central Ontario bulk planning study.

4. Activities

The IRRP process will consist of the activities listed below. The activities and anticipated timelines are summarized in Section 8 of this document. The first major planning activity following preparation of this Terms of Reference is the development of the electricity demand forecast, which serves as the basis for system assessments. The timing for initiating the assessment (Activity 3) and all subsequent plan development activities will be contingent on the TWG first agreeing on the demand forecast to be used.

- Develop an electricity demand forecast for the KWCG region. This may be comprised of a number of electricity demand scenarios that account for uncertain elements that can affect (e.g., raise or lower) the need for electricity in the region:
- Confirm baseline technical assumptions including infrastructure ratings, system topology and relevant base cases for simulating the performance of the electric power system. Collect information on:
    - Transformer, line and cable continuous ratings, long-term and short-term emergency ratings;
    - Known reliability issues and load transfer capabilities;
    - Customer load breakdown by transformer station;
    - Historical and present CDM peak demand savings and installed/effective DER capacity, by transformer station.
- Perform assessments of the capacity, reliability, and security of the electric power system under each demand outlook scenario.
    - Confirm and/or refine the needs listed earlier in this section using the demand outlook; establish the sensitivity of each need to different demand outlook scenarios.
    - Identify additional infrastructure capacity needs and any additional load restoration needs; if new needs are discovered, determine the appropriate planning approach for addressing them.
- Identify options for addressing the needs, including, non-wires and wires alternatives. Where necessary, develop portfolios of solutions comprising a number of options that, when combined, can address a need or multiple needs.
    - Collect information about the attributes of each option: cost, performance, timing, risk, etc.

    - Develop cost estimates for all screened-in options as a means of informing further evaluations of alternatives.
    - Seek cost-effective opportunities to manage growth, by identifying opportunities to reduce electricity demand.
- Evaluate options using criteria including, but not limited to the areas of: technical feasibility and timing, economics, reliability performance, risk, environmental, regulatory, and social factors. Evaluation criteria will be informed through community engagement activities and reflect attributes deemed important to the community-at-large.
- Develop recommendations for actions and document them in an implementation plan, to address needs in the near-term and medium-term.
- Develop a long-term plan for the electricity system in KWCG to address the identified long-term needs, taking into account uncertainty inherent in long-term planning, local and provincial policy goals, commitments, and climate change action plans.
    - Discuss possible ways the power system in KWCG could evolve to address potential long-term needs, support the achievement of local and provincial long-term policy goals and plans, and support the achievement of the long-term vision for the electricity sector.
    - During the development of the plan, seek community and stakeholder input to confirm the long-term vision, expected impacts on the electricity system, and inform the recommended actions through engagement.
- Complete an IRRP report documenting the near-term and medium-term needs, recommendations, and implementation actions, as well as long-term plan recommendations.

To carry out this scope of work, the TWG will consider the data and assumptions outlined in Section 5 below.

5. Data and Assumptions

Demand Data

- Historical coincident peak demand information
- Historical weather correction, median and extreme conditions
- Gross peak demand forecast scenarios
- 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
- 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 and non-Feed-in-Tariff 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
- Community Climate Action or Adaptation Plans
- Municipal Growth Plans
- Indigenous Community Energy Plans

Criteria, Codes, and Other Requirements

- Ontario Resource and Transmission Assessment Criteria
- North American Electric Reliability Corporation and Northeast Power Coordinating Council 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 long-term emergency rating) as per asset owner
- Load transfer capability
- Technical and operating characteristics of local generation

End-of-Life Asset Considerations/Sustainment Plans

- Transmission assets
- Distribution assets, as applicable

Other considerations, As Applicable

6. Technical Working Group

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

- Independent Electricity System Operator (Lead for the IRRP)
- Hydro One Networks Inc. (Transmission)
- GrandBridge Energy
- Enova Power Corp.
- Hydro One Networks Inc. (Distribution)
- Alectra Inc.
- Center Wellington Hydro
- Halton Hills Hydro Inc.
- Wellington North Power
- Milton Hydro

6.1.1 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.

7. 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 TWG is committed to conducting plan-level engagement throughout the development of the KWCG 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 5 will help to inform the scope of community and stakeholder engagement to be considered for this IRRP.

8. Activities, Timeline, and Primary Accountability

Table 3 | Deliverables and timeframe associated with IRRP activities

Activity	Lead Responsibility	Deliverable(s)	Timeframe
1. Prepare Terms of Reference considering stakeholder input	IESO	Finalized Terms of Reference	Q2-Q3 2024
2. Develop the planning forecast for the region		Long-term planning forecast scenarios	Q3-Q4 2024
Establish historical coincident and non-coincident peak demand information	IESO		
Establish historical weather correction, median and extreme conditions	IESO		
Establish gross peak demand forecast	LDCs		
Establish existing, committed, and potential DG	LDCs		
Establish near- and long-term conservation forecast based on planned energy efficiency activities and codes and standards	IESO		
Develop planning forecast scenarios for sensitivity analyses	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 2025
4. Provide and review relevant community plans, if applicable	LDCs, Indigenous Communities, and IESO	Relevant community plans	Q1 2025

Activity	Lead Responsibility	Deliverable(s)	Timeframe
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 The system studies for the imminent needs identified in section 3.3.1 will be prioritized in Q1 2025	IESO, Hydro One Transmission	Summary of needs based on demand forecast scenarios for the 20-year planning horizon	Q1-Q3 2025
6. Develop options and alternatives The development of options and alternatives for the imminent needs identified in section 3.3.1 will be prioritized in Q2 2025		Develop flexible planning options for forecast scenarios	Q2-Q3 2025
Conduct a screening to identify which wires and non-wires options warrant further analysis	IESO		
Verify the LMC of the system to better determine timing of needs and support options development	IESO		
Develop screened-in energy efficiency options	IESO and LDCs		
Develop portfolios of integrated alternatives	All		
Technical comparison and evaluation	All		
7. Plan and undertake community & stakeholder engagement		Community and Stakeholder Engagement Plan Input from local communities, First Nation communities, and Métis Nation of Ontario	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	All		
Develop communications materials	All		
Undertake community and stakeholder engagement	All		
Summarize input and incorporate feedback	All		
8. Develop long-term recommendations and implementation plan based on community and stakeholder input	IESO	Implementation plan Monitoring activities and identification of decision triggers Procedures for annual review	Q3-Q4 2025
9. Prepare the IRRP report detailing the recommended near, medium and long-term plan for approval by all parties	IESO	IRRP report	Q4 2025 – Q1 2026

Independent Electricity System Operator
1600-120 Adelaide Street West
Toronto, Ontario M5H 1T1

Phone: 905.403.6900
Toll-free: 1.888.448.7777
E-mail: customer.relations@ieso.ca

ieso.ca

@IESO_Tweets
facebook.com/OntarioIESO
linkedin.com/company/IESO

APPENDIX C-3
KWCG IRRP Report & Appendices (2021)



Kitchener-Waterloo-Cambridge-Guelph Region

Integrated Regional Resource Plan

May 2021

ieso
Connecting Today.
Powering Tomorrow.

Table of Contents

1 Introduction **5**

2 The Integrated Regional Resource Plan **9**

2.1 End-of-Life Replacement Optimization 9

2.2 Needs in Near- to Medium-Term Horizon 10

2.2.1 Station Capcity Needs and Recommended Solutions 10

2.2.2 Supply Capacity Need and Recommended Solution 11

2.3 Needs in Long-Term Horizon and Recommendations 11

2.4 Load Restoration Needs and Recommendations 11

2.5 Short Circuit Capability Needs 12

2.6 Conservation and Demand Management 12

3 Development of the Plan **13**

3.1 The Regional Planning Process 13

3.2 KWCG and IRRP Development 13

4 Background and Study Scope **14**

4.1 Study Scope 14

5 Electricity Demand Forecast **16**

5.1 Demand Forecast Methodology 16

5.2 Historical Electricity Demand 17

5.3 Gross and Net Demand Forecast 17

5.4 Contribution of Conservation to the Forecast 18

5.5 Contribution of Distributed Generation to the Forecast 19

5.6 Projects to Consider for Next Cycle or Addendum 20

6 Needs **21**

6.1 Needs Assessment Methodology 21

6.2 Needs Identified 22

7 Plan Options and Recommendations **25**

7.1 Conservation 25
7.2 End-of-Life Replacement Optimization 25
7.3 Near/Medium-Term Station Capacity Needs 26
7.4 Near/Medium-Term Supply Capacity Needs 26
7.5 Long-term Needs 27
7.6 Load Restoration Need 27

8 Engagement 28

8.1 Engagement Principles 28
8.2 Creating an Engagement Approach for KWCG 28
8.3 Engage Early and Often 29
8.4 Bringing Communities to the Table 30

9 Conclusion 31

List of Abbreviations

Alectra	Alectra Utilities Corp.
CDM	Conservation Demand Management
Centre Wellington Hydro	Centre Wellington Hydro Ltd.
DER	Distributed Energy Resources
DG	Distributed Generation
DSC	Distribution System Code
Energy+	Energy+ Inc.
FIT	Feed-in Tariff
GATR	Guelph Area Transmission Refurbishment
Halton Hills Hydro	Halton Hills Hydro Inc.
Hydro One	Hydro One Networks Inc.
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
KWCG Region	Kitchener, Waterloo, Cambridge and Guelph
LAC	Local Advisory Committee
LDC	Local Distribution Company
LMC	Load Meeting Capability
LRT	Light Rail Transit
LTR	Limited Time Rating
LV	Low-voltage
Milton Hydro	Milton Hydro Distribution Inc.
MTS	Municipal Transformer Station
MW	Megawatt
NERC	North American Electric Reliability Corporation
OEB	Ontario Energy Board
OPA	Ontario Power Authority
ORTAC	Ontario Resource and Transmission Assessment Criteria
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Plan
TOU	Time-of-Use
TS	Transformer Station
TSC	Transmission System Code
Wellington North Power	Wellington North Power Inc.
WNH	Waterloo North Hydro Inc.
Working Group	Technical Working Group of the KWCG Region

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

This IRRP was prepared on behalf of the Technical Working Group (Working Group) of the Kitchener-Waterloo-Cambridge-Guelph (KWCG) region which included the following members:

- Independent Electricity System Operator
- Alectra Utilities Corporation
- Centre Wellington Hydro Ltd.
- Waterloo North Hydro Inc.
- Energy+ Inc.
- Kitchener-Wilmot Hydro Inc.
- Wellington North Power Inc.
- Halton Hills Hydro Inc.
- Milton Hydro Distribution Inc.
- Hydro One Networks Inc. (Distribution)
- Hydro One Networks Inc. (Transmission)

The Working Group assessed the adequacy of electricity supply to customers in the KWCG Region over a 20-year period beginning in 2019; developed a plan that considers opportunities for coordination in anticipation of potential demand growth and varying supply conditions in the region; and developed an implementation plan for the recommended options, while maintaining flexibility in order to accommodate changes in key conditions over time.

The Working Group developed a plan that considers the potential for long-term electricity demand growth and varying supply conditions in the region and maintains the flexibility to accommodate changes to key conditions over time.

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

The KWCG Working Group members do not commit to any capital expenditures and must still obtain all necessary regulatory and other approvals to implement recommended actions.

1 Introduction

This Integrated Regional Resource Plan (IRRP) for the Kitchener-Waterloo-Cambridge-Guelph (KWCG) region addresses the regional electricity needs for the next 20 years (the "study period"). This region is located in southwestern Ontario and, as shown in Figure 1.1, encompasses the Region of Waterloo and the cities of Kitchener, Waterloo, Cambridge and Guelph, and the townships of Wellesley, Woolwich, Wilmot, North Dumfries, and portions of Perth, and Oxford. Wellington County and the municipalities of Blandford-Blenheim, Centre Wellington, Guelph/Eramosa, and Puslinch are also included in the region.

The KWCG Region is summer peaking and is served via 230 kV and 115 kV circuits originating from Detweiler TS and Burlington TS, and by load stations which tap double-circuit 230 kV lines connecting to Detweiler from Orangeville (D6V & D7V), from Middleport (M20D & M21D) and from Buchanan (D4W & D5W) as shown in Figure 1.2 and Figure 1.3. There are no transmission connected resources in this area. The area does include distribution connected resources, including contracted energy storage facilities at Arlen MTS, Kitchener MTS #5, and Elmira TS.

Figure 1.1| Map of KWCG Region

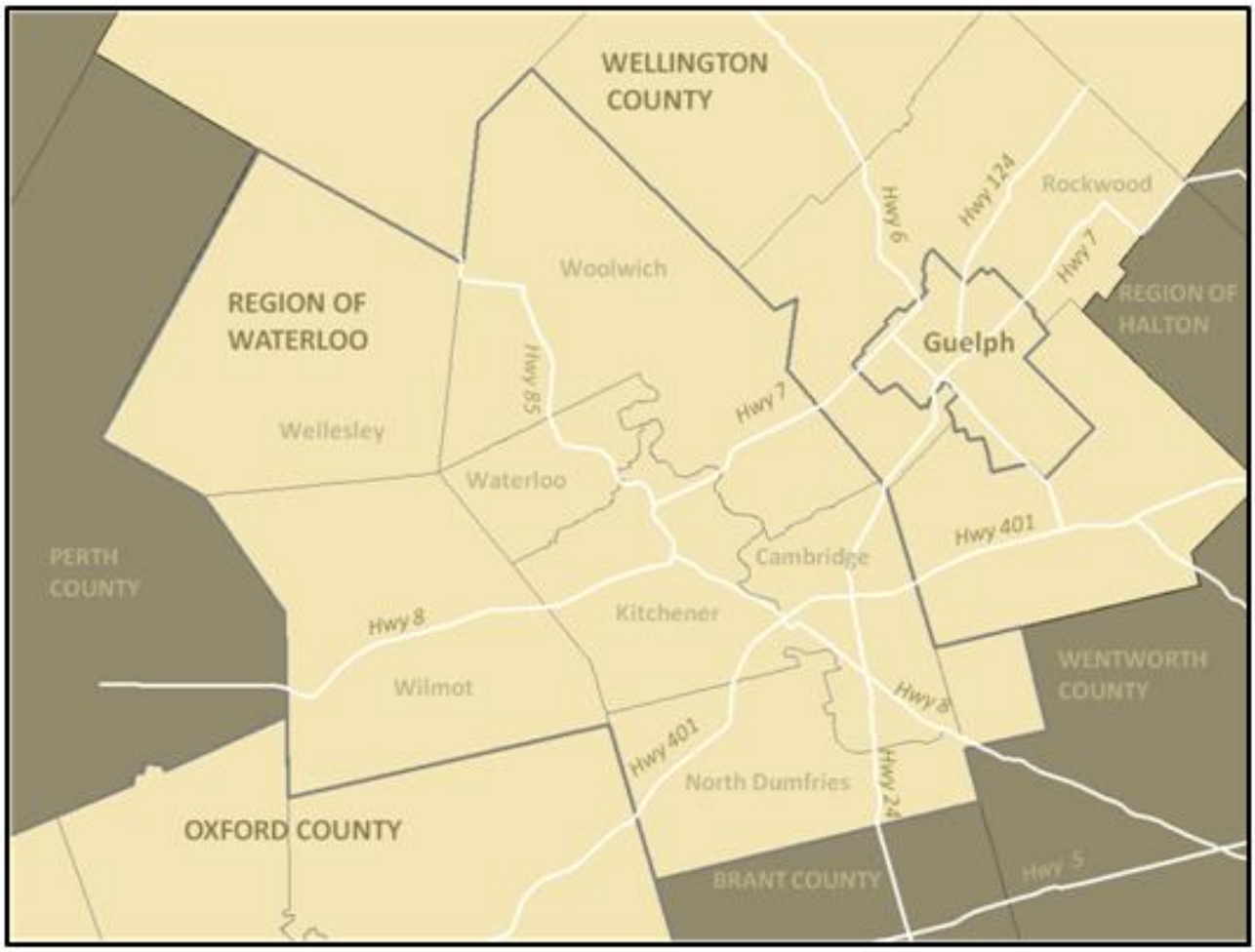


Figure 1.2| Overview of the KWCG Region

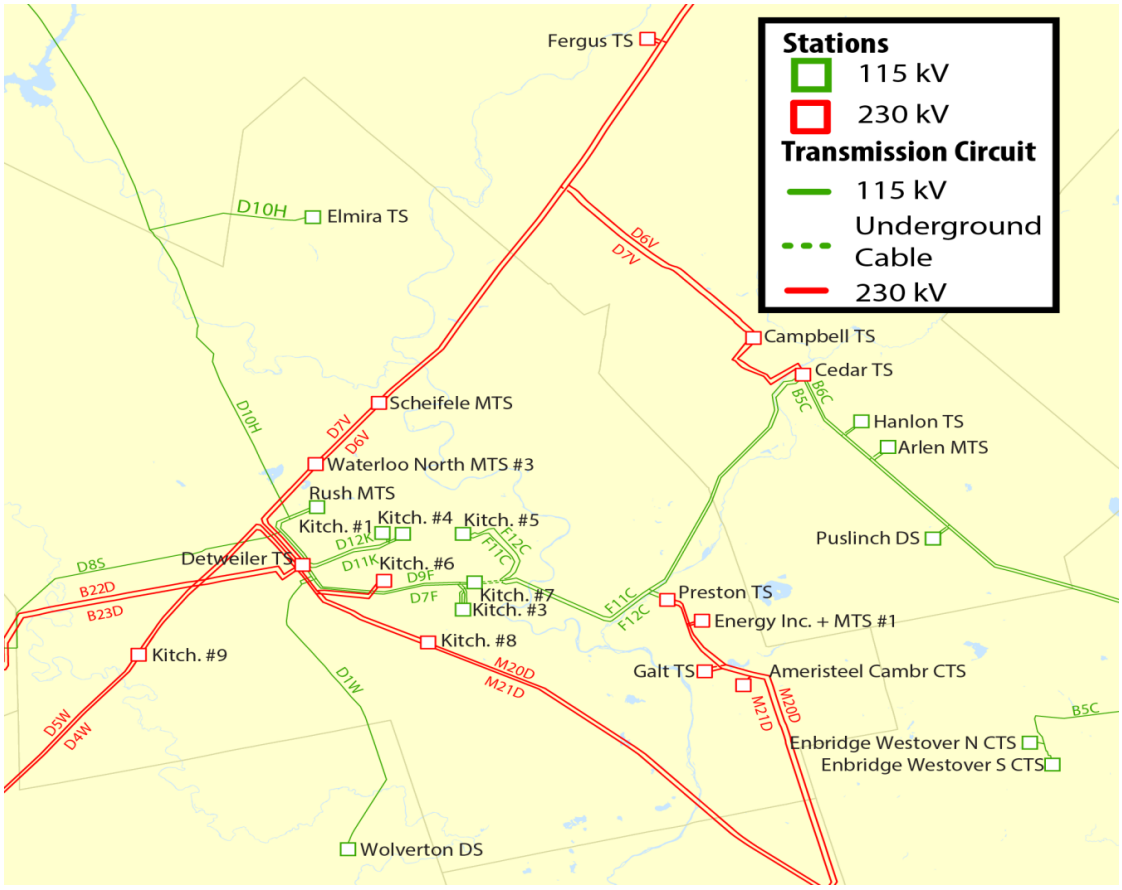
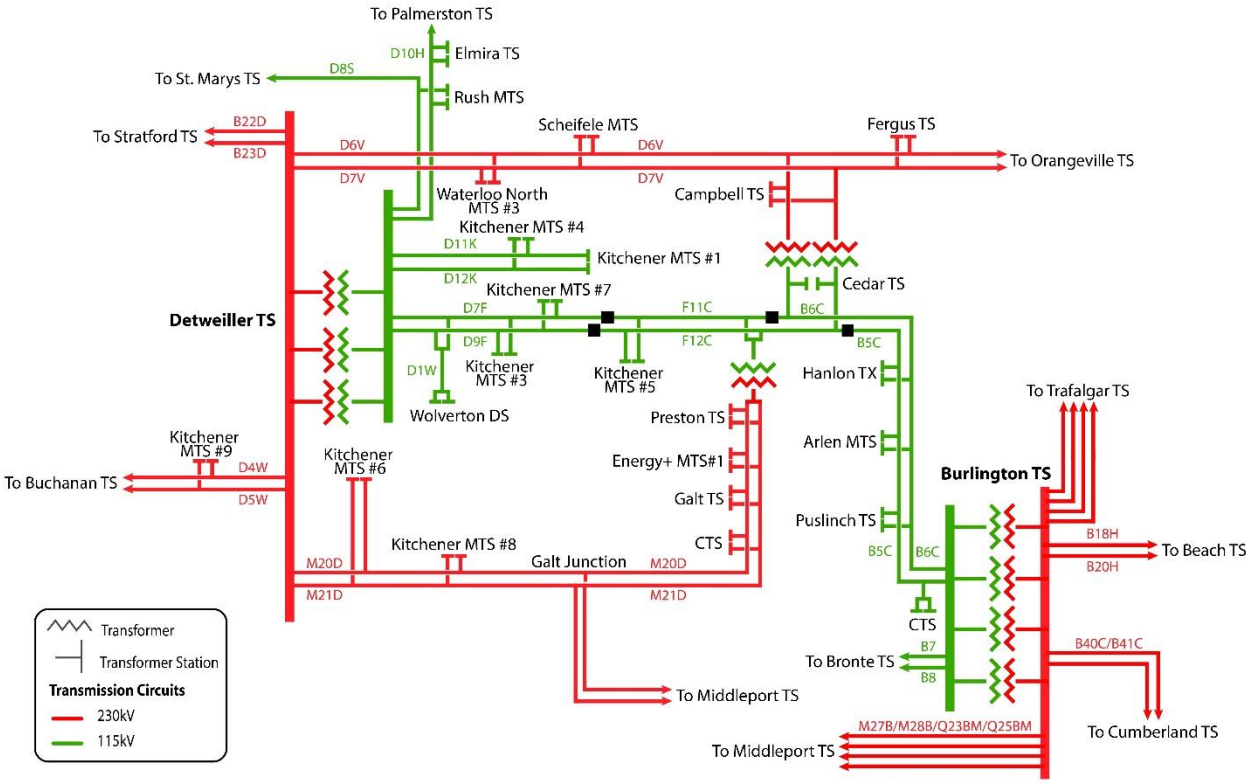


Figure 1.3| Single Line Diagram of the KWCG Region



The region's electricity is delivered by 10 local distribution companies (LDCs): Alectra Utilities (Guelph), Centre Wellington Hydro, Waterloo North Hydro, Energy+, Kitchener-Wilmot Hydro, Wellington North Power, Halton Hills Hydro, Milton Hydro and Hydro One. Hydro One is also the primary transmission asset owner. This IRRP report was prepared by the Independent Electricity System Operator (IESO) on behalf of a Working Group composed of the aforementioned LDCs and transmitter.

Development of the KWCG IRRP was initiated in May 2019 following the publication of the Needs Assessment report in December 2018 by Hydro One after which the IESO's Scoping Assessment Outcome Report and Terms of Reference identified needs that should be further assessed through an IRRP. The 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.

In Ontario, planning to meet the electrical supply and reliability needs of a large area or region is carried out through regional electricity planning, a process that was formalized by the Ontario Energy Board (OEB) in 2013. In accordance with this process, transmitters, distributors and the IESO are required to carry out regional planning activities for 21 electricity planning regions across Ontario, including the KWCG Region, at least once every five years. The process allows a regional planning cycle to be triggered before the five-year mark due to material changes such as demand or resource changes. The active part of this cycle is made up of Needs Assessment, Scoping Assessment, IRRP, and Regional Infrastructure Plan (RIP) stages, which take up approximately half of the typical five-year timeframe. In many regions, this period of active planning is followed by a period when plan implementation begins, and the Working Group monitors demand trends until the next cycle begins. The complexity of issues requires the Working Group to continue to be engaged in integrated planning throughout the regional planning cycle, after the completion of the IRRP.

Further information on the process can be found in Appendix C. The IESO has also 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.

The last IRRP for the KWCG Region was concluded in 2015 with two major recommendations which have since been completed. Those recommendations were: i) installing a circuit switcher on each of M20D and M21D at Galt junction and ii) implementing the Guelph Area Transmission Refurbishment (GATR) which included the installation of two 115 kV/230 kV auto-transformers, switching facilities, and the upgrade of an existing transmission line in Guelph.

The circuit switchers at Galt junction have substantially improved load restoration in the Cambridge and Kitchener areas following a major transmission contingency. The GATR project has addressed supply needs in the South-Central Guelph and Kitchener areas and minimized the impact of potential supply interruptions to customers in Waterloo, Guelph and surrounding areas.

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 to date and moving forward is provided in Section 8; and
- A conclusion is provided in Section 9.

2 The Integrated Regional Resource Plan

The KWCG IRRP provides recommendations to address the electricity needs for the region over the next 20 years based on application of the IESO's Ontario Resource and Transmission Assessment Criteria (ORTAC). The needs were identified over three main planning horizons, i) up to five years as near-term, ii) six to 10 years as medium-term and iii) 11 to 20 years as long-term. These planning horizons are distinguished in the IRRP to reflect the different levels of forecast certainty, lead time for development, and planning commitment required over these time horizons. The recommendations have been developed in consideration of a number of factors including reliability, cost, technical feasibility, environmental and social factors, and maximization of the use of the existing electricity system, where it is economic to do so.

In the near- to medium-term planning horizon, this IRRP identified capacity and end-of-life needs at a number of stations plus a marginal supply capacity need on 115 kV circuit B5C, when multiple elements are out-of-service. In the long-term planning horizon, additional station capacity needs and a marginal supply capacity need on 115 kV circuit D10H were identified. The potential for future developments in the Cambridge area to contribute to a long-term load restoration need was also identified. Supply capacity needs were also observed for the 230 kV double-circuit line M20D and M21D and the Detweiler TS 230/115 kV autotransformers.

The following sections provide details of the needs and recommendations to address these needs except for the supply capacity needs on M20D, M21D and the Detweiler TS autotransformers, which are deferred to the bulk planning activity for the broader Middleport area scheduled to start by the end of the year.

2.1 End-of-Life Replacement Optimization

Table 2.1 lists the elements that are approaching the end of their life with recommendations for replacement as confirmed by the Working Group.

Table 2.1 | Elements Reaching End-of-Life

Element	Year to Replace	Resposible	Replacement Recommendation
Kitchener #5 T9 & T10	2023-2024	Kitchener Wilmot Hydro	Like-for-like or closest available standard
Hanlon T1 & T2	2023-2024	Hydro One	
Cedar T7 & T8	2025-2026	Hydro One	
Preston T3 & T4	2025-2026	Hydro One	
Scheifele T1 & T2	2025-2026	Waterloo North Hydro	

During the IRRP scoping, possible further optimization was also flagged for the end-of-life replacement of the transformers at Cedar TS and Hanlon TS because of their proximity to each other and to Campbell TS and Arlen MTS. Assessments conducted by the Working Group determined that there was no opportunity to consolidate these assets since the stations are optimized for the configuration of distribution systems and as per the specific needs of customers.

2.2 Needs in Near- to Medium-Term Horizon

2.2.1 Station Capcity Needs and Recommended Solutions

The near- to medium-term station capacity needs and their recommended solutions are listed in Table 2.2. The needs were identified via two distinct approaches: i) exceedance of the non-coincident peak demand forecast at individual stations beyond the capability of each transformer and ii) post-contingency overloading of the transformers in the load flow studies using the coincident peak demand forecast.

Table 2.2 | Near/Medium-Term Station Capacity Needs and Recommended Solutions

Transformer	Estimated Need Year	Recommended Solution*	Responsible
Energy+ #1 T1/T2	2023	Load transfer to Galt TS and Preston TS	Energy+
Preston T3/T4	2021	Load transfer to Galt TS and Energy+ MTS #1 before end-of-life replacement** by 2025-2026	Hydro One, Energy+ & Waterloo North Hydro
Scheifele (T1+T3)/(T2+T4)	2023	Load transfer to Waterloo North Hydro MTS #3, Rush MTS and Elmira TS	Waterloo North Hydro
Campbell T3/T4	2023	Permanent load transfer of 4 MW to Cedar TS by 2023 plus load transfer to Campbell T1/T2 whose LTR capacity is estimated to increase by 6 MVA by 2028-2029 after replacement of minor components	Hydro One & Alectra
Cedar T7/T8	2026	End-of-life replacement** by 2025-2026; if delayed, load transfer to Cedar T1/T2	Hydro One & Alectra
Kitchener #5 T9/T10	2028	End-of-life replacement** by 2023-2024	Kitchener Wilmot Hydro
Kitchener #7 T13/T14	2028	Load transfer to Kitchener MTS #3 or #5	Kitchener Wilmot Hydro
Kitchener #8 T15/T16	2028	Load transfer to Kitchener MTS #3	Kitchener Wilmot Hydro

* Unless otherwise noted, load may be transferred on permanet or temporary basis at the discretion of LDCs.

** End-of-life replacements are like-for-like. However, available standard transformers may have higher ratings.

As indicated in Table 2.2, many of the needs can be managed by transferring the load to other stations with spare capacity on a permanent or temporary basis. A few stations are due for replacing their transformers as they reach their end-of-life. Although the replacements are like-for-like, the available standard transformers may have higher limited time ratings (LTR) which can also alleviate the station capacity needs.

2.2.2 Supply Capacity Need and Recommended Solution

While no near- or medium-term supply capacity needs were identified in the region for the loss of a single element, a marginal post-contingency supply capacity need was identified on B5C, the 115 kV circuit from Burlington to Cedar TS under outage conditions. This circuit can become slightly overloaded during peak demand following the loss of F12C, the circuit in series with B5C, under an outage on B6C, the circuit in parallel to B5C. This combination of outage and contingency results in B5C radially supplying all the loads at Hanlon TS, Arlen MTS, Puslinch TS and a customer owned transformer station.

Since the supply capacity need on B5C is marginal and under specific rare conditions (including multiple contingencies), it is recommended to manage the need into the medium term with operational measures, e.g. rescheduling outages on B6C. Meanwhile, the IESO will monitor the situation and explore long-term solutions with the Working Group and communities as appropriate if the need can no longer be managed without reliability impacts.

2.3 Needs in Long-Term Horizon and Recommendations

Minor station capacity needs are identified at Arlen MTS, Hanlon TS, Rush MTS, Elmira TS, Kitchener MTS #1, and Waterloo North MTS #3 in the long-term horizon.

A long-term marginal supply capacity need was also identified on D10H, the 115 kV circuit from Detweiler towards Hanover TS. This circuit may slightly be overloaded as a result of radially serving all of the loads at Rush MTS and Elmira TS following the loss of D8S, the circuit partially in parallel to D10H.

At this time, none of the station and supply capacity needs identified over the long term require early development work for major infrastructure projects in the KWCG Region. There may be opportunities for communities and local utilities to manage their future electricity demand through the development of community-based solutions under the IESO's Conservation and Demand Management (CDM) Framework or other mechanisms or opportunities that may evolve between planning cycles.

The IESO will re-evaluate these needs periodically including in the next regional planning cycle and explore non-wire solutions with the Working Group and communities as appropriate.

2.4 Load Restoration Needs and Recommendations

After the 2015 KWCG IRRP recommendation regarding the circuit switchers on M20D and M21D at Galt junction was implemented, the load restoration in the Cambridge and Kitchener areas following contingencies on these circuits has substantially been improved. The circuit switchers now allow for the quick isolation of any section with a permanent fault and the ability to place the other sections back into service for restoring load.

By 2040, faults on M20D and M21D will result in the loss of up to 400 MW of load in the Cambridge area. Up to 150 MW of this load must be restored within 30 minutes as required by ORTAC. This is within the capability of the system and, so, no load restoration concern has been identified in this IRRP. However, potential future developments in the area not currently considered in the load forecast may result in a load restoration concern before 2040 and, as such, the Working Group will continue to monitor this need.

Appendix B includes options to alleviate these future restoration needs. However, the appropriate solution for this need is highly dependent on the electricity demand growth, including possible new developments. It is recommended to continue monitoring the situation until the demand growth, and the location and timing of supply to any new developments, is sufficiently certain to inform a recommended solution.

2.5 Short Circuit Capability Needs

The IRRP Scoping Assessment identified a need to assess short circuit levels as they pertain to LDC equipment ratings as well as to challenges regarding the connection of generation or storage resources. The particular concerns raised at the time of the scoping assessment have since been satisfactorily resolved. However, the Working Group recognizes the importance of a holistic system planning approach, which includes analysis related to short circuit levels.

Short circuit levels are informative when assessing feasibility and potential location for non-wires alternatives. As non-wires alternatives will be evaluated for meeting the area's long-term needs, the Working Group examined and will continue to assess short circuit levels and other system constraints when evaluating long-term options in subsequent planning cycles. Further details are provided in Appendix D.

2.6 Conservation and Demand Management

Conservation is important in managing demand in Ontario and plays a key role in maximizing the utilization of existing infrastructure and maintaining a reliable supply of electricity. On September 30, 2020 the IESO received a Ministerial directive to implement a new 2021-2024 CDM Framework, which follows the conclusion of the 2019-2020 Interim Framework.

The new 2012-2024 CDM Framework will focus on cost-effectively meeting the needs of Ontario's electricity system, including by focusing on the achievement of provincial peak demand reductions, as well as targeted approaches to address regional and/or local electricity system needs.

It is recommended that the Working Group monitor the progress of the 2021-2024 CDM Framework and the contribution of savings from its programs to reducing net demand in the region, and to explore the opportunity for participation in the Local Initiatives Program as an option to help address needs in the long term.

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, reliable electricity supply. A regional plan considers the existing electricity infrastructure in an area, forecast growth and customer reliability, evaluates options for addressing needs, and recommends actions.

The current regional planning process was formalized by the OEB in 2013 and is performed on a five-year planning 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 planning 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.

Further details on the regional planning process and the IESO's approach to regional planning can be found in Appendix C.

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.

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 KWCG and IRRP Development

The process to develop the KWCG IRRP was initiated in May 2019 following the release of the needs assessment report for the region by Hydro One and the subsequent scoping assessment report produced by the IESO, which recommended needs identified for the KWCG Region be further pursued through an IRRP. This was due to the potential for coordinated solutions and due to the number of end-of-life assets. Shortly after, the Working Group was formed to develop terms of reference for the IRRP, gather data, identify near- to long-term needs in the area, and recommend near- to long-term solutions.

4 Background and Study Scope

This is the second cycle of regional planning for the KWCG Region. The first cycle of regional planning was concluded in 2015 with two major recommendations which have since been completed. Those recommendations were:

- Installing a circuit switcher on each of M20D and M21D at Galt junction.
- Implementing the GATR project which included the installation of two 115 kV/230 kV auto-transformers, switching facilities, and the upgrade of an existing transmission line in Guelph.

The circuit switchers at Galt junction have substantially improved load restoration in the Cambridge and Kitchener areas following a major transmission contingency. The GATR project has addressed supply needs in South-Central Guelph and the Kitchener area and minimized the impact of potential supply interruptions to customers in Waterloo, Guelph and surrounding areas.

This cycle of regional planning identified a number of needs requiring further regional coordination and recommended an IRRP be initiated. This report presents an integrated regional electricity plan for the next 20-year period starting from 2019.

4.1 Study Scope

This IRRP develops and recommends options to meet the supply needs of the KWCG Region in the near, medium, and long term. The plan was prepared by the IESO on behalf of the Working Group. The plan includes consideration of forecast electricity demand growth, CDM, DG, transmission and distribution system capability, relevant community plans, condition of transmission assets and developments on the bulk transmission system. The needs addressed in this IRRP include adequacy, security, and relevant end-of-life asset considerations.

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

- **230 kV connected stations:** Campbell TS, Energy+ MTS #1, Fergus TS, Galt TS, Kitchener MTS #6, Kitchener MTS #8, Kitchener MTS #9, Preston TS, Scheifele MTS, Waterloo North MTS #3 and a customer owned station
- **115 kV connected stations:** Arlen MTS, Cedar TS, Elmira TS, Hanlon TS, Kitchener MTS #1, Kitchener MTS #3, Kitchener MTS #4, Kitchener MTS #5, Kitchener MTS #7, Puslinch TS, Rush MTS, Wolverton DS and a customer owned station
- **230 kV transmission lines:** B22D, B23D, D4W, D5W, D6V, D7V, M20D and M21D
- **115 kV transmission lines:** B5C, B6C, D1W, D7F, D9F, D10H, D8S, D11K, D12K, F11C, F12C
- **230/115 kV autotransformers:** Burlington T4, T6, T9, & T12, Cedar T3 & T4, Detweiler T2, T3 & T4 and Preston T2

Supply to the KWCG Region is mainly provided from Detweiler TS and Burlington TS and to a lesser extent from Middleport TS and Orangeville TS. Any needs related to the 230/115 kV autotransformers and 230 kV circuits at these stations will be assessed by the IESO through a separate bulk planning study for the broader Middleport area starting by the end of the year.

The KWCG IRRP was developed by completing the following steps:

- Preparing a 20-year electricity demand forecast and establishing needs over this timeframe;
- Examining the load meeting capability (LMC) and reliability of the existing transmission system, 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;
- Assessing system needs by applying a contingency-based assessment and reliability performance standards for transmission supply in the IESO-controlled grid as described in Section 7 of ORTAC;
- Confirming identified end-of-life asset replacement needs and timing with LDCs;
- Establishing alternatives to address system needs, including, where feasible and applicable, possible energy efficiency, generation, transmission and/or distribution, and other approaches such as non-wires alternatives;
- Engaging with the community on needs, findings, and possible alternatives;
- Evaluating alternatives to address near- and long-term needs; and
- Communicating findings, conclusions, and recommendations within a detailed plan.

5 Electricity Demand Forecast

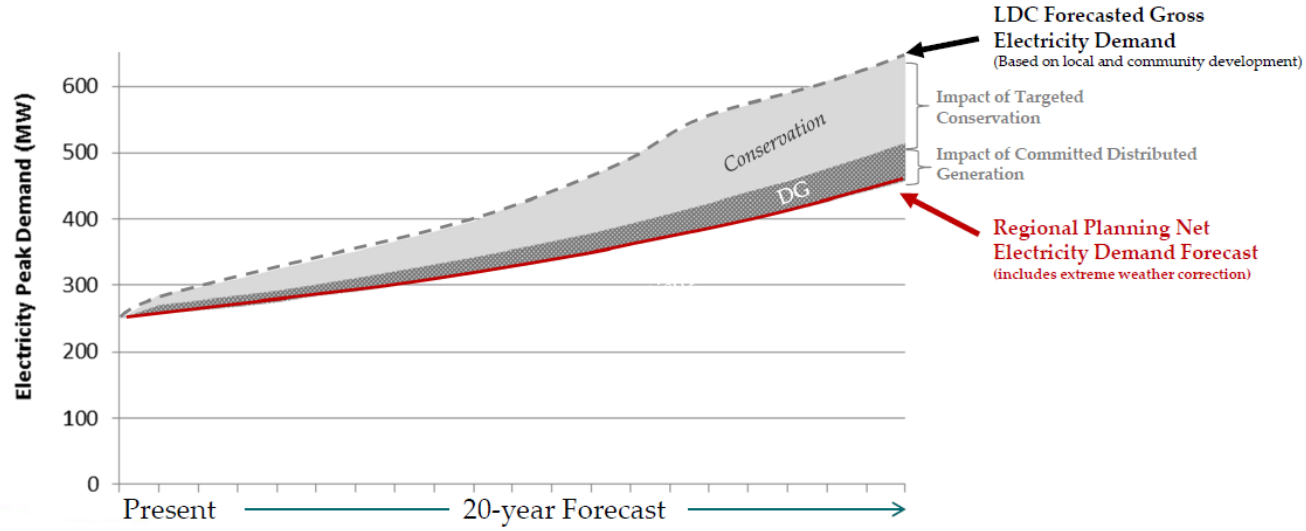
Regional planning in Ontario is driven by the need to meet peak electricity demand requirements in the region. This section describes the specific details of the development of the demand forecast for the KWCG Region. It highlights the assumptions made for peak demand forecasts, including the contribution of conservation and distributed generation (DG) to reducing peak demand. The resulting net demand forecast is used in assessing the electricity needs of the area over the planning horizon as explained in the next section.

To evaluate the adequacy of the electric system, the regional planning process involves measuring the demand observed at each station for the hour of the year when overall demand in the study area is at a maximum, also called the coincident peak demand. This differs from a non-coincident peak, which refers to each station's individual peak, regardless of whether the stations' peaks occur at different times. Within the KWCG Region, the peak loading hour for each year occurs in the summer.

5.1 Demand Forecast Methodology

For the purpose of this IRRP, a 20-year regional peak demand forecast was developed to assess supply and reliability needs for the KWCG area. The steps taken to perform this are depicted in Figure 5.1. Gross demand forecasts, which assume the weather conditions of an average year based on historical weather conditions and referred to 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 provincial programs such as FIT and microFIT, and then adjusted to reflect extreme weather conditions in order to produce a reference forecast for planning assessments. This 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 A.

Figure 5.1 | Development of Demand Forecast

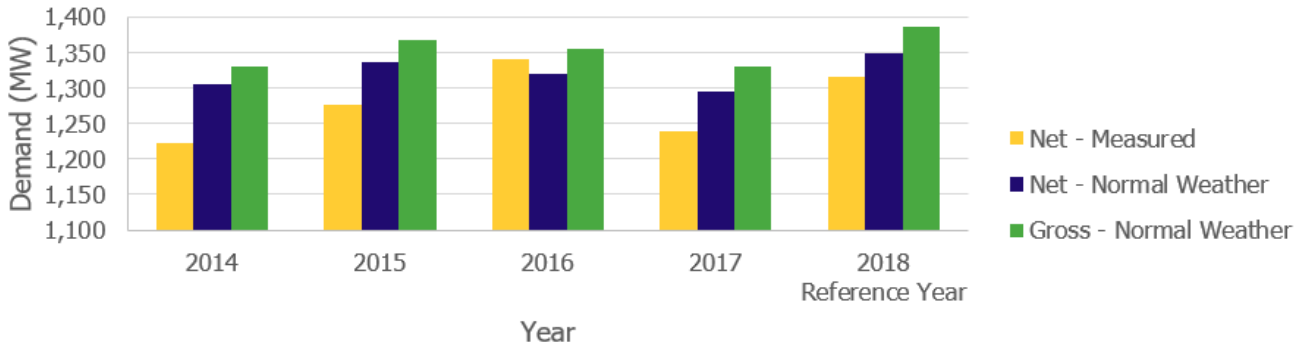


5.2 Historical Electricity Demand

The KWCG Region electricity demand is a mix of residential, commercial and industrial loads, encompassing diverse economic activities ranging from educational institutions to automobile manufacturing. While the industrial and commercial sector is the largest consumer of electricity, high-energy-consuming end uses such as air conditioning also play a significant role in contributing to peak electricity demand. During the summer months, peak demand can also be influenced by extreme weather conditions, with peaks in demand typically occurring after several days of high temperatures. In addition to temperature, factors affecting commercial and industrial energy demand, such as economy, improvements in energy efficiency, and on-site generation development have impact on the peak demand.

As shown in Figure 5.2, the historical summer peak demand has fluctuated between 1,200 MW to 1,350 MW in the recent years. This figure also shows the weather corrected net and gross coincident peak demand for normal weather. The gross demands on the station level in 2018 were the reference values for LDCs to forecast their 20-year gross demand as discussed in the next section.

Figure 5.2 | Measured & Weather Corrected Coincident Net and Gross Historical Peak Demand in the KWCG Region



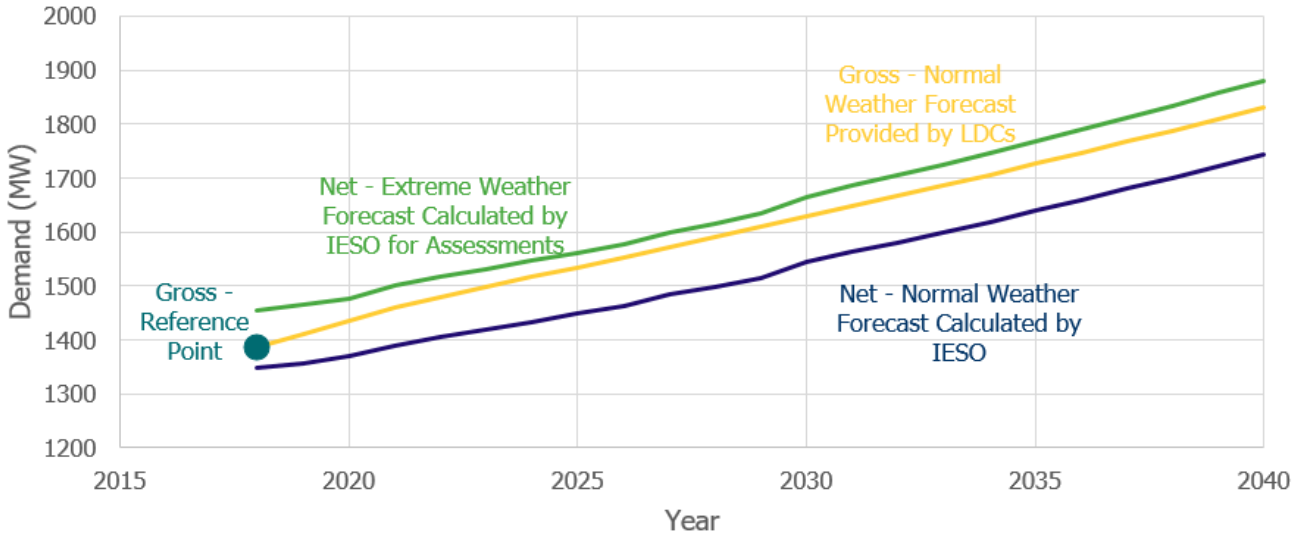
5.3 Gross and Net Demand Forecast

Each participating LDC in the KWCG Region prepared gross demand forecasts at the station level, or at the station bus level for multi-bus stations. Gross demand forecasts account for increases in demand from new or intensified development. LDCs are expected to account for changes in consumer demand resulting from typical efficiency improvements and response to increasing electricity prices, or "natural conservation", but not for the impact of future DG or new conservation measures, such as codes and standards and demand response programs, which will be accounted for by the IESO as discussed in Section 5.1.

LDCs have the best information on customer and regional growth expectations in the near and medium term, since they have the most direct involvement with their customers. Most LDCs cited alignment with municipal and regional official plans as a primary source for input data. Other common considerations included known connection applications and typical electrical demand for similar customer types. More details on the LDCs' load forecast assumptions can be found in Appendix A.

Figure 5.3 shows the total gross demand forecast in the next 20 years as provided by LDCs, based on the IESO's reference point for normal weather. Figure 5.3 also shows the net normal weather forecast compiled by the IESO, which accounts for the impacts of conservation and DG on peak demand, along with the IESO's net demand forecasts corrected to extreme weather, referred to as the planning demand forecast, used for the assessments in the IRRP. The contribution of conservation and DG to the planning demand forecast is discussed in the following sections.

Figure 5.3 | Normal/Extreme Weather Corrected Coincident Net and Gross Peak Demand in the KWCG Region



5.4 Contribution of Conservation to the Forecast

Conservation, including energy efficiency and demand management, is a clean and cost effective resource for helping to meet Ontario's electricity needs and have been an integral part of reliable and sustainable electricity system in provincial and regional planning. Conservation is achieved through a mix of program-related activities, rate structures, and mandated efficiencies from building codes and equipment standards. These approaches complement each other to maximize conservation results.

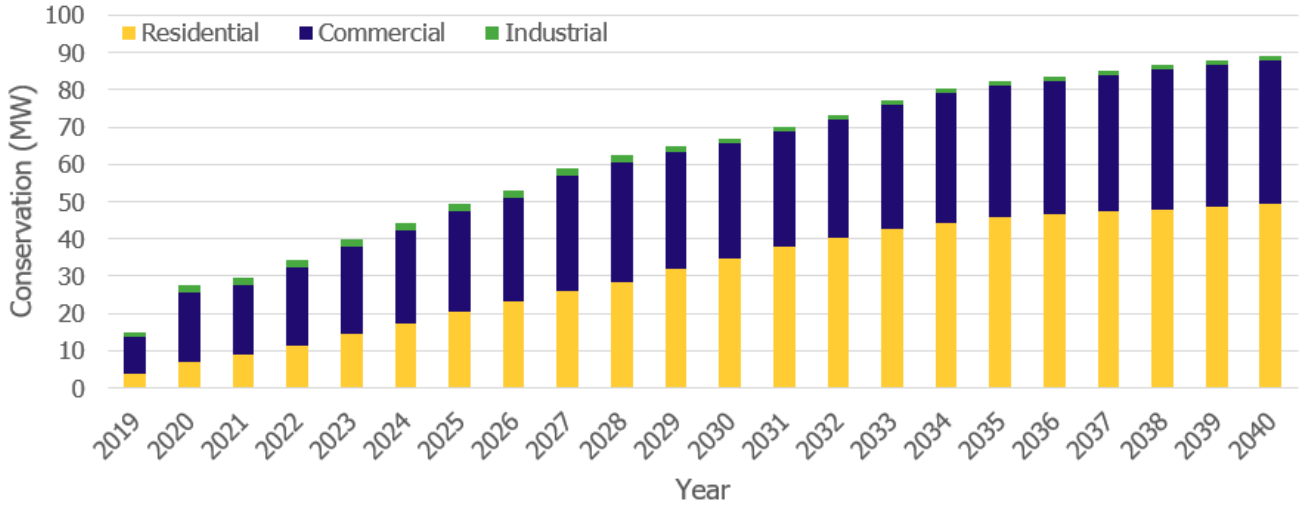
The estimates of demand reduction due to the codes and standards regulations are based on the expected improvement in the codes for new and renovated buildings and for specified categories of consumers, i.e. residential, commercial and industrial, through the regulation of minimum efficiency standards for equipment.

Save on Energy programs will result in new savings, reducing energy and peak demand in the region. The forecast included savings achieved through the wind-down of 2015-2020 Conservation First Framework and the 2019-2020 Interim Framework. The IESO centrally delivers programs on a province wide basis to serve business and low-income customers, as well as Indigenous communities.

On September 30, 2020 the IESO received a Ministerial directive to implement a new 2021-2024 CDM Framework starting in January 2021. As this directive was received after the KWCG Region's load forecast was finalized its impact is not included in the forecast.

Figure 5.4 shows the yearly estimate of the reduction to the demand forecast due to conservation for each of the residential, commercial and industrial consumers. Additional details are provided in Appendix A.

Figure 5.4 | Reduction to Demand Forecast due to Conservation

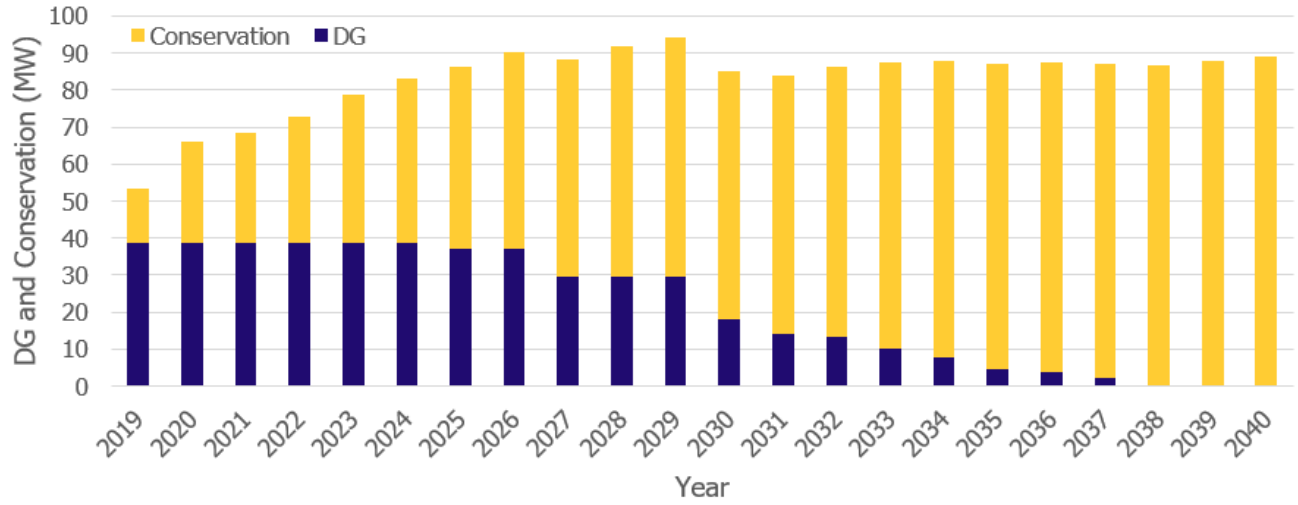


5.5 Contribution of Distributed Generation to the Forecast

In addition to conservation resources, DG in the KWCG Region is also forecast to offset peak-demand requirements. The introduction of the *Green Energy and Green Economy Act, 2009*, and the associated development of Ontario's FIT Program, has increased the significance of distributed renewable generation which, while intermittent, contributes to meeting the province's electricity demands.

After reducing the demand forecast due to conservation as described above, the forecast is further reduced by the expected contribution from contracted DG in the region. Figure 5.5 shows the combined impact of the conservation and DG on reducing the demand forecast. In the long term, as the DG contribution diminishes due to contract expiry, conservation further contributes to reducing the demand and as a result the combined impact remains relatively constant.

Figure 5.5 | Reduction to Demand Forecast due to DG and Conservation



Note that the KWCG Region also contains contracted energy storage facilities, namely 5 MW at Arlen MTS, 2 MW at Kitchener MTS #5 and 2 MW at Elmira TS. The Working Group has decided not to rely on these resources for providing any capacity relief because of uncertainties in their behavior at the time of peak demand as they provide grid services other than capacity.

Additionally, any facilities without a contract are not currently included in the DG forecast.

5.6 Projects to Consider for Next Cycle or Addendum

The following projects were not accounted for in the load forecast during this IRRP cycle because they did not have a confirmed status or connection point. The Working Group will continue to monitor the situation and if required, a new IRRP cycle or addendum will be launched.

- Metrolinx electrification project;
- East Side Lands: as discussed in Appendix E with a connection point in the Cambridge area in vicinity of Preston TS and potentially advancing the Cambridge area load restoration need;
- West Side Employment Lands; and
- Light rail transit project from Kitchener to Cambridge.

6 Needs

6.1 Needs Assessment Methodology

Based on the planning demand forecast (extreme weather, net demand), system capability, the transmitter's identified end-of-life asset replacement plans, and the application of ORTAC[1] and North American Electric Reliability Corporation (NERC) TPL 001-4 Standard[2], the Working Group identified electricity needs in the near-, medium- and long-term timeframe for the following categories:

- **Station Capacity Needs** describe the electricity system's inability to deliver power to the local distribution network through the regional step-down transformer stations at 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 LTR of a station's smallest transformer under the assumption that the largest transformer is out of service. A transformer station can also be limited when downstream or upstream equipment, e.g., breakers, disconnect switches, low-voltage bus or high voltage circuits, is undersized relative to the transformer rating.
- **Supply Capacity Needs** describe the electricity system's inability to provide continuous supply to a local area at peak demand. This is limited by the LMC of the transmission supply to an area. The LMC is determined by evaluating the maximum demand that can be supplied to an area accounting for limitations of the transmission elements, e.g., a transmission line, group of lines, or autotransformer, when subjected to contingencies and criteria prescribed by ORTAC and TPL 001-4. LMC studies are conducted using power system simulations analysis.
- **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.
- **End-of-life Asset Replacement Needs** are identified by the transmitter with consideration to a variety of factors such as asset age, the asset's expected service life, risk associated with the failure of the asset, and its condition. 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.

[1] https://www.ieso.ca/-/media/Files/IESO/Document-Library/Market-Rules-and-Manuals-Library/market-manuals/connecting/IMO-REQ-0041-TransmissionAssessmentCriteria.pdf

[2] https://www.nerc.com/files/TPL-001-4.pdf

6.2 Needs Identified

Figure 6.1 shows a summary of needs that were identified for the KWCG Region as listed below:

- Near/medium-term end-of-life replacement needs at Cedar TS, Hanlon TS, Kitchener MTS #5, Preston TS and Scheifele MTS;
- Near/medium-term station capacity needs at Campbell TS, Cedar TS, Energy+ MTS #1, Preston TS, Scheifele MTS, Kitchener MTS #5, #7 and #8;
- Medium-term marginal supply capacity need on B5C, 115 kV circuit from Burlington TS and Cedar TS following the loss of B6C with a prior outage on F12C (i.e. loss of multiple elements);
- Long-term station capacity needs at Arlen MTS, Hanlon TS, Rush MTS, Elmira TS, Kitchener MTS #1, and Waterloo North MTS #3;
- Post-contingency long-term marginal supply capacity need on D10H, 115 kV circuit from Detweiler TS towards Hanover TS following the loss of D8S; and
- Possible long-term restoration need in the Cambridge area after the addition of new but uncertain developments beyond what is included in the confirmed planning forecast. No restoration need was identified in this IRRP based on the confirmed planning forecast.

The aforementioned supply capacity needs were observed for the conditions shown in Table 6.1. The system was analyzed for both single and multiple element contingencies, according to planning standards. Only long-term supply capacity needs were identified for the loss of a single element. Figure 6.2 shows the ORTAC load restoration requirement in the Cambridge area for the extreme weather demand forecast. If new developments materialize (e.g. those in section 5.6) the load restoration requirements may be violated and solutions may be needed.

Figure 6.1 | Needs Identified for the KWCG Region

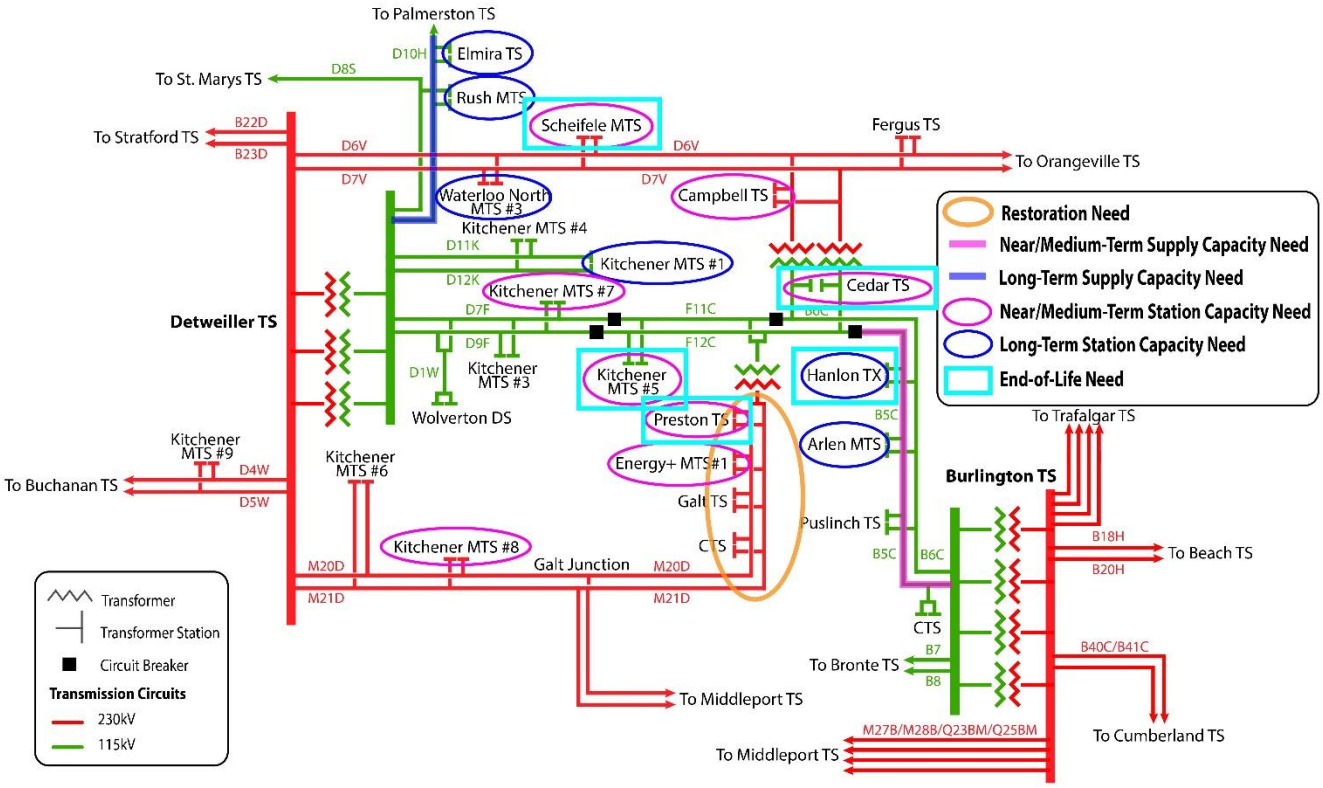


Figure 6.2 | ORTAC Load Restoration Requirement in the Cambridge Area

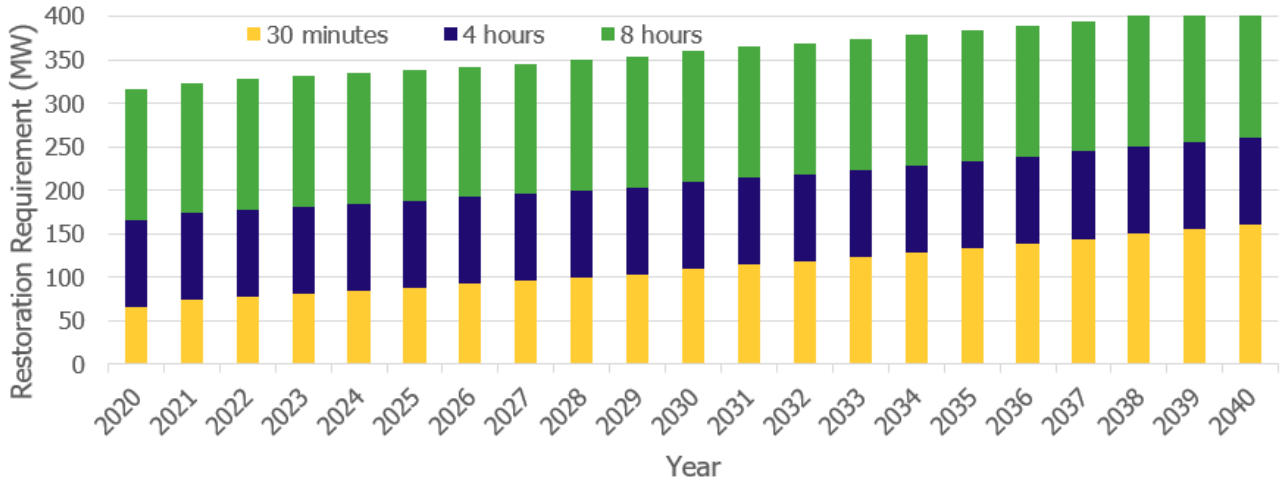


Table 6.1 | Conditions for Which Supply Capacity Needs Identified

Timeframe	Outage	Contingency	Overloaded Circuit	Cause
Medium-term	B6C	F12C	B5C	Radially serving loads at Hanlon TS, Arlen MTS, Puslinch TS, and a customer-owned station

Timeframe	Outage	Contingency	Overloaded Circuit	Cause
Long-term	-	D8S	D10H	Radially serving loads at Rush TS and Elmira TS

7 Plan Options and Recommendations

In developing the plan, the Working Group considered a range of integrated options. Considerations in assessing alternatives included maximizing use of existing infrastructure, provincial electricity policy, feasibility, cost, and consistency with longer-term needs in the area.

7.1 Conservation

Conservation is important in managing demand in Ontario and plays a key role in maximizing the useful life of existing infrastructure and maintaining reliable supply. Conservation is achieved through a mix of program-related activities including behavioural changes by customers and mandated efficiencies from building codes and equipment standards. These approaches complement each other to maximize conservation results.

Conservation expected to be achieved through codes and standards, and program delivery, has already been included in the planning forecast scenarios as described in section 5.4.

On September 30, 2020 the IESO received a Ministerial directive to implement a new 2021-2024 CDM Framework. The new CDM Framework will contribute to lowering the net demand as seen on the transmission system and ensures energy efficiency can continue to play a role in meeting the region's needs. As part of the framework, there is a Local Initiatives Program which can target CDM programs to regional and/or local areas to provide savings that are above and beyond those programs that are available provincially. These could further reduce the net demand.

The Working Group will monitor progress as the 2021-2024 CDM Framework is implemented, will assess the impact of these additional savings in further reducing the region's net demand and will explore the opportunity for participation in the Local Initiatives Program as an option to help address needs in the long term.

7.2 End-of-Life Replacement Optimization

When a piece of equipment reaches the end of its life and requires replacement, a number of alternatives often warrant consideration, for example, how the transmission and distribution system have changed, how community needs have evolved, and whether equipment standards have been updated over the decades the equipment has been in service. At the same time, opportunities for non-traditional options, such as CDM, may increasingly play a role in determining the future of a specific asset when it comes time for renewal.

Development of options considered three main alternatives:

- Replacement of the assets "like-for-like" or with the closest available standard;
- Reconfiguration of the existing assets to "right-size" the replacement option based on:
    - Demand forecast,
    - Changes to the use of the asset since it was originally installed,

    - Reliability or other system benefits that an alternate configuration may provide; and
- Retirement of a facility, considering the impact on load supply and reliability.

The asset replacement needs identified in this IRRP are all related to step-down station transformers. The Working Group considered the following opportunities of optimizations, in addition to reviewing the impact of like-for-like replacements with standard facilities:

- Upgrading transformers to address the identified near- to medium-term station capacity needs;
- Reconfiguring transformers and feeders at Hanlon TS and Arlen MTS to make more efficient use of existing facilities, as was flagged in the Scoping Assessment; and
- Permanently transferring load between nearby stations.

Working Group assessments indicated that there are no opportunities for end-of-life optimization at this time and like-for-like replacements with the closest available standard can best address the region's needs, as identified in Table 2.1.

Two possible opportunities were considered for optimization, reusing underutilized transformers and feeders at Hanlon and Arlen MTS and permanent load transfers between nearby stations. The Technical Working Group's assessments indicated that there are no opportunities for optimization at this time. Hanlon and Arlen transformers and feeders are not fully utilized because customers have purchased dedicated feeder capacity which cannot be used otherwise and LDCs cannot give up feeder positions. Permanent load transfers between stations are also restricted due to limitations at 13.8 kV distribution voltage and density of load on feeders and line sections. Distribution system challenges have been taken into consideration and is found already optimized to the local needs.

7.3 Near/Medium-Term Station Capacity Needs

The station capacity needs can be managed by transferring the load to other stations with spare capacity on a permanent or temporary basis. Transformers at four stations with capacity needs are due for end-of-life replacement. Although the end-of-life replacements are considered to be like-for-like, the current standard transformers available have higher ratings which help alleviate the station capacity needs. Table 2.2 summarizes the recommended solutions to resolve these needs.

7.4 Near/Medium-Term Supply Capacity Needs

There were no near- to medium-term supply capacity needs identified for the loss of a single element. When examining contingencies involving the loss of multiple elements, a marginal near- to medium-term supply capacity need was identified on B5C, with a contingency on B6C under an outage on F12C. Since this is a marginal need which would occur during an outage and under specific sets of system conditions, it is recommended to manage the need with operational measures in the near- to medium-term, e.g. rescheduling outages. Meanwhile, the IESO will monitor the situation and explore long-term solutions with the Working Group and communities as appropriate if the need can no longer be addressed without impacting reliability.

7.5 Long-term Needs

In addition to station capacity needs on six stations, a marginal long-term supply capacity need was identified on D10H for post-contingency condition after the loss of D8S.

None of the identified long term needs are significant and therefore early development work for major infrastructure projects in the KWCG Region is not required at this time. There may be opportunities for the Working Group to work with communities and local utilities to manage future electricity demand through the development of community-based solutions under the IESO's new CDM Framework or other mechanisms or opportunities that may evolve between planning cycles.

The IESO will re-evaluate these needs periodically and explore non-wire solutions with the Working Group and communities as appropriate.

7.6 Load Restoration Need

After the 2015 KWCG IRRP recommendation regarding the circuit switchers on M20D and M21D at Galt junction was implemented, the load restoration in the Cambridge and Kitchener areas following contingencies on these circuits has substantially been improved. The circuit switchers now allow for the quick isolation of any section with a permanent fault and the ability to place the other sections back into service for restoring load.

By 2040, faults on M20D and M21D will result in the loss of up to 400 MW of load in the Cambridge area. Up to 150 MW of this load must be restored within 30 minutes as required by ORTAC. This is within the capability of the system and, so, no load restoration concern has been identified in this cycle of the IRRP. However, developments in the area not considered in the load forecast may result in a load restoration concern before 2040 and, as such, the Working Group will continue to monitor this need.

Appendix B includes options to alleviate these future restoration needs. However, since the appropriate solution for this need is highly dependent on future electricity demand growth (potentially from future developments identified in section 5.6), it is recommended to continue monitoring the situation and devise an appropriate solution when any new demand growth and associated future developments are sufficiently certain.

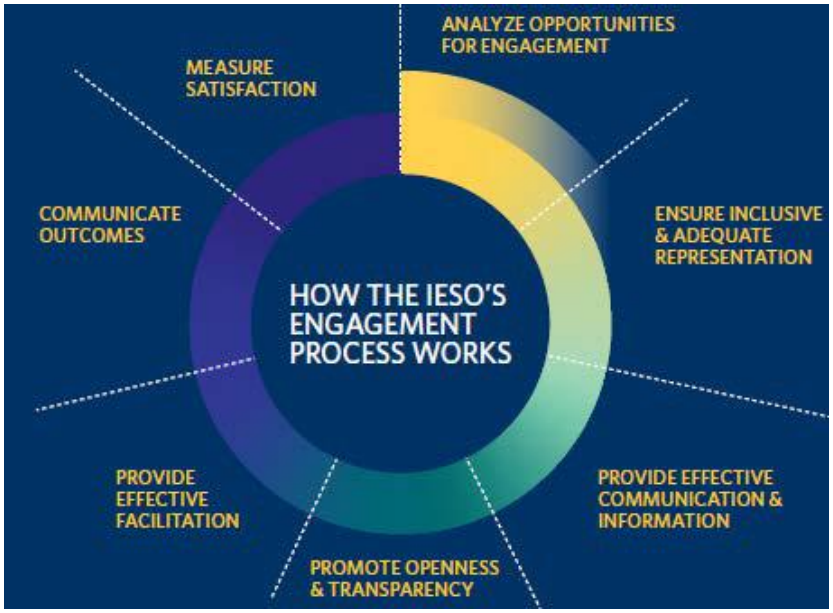
8 Engagement

Engagement is critical in the development of an IRRP. Providing opportunities for input in the regional planning process enables the views and preferences of communities to be considered in the development of the plan, and helps lay the foundation for successful implementation. This section outlines the engagement principles as well as the activities undertaken to date for the KWCG IRRP.

8.1 Engagement Principles

The IESO's engagement principles[3] help ensure that all interested parties are aware of and can contribute to the development of this IRRP. The IESO uses these principles to ensure inclusiveness, sincerity, respect and fairness in its engagements, striving to build trusting relationships as a result.

Figure 8.1 | The IESO's Engagement Principles



8.2 Creating an Engagement Approach for KWCG

The first step in ensuring that any IRRP reflects the needs of community members and interested stakeholders is to create an engagement plan to ensure that all interested parties understand the scope of the IRRP and are adequately informed about the background and issues in order to provide meaningful input on the development of the IRRP for the region.

- Creating the engagement plan for this IRRP involved:
- Discussions to help inform the engagement approach for the planning cycle;

[3] https://www.ieso.ca/en/sector-participants/engagement-initiatives/overview/engagement-principles

- Developing and implementing engagement tactics to allow for the widest communication of the IESO's planning messages, using multiple channels to reach audiences; and
- Identifying specific stakeholders and communities that should be targeted for one-on-one consultation, based on identified and specific needs.

As a result, the engagement plan[4] for this IRRP included:

- A dedicated webpage[5] 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;
- Face-to-face meetings; and
- One-on-one outreach with specific stakeholders to ensure that their identified needs are addressed (see Section 1.4 Outreach with Municipalities).

8.3 Engage Early and Often

Leveraging existing relationships built through the previous planning cycle, the IESO held preliminary discussions to help inform the engagement approach for this new round of planning. This started with an invitation to targeted communities and those with an identified interest in regional issues to learn more about how to provide comments on the KWCG Scoping Assessment Report before it was finalized.

Early communication and engagement activities began with invitations to all subscribers and communities in the KWCG Region to learn about and provide comments on the draft Scoping Assessment Outcome Report. The final Scoping Assessment, identified the need for an IRRP for the KWCG Region. Following a written comment window, the final Scoping Assessment Outcome Report was published in May 2019. Community feedback was received on the importance of considering community energy plans and other planning initiatives in IRRP development, and strong local preference for local sustainable energy resources to defer any future electricity infrastructure.

Outreach then began with targeted communities to inform early discussions for the development of the IRRP including the IESO's approach to engagement. The launch of a broader engagement initiative followed with an invitation to subscribers of the KWCG Region to ensure that all interested parties were made aware of this opportunity for input. Two public webinars were held at major junctures during IRRP development to give interested parties an opportunity to hear about its progress and provide comments on key components. Both webinars received strong participation with cross-representation of stakeholders and community representatives attending the webinar, and submitting written feedback during a 14-day comment period.

[4] https://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/KWCG-Region/KWCG-Engagement-Plan.ashx

[5] https://www.ieso.ca/en/Sector-Participants/Engagement-Initiatives/Engagements/Integrated-Regional-Resource-Plan-Kitchener-Waterloo-Cambridge-Guelph

The first webinar sought input on the draft engagement plan, the electricity demand forecast and needs. Comments received during the written feedback window touched on the following major themes:

- Impacts of climate change, energy conservation and associated initiatives
- Consideration of local developments
- Impact of Distributed Energy Resources

As a final step in the engagement initiative, a second public webinar was held to seek input on the analysis of options and draft IRRP recommendations. Feedback received during the written comment period was related to the importance of ongoing dialogue with a focus on local planning initiatives around climate change in preparation for the next electricity planning cycle for the KWCG Region.

Email updates were also sent to KWCG Region subscribers and municipalities as well as the members of the Southwest Regional Electricity Network[6] to advise on the status of the IRRP development and upcoming engagement opportunities.

Based on the discussions both through the KWCG IRRP engagement initiative and broader network dialogue, it is clear that there is broad interest in several Southwestern Ontario communities to further discuss the potential for alternative energy solutions. The medium- to long-term nature of the KWCG Region's future electricity needs presents a valuable opportunity for communities to mobilize projects and initiatives to meet local growth targets and energy priorities. To that end, ongoing discussions will continue through the IESO's Southwest Regional Electricity Network to keep interested parties engaged on local developments, priorities and planning initiatives.

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

8.4 Bringing Communities to the Table

The IESO held meetings with communities to seek input on their planning and to ensure that these plans were taken into consideration in the development of this IRRP. At major milestones in the IRRP process, meetings with the upper- and lower-tier municipalities in the region were held 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 provided opportunities to strengthen this relationship for ongoing dialogue beyond this IRRP process.

[6] https://iesoconnects.ca/collections/southwest-regional-electricity-network

9 Conclusion

This report documents an IRRP that has been developed for the KWCG Region, and identifies regional electricity needs and opportunities to preserve or enhance electricity system reliability for the next 20 years. The IRRP makes recommendations to address near- to medium-term issues, and lays out actions to monitor, defer, and address long-term needs.

To support the development of the plan, this IRRP includes recommendations with respect to developing alternatives, and monitoring load growth and efficiency achievements. Responsibility for these actions has been assigned to the appropriate members of the Working Group.

The Working Group will continue to meet at regular intervals to 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 OEB.

Independent Electricity System Operator
1600-120 Adelaide Street West
Toronto, Ontario M5H 1T1

Phone: 905.403.6900
Toll-free: 1.888.448.7777
E-mail: customer.relations@ieso.ca

ieso.ca

@IESO_Tweets
facebook.com/OntarioIESO
linkedin.com/company/IESO

ieso
Connecting Today.
Powering Tomorrow.



Kitchener-Waterloo-Cambridge-Guelph Region

Integrated Regional Resource Plan Appendicies

May 2021

ieso
Connecting Today.
Powering Tomorrow.

Table of Contents

Appendix A - Methodology and Assumptions for Demand Forecast **3**

A.1 Method for Accounting for Weather Impact on Demand 3

A.2 Hydro One Forecast Methodology 4

A.3 Waterloo North Hydro Forecast Methodology 5

A.4 Kitchener-Wilmot Hydro Forecast Methodology 7

A.5 Energy+ Forecast Methodology 8

A.6 Alectra Forecast Methodology 10

A.7 Energy Efficiency Assumptions in Demand Forecast 11

Appendix B - Solution Options to Load Restoration Need in the Cambridge Area **21**

Appendix C - Development of the Plan **22**

C.1 The Regional Planning Process 22

C.2 IESO's Approach to Regional Planning 24

Appendix D – Short Circuit Assessment **26**

Appendix E – East Side Lands **28**

E.1 Background 28

E.2 Executive Summary 28

E.3 Discussion 29

List of Abbreviations

Alectra	Alectra Utilities Corp.
CDM	Conservation Demand Management
Centre Wellington Hydro	Centre Wellington Hydro Ltd.
DER	Distributed Energy Resources
DG	Distributed Generation
DSC	Distribution System Code
Energy+	Energy+ Inc.
FIT	Feed-in Tariff
GATR	Guelph Area Transmission Refurbishment
Halton Hills Hydro	Halton Hills Hydro Inc.
Hydro One	Hydro One Networks Inc.
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
KWCG Region	Kitchener, Waterloo, Cambridge and Guelph
LAC	Local Advisory Committee
LDC	Local Distribution Company
LMC	Load Meeting Capability
LRT	Light Rail Transit
LTR	Limited Time Rating
LV	Low-voltage
Milton Hydro	Milton Hydro Distribution Inc.
MTS	Municipal Transformer Station
MW	Megawatt
NERC	North American Electric Reliability Corporation
OEB	Ontario Energy Board
OPA	Ontario Power Authority
ORTAC	Ontario Resource and Transmission Assessment Criteria
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Plan
TOU	Time-of-Use
TS	Transformer Station
TSC	Transmission System Code
Wellington North Power	Wellington North Power Inc.
WNH	Waterloo North Hydro Inc.
Working Group	Technical Working Group of the KWCG Region

Appendix A - Methodology and Assumptions for Demand Forecast

The sections that follow describe the IESO's methodology to adjust the forecast for extreme weather, LDC methodologies to forecast demand in their respective service area, and the energy efficiency assumptions used to modify the demand based on expected energy efficiency savings. Table A.1 on page 13, to Table A.2 on page 15 show the final non-coincident and coincident extreme demand forecast, respectively, per station used for the KWCG IRRP assessments. The coincident load forecast includes the estimated reduction due to CDM plus DG with the values shown in Table A.3 on page 17. Table A.4 on page 19 also shows the gross demand forecast per station as provided by LDCs.

A.1 Method for Accounting for Weather Impact on Demand

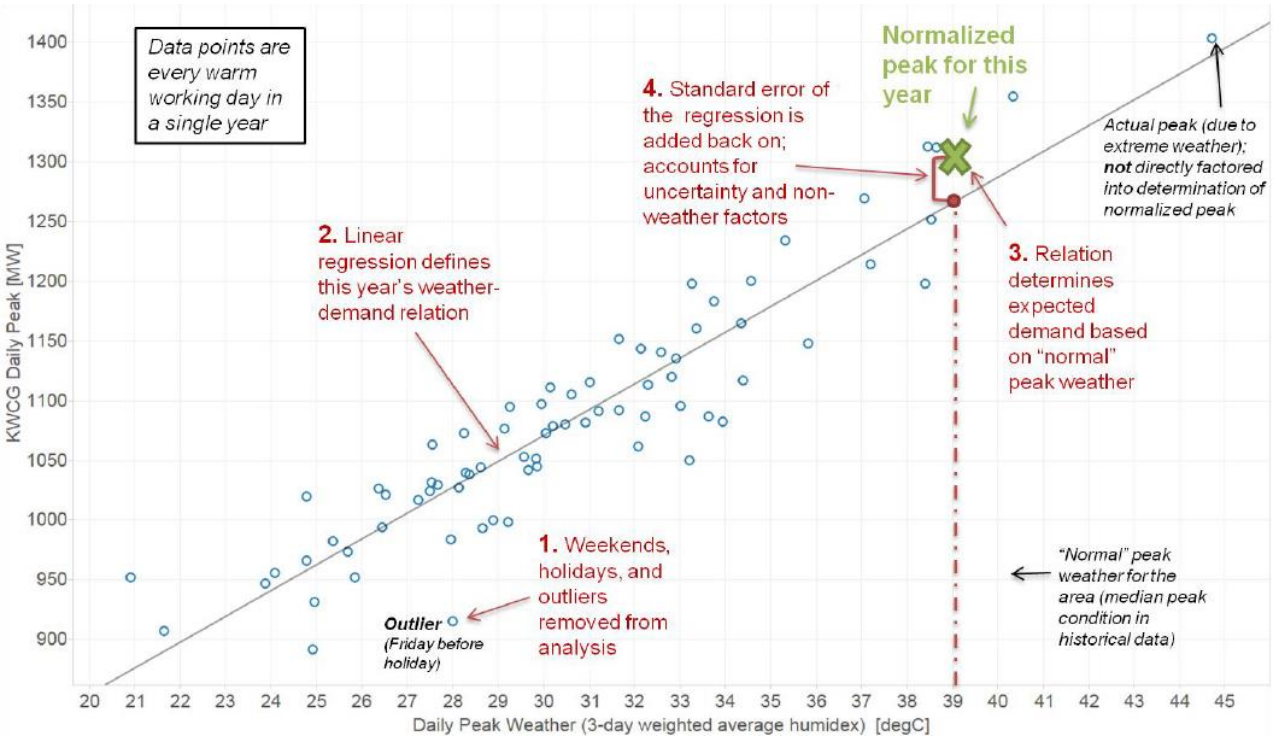
Weather has a large influence on the demand for electricity, so to develop a standardized starting point for the forecast, the historic electricity demand information is weather-normalized. This section details the weather-normalization process used to establish the starting point for regional demand forecasts.

First, the historical loads were adjusted to reflect the median peak weather conditions for each transformer station in the area for the forecast base year (in this case 2018). Median peak refers to what peak demand would be expected if the most likely, or 50th percentile, weather conditions were observed. This means that in any given year there is an estimated 50% chance of exceeding this peak, and a 50% chance of not meeting this peak. The methodological steps are described in Figure A.1.

The 2018 median weather peak on a station and LDC load basis was provided to each LDC. This data was used as a start point from which to develop 20-year demand forecasts, using the LDCs preferred methodology (described in the next sections).

Once the 20-year horizon, median peak demand forecasts were returned to the IESO, the normal weather forecast was adjusted to reflect the impact of extreme weather conditions on electricity demand. The studies used to assess the adequacy and reliability of the electric power system generally require studies to be based on extreme weather demand, or, expected demand under the hottest weather conditions that can be reasonably expected to occur. Peaks that occur during extreme weather (e.g. summer heat waves) are generally when the electricity system infrastructure is most stressed.

Figure A.1 | Method for Determining the Weather-Normalized Peak



A.2 Hydro One Forecast Methodology

Hydro One Distribution provides service to counties and townships surrounding the Region of Waterloo and Guelph area (Wellington County, and Oxford County - Blandford-Blenheim Township). Three step-down stations supply the area from the transmission system as follows:

- 230/44 kV Fergus TS supplied by 230 kV circuits D6V and D7V
- 115/27.6 kV Puslinch DS supplied by 115 kV circuits B5G and B6G
- 115/27.6 kV Wolverton DS supplied by 115 kV circuit D7F

There are about 14,000 Hydro One Distribution retail customers directly connected to Hydro One's distribution system. There are embedded LDCs connected to Hydro One's distribution system.

A.2.1. Factors that Affect Electricity Demand

Hydro One Distribution serves mostly the rural areas outside the major cities such as Kitchener, Waterloo, Guelph and Cambridge. The demand growth in the Hydro One Distribution service area is largely driven by the economic activities in these large communities and is expected to be modest as the population moves from the urban centers to the rural areas.

Some of the smaller communities such as Elora, Fergus and Rockwood are in the embedded LDCs to Hydro One Distribution. The load growth in these communities is therefore factored in the Hydro One Distribution load forecast.

A.2.2. Forecast Methodology and Assumptions

The reference level forecast is developed using macro-economic analysis, which takes into account the growth of demographic and economic factors. The forecast corresponds to the expected weather impact on peak load under average weather conditions, known as weather normality. Furthermore, the forecast is unbiased such that there is an equal chance of the actual peak load being above or below the forecast. In addition, local knowledge, information regarding the loading in the area within the next two to three years, is utilized to make minor adjustments to the forecast.

Hydro One Distribution conducts distribution area studies to examine the adequacy of the existing local supply network in the next 10 to 15 years and determine when new stations need to be built. These studies are performed on a needs basis, such as:

- Load approaching the planned capacity
- Issues identified by the field and customer
- Issues discovered during our 6-year cycle studies
- Additional supply required for large-step load connections
- Poor asset condition

A.3 Waterloo North Hydro Forecast Methodology

Waterloo North Hydro (WNH) owns and operates the electricity distribution system in its licensed service area in the City of Waterloo and the Townships of Woolwich and Wellesley, serving approximately 58,000 customers. WNH's customer base is comprised of primarily residential (89% by customer count) and commercial/institutional loads (10% by customer count). WNH's largest loads include universities, high-tech companies and financial institutions. A small component of the WNH load base comes from the industrial/manufacturing sector (1% by customer count).

WNH is supplied through the Hydro One transmission system at primary voltages of 115 kV and 230 kV. Electricity is then distributed through WNH's service area by three MTSs and 6 municipal distribution stations. WNH's distribution system is divided into the 13.8 kV system servicing the core of the City of Waterloo, and the 27.6 kV system servicing the outskirts of the City of Waterloo as well as the township areas. WNH also has some 8.32 kV distribution throughout its rural service territory.

A.3.1. Factors that Affect Electricity Demand

There are two major factors affecting electricity demand within WNH's service territory and both are municipally driven; one by the City of Waterloo, and one by the Region of Waterloo.

As a result of recessions in the late 1980's and early 1990's, the City of Waterloo formulated a strategic plan to capitalize on the two very reputable local universities (University of Waterloo and Wilfrid Laurier University) and create conditions for students who attend the local universities to start new business and remain in this area. The City of Waterloo became a leader in fostering high-tech industry start-ups and full businesses, with Blackberry being an example of its global business successes as a direct result. Demand in the housing market was very strong resulting in the City of Waterloo developing to the limits of its boundaries and running out of greenfield developable land. This resulted in the city setting a new strategy of brownfield re-development, which continues to grow. Most of the brownfield re-development is in the area abutting the two local universities as well as the uptown core of the City of Waterloo. In most cases, the re-development consists of the demolition of a few single dwelling residential units being replaced with multi-unit residential complexes. It is very common to see the footprint of four houses being developed into high rise apartments with 100 dwelling units. This plan has also lead to the development of the West-side employment lands, which is a 45.2-hectare employment business park, meant to create up to 8,000 new jobs in the area and further foster innovation and high-tech industry growth in the City of Waterloo.

The second driving factor for electricity demand growth in WNH's service territory is the Region of Waterloo's strategy in supporting the provincial Places to Grow policy. The Region of Waterloo has limited urban sprawl by setting hard boundaries for greenfield development to coincide with existing city limits. To support the provincial policy as well as the city's efforts to intensify the uptown and university neighbourhoods, the Region of Waterloo has installed the first phase of its light rail transit (LRT) system, connecting Waterloo and Kitchener, while planning a second phase that will ultimately connect the three local cities: Waterloo, Kitchener, and Cambridge. This initiative is meant to drive commercial and residential development along the new line, increasing electricity demand.

The regional plan also sets new areas of greenfield development, labeled as East Side Lands, to be just outside of Kitchener along Highway 7 leading toward Guelph, and extending south into Energy+ service territory all the way to Highway 401. The planned land uses involve residential, commercial, and industrial sectors and is located along the proposed new Highway 7 route, as well as a railway route identified by MetroLinx as their next major growth potential location. Electrical demand in this area is expected to be at higher densities due to the industrial component of land use as well as high-tech data centre applications of the commercial space. While residential development in this area has already begun, the timing of the railway route and new Highway 7 are expected to directly impact when the commercial and industrial development happens.

Over the last couple of years, WNH has also observed a peak demand impact as a result of further deployment of distributed energy resources, including behind-the-meter generation, and conservation efforts.

A.3.2. Forecast Methodology and Assumptions

In developing the load forecasts, WNH gathers development projection data from the local municipalities and developers to determine areas and timing of planned development as well as land uses. This information is then converted to electrical demand quantities and analyzed against past trends. A forecast is developed for each TS that is consistent with load growth potential within the service area of that station and overall system growth. WNH uses geometric growth trend methodology (trending) to extend past growth rates of electricity demand into the future.

WNH has been trending the system peak data for the past 26 years and has analyzed this data with respect to typical rolling 3-year, 5-year, and 10-year growth rates. WNH service territory has lately experienced rolling 10-year gross load growth rates between 1-2%, sometimes reaching almost 3% (this growth excludes effects of known CDM as well as generation). The coincident peak data (September 5th, 2018 at hour 17) has been used as the base for the load forecast. Due to the fabric of the WNH customer base, the system peak for WNH is affected to a higher degree by weather and local development conditions and to a lesser degree by provincial or global factors. WNH's system peak has a tendency to rebound from recessions faster than in other Ontario jurisdictions. The historical load data from 1992 to 2018 includes a mixture of hot and cool summers, and was therefore considered an appropriate blend to be used as a basis for future trending. The rolling gross geometric growth rate since 1992 is 2.37%. The latest 10-year gross geometric growth rate is 1.91%. The gross load forecast has been prepared such that by the end of the study period in 2038, the geometric growth rate is consistent with past trends, while taking into account short and long-term development potential.

A.4 Kitchener-Wilmot Hydro Forecast Methodology

Kitchener-Wilmot Hydro owns and operates the electricity distribution system in its licensed service area in the City of Kitchener and the Township of Wilmot, serving approximately 100,000 Residential, General Service, Large Use, Street Light, Unmetered Scattered Load and Embedded Distributor rate customers.

Kitchener-Wilmot Hydro is supplied through the Hydro One transmission system at primary voltages of 115 kV and 230 kV. Electricity is then distributed through Kitchener-Wilmot Hydro's service area (411 square kilometers) by eight MTSs (27.6 kV and 13.8 kV) and seven municipal distribution stations (8.32 kV).

A.4.1. Factors that Affect Electricity Demand

There are multiple factors affecting electricity demand within the Kitchener-Wilmot Hydro service area.

The first factor driving electricity demand is population growth. In response to the Ontario's Place to Grow plan, the Region of Waterloo has published its Official Plan with forecast population growth. In Kitchener-Wilmot Hydro's service area, it is estimated that the population will increase from 232,200 in 2006 to 341,500 in 2029, and the employment will increase from 106,100 in 2006 to 139,700 in 2029. The growth in population and employment will drive the electricity demand for the next 20 years.

The second factor impacting the electricity demand is the change in the industrial sector. The City of Kitchener is experiencing a conversion from being a manufacturing-oriented economy to a more diversified and balanced economy. Kitchener-Wilmot Hydro has lost its top three load customers in the past 10 years. In the meantime, more customers with smaller demand emerge in the industrial and commercial sectors.

The third factor impacting electricity demand growth is the Region of Waterloo's Regional Official Plan. To support the provincial policy in the Places to Grow Act, as well as the city's efforts to intensify the Kitchener downtown area, the Region of Waterloo installed a LRT system between Waterloo and Kitchener, with a plan to extend the rail system to Cambridge.

The installation of the LRT is spurring development along the train route in both the residential and commercial sectors.

The fourth factor impacting the electricity demand is the rising awareness of renewable energy generation development and CDM. As directed by the OEB, Kitchener-Wilmot Hydro is currently participating in multiple provincial renewable energy programs and CDM programs, which help control and reduce the electricity demand. Time-of-Use (TOU) is also shifting demand and conserving energy as the customers manage their electricity use and control their hydro costs.

A.4.2. Forecast Methodology and Assumptions

In developing the reference forecast, Kitchener-Wilmot Hydro uses trend analysis (trending) to extend past growth rates of electricity demand into the future. A linear-trend method that uses the historical data of demand growth to forecast future growth has been applied. The coincident peak data (September 5th, 2018 at hour 17) has been used as the base for load forecast. A long-term 6.22 MW annual gross demand growth from 2011 to 2030 has been projected, with 60% of the annual load growth (3.73 MW) attributable to residential customers, and 40% (2.49 MW) attributable to commercial and industrial customers. The annual demand growth has been allocated to each transformer station based on the municipal development plan, available vacant lands and other local knowledge.

This annual demand growth rate covers both load additions of new customers and load maturation of the existing customers. The projected long-term annual demand growth is derived from the average load growth for the observed summer peaks from 1993 to 2006. The more recent data of 2007-2020 were biased and ignored due to multiple factors, like conservation and distributed generation, TOU pricing, and the economic downturn of the credit crisis and the pandemic.

A.5 Energy+ Forecast Methodology

Energy+ Inc. ("Energy+") provides electricity distribution service to the City of Cambridge, the Township of North Dumfries, part of the County of Brant, part of the City of Brantford and a number of customers along its boundary in the Township of Blanford-Blenheim and the City of Hamilton. The Energy+ Brant/Brantford distribution system is electrically separate from the Cambridge/North Dumfries distribution system so Brant/Brantford information is not included as part of this study area.

Energy+ distributes electricity to approximately 67,000 customers, of which 88% are residential, 10.7% are commercial, 0.9% are generators and 0.4% are industrial. There are also some other customers who are embedded Local Distribution Companies, street lighting and unmetered scattered load.

Energy+'s service area covers 562 square kilometres. Energy+ receives power from Hydro One Networks and delivers power to its customers in Cambridge/North Dumfries via four high voltage transformer stations. One of those stations is owned by Energy+ and the others are owned by Hydro One. Energy+'s principal primary distribution voltage is 27.6 kV.

A.5.1. Factors that Affect Electricity Demand

The City of Cambridge and the Township of North Dumfries are located in the Region of Waterloo. The Region of Waterloo is included in the Province of Ontario's "A Place to Grow" Plan. This Plan shows a forecasted Region of Waterloo 2051 population of 923,000. The year-end 2019 Region of Waterloo population was 612,870.

The Cambridge area continues to see increased density in the form of high rise apartment/condominium residential buildings, re-use of decommissioned industrial land for new residential development in built-up areas and residential growth in new areas.

Significant future residential growth is expected to come from planned subdivisions located in the South-East Galt area bounded by Franklin Boulevard, Main Street, Dundas Street and the East limit of the city boundary, the Cambridge West community and new residential subdivisions North of Highway 401 and East of Speedsville Road. The total number of new residential units in the City of Cambridge increased from 566 units in 2018 to 942 units in 2019 for a 66% increase.

Servicing of the first areas of the "East Side Lands" is underway. The "East Side Lands" located in the North-West part of the City of Cambridge and the adjacent municipality of the Township of Woolwich will provide significant non-residential growth over the coming years.

The connection of Distributed Energy Resources (DERs) to the Energy+ distribution system will continue to impact the level of demand/energy obtained from the transmission grid.

The level of overall economic growth always has an impact on electricity demand especially for industry.

Weather extremes continue to have a large impact of peak demand because of air conditioning load on hot summer days.

The expected larger market share for electric vehicles may have a substantial impact on local electricity demand.

A.5.2. Forecast Methodology and Assumptions

The load forecast methodology looks at the historical load patterns as well as local development and growth projections for the distribution system. The projected load growth and timing of development required consultation and some assumptions are made with respect to the timing of when load will materialize. For the 2019/2020 forecast, Energy+ assessed its growth projections by each transformer station to make an informed assessment on the projected growth.

On average, Energy+ is expecting to see a 1% growth for most parts of its distribution system with the exception of loads that are in the North West part of Cambridge which are expected to be closer to 3% up until at least 2024. The outlook beyond 2024 is less certain and therefore Energy+ reduced the growth projection to 1.5% for the forecasted period for specifically the North West part of Cambridge.

A.6 Alectra Forecast Methodology

Alectra Utilities Corp. (Alectra) owns and operates the electricity distribution system in its licensed service area in the City of Guelph and the Village of Rockwood serving approximately 52,000 customers. Alectra's customer base is represented by a mixture of residential customers (91% by customer count, 22% by load) and Commercial/Industrial /Institutional customers (9% by customer count and 78% by load). Alectra services five Large Use rate customers represented by a university and industrial/manufacturing facilities.

Alectra is supplied through the Hydro One transmission system at primary voltages of 115 kV and 230 kV within the City of Guelph. Electricity is then distributed through Alectra's service territory by three Hydro One owned transformer stations, Campbell TS, Cedar TS and Hanlon TS and the Alectra owned Arlen MTS. The Alectra distribution system in the City of Guelph is serviced at 13.8 kV. The Village of Rockwood is supplied through the Hydro One distribution system at a primary voltage of 44 kV. Electricity is then distributed through the Village of Rockwood by two Alectra owned MTSs, and one Hydro One distribution station. Alectra's distribution system in the Village of Rockwood is serviced at 8.32 kV.

A.6.1. Factors that Affect Electricity Demand

The major variables affecting electricity demand within Alectra's service territory in the City of Guelph are related to population growth rate associated with the provincial places to grow targets as well as economic development within both the current industrial/manufacturing rate class sector and future development and use of industrial parks. The rate and level of future demand increases are highly dependent on each one of these factors.

The City of Guelph has been designated as one of 25 municipalities listed in the Growth Plan as an Urban Growth Centre. The city is directed to increase its population to 175,000, which is an increase of over 50,000 people.

Another significant factor in the demand of electricity is linked to economic development within both our current and future customer base. A significant portion of the electricity demand within Alectra's service territory is associated with the manufacturing sector.

Economic development as it relates to future utilization of industrial park land represents a large portion of future increase to electricity demand within the city. The most significant development is the Hanlon Creek Business Park located in the south end of Alectra's service territory and represents a total land mass of over 370 acres. Approximately 8% of the land within the business park has been consumed to date and reflective in the current electricity demand with the remaining accounted for in the forecast.

A.6.2. Forecast Methodology and Assumptions

Alectra's methodology for developing the base load forecast consisted of a number of elements including historical loading trends, local knowledge of planned development and City of Guelph development planning information. Planning information from the City of Guelph was the starting point to formulate a maximum development forecast in order to set the parameters of the long-range load forecast for its service territory given the study period. Using this information along with 30+years of historic peak loading information, local knowledge and information regarding transformer stations service areas within Alectra's service territory, the load forecast was created for each delivery point location.

A.7 Energy Efficiency Assumptions in Demand Forecast

Energy efficiency measures can reduce the electricity demand and their impact can be separated into the two main categories: Building Codes & Equipment Standards, and Energy Efficiency Programs. The assumptions used for the KWCG IRRP forecast are consistent with the energy efficiency assumptions in the IESO's 2019 Annual Planning Outlook, which was the latest provincial planning product when this IRRP was developed, the savings for each category were estimated according to the forecast residential, commercial, and industrial gross demand. A top down approach was used to estimate peak demand savings from provincial level to the Southwest transmission zone and then allocated to KWCG Region. This appendix describes the process and methodology used to estimate energy efficiency savings for the KWCG Region and provides more detail on how the savings for the two categories were developed.

A.7.1. Estimate Savings from Building Codes and Equipment Standards

Ontario building codes and equipment standards set minimum efficiency levels through regulations and are projected to improve and further contribute to demand reduction in the future. To estimate the impact on the region, the associated peak demand savings for codes and standards by sector were estimated for the Southwest zone and compared with the gross peak demand forecast for the zone. From this comparison, annual peak reduction percentages were developed for the purpose of allocating the associated savings to each station in the region.

Consistent with the gross demand forecast, 2018 was used as the base year. New peak demand savings from codes and standards were estimated from 2019 to 2038. The residential annual peak reduction percentages of each year were applied to the forecast residential demand at each station to develop an estimate of peak demand impacts from codes and standards. By 2038, the residential sector in the region is expected to see about 7.1% peak demand savings through standards. The same is done for the commercial sector, which will see about 4.9% peak-demand savings through codes and standards by 2038. The sum of the savings associated with the two sectors are the total peak demand impact from codes and standards. There are no savings from codes and standards considered to be associated with the industrial sector.

A.7.2. Estimate Savings from Energy Efficiency Programs

In addition to codes and standards, the delivery of energy efficiency programs reduces electricity demand. The impact of existing and committed energy efficiency programs were analyzed, which include the Conservation First Framework wind-down and the Interim Framework. A top down approach was used to estimate the peak demand reduction due to the delivery of 2019 and 2020 programs, from provincial to Southwest zone to the stations in the region. Persistence of the peak demand savings from energy efficiency programs were considered over the forecast period.

Similar to the estimation of peak demand savings from codes and standards, annual peak demand reduction percentages of program savings were developed by sector. The sectoral percentages were derived by comparing the forecasted peak demand savings with the corresponding gross forecasts in Southwest transmission zone. They were then applied to sectoral gross peak forecast of each station in the region. By 2020, the residential sector in the region is expected to see about 0.6% peak demand savings through programs, while commercial sector and industrial sector will see about 2.3% and 0.7% peak reduction respectively. Those savings will decay over time as the energy efficiency measures come to the end of their effective useful lives.

A.7.3. Total Energy Efficiency Savings and Impact on the Planning Forecast

As described in the above sections, peak demand savings were estimated by sector for each forecast category, and totalled for each station in the region. The analyses were conducted under normal weather conditions and can be adjusted to reflect extreme weather conditions. The resulting forecast savings were applied to gross demand to determine net peak demand for further planning analyses.

Table A.1 | Final Non-Coincident Extreme Peak Demand Forecast (MW) per Station in KWCG Region

Station	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Arlen MTS	30	31	32	32	33	34	35	36	37	38	40	41	42	43	45	46	47	49	50
Campbell TS (T1/T2)	91	91	92	92	92	92	93	93	93	94	95	97	97	98	98	99	99	100	100
Campbell TS (T3/T4)	53	53	53	53	53	55	56	56	56	56	57	57	57	58	58	58	59	59	59
Cedar TS (T1/T2)	78	79	79	80	81	81	82	82	83	84	85	85	86	87	88	89	90	91	92
Cedar TS (T7/T8)	39	40	40	40	40	40	40	40	40	41	41	41	41	41	41	42	42	42	42
CTS	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Elmira TS	39	39	40	41	41	42	43	43	44	45	49	50	51	52	57	58	59	60	61
Energy+ MTS #1	94	95	95	96	97	98	99	100	101	103	105	106	107	109	110	112	113	115	117
Fergus TS	106	108	110	112	112	112	113	115	115	116	122	123	124	125	121	122	122	123	124
Galt TS	126	127	128	129	130	131	132	134	135	136	138	140	142	144	146	147	149	151	153
Hanlon TS	31	31	32	32	33	33	33	34	34	35	35	36	36	37	37	38	39	39	40
Kitchener MTS #1	39	40	41	42	42	43	43	44	45	46	46	47	48	48	49	50	51	51	52
Kitchener MTS #3	57	57	58	59	59	60	60	61	62	62	63	64	65	66	67	67	68	69	70
Kitchener MTS #4	66	66	67	68	68	69	69	70	70	71	72	72	73	74	74	75	76	77	77

Station	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Kitchener MTS #5	74	75	76	76	77	77	78	78	79	80	80	81	82	82	83	84	85	86	86
Kitchener MTS #6	71	71	72	72	73	73	74	74	75	76	77	77	78	79	79	80	81	82	83
Kitchener MTS #7	48	49	49	50	50	51	52	52	53	53	55	55	56	56	57	58	59	59	60
Kitchener MTS #8	44	46	47	48	50	51	53	55	57	59	61	63	65	67	68	70	72	74	76
Kitchener MTS #9	39	40	40	41	41	41	42	49	50	51	51	52	52	53	54	55	55	57	57
Preston TS	108	114	117	119	120	122	123	125	126	128	130	132	134	136	137	139	141	143	145
Puslinch DS	33	33	34	34	34	35	35	36	36	36	37	37	38	38	39	39	40	40	41
Rush MTS	51	55	55	55	56	56	56	57	57	57	58	62	62	62	63	63	64	65	65
Scheifele MTS	153	154	155	156	157	158	159	160	161	163	165	163	164	166	167	169	171	172	174
WNH MTS #3	63	61	62	63	64	65	67	68	69	70	72	73	74	76	77	79	81	82	84
Wolverton DS	21	20	21	21	21	21	21	21	21	21	21	21	21	22	22	22	22	22	23
Total	1558	1581	1600	1615	1631	1648	1665	1689	1706	1725	1758	1781	1800	1821	1843	1867	1890	1913	1937

Table A.2 | Final Coincident Extreme Peak Demand Forecast (MW) per Station in KWCG Region

Station	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Arlen MTS	28	29	30	31	32	32	33	34	35	36	38	39	40	41	42	43	45	46	47
Campbell TS (T1/T2)	91	91	91	92	92	92	93	93	93	94	95	96	97	97	98	99	99	100	100
Campbell TS (T3/T4)	53	53	53	53	53	55	56	56	56	56	56	57	57	58	58	58	59	59	59
Cedar TS (T1/T2)	75	75	76	76	77	77	78	79	79	80	81	81	82	83	84	85	86	87	87
Cedar TS (T7/T8)	38	38	38	38	38	38	38	38	39	39	39	39	39	39	39	40	40	40	40
CTS	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Elmira TS	39	39	40	41	41	42	43	43	44	45	49	50	51	52	57	58	59	60	61
Energy+ MTS #1	92	93	93	94	95	96	97	98	99	100	102	104	105	106	108	109	111	113	114
Fergus TS	95	98	99	101	101	101	102	104	104	104	110	111	111	112	109	110	110	111	111
Galt TS	120	121	121	122	123	125	126	127	128	129	131	133	135	136	138	140	142	144	146
Hanlon TS	30	31	31	31	32	32	33	33	34	34	35	35	36	36	37	37	38	39	39
Kitchener MTS #1	35	36	37	37	38	38	39	40	40	41	42	42	43	44	44	45	46	46	47
Kitchener MTS #3	50	50	51	51	52	52	53	54	54	55	56	56	57	58	58	59	60	61	61
Kitchener MTS #4	63	64	65	65	66	66	67	67	68	68	69	70	70	71	72	72	73	74	75

Station	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Kitchener MTS #5	70	71	71	72	72	73	73	74	74	75	76	76	77	78	78	79	80	81	81
Kitchener MTS #6	66	67	67	68	68	69	69	70	70	71	72	72	73	74	74	75	76	77	77
Kitchener MTS #7	46	47	48	48	49	49	50	50	51	52	53	53	54	55	55	56	57	57	58
Kitchener MTS #8	37	38	39	40	42	43	45	46	48	50	51	53	54	56	58	59	61	63	64
Kitchener MTS #9	36	37	37	38	38	39	39	46	47	47	48	48	49	49	50	51	52	53	53
Preston TS	102	108	111	112	113	115	116	118	119	121	123	124	126	128	130	131	133	135	137
Puslinch DS	33	33	34	34	34	35	35	35	36	36	37	37	38	38	39	39	39	40	40
Rush MTS	48	52	52	52	53	53	53	54	54	54	55	58	59	59	60	60	61	61	62
Scheifele MTS	147	149	150	150	151	152	153	154	155	157	159	157	158	160	161	163	164	166	167
WNH MTS #3	60	58	59	60	61	62	63	64	66	67	68	69	71	72	74	75	77	78	80
Wolverton DS	18	18	18	18	18	18	18	18	19	19	19	19	19	19	19	19	20	20	20
Total	1478	1500	1517	1531	1546	1562	1578	1600	1617	1635	1665	1687	1705	1725	1746	1769	1790	1812	1835

Table A.3 | CDM and DG Contribution (MW) Considered in Coincident Extreme Peak Demand Forecast

Station	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Arlen MTS	0.8	0.8	0.9	1.1	1.1	1.2	1.3	1.5	1.5	1.5	1.5	1.6	1.6	1.7	1.8	1.8	1.9	1.9	2.0
Campbell TS (T1/T2)	4.1	4.2	4.4	4.6	4.8	5.0	5.1	5.4	5.5	5.5	5.1	3.8	3.9	3.9	3.9	3.6	3.6	3.6	3.7
Campbell TS (T3/T4)	3.2	3.3	3.4	3.6	3.7	2.1	2.2	2.4	2.5	2.5	2.4	2.1	2.2	2.2	2.3	2.2	2.2	2.2	2.2
Cedar TS (T1/T2)	1.5	1.6	1.7	2.0	2.1	2.3	2.5	2.7	2.9	3.0	3.2	3.3	3.4	3.5	3.4	3.4	3.4	3.4	3.4
Cedar TS (T7/T8)	0.6	0.6	0.7	0.8	0.9	0.9	1.0	1.1	1.2	1.2	1.2	1.3	1.3	1.3	1.4	1.4	1.4	1.4	1.4
CTS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Elmira TS	4.6	4.7	4.8	5.0	5.1	5.2	5.3	5.5	5.6	5.7	2.6	2.7	2.8	2.5	2.6	2.5	2.5	2.6	2.6
Energy+ MTS #1	3.7	3.8	4.0	4.3	4.5	4.8	5.0	5.3	5.5	5.6	5.0	4.9	5.0	5.2	5.2	4.9	4.9	4.6	4.6
Fergus TS	9.5	9.7	10.1	10.5	10.8	11.2	11.5	10.5	10.7	11.0	6.5	6.2	6.4	6.1	6.0	6.0	6.1	6.1	6.0
Galt TS	4.4	4.6	5.1	5.6	6.1	6.6	7.0	7.5	7.9	8.3	8.0	8.1	8.4	8.3	8.2	8.3	8.4	8.5	8.3
Hanlon TS	0.8	0.8	0.9	1.0	1.1	1.2	1.2	1.3	1.4	1.4	1.4	1.3	1.4	1.4	1.5	1.4	1.4	1.4	1.4
Kitchener MTS #1	1.0	1.1	1.2	1.4	1.5	1.7	1.8	2.0	2.1	2.2	2.3	2.2	2.3	2.5	2.6	2.6	2.7	2.7	2.7
Kitchener MTS #3	1.8	1.9	2.1	2.3	2.5	2.7	2.9	3.1	3.3	3.4	3.2	3.2	3.3	3.5	3.4	3.4	3.5	3.5	3.5
Kitchener MTS #4	2.0	2.1	2.4	2.7	2.9	3.1	3.3	3.6	3.8	3.9	4.0	4.0	4.1	4.3	4.3	4.2	4.3	4.3	4.3

Station	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Kitchener MTS #5	2.4	2.5	2.8	3.1	3.4	3.6	3.8	4.2	4.4	4.5	4.5	4.5	4.6	4.7	4.7	4.7	4.7	4.7	4.7
Kitchener MTS #6	2.5	2.6	2.9	3.2	3.4	3.7	3.9	4.2	4.4	4.4	4.2	4.3	4.4	4.5	4.6	4.6	4.6	4.6	4.5
Kitchener MTS #7	1.6	1.7	1.9	2.1	2.3	2.5	2.6	2.8	3.0	3.1	2.8	2.8	2.9	3.1	3.2	3.2	3.3	3.3	3.4
Kitchener MTS #8	1.3	1.4	1.6	1.8	1.9	2.2	2.3	2.6	2.8	2.9	3.0	3.1	3.3	3.4	3.5	3.6	3.6	3.7	3.7
Kitchener MTS #9	8.3	8.4	8.6	8.8	8.9	9.1	9.2	3.3	3.5	3.5	3.6	3.7	3.7	3.8	3.8	3.5	3.5	3.0	3.0
Preston TS	2.2	2.4	2.5	2.7	2.9	3.0	3.2	3.4	3.5	3.6	3.2	3.3	3.4	3.4	3.3	3.4	3.4	3.3	3.3
Puslinch DS	0.8	0.9	0.9	1.0	1.1	1.2	1.2	1.3	1.4	1.5	1.5	1.5	1.5	1.4	1.4	1.4	1.4	1.3	1.3
Rush MTS	1.3	1.5	1.6	1.9	2.0	2.3	2.4	2.6	2.8	2.8	2.9	3.2	3.3	3.4	3.5	3.6	3.6	3.6	3.6
Scheifele MTS	4.8	5.0	5.4	6.0	6.4	6.8	7.1	7.7	8.0	8.1	7.8	7.7	7.9	8.0	8.0	7.9	7.9	7.9	7.9
WNH MTS #3	1.9	2.0	2.1	2.4	2.6	2.8	3.0	3.3	3.5	3.6	3.7	3.7	3.9	4.1	4.1	4.1	4.1	4.2	4.1
Wolverton DS	0.5	0.7	0.8	0.9	0.9	1.0	1.1	1.1	1.2	1.3	1.3	1.4	1.4	1.4	1.3	1.3	1.4	1.4	1.2
Total	66.0	68.5	72.9	78.6	83.1	86.4	90.1	88.3	92.0	94.3	85.0	84.1	86.4	87.5	88.0	87.1	87.4	87.3	86.9

Table A.4 | LDC Coincident Gross Peak Demand Forecast (MW) per Station in KWCG Region

Station	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Arlen MTS	27	28	29	30	30	31	32	33	34	35	36	37	39	40	41	42	43	45	46
Campbell TS (T1/T2)	88	89	89	90	90	90	91	91	92	92	93	93	94	94	95	95	96	96	97
Campbell TS (T3/T4)	52	52	53	53	53	53	54	54	54	55	55	55	55	56	56	56	56	57	57
Cedar TS (T1/T2)	71	71	72	73	73	74	75	76	76	77	78	79	80	80	81	82	83	84	84
Cedar TS (T7/T8)	35	36	36	36	36	36	36	37	37	37	37	37	38	38	38	38	38	39	39
CTS	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Elmira TS	40	41	42	43	43	44	45	46	47	47	48	49	50	51	55	56	57	58	59
Energy+ MTS #1	89	90	90	92	93	94	95	96	97	99	100	101	102	104	105	106	108	109	110
Fergus TS	98	100	102	104	104	105	106	106	107	108	108	109	110	110	107	108	108	109	109
Galt TS	115	116	118	119	121	122	124	125	127	128	130	131	133	135	136	138	140	142	143
Hanlon TS	29	29	30	30	31	31	32	32	33	33	34	34	35	35	36	36	37	37	38
Kitchener MTS #1	33	34	35	36	37	37	38	39	39	40	41	41	42	43	44	44	45	46	46
Kitchener MTS #3	48	49	49	50	51	51	52	53	53	54	55	55	56	57	58	58	59	60	60
Kitchener MTS #4	61	61	62	63	64	64	65	66	67	67	68	69	69	70	71	71	72	73	73

Station	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Kitchener MTS #5	67	68	69	70	71	71	72	73	73	74	75	75	76	77	77	78	79	79	80
Kitchener MTS #6	64	65	65	66	67	67	68	69	69	70	71	71	72	73	73	74	75	75	76
Kitchener MTS #7	45	45	46	47	47	48	49	50	50	51	52	52	53	54	54	55	56	56	57
Kitchener MTS #8	36	37	38	39	41	42	44	46	47	49	50	52	54	55	57	59	60	62	63
Kitchener MTS #9	42	43	43	44	44	45	46	46	47	47	48	48	49	50	50	51	51	52	53
Preston TS	97	102	105	106	108	109	111	112	114	115	117	119	120	122	123	125	127	129	130
Puslinch DS	31	32	32	33	33	33	34	34	35	35	35	36	36	37	37	38	38	38	39
Rush MTS	46	50	50	50	51	51	52	52	53	53	54	57	58	58	59	59	60	60	61
Scheifele MTS	142	143	144	145	147	148	149	151	152	153	155	153	155	156	157	159	160	162	163
WNH MTS #3	58	56	57	58	59	61	62	63	64	65	67	68	70	71	72	74	75	77	78
Wolverton DS	17	18	18	18	18	18	18	18	18	19	19	19	19	19	19	19	19	20	20
Total	1436	1459	1479	1498	1516	1535	1553	1572	1591	1610	1629	1648	1667	1687	1707	1727	1747	1767	1788

Appendix B - Solution Options to Load Restoration Need in the Cambridge Area

Table B.1 | Maximum 30-Minute/Fast 4-Hours Load Restoration Capability in the Cambridge Area for Faults on Galt-Preston Section of M20D & M21D

Option	Description	Load Restoration Capability (MW)*	Total Cost	Cost per Additional MW of Restored Load
-	Status Quo	180**	$0	$0
1	Add capacitor banks at Preston 230 kV TS for a total of 200 Mvar	300***	$7M	$58k
2	Add second Preston autotransformer plus capacitor banks at Preston 230 kV TS for a total of 300 Mvar	500***	$27M	$84k

* Preston 230 kV terminals on both M20D and M21D were closed for restoration. Operational measures on the 115 kV system, e.g., open low voltage bus-tie breakers/switches at 115 kV connected stations, may be required to secure the transmission system to handle a subsequent contingency.

** Preston autotransformer was locked to its pre-contingency tap position.

*** Load restoration capability may be reduced by the limited transfer capability of 115 kV path; requires further study in future planning activities/regional planning cycles

Appendix C - Development of the Plan

C.1 The Regional Planning Process

In Ontario, meeting the electricity needs of customers at a regional level is achieved through regional planning. This comprehensive process starts with an assessment of the interrelated needs of a region—defined by common electricity supply infrastructure—over the near, medium, and long term and results in the development of a plan to ensure cost-effective, reliable electricity supply. Regional plans consider the existing electricity infrastructure in an area, forecast growth and customer reliability, evaluate options for addressing needs, and recommend actions.

Regional planning has been conducted on an as-needed basis in Ontario for many years. Most recently, planning activities to address regional electricity needs were the responsibility of the former Ontario Power Authority (OPA), now the Independent Electricity System Operator (IESO), which conducted joint regional planning studies with distributors, transmitters, the IESO and other stakeholders in regions where a need for coordinated regional planning had been identified.

In the fall of 2012, the OEB convened a Planning Process Working Group (PPWG) to develop a more structured, transparent, and systematic regional planning process. This group was composed of electricity agencies, utilities, and other stakeholders. In May 2013, the PPWG released its report to the OEB (PPWG Report), setting out the new regional planning process. Twenty-one electricity planning regions were identified in the PPWG Report, and a phased schedule for completion of regional plans was outlined. The OEB endorsed the PPWG Report and formalized the process timelines through changes to the Transmission System Code and Distribution System Code in August 2013, and to the former OPA's licence in October 2013. The licence changes required it to lead two out of four phases of regional planning. After the merger of the IESO and the OPA on January 1, 2015, the regional planning roles identified in the OPA's licence became the responsibility of the IESO.

The regional planning process begins with a needs assessment process performed by the transmitter, which determines whether there are needs requiring regional coordination. If regional planning is required, the IESO conducts a scoping assessment to determine what type of planning is required for a region. A scoping assessment explores the need for a comprehensive IRRP, which considers conservation, generation, transmission, and distribution solutions, or whether a more limited "wires" solution is the preferable option, in which case a transmission- and distribution-focused RIP can be undertaken instead. There may also be regions where infrastructure investments do not require regional coordination and can be planned directly by the distributor and transmitter outside of the regional planning process. At the conclusion of the scoping assessment, the IESO produces a report that includes the results of the needs assessment process and a preliminary terms of reference. If an IRRP is the identified outcome, the IESO is required to complete the IRRP within 18 months. If a RIP is the identified outcome, the transmitter takes the lead and has six months to complete it. Both RIPs and IRRPs are to be updated at least every five years. The draft Scoping Assessment Outcome Report is posted to the IESO's website for a two-week public comment period prior to finalization.

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

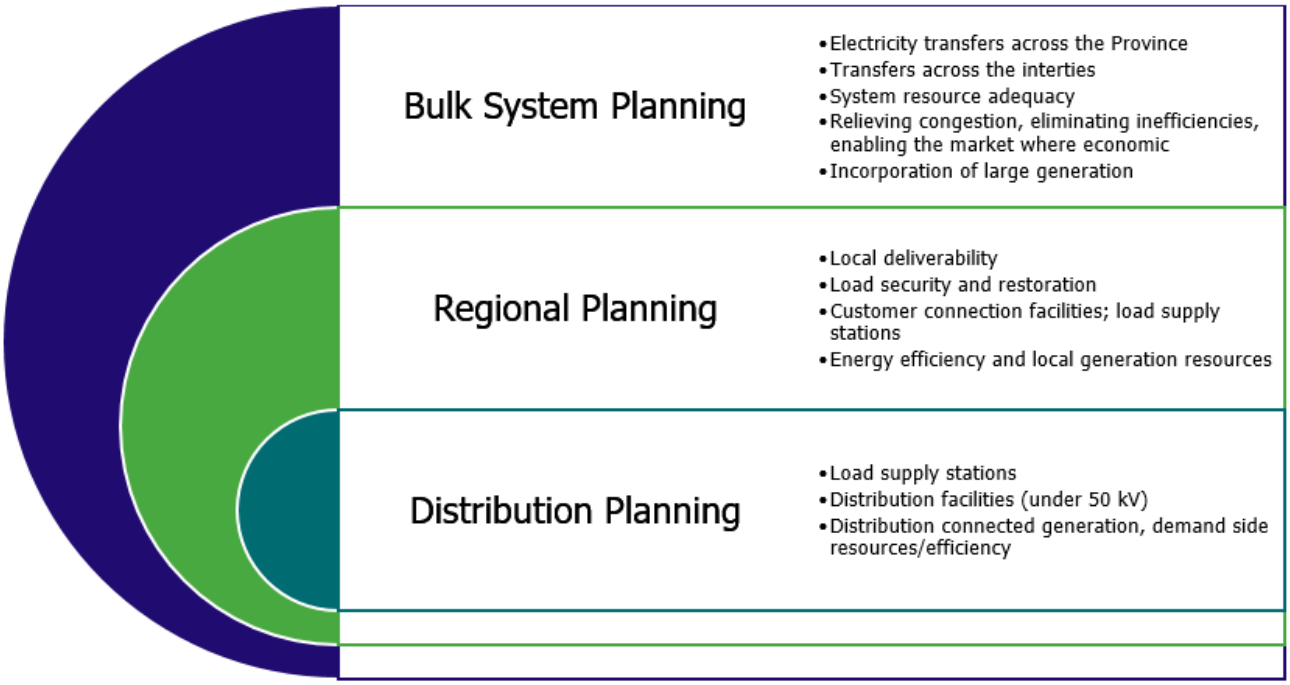
- Bulk system planning
- Regional system planning
- Distribution system planning

Planning at the bulk system level typically considers the 230 kV and 500 kV network and examines province-wide system issues. In addition to considering major transmission facilities or "wires", bulk system planning assesses the resources needed to adequately supply the province. This type of planning is typically carried out by the IESO pursuant to government policy. Distribution planning, which is carried out by LDCs, considers specific investments in an LDC's territory at distribution-level voltages.

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

By recognizing the linkages with bulk and distribution system planning, and coordinating the multiple needs identified within a region over the long term, the regional planning process provides a comprehensive assessment of a region's electricity needs. Regional planning aligns near- and long-term solutions and puts specific investments and recommendations coming out of the plan into perspective. Furthermore, in avoiding piecemeal planning and asset duplication, regional planning optimizes ratepayer interests, allowing them to be represented along with the interests of LDC ratepayers, and individual large customers. IRRPs evaluate the multiple options that are available to meet the needs, including conservation, generation, and "wires" solutions. Regional plans also provide greater transparency through engagement in the planning process, and by making plans available to the public.

Figure C.1 | Levels of Electricity System Planning



C.2 IESO's Approach to Regional Planning

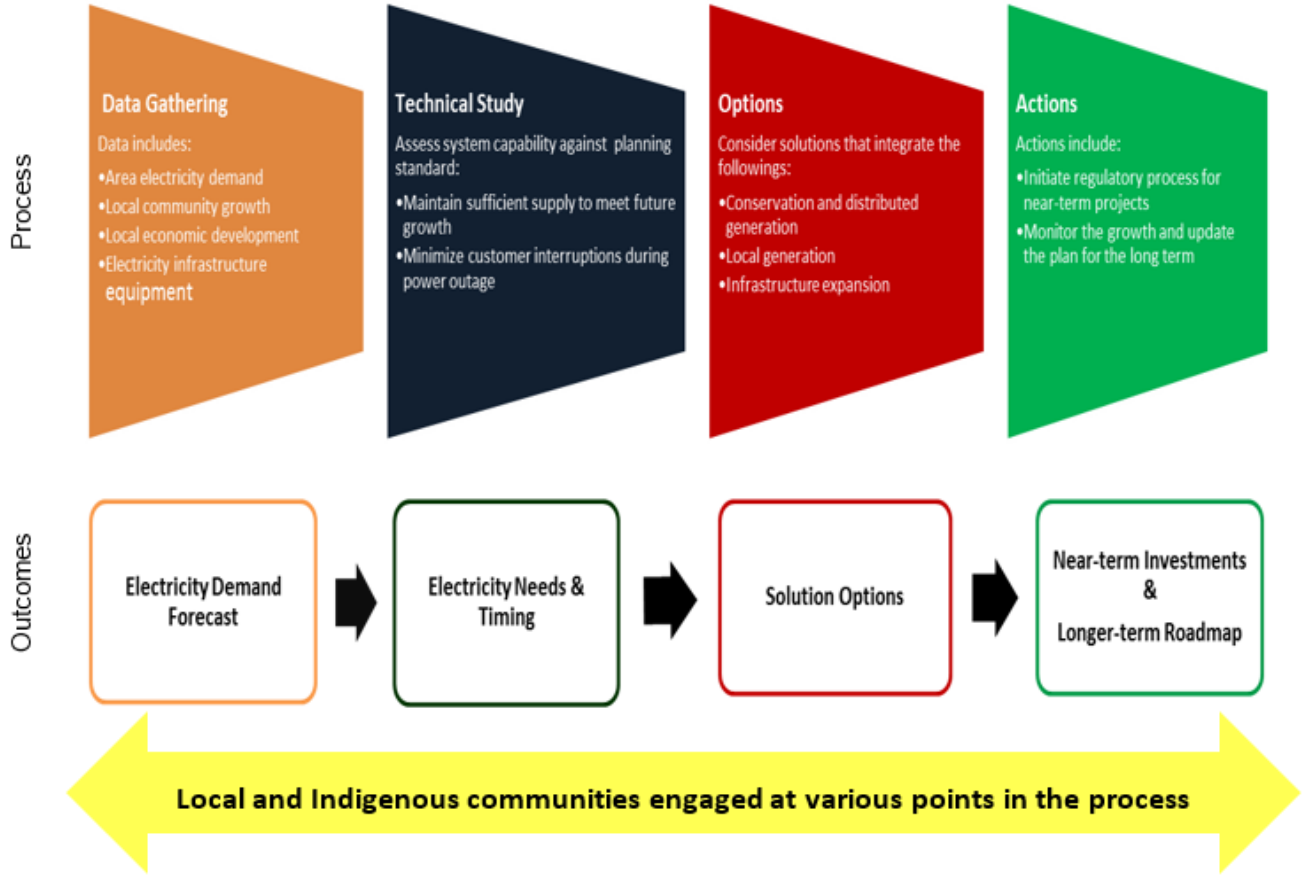
IRRPs assess electricity system needs for a region over a 20-year period, enabling near-term actions to be developed in the context of a longer-term view of trends. This enables coordination and consistency with the long-term plan, rather than simply reacting to immediate needs.

The IRRP describes the Working Group's recommendations for mitigating reliability and cost risks related to end-of-life asset replacement and demand forecast uncertainty associated with large load customers or due to any changes in the existing provincial conservation targets. The IRRP helps ensure that recommendations to address near-term needs are implemented, while maintaining the flexibility to accommodate changing long-term conditions.

In developing an IRRP, the IESO and the study team follow a process, with a clearly defined series of steps (see Figure C.2). These includes developing electricity demand forecasts; conducting technical studies to determine electricity needs and the timing of these needs; considering potential options; and creating a plan with recommended actions for the near and long term. Throughout this process, engagement is carried out with stakeholders and Indigenous communities who may have an interest in the area.

The IRRP report documents the inputs, findings and recommendations developed through this process, and outlines recommended actions for the various entities responsible for plan implementation. Where "wires" solutions are included in the plan recommendations, the completion of the IRRP triggers the initiation of the transmitter's RIP process to develop those options. Other recommendations in the IRRP may include: development of conservation, local generation, community engagement, or information gathering to support future iterations of the regional planning process in the region or sub-region.

Figure C.2 | Steps in the IRRP Process



Appendix D – Short Circuit Assessment

Distribution system short circuit levels, as measured at the low-voltage (LV) bus of transmission connected transformer stations, are subject to change due to two main driving factors: changes in upstream impedance and changes in amount and type of DERs connected to the station. Changes in upstream impedance typically result from transmission system changes, such as transformer replacement or network expansion or reconfiguration.

The upstream impedance generally has minimal impact on the station LV actual short circuit and vice versa because of the dominant effect of the station transformers impedance. However, changes in the amount and type of DERs connected to a LV bus of a station have a significant and direct impact on the station LV short circuit level.

While equipment which limits the available short circuit capacity on the LV side of a transformer station may potentially be upgraded with higher rated equipment, the Working Group is cognizant that there is an effective practical limit to this rating as established in Appendix 2 of the Transmission System Code (TSC). Distribution systems components, including equipment owned by end-use customers, in Ontario, is designed, manufactured, and applied to this standard with the following short circuit capacities:

- 500 MVA @ 13.8 kV
- 800 MVA @ 27.6 kV
- 1500 MVA @ 44 kV

The aforementioned short circuit capacities are used for evaluating the amount of DER that can be connected to a station LV bus. Some stations may have a smaller value due to pre-existing legacy equipment which was adequate and is deemed to be grandfathered.

Table D.1 lists all stations in the KWCG Region where new DER connection is restricted because the LV short circuit level is extremely high, that is approximately equal to or greater than 90% of the capacity. The information presented in this table is obtained with consideration of known generation connections as of March 2021 and is subject to change primarily due to new DER connections.

The appropriate LDC should be consulted for up-to-date short circuit information and feasibility of connecting new DER. In particular, Hydro One List of Station Capacity[1], which is updated periodically, provides the estimated thermal and short circuit capacities of its stations for generation connections. A capacity calculator[2] is also available to help customers evaluate their connection.

[1] Available at https://www.hydroone.com/businessservices_/generators_/Documents/honi_lsc.pdf

[2] Available at https://www.hydroone.com/business-services/generators/station-capacity-calculator

Table D.1 | Stations with Extremely High Short Circuit Level*

Station	Bus	Owner	Nominal Voltage (kV)	Short Circuit Capacity** (MVA)	Short Circuit Level (MVA)
Campbell	EZ	Hydro One	13.8	443	437
Kitchener #1	B1B2	Kitchener-Wilmot Hydro	13.8	468	447
Kitchener #3	B51B61	Kitchener-Wilmot Hydro	13.8	468	436
Kitchener #3	B52B62	Kitchener-Wilmot Hydro	13.8	468	474***
Kitchener #4	B71B81	Kitchener-Wilmot Hydro	13.8	468	466
Kitchener #4	B72B82	Kitchener-Wilmot Hydro	13.8	468	467
Kitchener #5	B91B101	Kitchener-Wilmot Hydro	13.8	468	415
Kitchener #5	B92B102	Kitchener-Wilmot Hydro	13.8	468	415
Kitchener #6	B111B121	Kitchener-Wilmot Hydro	13.8	468	459
Kitchener #6	B112B122	Kitchener-Wilmot Hydro	13.8	468	459
Kitchener #7	B13B14	Kitchener-Wilmot Hydro	13.8	468	446
Rush	B1B2	Waterloo North Hydro	13.8	467	441
Scheifele A	BY	Waterloo North Hydro	13.8	500	455
Scheifele B	QT	Waterloo North Hydro	13.8	500	454

* Data provided in this table are valid as of March 2021. For up-to-date information, contact LDCs.
** Capacities smaller than TSC requirement are due to pre-existing legacy equipment which was adequate and is deemed to be grandfathered.
*** Affected feeder breakers are to be replaced.

Appendix E – East Side Lands

This appendix is provided by Waterloo North Hydro Inc. (WNH) and Energy+ Inc. (Energy+) to document the current state of their studies for future capacity needs in their respected territories and to help inform participants in the next cycle of regional planning.

E.1 Background

WNH and Energy+ are in discussions to establish the optimal planning outcome to meet the future load growth needs of each utility. This involves coordinating efforts as part of the IRRP process to assess the timing and needs for potential future transformer stations.

This review will look at the opportunity to meet the needs of both Energy+ and WNH from a single station in an effort to maximize efficiencies. Additionally, Hydro One Transmission replaces the transformers at Preston TS in 2025-2026 with like-for-like due to end-of-life. The new transformers would have higher LTRs sufficient to meet the needs. There is also physical space at Preston TS to add four new breaker positions.

Energy+ also has the option of moving the replacement date forward for an advancement fee, should the extra capacity be needed prior to 2025. This extra capacity was also considered during this analysis. This study also examined if there were any interim capacity needs required that may not necessitate the construction of a new station by sharing of feeders.

E.2 Executive Summary

The WNH and Energy+ joint study is summarized as follows:

- The uncertainty around both the timing and the types of loads in the East Side Lands for both WNH and Energy+ make forecasting the needed in service date difficult.
- Energy+ expects that in 2022 there may be more clarity around the load growth and load density in the East Side Lands to be able to more accurately forecast a needed in service date for Energy+ MTS #2.
- Energy+ plans to receive additional capacity from Hydro One Preston TS when the transformers are replaced in 2025-2026 and there will be an opportunity to add four new breaker position to take advantage of this capacity.
- Energy+ is building its distribution infrastructure in the East Side Lands for multiple load growth scenarios which includes up to four circuits.
- WNH can feed 27.6 kV load in City of Waterloo, currently fed by WNH Scheifele TS using WNH MTS #4 or Energy+ MTS #2 or Hydro One Preston TS, provided they are express feeders.
- Energy+ feeders from MTS #2 or Hydro One Preston TS are not considered candidates to pick up significant load in Elmira due to the reliability concerns that accompany the feeder length.

E.3 Discussion

The possible future sites of WNH MTS #4 and Energy+ MTS #2 are strategically located to service the areas where the most concentrated load growth is expected to occur. Figure E.1 to Figure E.3 show the areas of load growth as depicted by the Region of Waterloo, while Figure E.4 shows the location of stations mentioned in this IRRP. WNH also has a smaller geographical load growth centre identified for commercial/industrial development in the south-east part of the town of Elmira. The WNH MTS #4 lands are located in the town of Winterbourne and the Energy+ MTS #2 lands are located on Boychuk Drive in the City of Cambridge.

At this point in time, both WNH and Energy+ have difficulty in accurately quantifying the demand that these areas will require given the current status of development. For WNH, much of the non-residential load growth in WNH's East Side Lands is expected to be tied to the new Provincial Highway 7 corridor between Kitchener and Guelph. This is expected to attract industrial and commercial businesses in the Township of Woolwich, for which the lands have been appropriately zoned. However, given the uncertainty and delays associated with this project, WNH is unable to predict the timing of this new load and the expected load growth.

Energy+ expects development of its part of the East Side Lands to begin in 2021-2022 after which the amount of load growth in this area will become clearer. Presently, while Energy+ has received site plan applications, the potential uses of these sites are so diverse (e.g. data centre, manufacturing, warehouse storage) that accurately estimating the load growth is extremely challenging. Energy+ is building its distribution infrastructure with multiple demand scenarios in mind to be able to accommodate a range of applications. Since the location of Energy+ MTS #2 is within these East Side Lands, if the load growth in this area is higher or more rapid than anticipated, exceeding capacity at existing stations, Energy+ MTS #2 is well situated to add capacity to the Energy+ system. Energy+ MTS #2 would be connected to the Hydro One F11C/F12C 115 kV transmission lines and would be able to take advantage of much of the existing distribution infrastructure to supply its intended load.

In WNH's long-term system plan, all of WNH Scheifele TS is expected to be required to supply 13.8 kV loads within the City of Waterloo as density increases in the uptown core which would require the existing 27.6 kV loads to be supplied from another source. WNH has completed a study and determined that this area could be fed by WNH's future MTS #4 or from two Energy+ express feeders from either Energy+ MTS #2 or Hydro One Preston TS. Either solution would sufficiently supply the existing load with its inherent natural growth, without concern from a capacity or voltage perspective. WNH also has spare capacity at Hydro One Elmira TS to backup either Waterloo or Breslau. However, WNH requires clarification from the IESO and Hydro One on how much spare capacity can be used from Hydro One Elmira TS based on contingency analysis of the D10H transmission line radially feeding Elmira TS. Energy+ feeders, even if built as express feeders, are not considered suitable candidates for future load growth in this area as the feeder length would be above 30 km, raising reliability and voltage concerns for what is anticipated to be an industrial area.

WNH continues to monitor 13.8 kV load growth in Waterloo, however based on the pace of new developments does not see a near-term need where this capacity would be needed from WNH Scheifele TS.

Figure E.1 | East Side Lands in Region of Waterloo

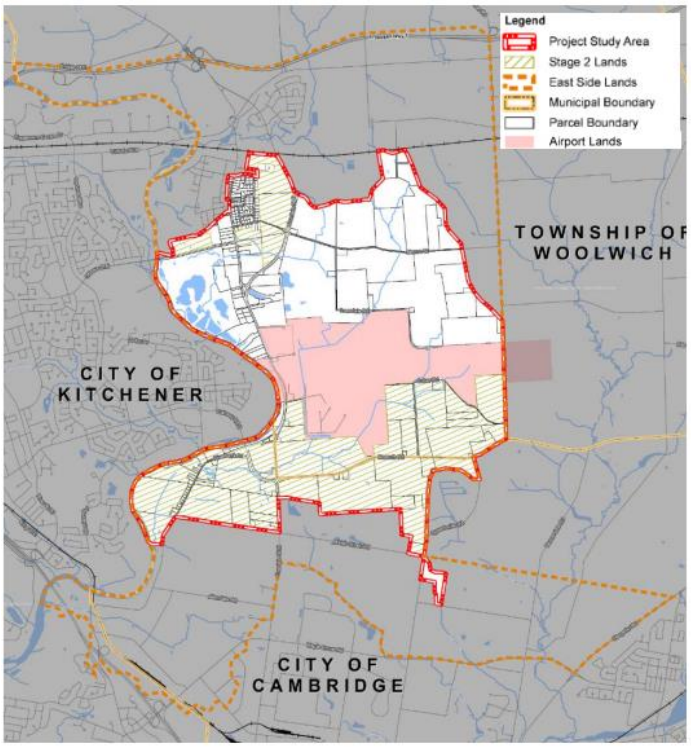


Figure E.2 | East Side Lands within Cambridge/North Dumfries (Including location of Energy+ MTS #2)

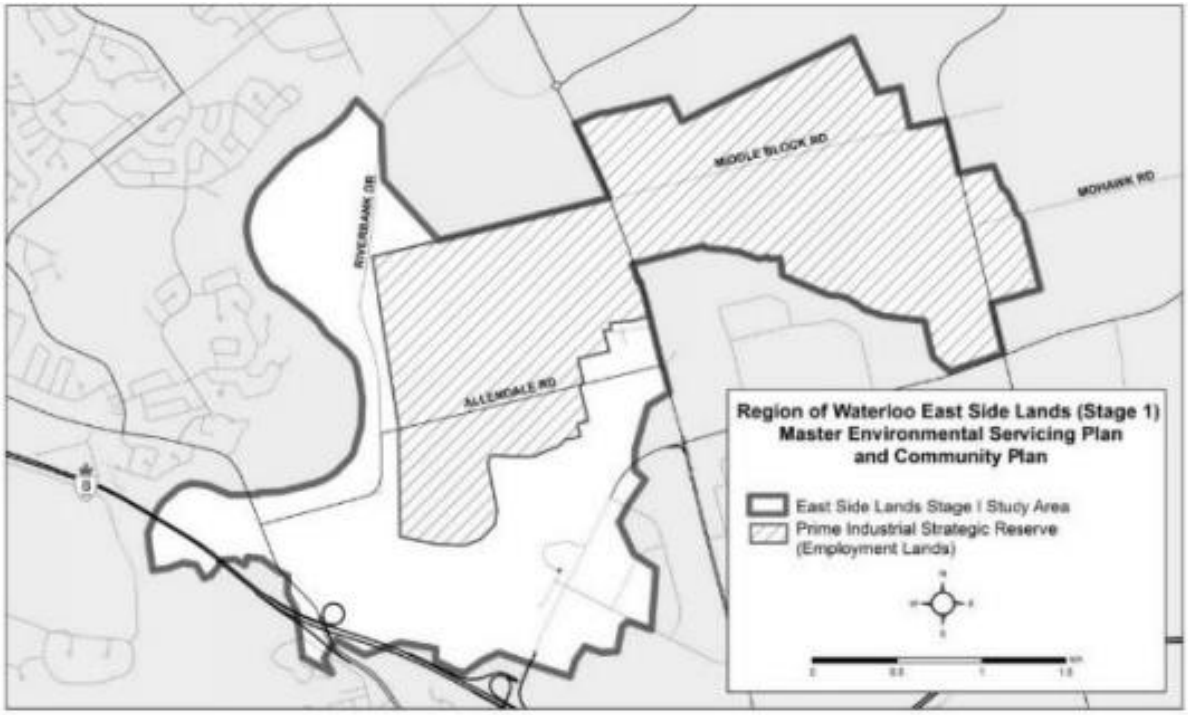


Figure E.3 | Elmira Load Growth Areas

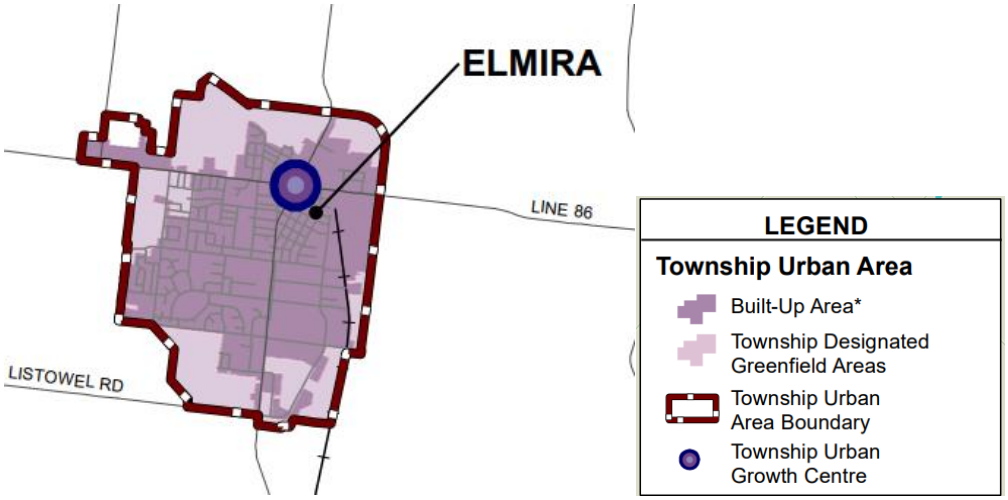
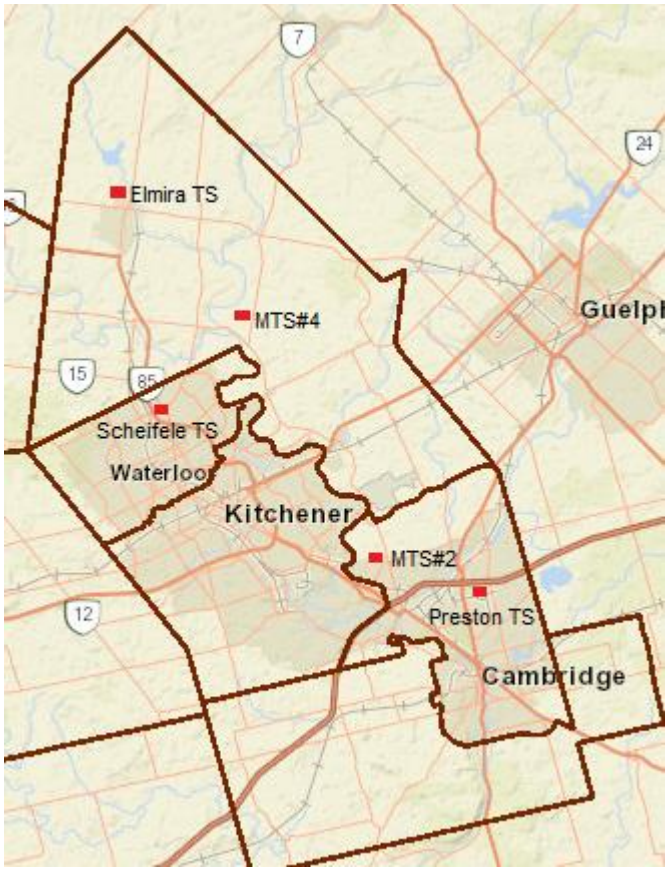


Figure E.4 | Station Locations in WNH and Energy+ Territory



Independent Electricity System Operator
1600-120 Adelaide Street West
Toronto, Ontario M5H 1T1

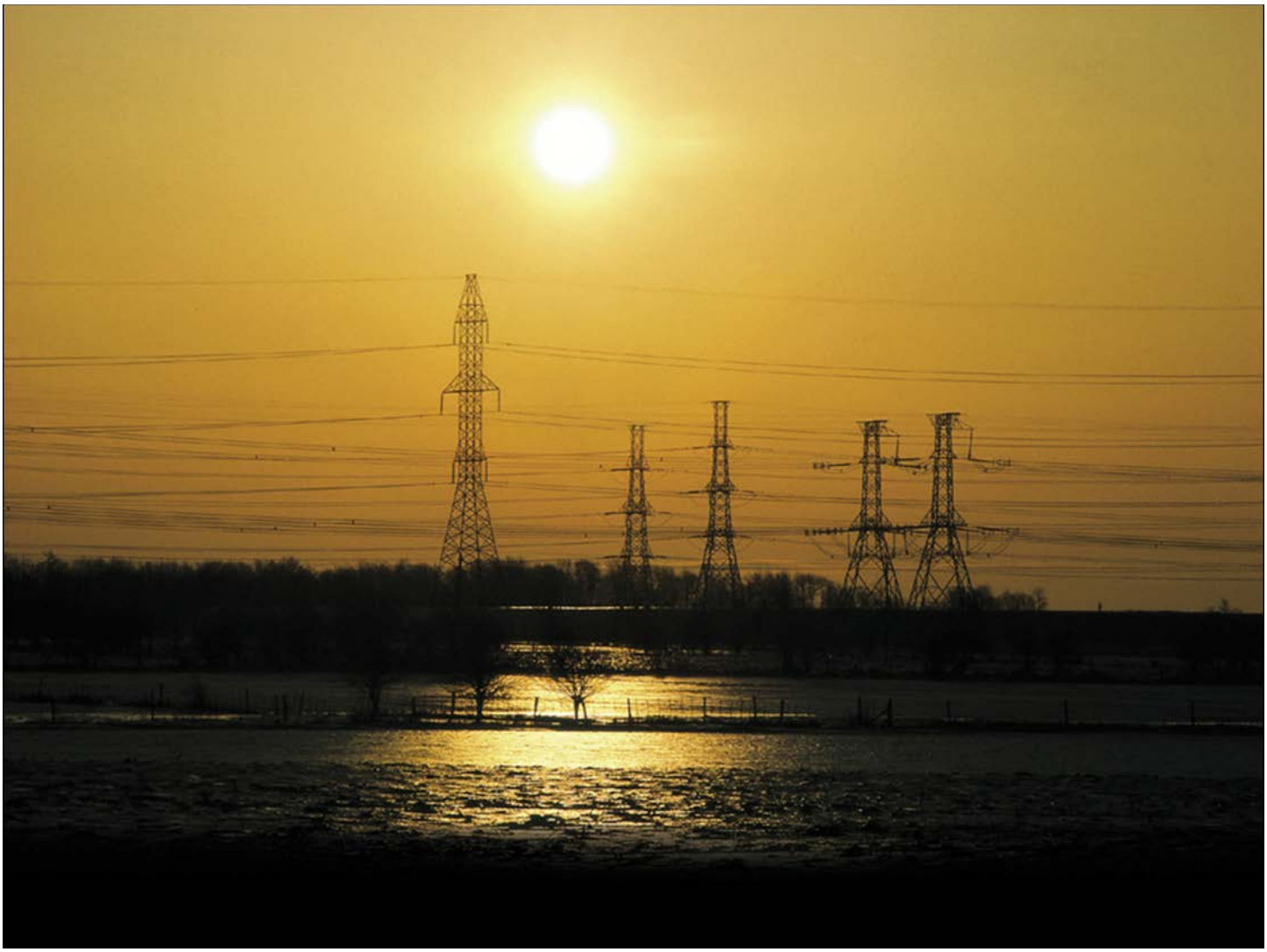
Phone: 905.403.6900
Toll-free: 1.888.448.7777
E-mail: customer.relations@ieso.ca

ieso.ca

@IESO_Tweets
facebook.com/OntarioIESO
linkedin.com/company/IESO

ieso
Connecting Today.
Powering Tomorrow.

APPENDIX C-4
KWCG RIP Report (2021)



Kitchener-Waterloo-Cambridge-Guelph Regional Infrastructure Plan

December 10, 2021

hydro one

[This page is intentionally left blank]

Prepared and supported by:

Company
Hydro One Networks Inc. (Transmission)
Independent Electricity System Operator (IESO)
Alectra Utilities Corporation
Centre Wellington Hydro Ltd.
Energy+ Inc.
Halton Hills Hydro Inc.
Hydro One Networks Inc. (Distribution)
Kitchener-Wilmot Hydro Inc.
Milton Hydro Distribution Inc.
Waterloo North Hydro Inc.
Wellington North Power Inc.

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 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.

Executive Summary

THIS REGIONAL INFRASTRUCTURE PLAN ("RIP") WAS PREPARED BY HYDRO ONE WITH SUPPORT FROM THE RIP STUDY TEAM IN ACCORDANCE TO THE ONTARIO TRANSMISSION SYSTEM CODE REQUIREMENTS. IT IDENTIFIES INVESTMENTS IN TRANSMISSION FACILITIES, DISTRIBUTION FACILITIES, OR BOTH, THAT SHOULD BE DEVELOPED AND IMPLEMENTED TO MEET THE ELECTRICITY INFRASTRUCTURE NEEDS WITHIN THE KITCHENER WATERLOO CAMBRIDGE GUELPH REGION.

The participants of the Regional Infrastructure Plan ("RIP") Study Team included members from the following organizations:

- Alectra Utilities Corporation ("Alectra")
- Centre Wellington Hydro Ltd. ("CWH")
- Energy + Inc. ("Energy+")
- Halton Hills Hydro Inc. ("HHH")
- Hydro One Networks Inc. (Distribution)
- Hydro One Networks Inc. (Transmission)
- Independent Electricity System Operator ("IESO")
- Kitchener Wilmot Hydro Inc.("KWH")
- Milton Hydro Distribution Inc. ("MHD")
- Waterloo North Hydro Inc. ("WNH")
- Wellington North Power Inc. ("WNP")

In the first cycle of the Regional Planning (RP) process for the KWCG Region, an Integrated Regional Resource Plan ("IRRP") was published in April 2015. The first cycle of RP process was completed in December 2015 [1] with the publication of the Regional Infrastructure Plan ("RIP") which provided a description of needs and recommendations of preferred wires plans to address near-term needs.

In accordance with the Regional Planning process, the Regional Planning cycle should be triggered at least every five years. In light of the timing of the needs identified in the previous IRRP and RIP reports as well as new replacement/ refurbishment needs identified in the KWCG Region, the 2nd Regional Planning cycle was triggered for the KWCG region in Q4 2018.

This RIP is the final phase of the second cycle of Kitchener Waterloo Cambridge Guelph (KWCG) regional planning process, which follows the completion of the KWCG Integrated Regional Resource Plan ("IRRP") in April 2021 [2][3] and the KWCG Region Needs Assessment ("NA") in December 2018 [4]. This RIP provides a consolidated summary of the needs and recommended plans for KWCG Region over the planning horizon (1 – 20 years) based on available information.

It discusses needs identified in the previous regional planning cycle, the Needs Assessment and IRRP reports for this cycle, and wires solutions recommended to address these needs. Implementation plans to address some of these needs are already completed or are underway.

The following needs identified in the first regional planning cycle have been addressed:

Needs	Needs Details
115kV System Supply Capacity	GATR Project Two new 230/115kV autotransformers at Cedar TS to reinforce supply to both 115kV sub-systems in the region.
230kV Load Restoration Needs	GATR Project Two new 230 kV in-line switches on D6V/D7V circuits to improve restoration capability of Waterloo-Guelph 230 kV sub-system.
	Galt Junction Two new 230kV in-line switches on M20D/M21D circuits to improve restoration capability of the Cambridge-Kitchener 230 kV sub-system.
Station Short Circuit Capacity	Arlen MTS Install 13.8 kV series reactors to mitigate LV bus short circuit levels.

Other projects completed in the region since the completion of first regional planning cycle are listed below:

Stations Refurbishment Project	
Campbell TS	Transformers T1 and T2 Replacement
Detweiler TS	AC Station Service and Component Replacement
Detweiler TS	230 /115 kV Auto Transformers T2 and T4 Replacement
D7F / D9F	115 kV Tower Refurbishment – Tower 157 near Freeport SS
D6V / D7V	230 kV Lines Refurbishment between Fergus TS and Campbell TS

The major infrastructure investments recommended for the KWCG Region over the near and mid-term planning horizon are provided in the Table 1 below, are all end of life needs along with their planned in-service date and budgetary estimates for planning purpose.

Table 1. Recommended Plans in KWCG Region over the Next 10 Years

Stations / Lines Project	Details	Timeframe	High Level Cost ($M)[1]
Hanlon TS	Transformers T1 and T2 Replacement	2022-2023	17.8
Kitchener MTS #5	Transformers T9 and T10 Replacement	2023-2024	7.5
Scheifele MTS	Transformers T1 and T2 Replacement	2025-2026	-
B5C/B6C	115KV Lines Refurbishment, refurbishing section from Burlington TS to a CTS	2025-2026	16.8
Preston TS	Transformers T3 and T4 Replacement	2026-2027	22.9
Cedar TS	Transformers T7 and T8 Replacement	2026-2027	23.7
Fergus TS	Transformers T3 and T4 Replacement	2028-2029	30.0
Galt TS	Breakers and Component Replacement	2028-2029	12.0
Campbell TS	Breakers and Component Replacement	2028-2029	18.1

The Study Team recommends that:

- Hydro One and LDCs to continue with the implementation of infrastructure investments listed in Table 1 above while keeping the Study Team apprised of project status;
- All the other identified needs/options in the long-term will be further reviewed by the Study Team in the next regional planning cycle.

[1] Budgetary estimates

Table of Contents

Disclaimer 4
Executive Summary 5
Table of Contents 8
List of Figures 9
List of Tables 9
1. Introduction 10
1.1. Objectives and Scope 11
1.2. Structure 11
2. Regional Planning Process 12
2.1. Overview 12
2.2. Regional Planning Process 12
2.3. RIP Methodology 14
3. Regional Characteristics 16
4. Transmission Facilities/ Projects Completed and/or Underway Over the Last Ten Years 19
5. Load Forecast and Study Assumptions 21
5.1. Load Forecast 21
5.2. Study Assumptions 22
6. Adequacy of Existing Facilities 23
6.1. 230 kV Transmission Facilities 23
6.2. 230/115 kV Autotransformer Facilities 24
6.3. 115 kV Transmission Facilities 24
6.4. Step-Down Transformer Station Facilities 25
6.5. System Reliability and Load Restoration 26
6.6. Station Short Circuit Capacities [2][3] 27
6.7. Longer Term Outlook 28
6.7.1. Other Planning Considerations in the KWCG Region 28
6.7.2. Uncertain Load Growths 28
7. Regional Needs and Plans 30
7.1. Deteriorating Infrastructure, Optimization Opportunities and Replacement Plan of Major Equipment 31
7.1.1. Deteriorating Infrastructure 31
7.1.2. Optimization Opportunities and Replacement Plans 32
7.2. Needs in Near-Term (Projects in Execution) 33
7.2.1. 115 kV B5C/ B6C Line Sections 33
7.2.2. Hanlon TS T1/T2 Transformer 34
7.2.3. Kitchener MTS #5 T9/T10 Transformers 34
7.3. Needs in Near, Mid and Long Term 34
7.3.1. Scheifele MTS – T1/ T2 Transformers 34
7.3.2. Cedar TS – T7/ T8 Transformers 35
7.3.3. Preston TS T3/T4 Transformers 35
7.3.4. Fergus TS T3/T4 Transformers 36
7.3.5. Galt TS Breakers and Components 36
7.3.6. Campbell TS (T1/T2) Breakers 37
7.4. Mid and Long Term Supply Capacity Needs 37
8. Conclusions and Next Steps 38
References 39

Appendix A. Stations in the KWCG Region 40
Appendix B. Transmission Lines in the KWCG Region 41
Appendix C. Distributors in the KWCG Region....42
Appendix D. KWCG Region Load Forecast....43
Appendix E. Stations with Extremely High Short Circuit Level* 45
Appendix F. List of Acronyms....46

List of Figures

Figure 1-1: KWCG Region Map 10
Figure 2-1: Regional Planning Process Flowchart....14
Figure 2-2: RIP Methodology 15
Figure 3-1: Single Line Diagram of the KWCG Region's Transmission Network 16
Figure 5-1: KWCG Region Load Forecast....21
Figure 7-1: Burlington TS to Harper's Jct. to CTS 33

List of Tables

Table 6-1: KWCG Step-Down Existing Transformer Stations....25
Table 6-2: KWCG Step-Down Transformer Stations Supply Capacity Needs....26
Table 7-1: Identified Near and Mid-Term Needs in KWCG Region....30
Table 7-2: Identified Long-Term Needs in KWCG Region....30
Table 7-3: Deteriorating Infrastructure, EOL Needs in KWCG Region....32
Table 8-1: Recommended Plans in KWCG Region over the Next 10 Years....38

1. Introduction

THIS REPORT PRESENTS THE REGIONAL INFRASTRUCTURE PLAN ("RIP") TO ADDRESS THE ELECTRICITY NEEDS OF THE KITCHENER WATERLOO CAMBRIDGE GUELPH (KWCG) REGION BETWEEN 2021 AND 2041.

The report was prepared by Hydro One Networks Inc. (Transmission) ("Hydro One") on behalf of the Study Team that consists of Hydro One, Alectra Utilities ("Alectra"), Centre Wellington Hydro Ltd., Energy+ Inc., Halton Hills Hydro Inc., Hydro One Networks Inc. (Distribution), the Independent Electricity System Operator ("IESO"), Kitchener-Wilmot Hydro Inc., Milton Hydro Distribution Inc., Waterloo North Hydro Inc. and Wellington North Power Inc., in accordance with the new Regional Planning process established by the Ontario Energy Board in 2013 [5].

The Kitchener, Waterloo, Cambridge and Guelph (KWCG) region is located to the west of the Greater Toronto area in southwestern Ontario. The KWCG Region includes the cities of Kitchener, Waterloo, Cambridge and Guelph, portions of Oxford and Wellington counties and the townships of North Dumfries, Puslinch, Woolwich, Wellesley and Wilmot. Electrical supply to the Region is provided from eleven 230 kV and thirteen 115 kV step-down transformer stations. The approximate boundaries of the KWCG Region are shown below in Figure 1-1.

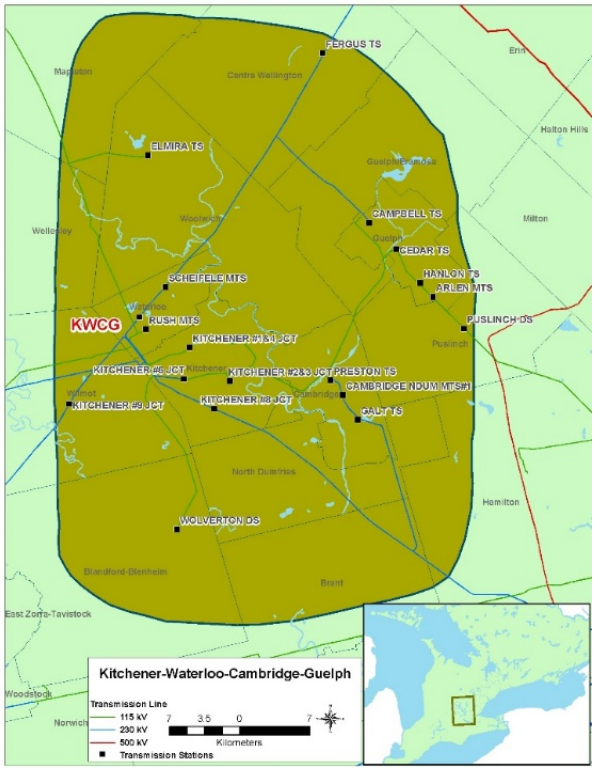


FIGURE 1-1: KWCG REGION MAP

1.1. Objectives and Scope

The RIP report examines the needs in the KWCG 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"), Scoping Assessment ("SA"), and/or Integrated Regional Resource Plan ("IRRP");
- Assess and develop a wires plan to address these 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 report of the relevant wires plans to address near and medium-term needs identified in previous planning phases (Needs Assessment, Scoping Assessment, and/or Integrated Regional Resource Plan);
- Discussion of any other major transmission infrastructure investment plans over the planning horizon;
- Identification of any new needs and a wires plan to address these needs based on new and/or updated information;
- Develop a plan to address any longer term needs identified by the Study Team.

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 adequacy of the transmission facilities in the region over the study period.
- 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[2] ("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 (non-wires alternatives) 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 need are then further planned in greater detail by the IESO.

[2] Also referred to as Needs Screening

The IRRP phase also includes IESO led stakeholder engagement with municipalities, Indigenous communities, business sectors and other interested stakeholders in the region.

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.

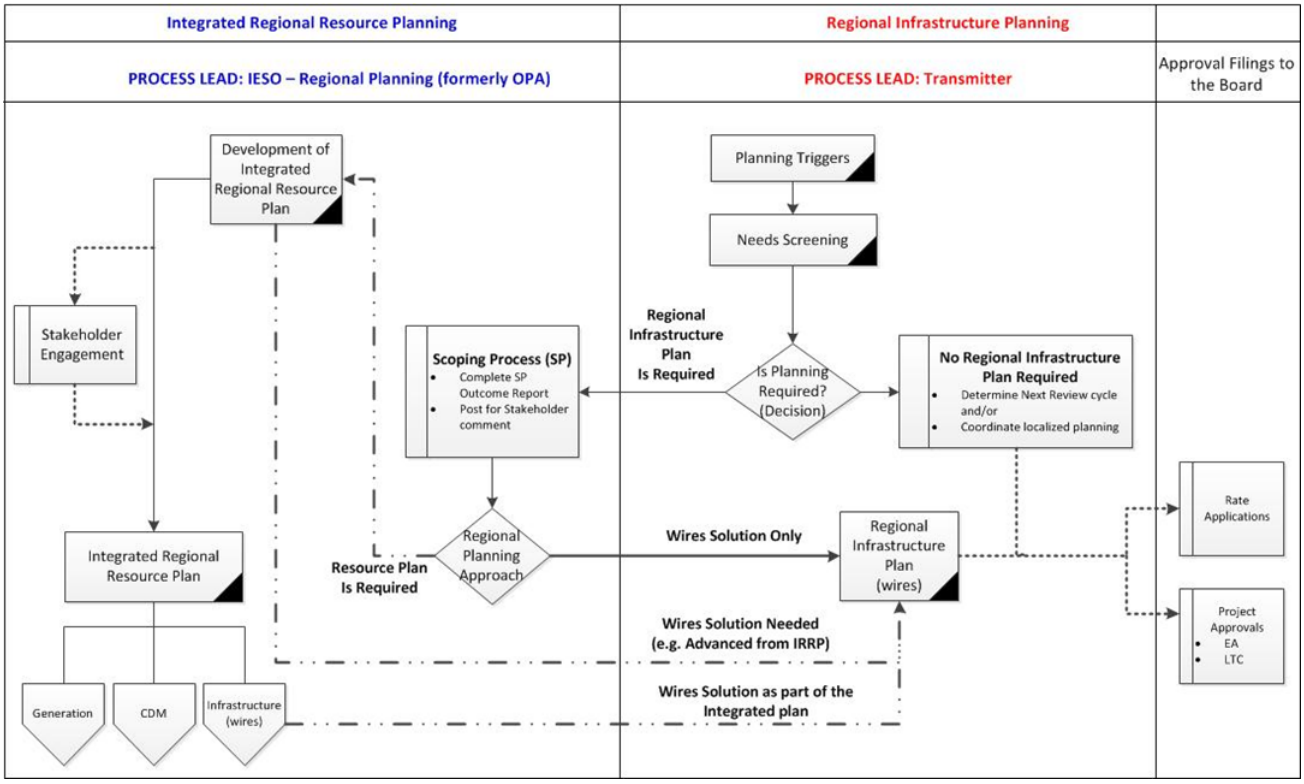


FIGURE 2-2: REGIONAL PLANNING PROCESS FLOWCHART

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.

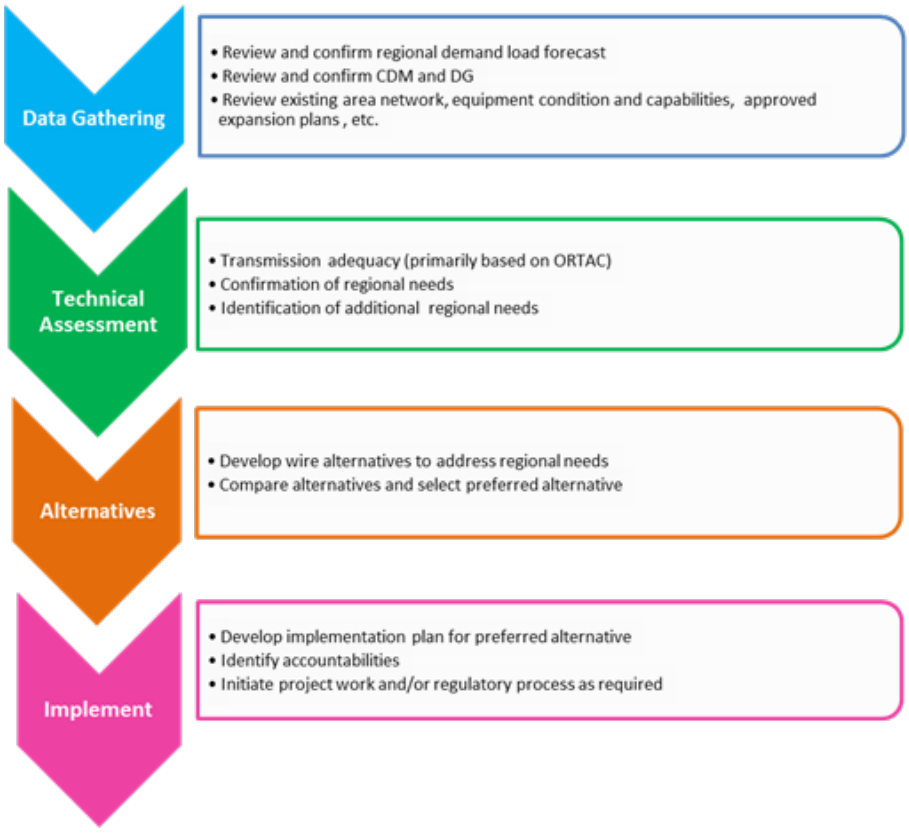


FIGURE 2-3: RIP METHODOLOGY

3. Regional Characteristics

THE KWCG REGION COMPRISES OF THE CITIES OF KITCHENER, WATERLOO, CAMBRIDGE AND GUELPH, PORTIONS OF OXFORD AND WELLINGTON COUNTIES AND THE TOWNSHIPS OF NORTH DUMFRIES, PUSLINCH, WOOLWICH, WELLESLEY AND WILMOT AS SHOWN IN FIGURE 3-1.

The main sources of electricity into the KWCG Region are from four Hydro One transformer stations: Middleport TS, Detweiler TS, Orangeville TS and Burlington TS. Electricity is transformed from 500 kV and 230 kV to 230 kV and 115 kV, respectively, at these stations. Electricity is then delivered to the end users of LDCs and directly-connected industrial customers by twenty-four (24) step-down transformer stations.

A single line diagram showing the electrical facilities of the KWCG Region is provided in Figure 3-1, which illustrates these stations as well as the four major regional sub-systems: Waterloo-Guelph 230 kV sub-system, Cambridge-Kitchener 230 kV sub-system, Kitchener-Guelph 115 kV sub-system and South-Central Guelph 115 kV sub-system.

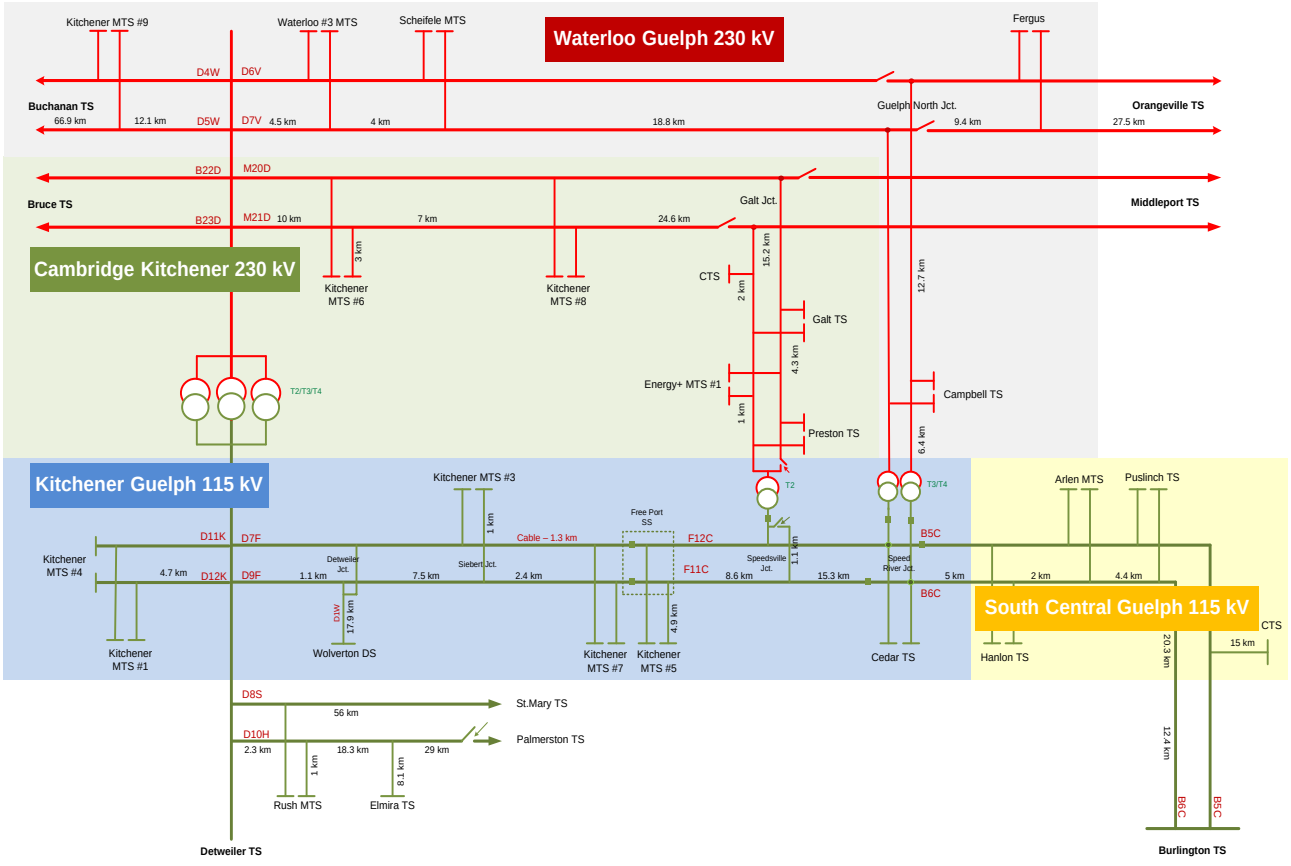


FIGURE 3-4: SINGLE LINE DIAGRAM OF THE KWCG REGION'S TRANSMISSION NETWORK

The twenty-four (24) KWCG's transformer stations can be grouped into six electrical (four major) zones based on their HV supply network:

1. **Waterloo-Guelph 230 kV Area:** The transformer stations in this area are supplied by Detweiler TS 230kV. This area includes transformer stations connected to the 230 kV circuits between Detweiler TS and Orangeville TS D6V/D7V, serving customers in the KWCG area. Below are the transformer stations in Waterloo-Guelph 230 kV area.
    - Campbell TS
    - Fergus TS
    - Scheifele MTS
    - Waterloo North MTS# 3

2. **Cambridge-Kitchener 230 kV Area:** The transformer stations in this area are supplied by Detweiler TS 230kV. This area includes transformer stations connected to the 230 kV circuits between Detweiler TS and Middleport TS M20D/M21D, serving customers in the KWCG area. Below are the transformer stations in Cambridge-Kitchener 230 kV area.
    - Energy + MTS# 1
    - Galt TS
    - Preston TS
    - Kitchener MTS# 6
    - Kitchener MTS# 8
    - CTS# 1

3. **Kitchener-Buchanan 230 kV Area:** The transformer stations in this area are supplied by Detweiler TS 230kV. This area includes transformer stations connected to the 230 kV circuits between Detweiler TS and Buchanan TS. This area has only one transformer station.
    - Kitchener MTS# 9.

4. **Kitchener-Elmira 115 kV Area:** This area covers the north-western part of the KWCG area which is supplied by the Detweiler TS 230/115 kV autotransformers. The transformer stations in this area are:
    - Elmira TS
    - Rush MTS

5. **Kitchener-Guelph 115 kV Area:** This area covers the Kitchener area and northern Guelph area, which is supplied by the Detweiler TS 230/115 kV autotransformers. The transformer stations in this area are:
    - Cedar TS
    - Kitchener MTS# 1
    - Kitchener MTS# 3
    - Wolverton DS
    - Kitchener MTS# 4
    - Kitchener MTS# 5

- Kitchener MTS# 7

6. **South-Central Guelph 115 kV Area:** This area covers the southern part of Guelph, which is supplied by the Burlington TS 230/115 kV autotransformers. The transformer stations in this area are:
    - Arlen MTS
    - Puslinch DS
    - Hanlon TS
    - CTS# 2

4. Transmission Facilities/ Projects Completed and/or Underway Over the Last Ten Years

OVER THE LAST TEN YEARS, A NUMBER OF TRANSMISSION PROJECTS HAVE BEEN PLANNED AND UNDERTAKEN BY HYDRO ONE AIMED TO MAINTAIN THE RELIABILITY AND ADEQUACY OF ELECTRICITY SUPPLY TO THE KWCG REGION.

A summary and description of the major projects completed and/or currently underway over the last ten years is provided below. These projects were identified as a result of joint planning studies undertaken by Hydro One, IESO and the LDCs; or initiated to meet the needs of the LDCs; and/or to meet Provincial Government policies. A brief listing of the completed projects is given below.

For distribution voltage level transformation capacity needs:

- Arlen MTS connected in 2011

For reactive and voltage support needs:

- 230 kV SVC (+350 MVAr @ 250 kV) installed at Detweiler TS in 2011[3]
- 115 kV shunt capacitor bank installed at Detweiler TS in 2012

For 230 kV transmission circuit capacity needs:

- 230 kV M20D/M21D circuit sections capacity increased by sag limit mitigation in 2014

For 115 kV transmission circuit capacity and 230 kV load restoration needs:

- Guelph Area Transmission Reinforcement (GATR) project in 2016 that includes:
  - extension the 230kV circuits D6V/D7V to Cedar TS;
  - two new 250 MVA, 230/115kV autotransformers at Cedar TS;
  - And two 230 kV in-line switches at Guelph North Junction on circuits D6V/D7V.

  This project reinforces the Kitchener-Guelph and South-Central Guelph 115kV sub-systems as well as improves restoration capability to the Waterloo-Guelph 230 kV sub-system.

- Two new additional 230kV in-line switches on M20D/M21D circuits installed at Galt Junction in 2017 to improve restoration capability of the Cambridge-Kitchener 230 kV sub-system

For station short circuit capacity needs:

[3] Two SVCs were installed for the contingency support in the South-western Ontario

- 13.8 kV series reactors were installed to mitigate short circuit levels at Arlen MTS. This project was identified in the last RIP phase.

For end of life needs addressed:

- Galt TS T7 and T8 Transformers Replacement
- Campbell TS T1 and T2 Transformers Replacement
- Detweiler TS AC Station Service and Component Replacement
- D7F / D9F 115 kV Tower Refurbishment, Tower 157 near Freeport SS
- D6V / D7V 230 kV Lines Refurbishment between Fergus TS and Campbell TS
- Detweiler TS 250 MVA 230/115 kV T2 and T4 autotransformers replaced

5. Load Forecast and Study Assumptions

5.1. Load Forecast

The electricity demand in the KWCG Region is anticipated to grow by about 10% over the next ten years. Figure 5-1 shows the KWCG Region's planning load forecast (summer net, coincident extreme weather corrected peak) developed during this RIP phase.

This RIP load forecast was used to determine the loading that would be seen by transmission lines and autotransformer stations and to identify the need for additional line and auto-transformation capacity.

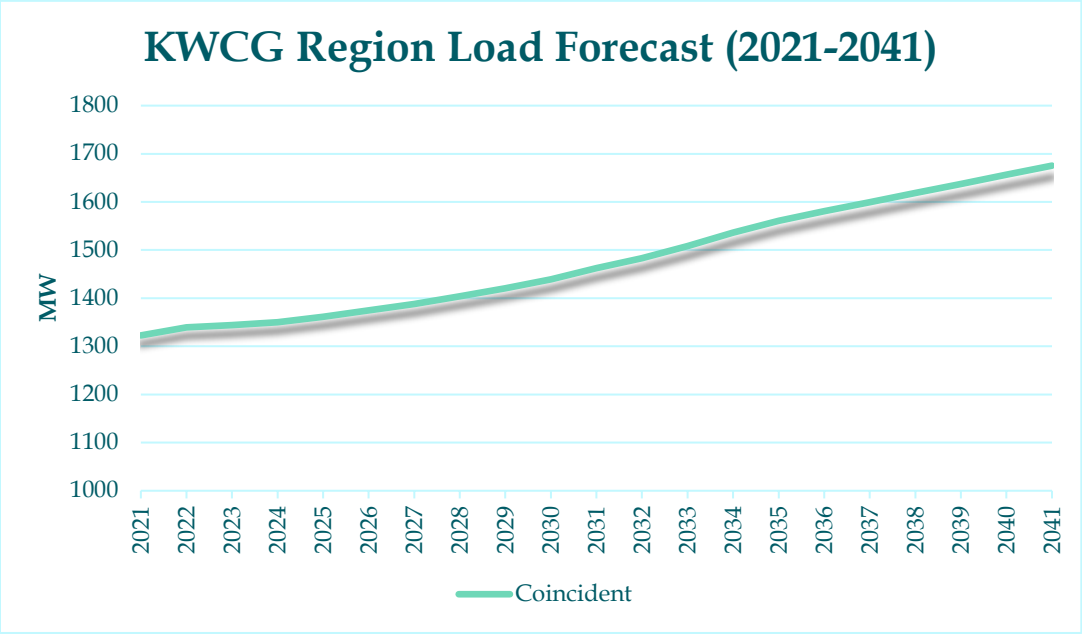


FIGURE 5-5: KWCG REGION LOAD FORECAST

The regional-coincident load forecast represents the total peak load of the 24 step-down transformer stations in the KWCG Region. The Region's peak summer load is forecasted to increase from 1323 MW in 2021 to 1462 MW by 2031.

The load forecast for KWCG RIP is provided in Appendix D. This load forecast is based upon the 2020 actual loads and the load forecast prepared by the IESO for the recently completed IRRP. The NA and the IRRP used the 2018 actual loads as the base. More than two years have passed since then and though 2020 seems to be unusual year in light of the COVID-19 pandemic; with all the applicable adjustments and the comparisons with 2018, 2019 and 2021 actual loads, it made sense to base the load forecast on 2020 actual station loads.

This approach was reviewed and accepted by the Study Team during the RIP phase. During the data gathering, some LDCs provided a revised load forecast while the other confirmed no changes to their load forecasts provided earlier to the IESO for the IRRP during the current

Regional Planning cycle. The IESO also updated the CDM and DG targets for the preparation of this RIP load forecast. The load forecast for this RIP was prepared by adjusting the actual 2020 summer peak loads applying an extreme weather correction factor and then applying growth rates derived from the LDCs' forecast. This forecast was further adjusted taking into account the impact of CDM and DGs provided by the IESO. Further details regarding the CDM and connected DG are provided in reference [2] [3]. The load forecast prepared for this RIP is slightly lower than the one prepared by the IESO for the purpose of IRRP but is in the same order of magnitude. The change in the load forecast due to the factors listed above has resulted in the shifting or elimination of previously identified needs, along with the emergence of new needs close to the end of the study period.

5.2. Study Assumptions

The following assumptions are made in this report.

- The study period for the RIP assessments is 2021-2041.
- All facilities that are identified in Section 4 and that are planned to be placed in-service within the study period 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. Normal planning supply capacity for transformer stations is determined by the summer 10-day Limited Time Rating (LTR).
- Line capacity adequacy is assessed by using coincident peak loads in the area.
- Adequacy assessment is conducted as per Ontario Resource Transmission Assessment Criteria (ORTAC) [6].

6. Adequacy of Existing Facilities

THIS SECTION REVIEWS THE ADEQUACY OF THE EXISTING TRANSMISSION AND TRANSFORMER STATION FACILITIES SUPPLYING THE KWCG REGION OVER THE PLANNING PERIOD (2021-2041).

During this regional planning cycle three (3) separate assessments have been completed for the KWCG Region. The findings of these studies are the inputs to this Regional Infrastructure Plan (RIP). These assessments are:

- 2018 KWCG Region Needs Assessment ("NA") Report
- 2019 KWCG Region Scoping Assessment ("SA") Report
- 2021 KWCG Integrated Regional Resource Plan ("IRRP") Report

The NA and IRRP reports identified a number of needs to meet the forecasted load demands and assets approaching end of life (EOL). This section provides a review of the adequacy of the transmission lines and stations in the KWCG Region. The adequacy is assessed using the latest regional load forecast provided in Appendix D from a loading perspective. Sections 6.1 to 6.6 present the results of this review. Sustainment aspects were identified in the NA report and are addressed in Section 7 of this report.

6.1. 230 kV Transmission Facilities

All 230 kV transmission circuits in the KWCG Region are classified as part of the Bulk Electricity System ("BES"). They connect the Region to the rest of the Ontario's transmission system and are also part of the transmission path from generation in Southwestern Ontario to the load centers in the Hamilton, Niagara and GTA areas. These circuits also serve local area stations within the Region and the power flow on them depends on the bulk system transfer as well as local area loads. These circuits are as follows (please refer to Figure 3-1):

a) Detweiler TS to Orangeville TS 230 kV circuits D6V and D7V
   - supplies Fergus TS, Campbell TS, Waterloo North MTS# 3 and Scheifele MTS

b) Detweiler TS to Middleport TS 230 kV circuits M20D and M21D
   - supplies Kitchener MTS# 6, Kitchener MTS# 8, Energy + MTS# 1, Galt TS, Preston TS and Customer # 1 CTS

c) Detweiler TS to Buchanan TS 230 kV circuits D4W and D5W
   - supplies Kitchener MTS# 9

The RIP review of the current load forecast shows that based on the forecasted station loadings, all the above three (3) 230 kV transmission lines are expected to be adequate over the study period.

6.2. 230/115 kV Autotransformer Facilities

Bulk power supply to the KWCG Region is provided by Hydro One's 500 kV to 230 kV and 230 kV to 115 kV autotransformers. The number and location of these autotransformers are as follows:

a) Two 500/230 kV autotransformers at Middleport TS
b) Four 230/115 kV autotransformers at Burlington TS
c) Three 230/115 kV autotransformers at Detweiler TS
d) Two 230/115 kV autotransformers at Cedar TS
e) One 230/115 kV autotransformer at Preston TS

Middleport autotransformers are part of the south-western Ontario bulk supply system and will be studied separately under Middleport bulk planning studies for a more comprehensive understanding of the bulk system needs. However for the purpose of KWCG regional planning needs, these auto-transformer facilities are adequate over the study period.

Burlington TS autotransformers supply the South-Central Guelph 115 area that in turn supply Arlen MTS, Hanlon TS, Customer# 2 CTS and Puslinch DS. The Burlington TS autotransformer facilities are adequate over the study period.

Detweiler TS, Preston TS and Cedar TS autotransformers supply the Kitchener-Guelph 115 kV area that in turn supply Cedar TS, Kitchener MTS #1, Kitchener MTS #3, Kitchener MTS #4, Kitchener MTS #5, Kitchener MTS #7, Elmira TS, Rush MTS and Wolverton DS. The transformation facilities are adequate over the study period.

Note that the Preston TS autotransformer and the 115 kV Kitchener Guelph supply system may not have adequate supply capacity due to its inherent limitation of 115 kV supply system to address the load restoration concerns beyond the study period in case of the simultaneous loss of both the 230 kV circuits, M20D and M21D.

6.3. 115 kV Transmission Facilities

The KWCG Region contains five pairs of double circuit 115 kV lines. This 115 kV network serves local area load. The 115 kV transmission facilities can be divided into five main corridors summarized below.

a) Detweiler TS to Freeport SS 115 kV transmission circuits D7F/D9F
    - supplies Wolverton DS, Kitchener MTS #3, Kitchener MTS#7
b) Freeport SS to Cedar TS 115 kV transmission circuits F11C/F12C
    - supplies Kitchener MTS #5 and Cedar T1/T2 transformers
c) Burlington TS to Cedar TS 115 kV transmission circuits B5C/B6C
    - supplies Puslinch DS, Arlen MTS, Hanlon TS, Customer #2 CTS and Cedar T7/T8 transformers
d) Detweiler TS 115 kV radial transmission circuit D11K/ D12K

- supplies Kitchener MTS #1 and Kitchener MTS #4

e) Detweiler TS to Seaforth TS / Hanover TS 115 kV transmission circuit D8S/D10H with Normally Open (N/O) points

- supplies Rush MTS and Elmira TS (D10H only)

In the near and mid-term, all the 115 kV circuits are adequate and no supply capacity needs are identified under loss of one element. A marginal overloading was identified during the IRRP phase on B5C under the outage scenario of B6C and a subsequent loss of F12C. This marginal overloading can be managed by coordinated outage planning.

In the long term, near the end of the study period, the section of 115 kV D10H circuit between Detweiler TS and tap to Rush MTS may slightly be overloaded following the loss of companion D8S circuit under a peak load scenario. This is a need in the long term and will be revisited in the next planning cycle.

6.4. Step-Down Transformer Station Facilities

There are 24 step-down transformer stations within the KWCG Region. Twenty-two supply electricity to LDCs and two are transmission-connected customer transformer stations. These stations are listed within the load forecast in Appendix D. Of those 24 stations, 15 of them are owned and operated by the LDCs.

The stations summer peak non-coincident load forecast is given in Table D-1 of Appendix D.

TABLE 6-1: KWCG STEP-DOWN EXISTING TRANSFORMER STATIONS

230 kV		115 kV	
Campbell TS	Preston TS	Arlen MTS	Kitchener MTS #5
Energy + MTS # 1	Scheifele MTS	Cedar TS	Kitchener MTS #7
Fergus TS	Waterloo North MTS# 3	Elmira TS	Puslinch DS
Galt TS	CTS# 1	Hanlon TS	Rush MTS
Kitchener MTS # 6		Kitchener MTS# 1	Wolverton DS
Kitchener MTS # 8		Kitchener MTS# 3	CTS # 2
Kitchener MTS # 9		Kitchener MTS # 4	

As a part of RIP assessment, the step-down transformation station capacity was reviewed considering the non-coincident load forecast. Accordingly, the following step down transformation capacity needs are identified. The need timeframe defines the time when the peak load forecast first approaches the station's summer 10 day LTR:

TABLE 6-2: KWCG STEP-DOWN TRANSFORMER STATIONS SUPPLY CAPACITY NEEDS

Stations	Need Timeframe
Kitchener MTS # 5	2028
Cedar TS (T7/T8)	2030
Kitchener MTS # 8 T15/T16	2033
Energy + MTS # 1	2036
Campbell TS (T1/T2)	2038
Preston TS	2038
Arlen MTS	2040
Scheifele MTS	2041
Elmira TS	2041
Waterloo North MTS # 3	2041

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.

- All loads must be restored within 8 hours.
- Load interrupted in excess of 150 MW must be restored within 4 hours.
- Load interrupted in excess of 250 MW must be restored within 30 minutes.

After the in-service of the Guelph Area Transmission Reinforcement project that included the installation of two new 230/115kV autotransformers at Cedar TS, two new 230 kV in-line switches on D6V/D7V circuits to improve restoration capability of Waterloo-Guelph 230 kV sub-system and two new 230kV in-line switches on M20D/M21D circuits to improve restoration capability of the Cambridge-Kitchener 230 kV sub-system; it is expected that all loads can be restored within 8 hours in the KWCG Region over the study period.

A simultaneous loss of M20D and M21D will result in the loss of up to 375 MW of load, by 2041, in the Cambridge area. Up to 150 MW of this load must be restored within 30 minutes as required by ORTAC. This is within the capability of the system and, so, no load restoration concern has been identified in this RIP. However, the Study Team agrees to monitor the load in the region for any new developments to ascertain that load restoration concern are identified ahead of time. Note that the Preston TS autotransformer and the 115 kV Kitchener Guelph supply system may not be adequate due to its inherent limitations to address the load restoration concerns beyond the study period in case of the simultaneous loss of both 230 kV circuits, M20D/M21D.

6.6. Station Short Circuit Capacities [2][3]

The regional planning process identified a need to examine short circuit levels at all the stations in the region as they pertain to LDC equipment ratings as well as to generation or storage resources connection challenges. The particular concerns raised at the time of initiation of this second cycle of the regional planning for the region have since been satisfactorily resolved. However, the Study Team recognizes the importance of a holistic system planning approach, which includes analysis related to short circuit levels.

Distribution system short circuit levels, as measured at the low-voltage (LV) bus of transmission connected transformer stations, are subject to change due to two main driving factors: changes in upstream impedance and changes in amount and type of DERs connected to the station. Changes in upstream impedance typically result from transmission system changes, such as network expansion or reconfiguration or changes in transformer impedance at the time of transformer replacement.

The upstream impedance generally has minimal impact on the station LV actual short circuit level because of the dominant effect of the station transformers impedance. However, changes in the amount and type of DERs connected to a LV bus of a station, unlike changes in upstream impedance, have a significant and direct impact on the station's LV short circuit level.

While equipment which limits the available short circuit capacity on the LV side of a transformer station may have options to be upgraded with higher rated equipment, the Study Team is cognizant that there is an effective practical limit to this rating established by in Appendix 2 of the Transmission System Code. Distribution systems components, including equipment owned by end-use customers, in Ontario, is designed, manufactured, and applied to this standard, which effectively is:

- 500 MVA @ 13.8 kV
- 800 MVA @ 27.6 kV
- 1500 MVA @ 44 kV

The amount of DER that can be connected to a station LV bus is thus limited by the above-mentioned short circuit level requirements. Some stations may have a smaller value due to pre-existing legacy equipment which was adequate and is deemed to be grandfathered. Hence, in examining the rated short circuit capacity of LV station components, the Study Team used lowest equipment rating, or TSC rating, whichever is lower in identifying stations that are at or approaching short circuit capacity limits.

Appendix E lists all stations in the KWCG region where new DER connection is restricted due to the LV short circuit level being extremely high, that is approximately equal to or greater than 90% of the equipment ratings or the TSC ratings capacity. The information presented in this table is obtained with consideration of known generation connections as of March 2021 and is subject to change primarily due to new DER connections.

The appropriate LDC should be consulted for up-to-date short circuit information and feasibility of connecting new DER.

6.7. Longer Term Outlook

While the RIP was focused on the 2021-2041 period, the Study Team has also looked at longer-term electricity sector scenarios and uncertain load growth possibilities within the study period under certain pockets within the KWCG region. Following two subsections describes two such items that requires longer-term insight for the regional needs.

6.7.1. Other Planning Considerations in the KWCG Region

Municipalities in KWCG region have developed their community energy plans with a primary focus to reduce their energy consumption by local initiatives over next 25 to 30 years. With respect to electricity, these communities are planning for an increased reliance on community energy sources such as distributed generation, generation behind the meters like rooftop solar systems and local battery storage systems to reduce cost and for improved reliability of electricity supply. The implementation timelines, as suggested in these plans, starts in longer term just near the end of the study period and requires greater attention in the next regional planning cycle.

Note that community energy plans may have potential to supplement and/or defer future transmission infrastructure development needs. The Study Team therefore recommends reviewing the community energy plans in the next regional planning cycle.

There are situations where behind the meter battery storage cannot be connected due to technical constraints. The LDCs in this region and Hydro One, outside the regional planning forum, can undertake the task of exploring the issue to assess technical constraints and /or other solutions that can facilitate connection of additional battery storage.

In parallel and within the Conservation and Demand Management initiatives, communities are also working towards self-sufficiency by improving efficiencies of existing local energy systems i.e. reducing energy consumption and losses by means of utilizing smarter buildings, houses, efficient heating, cooling, appliances, equipment, and processes for all community needs. Ultimately, the objective of these energy plans in the region is to be a net zero carbon community.

6.7.2. Uncertain Load Growths

There are some load growth possibilities in pockets of the region where, due to lack of confirmed status of development projects or uncertainty with connection point, were not included in the load forecast. These load growth triggers will be closely monitored and reviewed for further analysis in the next regional planning cycle:

- Metrolinx electrification project: Metrolinx is electrifying its rail lines and planning a traction power substation (TPSS). The amount of traction load is insignificant but has a very sensitive and peculiar characteristics that makes it troublesome for other customers in a weaker system. The connection point of TPSS is not yet finalized and therefore has a higher uncertainty.
- East Side Lands: Energy + is expecting load growth in its east side lands and are planning Energy + MTS # 2 to meet the increased load demand which has not materialized yet. Similarly, Waterloo North Hydro is also anticipating load growth in

the east side lands near Scheifele TS and are planning WNH MTS # 4 to cater the new load growth and some existing loads currently supplied from Scheifele TS. In addition, Hydro One is carrying out end of life like for like replacement of transformers at Preston TS in the 2026-2027 timeframe that will impart additional supply capacity to the station due to the alleviation of an inherent equipment limitation. This incremental capacity to be available in 2026 at Preston TS would be examined to determine if it is technically and economically feasible, meeting power quality requirements, to service both Energy+ and Waterloo North Hydro's East Side Lands development and surrounding areas under normal and/or contingency situations. These needs along with increased station capacity, therefore, will be revisited in the next regional planning cycle for optimal solution, hoping to have more clarity on the development projects in the pocket by then.

- Development of other projects such as Data Centers and Light Rail Transit from Kitchener to Cambridge will be monitored and assessed in the next regional planning cycle.

7. Regional Needs and Plans

THIS SECTION DISCUSSES ELECTRICAL INFRASTRUCTURE NEEDS IN THE KWCG REGION IDENTIFIED IN THE PREVIOUS REGIONAL PLANNING CYCLE, THE NEEDS ASSESSMENT REPORT FOR THIS CYCLE, SCOPING ASSESSMENT AND THE 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 plans and the supply capacity needs. The long term needs will be assessed in the next regional planning cycle.

The near-term and mid to long-term electrical infrastructure needs in the Region are summarized below in Table 7.1 and Table 7.2, respectively. The details of the project / plan are discussed further in sections 7.1 and 7.2.

TABLE 7-3: IDENTIFIED NEAR AND MID-TERM NEEDS IN KWCG REGION

No.	Needs	Project / Need Timeframe	Section
1	Hanlon TS: EOL T1/T2 Supply Transformers Replacement	2022-2023	7.2
2	Kitchener MTS #5: EOL T9/T10 Supply Transformers Replacement	2023-2024	7.2
3	Scheifele MTS: EOL T1/T2 Supply Transformers Replacement	2025-2026	7.3
4	115 kV B5C/ B6C**:** EOL Burlington TS to Westover CTS Line Sections Refurbishment	2025-2026	7.2
5	Preston TS: EOL T3/T4 Supply Transformers Replacement	2026-2027	7.3
6	Cedar TS: EOL T7/T8 Supply Transformers Replacement	2026-2027	7.3

TABLE 7-4: IDENTIFIED LONG-TERM NEEDS IN KWCG REGION

No.	Needs	Timing	Section
1	Fergus TS: EOL T3/T4 Supply Transformers Replacement	2028-2029	7.3
2	Galt TS: EOL Breakers and other component Replacement	2028-2029	7.3
3	Campbell TS: EOL three (3) Breakers and other component Replacement	2028-2029	7.3
4	Kitchener MTS # 8 (T15/T16): Station Supply Capacity	2033	7.4
5	Energy + MTS # 1: Station Supply Capacity	2036	7.4
6	Campbell TS (T1/T2): Station Supply Capacity	2038	7.4

7	Arlen MTS: Station Supply Capacity	2040	7.4
8	Elmira TS: Station Supply Capacity	2041	7.4
9	Waterloo North MTS # 3: Station Supply Capacity	2041	7.4

7.1. Deteriorating Infrastructure, Optimization Opportunities and Replacement Plan of Major Equipment

7.1.1. Deteriorating Infrastructure

Hydro One and LDCs have provided high voltage asset information under the following categories that have been identified at this time and are likely to be replaced over the next 10 years:

- Autotransformers
- Power transformers
- HV breakers
- Transmission lines requiring refurbishment where an uprating is being considered for planning needs and require Leave to Construct (i.e., Section 92) application and approval
- HV underground cables where an uprating is being considered for planning needs and require EA and Leave to Construct (i.e., Section 92) application and approval

The end-of-life (EOL) assessment, which includes right sizing, for the above high voltage equipment typically includes consideration of the following options:

1. Maintaining the status quo;
2. Replacing equipment with similar equipment of lower ratings and built to current standards;
3. Replacing equipment with lower ratings and built to current standards by transferring some load to other existing facilities;
4. Eliminating equipment by transferring all of the load to other existing facilities;
5. Replacing equipment with similar equipment and built to current standards (i.e, “like-for-like” replacement);
6. Replacing equipment with higher ratings and built to current standards; and
7. Station reconfiguration

Accordingly, following major high voltage equipment has been identified as approaching its end of life, based on current condition information, over the next 10 years.

TABLE 7-5: DETERIORATING INFRASTRUCTURE, EOL NEEDS IN KWCG REGION

Stations / Lines Project	Details	Timeframe	High Level Cost[4] ($M)
Hanlon TS	T1/ T2 Transformer Replacement	2022-2023	17.8
Kitchener MTS #5	T9/ T10 Transformer Replacement	2023-2024	7.5
Scheifele MTS	T1/ T2 Transformer Replacement	2025-2026	-
B5C/B6C	Refurbishing 115kV line section from Burlington TS to Enbridge Westover CTS	2025-2026	16.8
Preston TS	T3/ T4 Transformer Replacement	2026-2027	22.9
Cedar TS	T7/ T8 Transformer Replacement	2026-2027	23.7
Fergus TS	T3/ T4 Transformer Replacement	2028-2029	30.0
Galt TS	Breakers and Other Component Replacement	2028-2029	12.0
Campbell TS	Breakers and Other Component Replacement	2028-2029	18.1

Maintaining status quo is not an option for any of the end of life autotransformers, station transformers or line sections due to risk of equipment failure, and would result in increased maintenance cost and prolonged customer outages and interruptions. Replacing “like-for-like” with nonstandard transformers would result in complexity with failures, difficulty with spares management strategies and with unique installation requirements. Nonstandard equipment also poses serious safety risk for employees under normal and emergency situations.

No other lines or HV station equipment in the KWCG region than listed above, have been identified for major replacement/refurbishment at this time.

7.1.2. Optimization Opportunities and Replacement Plans

For stations in the Cambridge-Guelph sub region, an analysis of the current distribution situation that includes under-utilized dedicated feeder capacities, determined that there are not enough spare feeder positions and capacity at HONI and Alectra stations to reallocate DESN loads in the sub-system without significant distribution system and neighboring station upgrades.

Similar is the situation with Kitchener-Waterloo sub region and therefore there are little or no significant optimization opportunities present at this time.

[4] Budgetary estimates

Hence, the Study Team recommends that the LDCs undertakes replacement of their end-of-life high voltage equipment as planned with standard size units, being technically and economical most suitable solution.

7.2. Needs in Near-Term (Projects in Execution)

The following end-of-life refurbishment needs are under execution. These needs were identified in the earlier phases of this 2nd cycle of regional planning.

7.2.1.115 kV B5C/ B6C Line Sections

The 115 kV B5C/B6C circuits consist of about 45 km of double circuit line and 15 km of single circuit line supplying South-Central Guelph 115 kV loads. About 12 km of double circuit line section from Burlington TS to Harper's Jct. and about 15 km B5C 115 kV line tap from Harper's Jct. to a Westover Jct. requires refurbishment.

Not refurbishing these line sections would increase risk of failure due to asset condition, maintenance expenses and reduce supply reliability to the customers.

The refurbishment of the 27 km 115 kV B5C/B6C line sections from Burlington TS to a CTS is currently under execution and the work is planned to be completed by the end of year 2025. The delay in the in-service is attributed to a hold on project due to outage concerns with a customer.

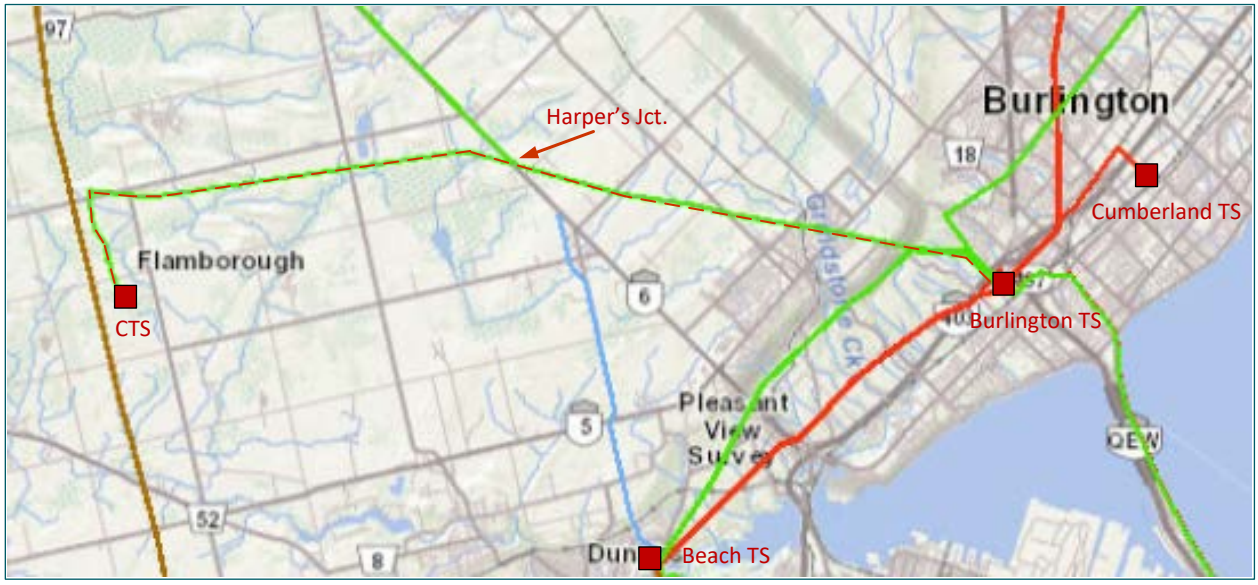


FIGURE 7-6: BURLINGTON TS TO HARPER'S JCT. TO CTS

7.2.2. Hanlon TS T1/T2 Transformer

Hanlon TS is located south of the city of Guelph supplying Alectra loads. Hanlon TS is a single T1/T2 DESN station of 33 MVA nonstandard transformers having a LTR of 48 MVA (43 MW @ 0.9 PF). This station is currently supplying about 27.5 MW of peak load. The loads at Hanlon TS are currently forecasted to remain flat over the entire study period. The supply capacity of this station is therefore expected to be sufficient over and beyond the study period.

The T1/T2 transformers were built in 1955-56 and have been identified as EOL due to poor condition requiring replacement. At this time none of other HV/LV equipment at this station has been identified as approaching EOL over the next 5-10 years.

There are no nearby supply stations to Hanlon TS with surplus capacity where this station's loads can be transferred therefore Hydro One plans to replace these EOL transformers with standard size units of 42 MVA in 2022-2023.

7.2.3. Kitchener MTS #5 T9/T10 Transformers

Kitchener MTS #5 is located in the city of Kitchener supplying Kitchener-Wilmot Hydro Inc. loads. Kitchener MTS #5 is a 115/ 13.8 kV single T9/T10 DESN station of 83 MVA nonstandard transformers having a LTR of 89 MVA (80 MW @ 0.9 PF), currently supplying 67 MW of peak load. The loads at Kitchener MTS #5 are currently forecasted to grow at about 15% over the entire study period and approaches the supply capacity of this station by 2028.

Both the T9/T10 transformers at this station have been identified as approaching end of life requiring replacement. At this time none of other HV/LV equipment at this station has been identified as approaching EOL over the next 5-10 years.

The station cannot be downsized or eliminated because there is no nearby supply station/s to Kitchener MTS #5 having surplus capacity where this station's loads can be transferred. The Study Team recommends replacing the T9/T10 nonstandard transformers with standard units of similar or greater size, that can provide higher LTR for station capacity to be sufficient beyond study period, is the preferred option. Kitchener-Wilmot Hydro Inc. and Hydro One will coordinate the replacement plan of these transformers. The replacement of the EOL equipment is expected to be completed by 2023-2024.

7.3. Needs in Near, Mid and Long Term

The following end-of-life refurbishment needs have been identified in this regional planning cycle:

7.3.1. Scheifele MTS – T1/ T2 Transformers

Scheifele MTS is located in the city of Waterloo supplying Waterloo North Hydro Inc. loads. Scheifele MTS has four 230/13.8 kV transformers T1 and T2 of 69 MVA (LTR), and T3 and T4 of 110 MVA (LTR) currently supplying 145 MW of peak loads. The load at this station is forecasted to remain almost flat over the entire study period. The total supply capacity of Scheifele MTS is 161 MW expected to be sufficient over the study period, except marginal overloading in 2041.

The T1/T2 transformers based on their age have been identified by Waterloo North Hydro Inc. as approaching end of life potentially requiring replacement in the 2025- 2026 timeframe. Waterloo North Hydro will be monitoring the condition of these transformers to assess their replacement need. At this time none of other HV/LV equipment at this station has been identified as approaching EOL over the next 5-10 years.

The station cannot be downsized or eliminated because there is no nearby supply station/s to Scheifele MTS having surplus capacity where this station's loads can be transferred. The Study Team recommends that Waterloo North Hydro continue monitoring the condition of these T1/T2 transformers at Scheifele MTS and if required, proceed with replacement plan otherwise this need may be reassessed in the next regional planning cycle.

7.3.2. Cedar TS – T7/ T8 Transformers

Cedar TS is located in the city of Guelph supplying Alectra loads. Cedar TS has two 115/13.8 kV DESN units T1/T2 and T7/T8 of 75 MVA with a LTR of 115 MVA (103 MW @ 0.9 PF) and 37 MVA with a LTR of 44 MVA (40 MW @ 0.9 PF), currently supplying 67 MW and 36 MW of peak loads respectively. The loads at both Cedar TS DESNs are currently forecasted to grow at an average of about four percent (4%) over the entire study period. The supply capacity of T7/T8 may approach its LTR by year 2030 while that of T1/T2 is expected to be sufficient over the study period.

The T7/T8 DESN 38 MVA nonstandard transformers were built in 1958 and have been identified for replacement due to poor condition. The T1/T2 transformers are relatively newer and were built in early 1990s. At this time none of other HV/LV equipment at this station has been identified as approaching EOL over the next 5-10 years.

The station cannot be downsized or eliminated because there is no nearby supply station/s to Cedar TS having surplus capacity where this station's loads can be transferred therefore the Study Team recommends replacing the nonstandard transformers with standard units of 42 MVA in 2026-2027 timeframe, which will impart sufficient capacity (higher LTR) to the station over the study period.

7.3.3. Preston TS T3/T4 Transformers

Preston TS (DESN) is located in the city of Cambridge supplying Energy+ loads. Preston TS is a single T3/T4 DESN station of 125 MVA transformers with no additional LTR capability available i.e. 125 MVA (113 MW @ 0.9 PF). This station is currently supplying about 92 MW of peak load. The loads at Preston TS are currently forecasted to peak at about 120 MW during the study period.

The T3/T4 transformers are almost 50 years old, having been built in 1968. Condition assessment has identified that both T3/T4 transformers at EOL, requiring replacement. At this time none of other HV/LV equipment at this station has been identified as EOL over the next 5-10 years.

The station cannot be downsized or eliminated because there is no nearby supply station/s to Preston TS having spare supply capacity where this station's loads can be transferred. The Study Team recommends replacing the existing 125 MVA 230/ 27.6 kV T3/T4 transformers at Preston

TS with 125 MVA standard units. This will also result in an increased supplying capacity at Preston TS due to the alleviation of an inherent equipment limitation, required to meet the future Energy+ needs in the Cambridge distribution area. This incremental capacity may be available for Waterloo North Hydro's East-Side-Lands development as deemed technically and economically feasible, meeting power quality requirements. The replacement plan for the equipment will be developed by Hydro One and coordinated with the affected LDC and/or customers and it is expected to be completed by 2026-2027.

7.3.4. Fergus TS T3/T4 Transformers

Fergus TS is located in the township of Fergus supplying various loads LDCs in the KWCG region. Fergus TS has two 230/ 44 kV transformers T3 and T4 of 75/100/125 MVA, currently supplying 90 MW of peak loads. The load at this station is forecasted to grow at about 20 percent over the entire study period. The total supply capacity of Fergus TS is 154 MW expected to be more than adequate over the study period.

The T3/T4 transformers are almost 50 years old, having been built in 1972. Condition assessment has identified that both T3/T4 transformers and the feeder breakers are at their EOL requiring replacement.

The station cannot be downsized or eliminated because there is no nearby supply station/s to Fergus TS having surplus capacity where this station's loads can be transferred. The Study Team recommends that Hydro One continue monitoring the condition of these T3/T4 transformers and other components at Fergus TS and if required proceed with the replacement plan by 2028-2029 or otherwise this need may be reassessed in the next regional planning cycle.

7.3.5. Galt TS Breakers and Components

Galt TS is located in the city of Cambridge supplying Energy + loads in the KWCG region. Galt TS has two 230/ 28-28 kV transformers T7 and T8 of 75/100/125 MVA, currently supplying 112 MW of peak loads. The load at this station is forecasted to grow at about 20 percent over the entire study period. The total supply capacity of Galt TS is 169 MW, expected to be more than adequate over the study period.

The T7/T8 transformers were replaced in 2010 and 2012 respectively to technical issue with the transformers. The breakers and other component at the station are almost 50 years old. Condition assessment has identified that these components are at EOL, requiring replacement.

The station cannot be downsized or eliminated because there is no nearby supply station/s to Galt TS having surplus capacity where this station's loads can be transferred. The Study Team recommends that Hydro One continue monitoring the condition of these EOL components at Galt TS and if required proceed with the replacement plan by 2028-2029 or otherwise this need may be reassessed in the next regional planning cycle.

7.3.6. Campbell TS (T1/T2) Breakers

Campbell TS is located in the city of Guelph supplying Alectra loads. Campbell TS has two 230/ 13.8 kV DESNs T1/T2 and T3/T4, both 100 MVA transformers. The loads on these two DESNs are currently supplying about 89 MW and 47 MW respectively and their loads are forecasted to grow at about 9 percent by the end of study period.

Two feeder breakers and a tie breaker for T1/T2 DESN are deemed to be end of life and requires replacement. Replacing these three breakers will impart additional 5 to 7 MW of capacity to the DESN, help mitigating the marginal station supply capacity concern at the end of the study period. The Study Team recommends implementing replacement plan by 2028-2029.

7.4. Mid and Long Term Supply Capacity Needs

When the station capacities were reviewed considering the net peak load forecast, below listed ten (10) stations were identified to approach their 10 day LTR. The last four stations were found to approach their 10 day LTR just at the end of the study period of this second regional planning cycle.

TABLE 7-4: KWCG STEP-DOWN TRANSFORMER STATIONS SUPPLY CAPACITY NEEDS

Stations	Need Timeframe
Kitchener MTS #5	2028
Cedar TS (T7/T8)	2030
Kitchener MTS #8 T15/T16	2033
Energy + MTS # 1	2036
Campbell TS (T1/T2)	2038
Preston TS	2038
Arlen MTS	2040
Scheifele MTS	2041
Elmira TS	2041
Waterloo North MTS # 3	2041

The deteriorating infrastructure replacement plans at Kitchener MTS # 5 (T9/T10), Scheifele MTS, Preston TS and Cedar TS (T7/T8) will help mitigate the station supply capacity needs of these stations over and beyond the study period. The Study Team recommends to review other long term station supply capacity needs in the next regional planning cycle.

8. Conclusions and Next Steps

THIS REGIONAL INFRASTRUCTURE PLAN CONCLUDES THE REGIONAL PLANNING PROCESS FOR THE KWCG REGION.

The major infrastructure investments recommended by the Study Team in the near and mid-term planning horizon are provided in Table 8-1 below are all end of life needs, along with their planned in-service date and budgetary estimates for planning purpose.

TABLE 8-6: RECOMMENDED PLANS IN KWCG REGION OVER THE NEXT 10 YEARS

Stations / Lines Project	Details	Timeframe	High Level Cost[5] ($M)
Hanlon TS	Transformers T1 and T2 Replacement	2022-2023	17.8
Kitchener MTS #5	Transformers T9 and T10 Replacement	2023-2024	7.5
Scheifele MTS	Transformers T1 and T2 Replacement	2025-2026	-
B5C/B6C	115KV Lines Refurbishment, refurbishing section from Burlington TS to Enbridge Westover CTS	2025-2026	16.8
Preston TS	Transformers T3 and T4 Replacement	2026-2027	22.9
Cedar TS	Transformers T7 and T8 Replacement	2026-2027	23.7
Fergus TS	Transformers T3 and T4 Replacement	2028-2029	30.0
Galt TS	End of life Breakers and Other Component Replacement	2028-2029	12.0
Campbell TS	End of life Breakers and Other Component Replacement	2028-2029	18.1

The Study Team recommends that:

- Hydro One and LDCs to continue with the implementation of infrastructure investments listed in Table 8-1 above while keeping the Study Team apprised of project status;
- All the other identified needs/options in the long-term will be further reviewed by the Study Team in the next regional planning cycle.

[5] Budgetary estimates

References

[1] KWCG Region Regional Infrastructure Plan (2015)
[2] KWCG Integrated Regional Resource Plan (2021)
[3] KWCG Integrated Regional Resource Plan - Appendices (2021)
[4] KWCG Region Needs Assessment (2018)
[5] Planning Process Working Group (PPWG) Report to the Board: The Process for Regional Infrastructure Planning in Ontario – May 17, 2013
[6] Ontario Resource and Transmission Assessment Criteria

Appendix A. Stations in the KWCG Region

Station*	Voltage (kV)	Supply Circuits
Waterloo-Guelph 230 kV sub-system		
Fergus TS	230 kV	D6V/D7V
Scheifele MTS	230 kV	D6V/D7V
Waterloo North MTS #3	230 kV	D6V/D7V
Campbell TS	230 kV	D6V/D7V
Cambridge-Kitchener 230 kV sub-system		
Kitchener MTS #6	230 kV	M20D/M21D
Kitchener MTS #8	230 kV	M20D/M21D
Energy + MTS #1	230 kV	M20D/M21D
Preston TS	230 kV	M20D/M21D
Galt TS	230 kV	M20D/M21D
Customer #1 CTS	230 kV	M21D
Kitchener–Guelph 115 kV sub-system		
Wolverton DS	115 kV	D7F/D9F
Kitchener MTS #3	115 kV	D7F/D9F
Kitchener MTS #7	115 kV	D7F/D9F
Kitchener MTS #5	115 kV	F11C/F12C
Cedar TS (T1/T2)	115 kV	F11C/F12C
South-Central Guelph 115 kV sub-system		
Puslinch DS	115 kV	B5C/B6C
Arlen MTS	115 kV	B5C/B6C
Hanlon TS	115 kV	B5C/B6C
Cedar TS (T8/T7)	115 kV	B5C/B6C
Customer #2 CTS	115 kV	B5C
Other Stations in the KWCG Region		
Kitchener MTS #9	230 kV	D4W/D5W
Rush MTS	115 kV	D8S/D10H
Elmira TS	115 kV	D10H
Kitchener MTS #1	115 kV	D11K/D12K
Kitchener MTS #4	115 kV	D11K/D12K

*All MTSs are LDC owned stations

Appendix B. Transmission Lines in the KWCG Region

Location	Circuit Designations	Voltage (kV)
Detweiler TS – Orangeville TS	D6V/D7V	230 kV
Detweiler TS - Middleport TS	M20D/M21D	230 kV
Detweiler TS - Buchanan TS	D4W/D5W	230 kV
Detweiler TS - Freeport SS	D7F/D9F	115 kV
Freeport SS - Cedar TS	F11C/F12C	115 kV
Burlington TS - Cedar TS	B5C/B6C	115 kV
Detweiler TS – Kitchener MTS # 4	D11K/D12K	115 kV
Detweiler TS – Palmerston TS	D10H	115 kV
Detweiler TS – Seaforth TS	D8S	115 kV

Appendix C. Distributors in the KWCG Region

Distributor Name	Station Name	Connection Type
Alectra Utilities Corporation	Fergus TS	Dx
Alectra Utilities Corporation	Arlen MTS	Tx
	Campbell TS	Tx
	Cedar TS	Tx
	Hanlon TS	Tx
Centre Wellington Hydro Ltd.	Fergus TS	Dx
Energy + Inc.	Energy + MTS# 1	Tx
	Galt TS	Tx
	Preston TS	Tx
	Wolverton DS	Dx
Halton Hills Hydro Inc.	Fergus TS	Dx
Hydro One Networks Inc.	Fergus TS	Tx
	Elmira TS	Tx
	Puslinch DS	Tx
	Wolverton DS	Tx
	Galt TS	Dx
Kitchener-Wilmot Hydro Inc.	Kitchener MTS#1	Tx
	Kitchener MTS#3	Tx
	Kitchener MTS#4	Tx
	Kitchener MTS#5	Tx
	Kitchener MTS#6	Tx
	Kitchener MTS#7	Tx
	Kitchener MTS#8	Tx
	Kitchener MTS#9	Tx
Milton Hydro Distribution Inc.	Fergus TS	Dx
Waterloo North Hydro Inc.	Elmira TS	Dx
		Tx
	Fergus TS	Dx
	Rush MTS	Tx
	Scheifele MTS	Tx
	Waterloo North MTS #3	Tx
	Preston TS	Dx
	Kitchener MTS#9	Dx
Wellington North Power Inc.	Fergus TS	Dx

Appendix D. KWCG Region Load Forecast

TABLE D1: KWCG NET NON-COINCIDENT LOAD FORECAST

Transformer Station	Station Capacity	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Arlen MTS	45	26	27	27	28	29	30	30	31	32	33	34	35	36	38	39	40	41	42	44	45	46
Campbell TS (T1/T2)	94	86	86	86	86	86	86	86	86	87	87	88	90	91	92	92	93	94	94	95	95	96
Campbell TS (T3/T4)	56	46	46	46	45	45	46	46	46	46	46	47	47	48	48	48	49	49	49	50	50	50
Cedar TS (T1/T2)	103	93	94	94	95	96	96	97	97	98	99	99	99	100	100	100	101	101	101	101	101	102
Cedar TS (T7/T8)	40	30	32	34	35	37	38	38	39	40	40	41	41	41	41	41	42	42	42	42	42	43
Elmira TS	55	34	35	35	35	36	36	37	38	38	39	40	41	42	49	50	51	52	53	54	55	56
EnergyInc(Cam) MTS#1	102	86	87	87	87	87	88	89	90	91	93	94	96	97	99	101	103	104	106	107	108	110
Fergus TS	154	88	91	91	91	92	92	93	94	94	95	98	99	103	104	106	108	108	109	110	111	111
Galt TS	169	112	113	113	114	115	116	117	118	120	122	124	125	127	129	132	134	136	137	139	141	143
Hanlon TS	43	27	28	28	28	29	29	29	30	30	31	31	32	32	33	33	34	34	35	36	36	37
Kitchener MTS # 1	54	33	34	34	34	35	35	36	36	37	38	38	39	40	41	41	42	43	43	44	45	45
Kitchener MTS # 3	108	55	55	55	56	56	57	57	58	59	59	60	61	62	63	64	65	66	67	67	68	69
Kitchener MTS # 4	90	54	55	55	55	55	56	56	56	57	58	58	59	60	61	61	62	63	63	64	64	65
Kitchener MTS#5	80	77	77	77	78	78	78	79	80	80	81	82	83	84	85	86	87	88	88	89	90	91
Kitchener MTS#6	90	72	73	73	73	74	74	75	76	76	77	78	79	80	81	82	83	83	84	85	86	87
Kitchener MTS#7	54	34	34	34	34	35	35	35	36	36	37	38	38	39	40	40	41	41	42	42	43	43
Kitchener MTS#8	54	37	38	40	41	42	44	45	47	48	50	51	53	55	56	58	60	61	63	64	66	68
Kitchener MTS#9	90	32	33	33	33	33	33	34	34	34	35	35	36	36	37	38	38	39	40	40	41	41
Preston TS	113	90	92	93	93	94	95	96	97	99	100	102	103	105	107	109	110	112	114	115	117	118
Puslinch DS	56	31	32	32	32	32	32	33	33	34	34	34	35	35	36	36	37	37	38	38	39	39
Rush MTS	68	52	52	52	52	52	52	53	53	54	54	58	58	59	60	60	61	61	62	63	63	64
Scheifele MTS	161	140	140	140	140	141	142	143	144	145	147	145	147	149	150	152	154	155	157	158	160	161
Waterloo North MTS 3	77	51	53	53	54	54	55	56	57	59	60	61	62	64	65	67	68	70	71	73	74	76
Wolverton DS	54	12	13	12	12	12	12	12	12	12	13	13	13	13	13	13	13	13	13	13	13	14
CTS Total	-	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
Total	**-**	**1409**	**1428**	**1433**	**1441**	**1453**	**1467**	**1482**	**1498**	**1516**	**1536**	**1560**	**1581**	**1607**	**1636**	**1662**	**1682**	**1702**	**1722**	**1742**	**1762**	**1782**

TABLE D2: KWCG NET COINCIDENT LOAD FORECAST

Transformer Station	Station Capacity	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Arlen MTS	45	26	26	27	27	28	29	30	31	32	32	33	34	36	37	38	39	40	41	43	44	45
Campbell TS (T1/T2)	94	81	81	80	80	80	80	81	81	81	82	82	84	85	86	87	87	88	88	89	89	90
Campbell TS (T3/T4)	56	42	42	42	41	41	42	42	42	42	42	43	43	44	44	44	45	45	45	45	46	46
Cedar TS (T1/T2)	103	76	77	77	77	78	79	79	79	80	80	81	81	81	82	82	82	82	83	83	83	83
Cedar TS (T7/T8)	40	27	29	30	31	33	34	34	35	35	36	36	36	36	37	37	37	37	37	38	38	38
Elmira TS	55	33	34	34	35	35	36	36	37	38	38	39	40	41	48	49	50	51	52	53	54	55
Energylnc(Cam) MTS#1	102	86	86	86	86	87	88	89	90	91	92	94	95	97	98	100	102	103	105	106	108	109
Fergus TS	154	87	89	90	90	90	91	91	92	93	94	96	97	101	103	105	106	107	107	108	109	110
Galt TS	169	112	113	113	114	115	116	117	118	120	122	124	125	127	129	132	134	136	137	139	141	143
Hanlon TS	43	25	26	26	26	26	26	27	27	28	28	29	29	30	30	31	31	32	32	33	33	34
Kitchener MTS # 1	54	33	34	34	34	35	35	36	36	37	38	38	39	40	41	41	42	43	43	44	45	45
Kitchener MTS # 3	108	53	53	53	53	54	54	55	56	56	57	58	59	60	61	62	63	63	64	65	65	66
Kitchener MTS # 4	90	54	55	55	55	55	56	56	56	57	58	58	59	60	61	61	62	63	63	64	64	65
Kitchener MTS#5	80	73	74	74	74	74	74	75	76	76	77	78	79	80	80	82	83	83	84	85	85	86
Kitchener MTS#6	90	66	67	67	67	67	68	68	69	70	70	71	72	73	74	75	76	76	77	78	78	79
Kitchener MTS#7	54	34	34	34	34	35	35	35	36	36	37	38	38	39	40	40	41	41	42	42	43	43
Kitchener MTS#8	54	37	38	39	40	42	43	45	46	48	49	51	52	54	56	57	59	61	62	64	65	67
Kitchener MTS#9	90	32	32	32	32	33	33	33	34	34	34	35	35	36	37	37	38	38	39	40	40	41
Preston TS	113	74	76	76	76	77	77	78	79	80	81	83	84	85	87	89	90	91	93	94	95	97
Puslinch DS	56	29	30	30	30	30	30	31	31	32	32	32	33	33	34	34	35	35	35	36	36	37
Rush MTS	68	49	49	49	49	50	50	50	51	51	52	55	56	56	57	57	58	58	59	60	60	61
Scheifele MTS	161	122	122	122	122	122	123	124	125	126	127	126	128	129	131	133	134	135	137	138	139	141
Waterloo North MTS 3	77	50	51	52	52	53	54	55	56	57	58	60	61	63	64	65	67	68	70	71	72	74
Wolverton DS	54	12	13	12	12	12	12	12	12	12	13	13	13	13	13	13	13	13	13	13	13	14
CTS Total	-	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
Total	**-**	**1323**	**1340**	**1344**	**1350**	**1361**	**1375**	**1388**	**1404**	**1421**	**1439**	**1462**	**1483**	**1508**	**1536**	**1561**	**1581**	**1599**	**1619**	**1637**	**1657**	**1675**

Appendix E. Stations with Extremely High Short Circuit Level*

Station	Bus	Owner	Nominal Voltage (kV)	Short Circuit Capacity** (MVA)	Short Circuit Level (MVA)
Campbell TS	EZ	Hydro One	13.8	443	437
Kitchener MTS # 1	B1B2	Kitchener-Wilmot Hydro	13.8	468	447
Kitchener MTS # 3	B51B61	Kitchener-Wilmot Hydro	13.8	468	436
	B52B62	Kitchener-Wilmot Hydro	13.8	468	474***
Kitchener MTS # 4	B71B81	Kitchener-Wilmot Hydro	13.8	468	466
	B72B82	Kitchener-Wilmot Hydro	13.8	468	467
Kitchener MTS # 5	B91B101	Kitchener-Wilmot Hydro	13.8	468	415
	B92B102	Kitchener-Wilmot Hydro	13.8	468	415
Kitchener MTS # 6	B111B121	Kitchener-Wilmot Hydro	13.8	468	459
	B112B122	Kitchener-Wilmot Hydro	13.8	468	459
Kitchener MTS # 7	B13B14	Kitchener-Wilmot Hydro	13.8	468	446
Rush MTS	B1B2	Waterloo North Hydro	13.8	467	441
Scheifele MTS A	BY	Waterloo North Hydro	13.8	500	455
Scheifele MTS B	QT	Waterloo North Hydro	13.8	500	454

*** Data provided in this table are valid as of March 2021. For up-to-date information, contact LDCs.**

**** Capacities smaller than TSC requirement are due to pre-existing legacy equipment which was adequate and is deemed to be grandfathered.**

***** To be replaced.**

Appendix F. 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
DESN	Dual Element Spot Network
DG	Distributed Generation
DSC	Distribution System Code
GATR	Guelph Area Transmission Reinforcement
GS	Generating Station
HV	High Voltage
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
LDC	Local Distribution Company
LP	Local Plan
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low Voltage
MTS	Municipal Transformer Station
MW	Megawatt
MVA	Mega Volt-Ampere
MVAR	Mega Volt-Ampere Reactive
NA	Needs Assessment
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.
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
TS	Transformer Station
TSC	Transmission System Code

APPENDIX C-5
KWCG Regional Planning Status Letter

April 9th , 2026

Shaun Wang,
Manager of Distribution
Enova Power Corp
301 Victoria St. South,
Kitchener, ON N2G 4L2

Via email: shaun.wang@enovapower.com

Hydro One Networks Inc.

483 Bay Street
8th Floor South Tower
Toronto, Ontario M5G 2P5

HydroOne.com

Dear Mr. Wang,

Subject: Regional Planning Status – Enova Power Corp Service Area

This letter is in response to your request for a Planning Status letter. For the purposes of regional planning the province has been divided into 21 regions. A map showing details with respect to the 21 regions and the list of Local Distribution Companies (LDCs) in each region are attached in Appendix A and B respectively. Hydro One Networks Inc. is the lead transmitter in 20 regions and Enova Power Corp's service area belongs to the Kitchener-Waterloo-Cambridge-Guelph (KWCG) region. The region includes the municipalities of Kitchener, Waterloo, Cambridge and Guelph, as well as portions of Perth and Wellington counties and the townships of Wellesley, Woolwich, Wilmot, and North Dumfries.

Enova Power Corp's load is supplied by Elmira TS, Fergus TS, Kitchener MTS #1, Kitchener MTS #3, Kitchener MTS #4, Kitchener MTS #5, Kitchener MTS #6, Kitchener MTS #7, Kitchener MTS #8, Kitchener MTS #9, Rush MTS, Scheifele MTS, and Waterloo North MTS #3.

This letter confirms that the second cycle of the Regional Planning process for the KWCG region was completed in December 2021. The third regional planning cycle began with the Needs Assessment (NA), which was completed in April 2024. The NA concluded that further regional coordination is required. As a result, the Independent Electricity System Operator (IESO) completed a Scoping Assessment (SA) in June 2024 and initiated the Integrated Regional Resource Planning (IRRP) process, which is scheduled for completion in Q2 2026. The final phase of the regional planning process, the Regional Infrastructure Plan (RIP) phase, will follow the completion of the IRRP.

A summary of the needs and plans currently identified in the KWCG region's second cycle RIP and third cycle NA that affects Enova Power Corp's service area is provided below:

Asset Renewal Needs:

Scheifele MTS – T1/T2 & T3/T4 Transformer Replacement: Based on asset condition assessment, transformers T1/T2/T3/T4 are planned for replacement by Enova Power Corp. The current planning forecast indicates that these replacements are projected to occur between 2030 and 2034.

Station Capacity Needs:

Kitchener MTS #7: Kitchener MTS #7 is a single-station 115/13.8 kV DESN. Based on the NA load forecast, a capacity need was identified at this station, and it was recommended that Enova Power Corp will monitor loading and manage any overload through load transfers as needed.

Rush MTS: Rush MTS is a 115/13.8 kV single-station DESN. Based on the NA load forecast, a capacity need was identified at this station, and it was recommended that Enova Power Corp will monitor loading and address any mid-term overload through load transfers, with a new supply station considered for the long term. As per more recent discussions being had in the IRRP, other options being considered to reduce this load are eDSM and Demand Response (DRs). A formal recommendation to address this need will be provided in the IRRP once completed.

Transmission Line Capacity Needs:

D11K/D12K (Detweiler x Kitchener #1 & 4 JCT) – Mid Term
D11K/D12K is a 115 kV supply to Kitchener MTS #1 and MTS #4. Based on current load forecasts, both circuits are expected to experience overloads under loss-of-companion circuit in the mid-term. This need is currently under assessment as part of the ongoing IRRP.
A recommendation to address this need will be provided in the IRRP and RIP reports once completed.

D10H – Long term
The 115 kV D10H circuit between Detweiler TS and Hanover TS supplies Rush MTS and Elmira TS. A normally open motorized switch south of Palmerston TS provides emergency supply to Palmerston, with the northern section fed radially from Hanover TS and the southern section from Detweiler TS, supplying Elmira TS load. Rush MTS also receives dual supply via the 115 kV D8S circuit. Under an outage of D8S, the D10H section between Detweiler and Leong JCT is forecasted to approach its supply capacity in the long term. This need is currently under assessment as part of the ongoing IRRP. A recommendation to address this need will be provided in the IRRP and RIP reports once completed. .

Transmission Reliability, Operation and Restoration Needs :

M20D/M21D Load Security and Restoration Needs
A double-circuit outage on the M20D/M21D 230 kV line would leave insufficient capability to restore required load within 30 minutes per Ontario Resource and Transmission Assessment Criteria (ORTAC). This affects multiple stations supplied by the corridor, including Kitchener MTS #6, Kitchener MTS #8, Galt TS, Preston TS, Energy+ Inc., and a customer CTS. Current restoration options only recover partial load, resulting in both load security and load restoration criteria not being met. This need is currently under assessment as part of the ongoing IRRP. A recommendation to address this need will be provided in the IRRP and RIP reports once completed.

Capital contribution may be required by Hydro One Networks Inc. from Enova Power Corp for some of the projects recommended through regional planning in the KWCG Region.

Hydro One Networks Inc. would like to acknowledge and thank you for your work and effort in support of the Regional Planning process. We look forward to continuing to work with you in the future. If you have any further questions, please feel free to contact me.

Sincerely,



Ajay Garg,
Senior Manager, System Planning & Regional Planning Coordination
Hydro One Networks Inc.
Tel: (647) – 242 – 2105
ajay.garg@HydroOne.com

Appendix A: Map of Ontario's Planning Regions

Northern Ontario



Southern Ontario



Greater Toronto Area (GTA)



Appendix B: List of LDCs for Each Region

[Hydro One as Upstream Transmitter]

Region	LDCs
1. Burlington to Nanticoke	• Burlington Hydro Inc. • GrandBridge Energy Inc. (Formerly Energy+ and Brantford Power) • Alectra Utilities Corporation (Formerly Horizon Utilities Inc.) • Hydro One Networks Inc. (Distribution) • Oakville Hydro Electricity Distribution Inc.
2. Greater Ottawa	• Hydro 2000 Inc. • Hydro Ottawa Limited • Hydro Hawkesbury Inc. • Ottawa River Power Corporation • Hydro One Networks Inc. (Distribution) • Renfrew Hydro Inc
3. GTA North	• Alectra Utilities Co. • Hydro One Networks Inc. (Distribution) • Newmarket-Tay Power Distribution Ltd. • Toronto Hydro Electric System Limited
4. GTA West	• Burlington Hydro Inc. • Hydro One Networks Inc. (Distribution) • Alectra Utilities Co. • Milton Hydro Distribution Inc. • Halton Hills Hydro Inc. • Oakville Hydro Electricity Distribution Inc.
5. Kitchener- Waterloo-Cambridge-Guelph ("KWCG")	• Alectra Utilities Corporation. • Enova Power Corporation. • Grandbridge Energy Inc. • Centre Wellington Hydro Ltd. • Hydro One Networks Inc. (Distribution) • Halton Hills Hydro Inc. • Wellington North Power Inc.

6. Toronto	• Alectra Utilities • Elexicon Energy Inc. • Hydro One Networks Inc. (Distribution) • Toronto Hydro Electric System Limited
7. Northwest Ontario	• Atikokan Hydro Inc. • Fort Frances Power Corporation • Hydro One Networks Inc. (Distribution) • Synergy North • Sioux Lookout Hydro Inc.
8. Windsor-Essex	• E.L.K. Energy Inc. • Entegrus Powerlines lnc. (Chatham-Kent) • EnWin Utilities Ltd. • Essex Powerlines Corporation • Hydro One Networks Inc. (Distribution)
9. East Lake Superior [Hydro One Sault Ste. Marie L.P. is the Lead Transmitter for the region]	• Algoma Power Inc. • Hydro One Networks Inc. (Distribution) • PUC Distribution
10. GTA East	• Elexicon Energy Inc. • Oshawa PUC Networks Inc. • Hydro One Networks Inc. (Distribution)
11. London Area	• Entegrus Powerlines lnc. • ERTH Power Inc. • Hydro One Networks Inc. (Distribution) • London Hydro Inc. • Tillsonburg Hydro Inc.

12. Peterborough to Kingston	• Eastern Ontario Power Inc. • Elexicon Energy Inc. • Hydro One Networks Inc. (Distribution) • Kingston Hydro Corporation • Lakefront Utilities Inc.
13. South Georgian Bay/Muskoka	• Hydro One Networks Inc. (Distribution) • Alectra Utilities • InnPower • Orangeville Hydro • Elexicon Energy • Lakeland Power • EPCOR Electricity Dist. Ontario Inc. • Newmarket-Tay Power Distribution Ltd. • Wasaga Distribution Inc.
14. Sudbury/Algoma	• Greater Sudbury Hydro Inc. • North Bay Hydro • Hydro One Networks Inc. (Distribution)
15. Chatham-Kent/Lambton/Sarnia	• Bluewater Power Distribution Corporation • Entegrus Power Lines Inc. (Chatham-Kent) • Hydro One Networks Inc. (Distribution)
16. Greater Bruce/Huron	• Entegrus Powerlines Inc. • ERTH Power Corporation • Hydro One Networks Inc. (Distribution) • Festival Hydro Inc. • Wellington North Power Inc. • Westario Power Inc.

17. Niagara	• Canadian Niagara Power Inc. [Port Colborne] • Hydro One Networks Inc. (Distribution) • Grimsby Power Inc. • Niagara Peninsula Energy Inc. • Niagara-On-The-Lake Hydro Inc. • Alectra Utilities Co. • Welland Hydro-Electric System Corporation
18. North of Moosonee [Five Nations Energy Inc (FNEI) is the Lead Transmitter for the region]	• Distribution in this region is provided by FNEI
19. North/East of Sudbury	• Northern Ontario Wires Inc. • Hearst Power Distribution Company Limited • North Bay Hydro Distribution Ltd. • Hydro One Networks Inc. (Distribution) • Greater Sudbury Hydro Inc.
20. Renfrew	• Hydro One Networks Inc. (Distribution) • Ottawa River Power Corporation
21. St. Lawrence	• Cooperative Hydro Embrun Inc. • Hydro One Networks Inc. (Distribution) • Rideau St. Lawrence Distribution Inc.

APPENDIX D-1

Renewable Energy Generation (REG) Investment Plan

RENEWABLE ENERGY GENERATION INVESTMENTS PLAN



May 13, 2026

TABLE OF CONTENTS

TABLE OF CONTENTS i
LIST OF TABLES ii
LIST OF FIGURES ii
1. Introduction 1
2. Enova's Distribution System 3
3. Current and Forecast Generation Connections 6
4. Generation Contribution to System Peak Demand 10
5. Generation Capacity 11
    5.1 Transformer Stations 11
    5.2 Distribution Stations & Feeders (8.32 kV) 13
    5.3 Feeders (13.8 kV and 27.6 kV) 14
6. System Assessment to Identify Constraints 16
7. Distribution Automation and Smart Grid Development 18
8. Non-Infrastructure Approaches to Promote REGs 19
    8.1 Flexible Hosting Capacity Arrangements 19
    8.2 Research Investment in Distribution System Optimization 19
    8.3 Forward-Looking Commitment 20
9. Summary 21
    9.1 Overview 21
    9.2 Measures that will Relieve Short-Circuit Constraints 21
APPENDIX A - Enova Generation Feeder Capacities 23
APPENDIX B - Enova 20 Largest Embedded Generators 28

LIST OF TABLES

Table 1-1: Enova Transmission Stations & Points of Supply 4
Table 1-2: Enova Points of Supply < 50 kV 5
Table 1-3: Enova Generator Connections by Type 6
Table 1-4: Enova Generation, Connected, Allocated, Pending & Forecast 7
Table 1-5: Enova Total Generator Connections by Year 7
Table 1-6: Enova REG Connections by Year 8
Table 1-7: Enova Total Generation at time of System Peak (2024) 10
Table 1-8: Enova REG at time of System Peak (2024) 10
Table 1-9: Enova Transformer Station Generation Capacity 11
Table 1-10: SCL-Constrained Transformer Stations 12
Table 1-11:Constrained Distribution Stations 13
Table 1-12: Enova Feeder Generation Capacity 14
Table A-1a: Enova REG Feeder Capacities 23
Table A-1b: Enova REG Feeder Capacities (continued) 24
Table A-1c: Enova REG Feeder Capacities (continued) 25
Table A-1d: Enova REG Feeder Capacities (continued) 26
Table A-1e: Enova REG Feeder Capacities (continued) 27
Table B-1: Enova 20 Largest Embedded Generators 28

LIST OF FIGURES

Figure 1-1: Enova Service Area 2
Figure 1-2: Historical and Forecast Growth in Connected Generation 9
Figure 1-3: Enova Feeder Generation Capacity Map 15

1. Introduction

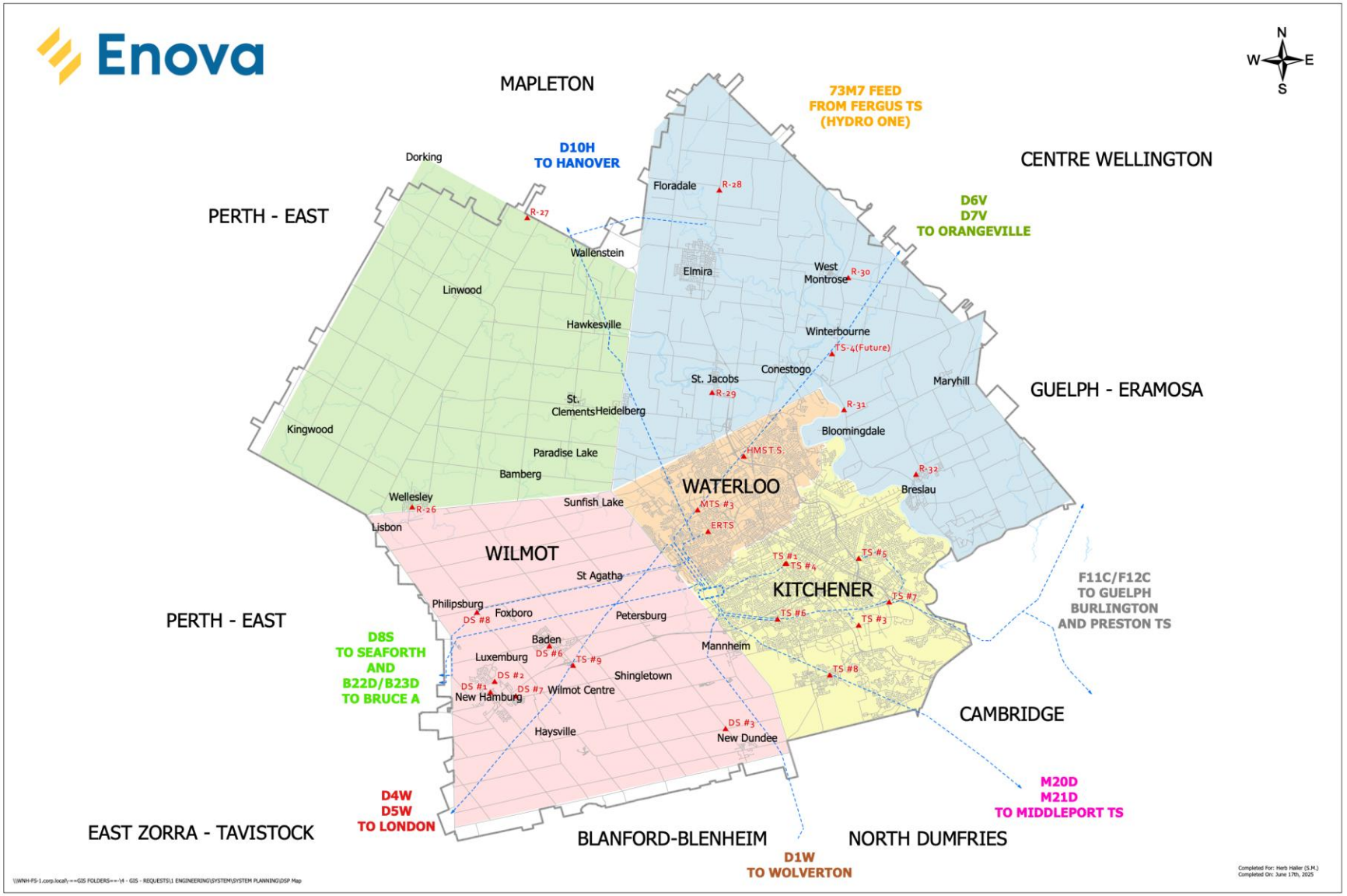
Enova Power Corp. (Enova) is an electrical Local Distribution Company (LDC) licensed by the Ontario Energy Board (OEB) in accordance with its Distribution License ED-2022-0006. Enova was formed on September 1, 2022, by the merger of Waterloo North Hydro Holding Corporation (WNHHC) and Kitchener Power Corporation (KPC) and subsequently Waterloo North Hydro Inc. (WNH) with Kitchener-Wilmot Hydro Inc. (KWH).

With a service area of approximately 1,108 sq. km, Enova provides electricity distribution services to approximately 165,000 business and residential customers in the City of Kitchener, the City of Waterloo, the Township of Wellesley, the Township of Wilmot and the Township of Woolwich, all of which are located within the Regional Municipality of Waterloo. As a result of past service area amendments, Enova also provides regulated electricity distribution services to approximately 142 customers in the bordering counties of Wellington, Perth, Oxford and the City of Cambridge.

This Renewable Energy Generation Investments Plan (Plan) provides information to the OEB and interested stakeholders regarding the readiness of Enova's distribution system to connect Renewable Energy Generation (REG), including details on existing generation connections, available capacity and a forecast of proposed connections. The Plan also identifies if any investments are required to accommodate REG connections including any expansion or reinforcement necessary to remove grid constraints to accommodate these connections for the period 2026 to 2031.

Enova's legacy LDC's last prepared REGI Plans in 2017 (KWH) and 2020 (WNH). Unless otherwise stated, the information contained in this report is current as of December 31, 2024.

Figure 1-1: Enova Service Area



2. Enova's Distribution System

Enova is connected to the Hydro One Networks Inc. (HONI) Transmission System (HONI Tx) through 13 grid connected Transformer Stations as illustrated in **Table 1-1**. Twelve of these stations are owned and operated by Enova and are Dual Element Spot Network (DESN) stations.

The Elmira Transformer Station (ELTS), which is owned and operated by HONI, is embedded inside of Enova's service territory. ELTS is fed from a radial, single circuit, 115 kV transmission line. Enova owns 2 feeders and portions of the third feeder emanating from the ELTS. Approximately 80% of the ELTS load is supplied to Enova customers with the remaining load supplied to HONI Dx customers in nearby Wellington County.

Enova, along with its legacy utilities, have made System Access, System Renewal and System Service investments to construct new or refurbish transformer station and distribution assets. Although these investments have not been made specifically to accommodate generation, upgrading to higher operating voltages, increasing available fault current capabilities of new equipment and improving protection systems not only benefit load customers but also existing and future REG connections.

Table 1-1: Enova Transmission Stations & Points of Supply

#	Transformer Stations	Owned & Operated by	Supplied By	HONI Tx Line	HV (kV)	Station Location	LV (kV)	Tx ID	Tx ONAF Rating (MVA)	LTR (MVA)
1	HMSTS 'A'	Enova	HONI Tx	D6V	230	Waterloo	13.8	T1	30 / 50	69
				D7V	230		13.8	T2	30 / 50	69
2	HMSTS 'B'	Enova	HONI Tx	D7V	230	Waterloo	13.8	T3	50 / 83	110
				D6V	230		13.8	T4	50 / 83	110
3	MTS #3	Enova	HONI Tx	D6V	230	Waterloo	27.6	T1	40 / 67	85
				D7V	230		27.6	T2	40 / 67	85
4	ERTS (Note1)	Enova	HONI Tx	D10H	115	Waterloo	13.8	T1	30 / 50	75
				D8S	115		13.8	T2	30 / 50	75
5	ELTS	HONI	HONI Tx	D10H	115	Woolwich Twp	27.6	T1	25 / 42	62
				D10H	115		27.6	T2	25 / 42	62
6	1TS	Enova	HONI Tx	D12K	115	Kitchener	13.8	T1	30 / 50	60
				D11K	115		13.8	T2	30 / 50	60
7	3TS	Enova	HONI Tx	D9F	115	Kitchener	13.8	T5	60 / 100	120
				D7F	115		13.8	T6	60 / 100	120
8	4TS	Enova	HONI Tx	D12K	115	Kitchener	13.8	T7	50 / 83	102
				D11K	115		13.8	T8	50 / 83	102
9	5TS	Enova	HONI Tx	F12C	115	Kitchener	13.8	T9	60 / 100	120
				F11C	115		13.8	T10	60 / 100	120
10	6TS	Enova	HONI Tx	M21D	230	Kitchener	13.8	T11	50 / 83	102
				M20D	230		13.8	T12	50 / 83	102
11	7TS	Enova	HONI Tx	D7F	230	Kitchener	13.8	T13	30 / 50	61
				D9F	230		13.8	T14	30 / 50	61
12	8TS	Enova	HONI Tx	M21D	230	Kitchener	13.8	T15	30 / 50	60
				M20D	230		13.8	T16	30 / 50	60
13	9TS	Enova	HONI Tx	D4W	230	Wilmot Twp	27.6	T17	50 / 83	100
				D5W	230		27.6	T18	50 / 83	100

From the transmission grid connected transformer stations, Enova distributes electricity to its customers over 127 feeders at distribution voltages of 27.6 kV, 13.8 kV, and 28 feeders at 8.32 kV. Enova's end-of-life Asset Renewal Program has produced secondary benefits such as eliminating the 4.16 kV distribution and steadily reducing the 8.32 kV distribution. Replacing these lower and less efficient voltages with higher capacity 13.8 kV and 27.6 kV distribution has also provided a secondary benefit of creating additional REG capacity.

Enova also receives electrical supply at <50 kV through feeders from two neighbouring LDCs, HONI Dx and GrandBridge Energy Inc. (GBE). **Table 1-2** provides a listing of these points of supply. The capacities listed in **Table 1-2** for HONI Dx, and GBE supply points are estimates only. Capacity to connect generation to feeders owned by other LDCs is

subject to activities outside of Enova's service territory and need to be determined on a case-by-case basis at the time of application.

Table 1-2: Enova Points of Supply < 50 kV

Feeder ID	Supplied From	Supply Point Location	LV (kV)	Load Capacity at Enova Boundary (MVA)
73M7	HONI	Woolwich	44	5.0
21M25	GrandBridge Energy Inc.	Woolwich	27.6	14.3

3. Current and Forecast Generation Connections

As of December 31, 2024, 1,934 generators were connected to the Enova distribution system for a total connected capacity of 71,462 kW. Of these, 1,912 were REG connections totalling 42,832 kW. **Table 1-3** provides a breakdown of the 2024 connections by generation type.

Table 1-3: Enova Generator Connections by Type

Generation Type	microFIT		FIT		Net Metered		Load Displacement		Others		Total Connected	
	Num	(kW)	Num	(kW)	Num	(kW)	Num	(kW)	Num	(kW)	Num	(kW)
Solar	1,375	11,273	80	13,940	445	7,232	5	412			1,905	32,857
CHP							14	12,510			14	12,510
Wind			1	35	3	63	0	0			4	98
Biogas			1	2,852			1	800	1	6,225	3	9,877
Battery							7	14,120	1	2,000	8	16,120
Total	1,375	11,273	82	16,827	448	7,295	27	27,842	2	8,225	1,934	71,462
% of Total	71%	16%	4%	24%	23%	10%	1%	39%	0%	12%	100%	100%
REG	1,375	11,273	82	16,827	448	7,295	6	1,212	1	6,225	1,912	42,832
% REG	72%	26%	4%	39%	23%	17%	0%	3%	0%	15%	100%	100%
NON REG											22	28,630

The Independent Electricity System Operator (IESO) ceased to accept applications under the microFIT and FIT Programs as of December 31, 2016. The last connections made by Enova under these programs were made in 2018. Enova has lost 21 MicroFIT (630 kW) and 8 FIT (5,827 kW) REGs over the historical period.

Incented by high Global Adjustment charges and electricity commodity pricing, Load Displacement Generation (LDG) has been the largest segment of connected generation over the historical period.

Appendix B, Table B-1 provides a listing of Enova's 20 largest embedded generators.

Table 1-4 provides a summary of the amount of connected, allocated and pending generation connections.

Table 1-4: Enova Generation, Connected, Allocated, Pending & Forecast

Status	Total Generator Connections	Total Gen (kW)	REG Connections	REG (kW)	NON REG Connections	NON-REG (kW)
Connected	1,934	71,462	1,912	42,832	22	28,630
Allocated	19	4,022	19	4,022	0	0
Pending	3	725	2	285	1	0
Forecast to 2031	720	17,920	707	11,360	13	6,560
Total	2,676	94,129	2,640	58,499	36	35,630

Table 1-5 illustrates the growth in total generation since 2020 and the forecast generation to 2031.

Table 1-5: Enova Total Generator Connections by Year

	microFIT		FIT		Net Metered		Load Displacement		Total Connected		Accumulated Total (kW)
Year	Num	(kW)	Num	(kW)	Num	(kW)	Num	(kW)	Num	(kW)	
2020	0	0	0	0	11	295	0	0	11	295	54,857
2021	(2)	(19)	0	960	54	1,189	0	0	52	2,131	56,988
2022	(17)	(607)	(7)	(6,722)	91	1,473	16	15,677	83	9,820	66,808
2023	0	9	0	0	115	1,346	0	0	115	1,355	68,163
2024	(2)	(13)	(1)	(65)	106	1,510	2	1,867	105	3,298	71,462
2025					90	1,006	4	2,000	94	3,006	74,467
2026					94	1,083	4	2,000	98	3,083	77,550
2027					98	1,161	4	2,000	102	3,161	80,711
2028					102	1,238	4	2,000	106	3,238	83,949
2029					106	1,316	4	2,000	110	3,316	87,265
2030					110	1,393	4	2,000	114	3,393	90,658
2031					114	1,471	4	2,000	118	3,471	94,129
Total 2020 - 2024	(21)	(630)	(8)	(5,827)	377	5,812	18	17,544	366	16,899	
Total 2025 - 2031	0	0	0	0	714	8,667	28	14,000	742	22,667	

Enova notes an increasing trend in the connection of Load Displacement Generation (LDG) between 2020 and 2025. A significant amount of the LDG utilizes gas fueled engines with rotating generators. These units can contribute substantially higher fault current levels thereby reducing available generation capacity at a much faster rate than renewable inverter-based generation.

Table 1-6 illustrates the growth of REG in Enova's service area from 2020 - 2024 and Enova's forecast in REG from 2025 - 2031.

Table 1-6: Enova REG Connections by Year

	microFIT		FIT		Net Metered		Load Displacement		Total Connected		
Year	Num	(kW)	Num	(kW)	Num	(kW)	Num	(kW)	Num	(kW)	Accumulated Total (kW)
2020	0	0	0	0	11	295	0	0	11	295	43,360
2021	(2)	(19)	0	960	54	1,189	0	0	52	2,131	45,490
2022	(17)	(607)	(7)	(6,722)	91	1,473	5	412	72	(5,445)	40,046
2023	0	9	0	0	115	1,346	0	0	115	1,355	41,400
2024	(2)	(13)	(1)	(65)	106	1,510	0	0	103	1,431	42,832
2025	0	0	0	0	90	1,006	2	1,000	92	2,006	44,837
2026	0	0	0	0	94	1,083	2	1,000	96	2,083	46,921
2027	0	0	0	0	98	1,161	2	1,000	100	2,161	49,081
2028	0	0	0	0	102	1,238	2	1,000	104	2,238	51,320
2029	0	0	0	0	106	1,316	2	1,000	108	2,316	53,635
2030	0	0	0	0	110	1,393	2	1,000	112	2,393	56,028
2031	0	0	0	0	114	1,471	2	1,000	116	2,471	58,499
Total 2015 - 2024	(21)	(630)	(8)	(5,827)	377	5,812	5	412	353	(233)	
Total 2025 - 2031	0	0	0	0	714	8,667	14	7,000	728	15,667	

Forecast Methodology

Enova's generation connection forecast for the period 2025 - 2031 is based on an analysis of historical connection trends within its service territory. Enova examined both three-year (2022 - 2024) and five-year (2020 - 2024) rolling averages of actual connections by generation type and program category, including net metered, load displacement, and other connection classifications.

A linear growth rate was derived from the historical trend data and applied over the forecast period, assuming steady and sustained growth in REG adoption consistent with observed patterns in Enova's service area. The forecast reflects the following key assumptions:

- Net metered connections are expected to continue at a pace consistent with the

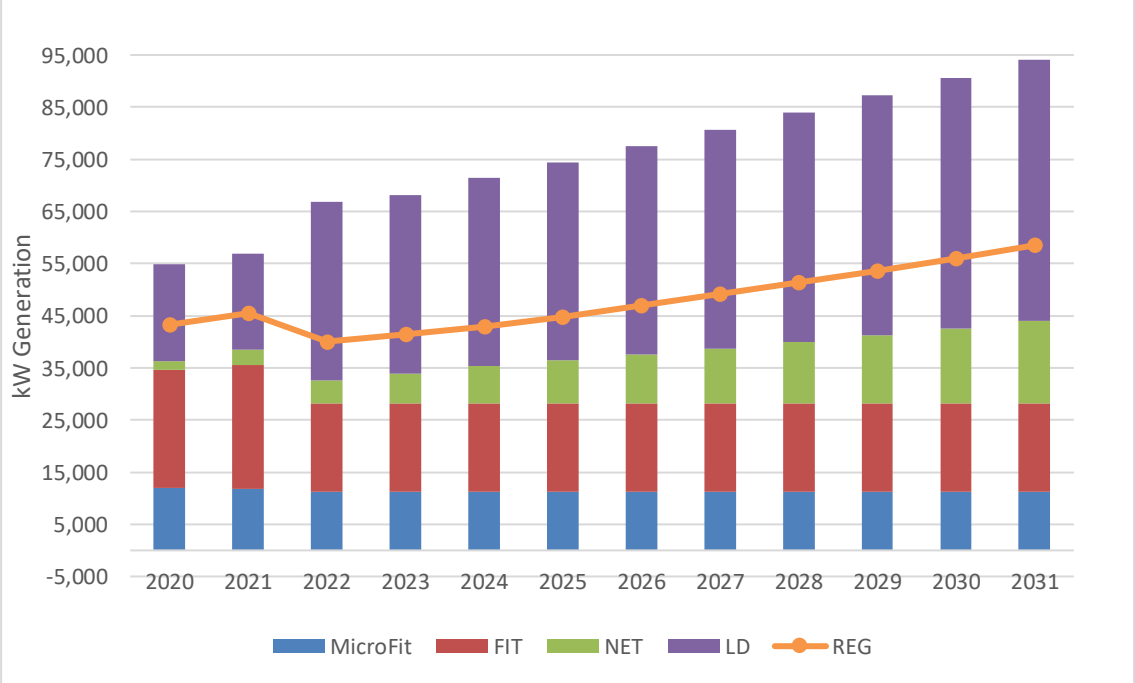
historical growth trend, reflecting ongoing residential and commercial adoption of behind-the-meter solar generation;

- Load displacement generation connections are forecast based on recent connection activity and known customer interest within the service territory.

Enova considers this approach to be reasonable and appropriate given the relatively stable growth trajectory observed in its service territory. Enova will continue to refine its forecast methodology in future filings as additional data on emerging DER adoption trends, including battery energy storage and electric vehicle integration, becomes available.

Figure 1-2 illustrates the growth of REG and NON-REG in Enova's service area from 2020 - 2024 and Enova's forecast for each from 2025 - 2031.

Figure 1-2: Historical and Forecast Growth in Connected Generation



4. Generation Contribution to System Peak Demand

On June 19th, 2024, at approximately 17:00 hours EST, Enova experienced a gross summer system peak demand of 690 MW.

At the time of Enova's system peak, total embedded generation supplied approximately 28.9 MW or 4.2% of the system peak. This represents 40.5% of installed generation capacity. REGs contributed 14 MW or 2% of the system peak. This represents 32.8% of the total REG installed capacity. The remainder of Enova's peak demand was supplied through IESO wholesale transmission and < 50 kV points of supply.

Break downs of total connected generation and REG at time of system peak are provided in **Table 1-7** and **Table 1-8**.

Table 1-7: Enova Total Generation at time of System Peak (2024)

Generation Type	Connections	Total Capacity (kW)	Total Output at System PK (kW)
microFIT	1,375	11,273	3,419
FIT	82	16,827	5,104
Net Metering	448	7,295	2,212
Load Displacement	27	27,842	15,563
Others	2	8,225	2,637
Total	1,934	71,462	28,935

Table 1-8: Enova REG at time of System Peak (2024)

Generation Type	Connections	Total Capacity (kW)	Total Output at System PK (kW)
microFIT	1,375	11,273	3,419
FIT	82	16,827	5,104
Net Metering	448	7,295	2,212
Load Displacement	6	1,212	678
Others	1	6,225	2,637
Total	1,912	42,832	14,050

5. Generation Capacity

5.1 Transformer Stations

Table 1-9 illustrates the estimated generation capacity that is available at Enova points of supply.

Table 1-9: Enova Transformer Station Generation Capacity

Station	Buses	Owner	Total Generation Capacity (kW)	Connected Generation (kW)	Remaining Generation Capacity (kW)	Remaining Generation Capacity (%)	Limitation
Rush	B1B2	Enova	12,350	1,600	-	0%	SCL
Scheifele A (1)	BY	Enova	13,140	11,083	2,057	16%	
Scheifele B (2)	JH	Enova	11,360	3,650	7,710	68%	
Scheifele B (2)	QT	Enova	16,620	2,939	13,681	82%	
WNH MTS #3	B2B2	Enova	14,140	4,030	10,110	71%	
Elmira TS		HONI Tx	14,689	10,824	3,865	26%	
Kitchener 1TS	B1B2	Enova	5,180	1,583	-	0%	SCL
Kitchener 3TS	B51B61	Enova	7,920	425	7,495	95%	
Kitchener 3TS	B52B62	Enova	7,890	1,772	6,118	78%	
Kitchener 4TS	B71B81	Enova	12,990	380	-	0%	SCL
Kitchener 4TS	B72B82	Enova	8,450	766	-	0%	SCL
Kitchener 5TS	B91B101	Enova	6,370	1,159	5,211	82%	
Kitchener 5TS	B92B102	Enova	6,250	2,409	3,841	61%	
Kitchener 6TS	B111B121	Enova	8,130	2,919	5,211	64%	
Kitchener 6TS	B112B122	Enova	9,680	1,189	8,491	88%	
Kitchener 7TS	B13B14	Enova	10,710	1,537	9,173	86%	
Kitchener 8TS	B15B16	Enova	8,110	1,384	6,726	83%	
Kitchener 9TS	B17B18	Enova	8,330	2,578	5,752	69%	
			182,309	52,225	95,442	52%	

Limitations: (SCL) Short Circuit Limited, (THL) Thermal Rating Limited

In general, short circuit capacity limitations at the stations are due to transformer, station bus or circuit breaker short circuit ratings. Available generation capacity is determined by both the short circuit and thermal ratings of the station's equipment, whichever is lower. In addition, various transformer configurations are not designed for reverse power flows and limitations are determined by design limits and minimum load values.

Overall, Enova has approximately 130 MW (71%) of generation capacity remaining on its power transformers; however, overall generation capacity is limited to 95 MW (52%)

due to short circuit limitations on some of Enova's switchgear and circuit breakers.

Table 1-10 lists the three stations that have SCL constraints at this time. These limitations, however, do not prevent inverter based microgeneration (< 12 kW) from being connected to these stations as this generation type contributes negligible short circuit current to the feeder.

Table 1-10: SCL-Constrained Transformer Stations

Station	Buses	Total Generation Capacity (kW)	Connected Generation (kW)	Remaining Capacity	Connected Customers	Limitation	Primary Constraint
Rush	B1B2	12,350	1,600	0 kW (0%)	11,340	SCL	Circuit breaker / bus short-circuit ratings
Kitchener 1TS	B1B2	5,180	1,583	0 kW (0%)	5,338	SCL	Circuit breaker / bus short-circuit ratings
Kitchener 4TS	B71B81	12,990	380	0 kW (0%)	7,915	SCL	Circuit breaker / bus short-circuit ratings and reverse power limitations
Kitchener 4TS	B72B82	8,450	766	0 kW (0%)	8,944	SCL	Circuit breaker / bus short-circuit ratings and reverse power limitations
Total		38,970	4,329	0 kW (0%)	33,537		

Short circuit limitations will be relieved over time as equipment is replaced through Enova's System Renewal program. Older equipment in poor condition will be replaced with newer equipment that will have higher ratings, increasing the capacity to connect additional future generation. Given the capacity available in Enova's transformers, there is room to allow overall generation capacity to grow above current levels.

From **Table 1-5,** Enova is forecasting the connection of approximately 22.7 MW of total generation, over the forecast period. Enova does not believe that the aforementioned constraints will have any material impact on the connection of REGs. Enova reevaluates its capacity to connect REG on a quarterly basis and will modify its plans in the future if additional generation capacity is required.

5.2 Distribution Stations & Feeders (8.32 kV)

Enova's 8.32 kV distribution system has limited capacity and can only accept small amounts of generation (< 12 kW). With 880 kW connected, only 27% capacity remains. **Table 1-11** provides a summary of the distribution stations' capacity to connect generation.

Table 1-11:Constrained Distribution Stations

Name	Total Generation Capacity (kW)	Remaining Generation Capacity (kW)
Wallenstein (R27)	100	No Capacity
Floradale (R28)	140	No Capacity
West Montrose (R30)	750	101
Bloomingdale (R31)	590	26
Kitchener 1DS	1,370	709
Kitchener 2DS	290	No Capacity
Kitchener 3DS	200	No Capacity
Kitchener 6DS	150	No Capacity
Kitchener 7DS	920	456
Kitchener 8DS	550	53
	5,060	1,346
		27%

Enova is in the process of retiring its 8.32 kV distribution system. The 8.32 kV distribution lines are being replaced with new assets that are more efficient and operate at 27.6 kV. The replacement of these assets are part of Enova's System Renewal program and driven by asset condition assessments.

As the 8.32 kV distribution system load reduces, the associated distribution stations will be removed from service and decommissioned.

Overall, this will allow Enova greater flexibility to connect larger scale load and generation customers.

5.3 Feeders (13.8 kV and 27.6 kV)

Appendix A, Tables A-1a through to A-1e provide a summary of Enova's major feeder generation capacity. Feeders with little to no remaining generation capacity are typically limited by the short circuit ratings of the station transformer, bus or breaker from which they are supplied.

Enova's 13.8 kV and 27.6 kV feeders currently have a remaining generation capacity of 76%. There is capacity to connect larger scale generation at the higher voltages, up to 5.0 MW at 13.8 kV and 10.0 MW at 27.6 kV. Capacity to connect generation of this size would still need to be determined on a case by case basis at the time of application.

The capacities listed in **Table 1-12** for HONI Dx and GBE supply points are estimates only. Capacity to connect generation to feeders owned by other LDCs is subject to activities outside of Enova's service territory and need to be determined on a case-by-case basis at the time of application. These feeders are not a significant contributor to Enova's Renewable Generation Capacity but are noted here only for completeness.

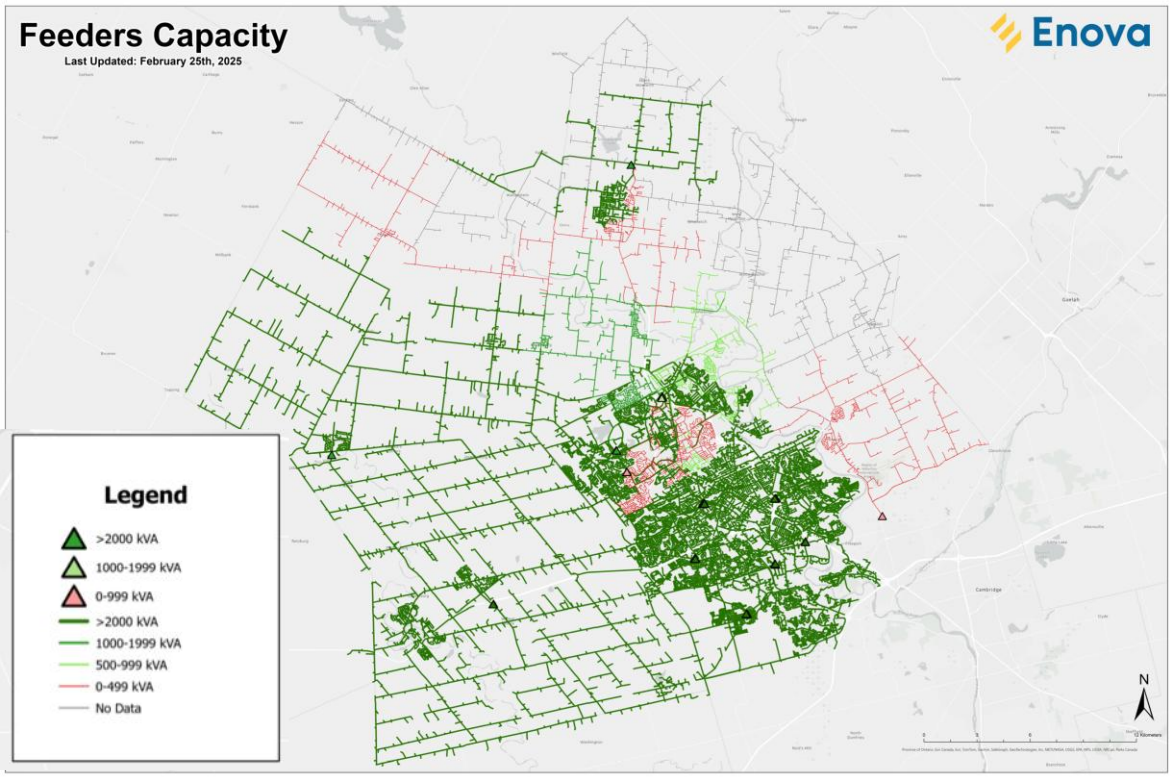
Table 1-12: Enova Feeder Generation Capacity

Station	Feeder ID	Supplied From	LV (kV)	Generation Capacity at Enova Boundary (MVA)	Connected Generation (MVA)	Remaining Generation Capacity (MVA)
Fergus TS	73M7	HONI	44	0.75	0.4	0.3
Preston TS	21M25	GrandBridge Energy Inc.	27.6	3.6	3.1	0.5

Enova does not believe that the aforementioned constraints and limitations will have any material impact on the ability to connect REG over the forecast period.

Figure 1-3, Feeder Generation Capacity Map, is available to the public on the Enova website **www.enovapower.com.**

Figure 1-3: Enova Feeder Generation Capacity Map



6. System Assessment to Identify Constraints

On a quarterly basis, Enova internally assesses its transformer stations and distribution network for available capacity and constraints. Based on Enova's assessment, there is sufficient generation hosting capacity across its points of supply, transformer stations, and 13.8 kV feeders and 27.6 kV feeder systems to accommodate the anticipated number of REG connections over the forecast period.

Enova also works with the organizations listed below to develop the Kitchener-Waterloo-Cambridge-Guelph (KWCG) Integrated Regional Resources Plans (IRRP) and the Regional Infrastructure Plans (RIP).

i. GrandBridge Energy Inc. (Cambridge area)
ii. Alectra Utilities Corporation (Guelph area)
iii. Hydro One Distribution (HONI Dx),
iv. Hydro One Transmission, (HONI Tx)
v. Independent Electricity System Operator (IESO)

The second cycle of the Regional Planning process for the KWCG region was completed in December 2021. The last IRRP for the KWCG region, dated May 6, 2021, is provided in **Appendix C-3** and the last RIP for the KWCG region, dated Dec 10, 2021, is provided in **Appendix C-4** of this DSP.

The third regional planning cycle is currently underway for the KWCG region. Enova has participated in the planning meetings and consulted with all of the aforementioned stakeholders. The KWCG Needs Assessment was completed in April 2024 (**Appendix C-1**). The Needs Assessment concluded that further regional coordination was required. As a result, the IESO completed a Scoping Assessment in June 2024 (**Appendix C-2**). The IESO also initiated the KWCG IRRP process, which was scheduled for completion in Q2 of 2026.

The IESO has since adjusted the timing of the KWCG IRRP regional planning study to allow for the completion of the IESO's South Central Bulk Planning Study (SCBPS). The IESO recognizes that, with the forecasted load growth, additional 500 kV transmission

may be needed in the KWCG area. The SCBPS has developed several options; however, at the time of this report, the preferred option has not yet been selected. The final selection and engagement stages for the proposed options are scheduled for Q3 of 2026.

The final phase of the regional planning process, the Regional Infrastructure Plan (RIP) phase, will follow the completion of the IRRP.

Enova cannot adequately comment on transmission capacity constraints over the forecast period until there is greater certainty regarding the outcome of the KWCG IRRP.

7. Distribution Automation and Smart Grid Development

All Enova grid connected Transformer Stations have SCADA monitoring and control, programmable electronic protection systems and communication systems. The same is true of all < 50 kV points of supply from HONI Dx and GBE. All are interfaced with Enova's Survalent Outage Management System (OMS).

Enova also has on its distribution lines, 190 electronic reclosers and 46 switches, all with SCADA monitoring and control, programmable electronic protection and communications installed at various locations on its distribution system.

Enova is also employing automatic "Fault Location Isolation and System Restoration" (FLISR) smart grid technology to reduce customer outage times and provide flexible operation on its distribution system. To date, FLISR has been deployed on 58 of its 127 in-service feeders. Although REG has not been the primary driver for these investments, these investments also benefit REG connections by minimizing outage areas and allowing faster reconnection times after an electrical fault.

8. Non-Infrastructure Approaches to Promote REGs

8.1 Flexible Hosting Capacity Arrangements

Enova is aware of the OEB's amendments to the Distribution System Code (DSC Section 6.2.4.1A) that enable distributors to offer flexible hosting capacity arrangements on a voluntary basis. Under such arrangements, distributed energy resource (DER) connections may be accommodated at locations where aggregate generation may exceed feeder or station technical capacity limits, provided the distributor has the technical capability to manage DER output in accordance with agreed-upon operating conditions.

Enova does not currently offer flexible hosting capacity arrangements. Enova is evaluating the technical and operational requirements to implement such arrangements and will consider their adoption as part of its ongoing grid modernization and DER integration planning efforts.

8.2 Research Investment in Distribution System Optimization

Enova is participating in a sponsored research project with the University of Waterloo and Rogers Communications Canada Inc. entitled “Electricity Distribution System Operator (DSO) Ancillary Service Procurement to Alleviate Constraints Using 5G Internet of Things and Distributed Computing”.

Project Objectives:

1) Develop a distribution power flow analysis framework to identify DSO-specific constraints and apply it to construct new formulations of dynamic operating envelopes for ancillary service activation and dispatch.

2) Design DSO ancillary service markets for voltage support and peak shaving using dynamic operating envelope dispatch.

3) Develop distributed optimization methods to solve the decision making problems required to clear the ancillary service markets.

4) Assess the impact of the proposed market design on system operations and planning with practical use cases developed from historical data.

The outcomes of this research will inform Enova's future evaluation of non-infrastructure-based approaches to alleviating hosting capacity constraints, including the potential application of dynamic operating envelopes and ancillary service procurement at SCL-constrained stations.

8.3 Forward-Looking Commitment

Enova acknowledges the direction established through the Government of Ontario's Integrated Energy Plan (Energy for Generations, June 2025) and the OEB's ongoing efforts to update DER connection processes. Consistent with these objectives, Enova intends to conduct a comprehensive assessment of both infrastructure-based and non-infrastructure-based options for improving generation hosting capacity at constrained locations as part of its next Distribution System Plan filing.

9. Summary

9.1 Overview

Based on Enova's assessment, there is sufficient generation hosting capacity across its points of supply, transformer stations, 13.8 kV feeders and 27.6 kV feeder systems to accommodate the anticipated number of REG connections over the forecast period. Enova is not proposing any capital investments specifically to accommodate the connection of generation over the forecast period.

Enova cannot adequately comment on transmission capacity constraints over the forecast period until there is greater certainty regarding the outcome of the KWCG IRRP.

9.2 Measures that will Relieve Short-Circuit Constraints

As identified in **Table 1-9**, three of Enova's transformer stations, encompassing four bus configurations, are currently constrained by short-circuit level (SCL) limitations. **Table 1-10** summarizes the constrained stations. These limitations, however, do not prevent microgeneration (< 12 kW) from being connected as they contribute negligible short circuit current to the feeder.

Short-circuit limitations at the constrained stations are expected to be progressively relieved as equipment is replaced or refurbished through Enova's ongoing System Renewal program. Older equipment in deteriorated condition will be replaced with modern equipment with higher fault-current ratings, thereby increasing the capacity to connect future generation as a co-benefit of these investments.

For customers whose connection requirements cannot be accommodated within the timing of Enova's planned system investments, alternative options may be available. Where system capacity exists, customers may elect to connect to an alternate feeder. Alternatively, customers may request that Enova undertake an earlier system expansion or reinforcement to accommodate their connection. In such cases, Enova will provide a cost estimate and proceed in accordance with the requirements of the

Ontario Energy Board's Distribution System Code (DSC), including the applicable customer contribution provisions.

APPENDIX A - Enova Generation Feeder Capacities

Table A-1a: Enova REG Feeder Capacities

Transformer Station	Bus	Feeder	Voltage (kV)	Total Generation Capacity (kW)	Remaining Generation Capacity (kW)	Remaining Capacity (%)	Restricted Feeder (Yes / No)
Rush	B1	ER-41	13.8	6,812	0	0.0%	YES
		ER-42	13.8	6,812	0	0.0%	YES
		ER-43	13.8	6,812	0	0.0%	YES
		ER-44	13.8	6,812	0	0.0%	YES
Rush	B2	ER-45	13.8	6,812	0	0.0%	YES
		ER-46	13.8	6,812	0	0.0%	YES
		ER-47	13.8	6,812	0	0.0%	YES
		ER-48	13.8	6,812	0	0.0%	YES
Scheifele A	B	HS-7	13.8	6,812	6,647	97.6%	NO
		HS-8	13.8	6,812	6,562	96.3%	NO
		HS-9	13.8	6,812	6,812	100.0%	NO
		HS-10	13.8	6,812	3,892	57.1%	NO
Scheifele A	Y	HS-11	13.8	6,812	4,644	68.2%	NO
		HS-12	13.8	6,812	2,396	35.2%	NO
		HS-13	13.8	6,812	6,654	97.7%	NO
		HS-14	13.8	6,812	6,812	100.0%	NO
Scheifele B	H	HS-15	13.8	6,812	6,512	95.6%	NO
		HS-16	13.8	6,812	6,812	100.0%	NO
		HS-17	13.8	6,812	6,645	97.5%	NO
		HS-18	13.8	6,812	6,812	100.0%	NO
Scheifele B	J	HS-19	27.6	13,624	12,612	92.6%	NO
		HS-20	13.8	6,812	6,495	95.3%	NO
		HS-21	13.8	6,812	6,302	92.5%	NO
		HS-22	13.8	6,812	5,874	86.2%	NO
		HS-32	13.8	Future			
Scheifele B	Q	HS-23	13.8	6,812	6,384	93.7%	NO
		HS-24	13.8	6,812	6,157	90.4%	NO
		HS-25	13.8	6,812	6,812	100.0%	NO
		HS-26	27.6	13,624	12,466	91.5%	NO
		HS-31	13.8	Future			
Scheifele B	T	HS-27	13.8	6,812	6,701	98.4%	NO
		HS-28	13.8	6,812	6,374	93.6%	NO
		HS-29	13.8	6,812	6,663	97.8%	NO
		HS-30	13.8	6,812	6,787	99.6%	NO

Table A-1b: Enova REG Feeder Capacities (continued)

Transformer Station	Bus	Feeder	Voltage (kV)	Total Generation Capacity (kW)	Remaining Generation Capacity (kW)	Remaining Capacity (%)	Restricted Feeder (Yes / No)
WNH MTS#3	B1	3F-60	27.6	13,624	13,624	100.0%	NO
		3F-61	27.6	13,624	12,817	94.1%	NO
		3F-50	13.8	6,812	6,726	98.7%	NO
		3F-63	27.6	13,624	13,042	95.7%	NO
		3F-64	27.6	13,624	13,624	100.0%	NO
WNH MTS#3	B2	3F-65	27.6	13,624	12,705	95.5%	NO
		3F-66	27.6	13,624	13,247	97.9%	NO
		3F-51	13.8	6,812	6,803	99.9%	NO
		3F-68	27.6	13,624	12,751	85.5%	NO
		3F-69	27.6	13,624	13,624	100.0%	NO
Kitchener 1TS	1B2	1M1	13.8	6,812	6,752	99.1%	NO
		1M2	13.8	Future			
		1M3	13.8	6,812	0	0.0%	YES
		1M4	13.8	6,812	0	0.0%	YES
		1M5	13.8	6,812	0	0.0%	YES
		1M6	13.8	6,812	0	0.0%	YES
		1M7	13.8	6,812	0	0.0%	YES
		1M8	13.8	6,812	0	0.0%	YES
		1M9	13.8	6,812	0	0.0%	YES
		1M10	13.8	Future			
Kitchener 3TS	51B61	3M11	13.8	6,812	6,812	100.00%	NO
		3M13	13.8	6,812	6,710	98.50%	NO
		3M14	13.8	6,812	6,762	99.30%	NO
		3M15	13.8	6,812	6,812	100.00%	NO
		3M16	13.8	6,812	6,562	96.30%	NO
		3M18	13.8	6,812	6,789	99.70%	NO
	52B62	3M20	13.8	6,812	6,812	100.00%	NO
		3M21	13.8	6,812	6,771	99.40%	NO
		3M22	13.8	6,812	6,025	88.50%	NO
		3M23	13.8	6,812	6,812	100.00%	NO
		3M24	13.8	Future			
		3M25	13.8	Future			
		3M26	13.8	6,812	6,812	100.00%	NO
		3M27	13.8	6,812	6,756	99.20%	NO
		3M28	13.8	6,812	6,592	96.80%	NO
		3M29	13.8	Future			
		3M210	13.8	6,812	6,562	96.30%	NO
		3M211	13.8	Future			
		3M212	13.8	Future			

Table A-1c: Enova REG Feeder Capacities (continued)

Transformer Station	Bus	Feeder	Voltage (kV)	Total Generation Capacity (kW)	Remaining Generation Capacity (kW)	Remaining Capacity (%)	Restricted Feeder (Yes / No)
Kitchener 4TS	71B81	4M10	13.8	Future			
		4M11	13.8	6,812	0	0.00%	YES
		4M12	13.8	6,812	0	0.00%	YES
		4M13	13.8	6,812	0	0.00%	YES
		4M14	13.8	6,812	0	0.00%	YES
		4M15	13.8	6,812	0	0.00%	YES
		4M16	13.8	6,812	0	0.00%	YES
		4M17	13.8	6,812	0	0.00%	YES
		4M18	13.8	6,812	0	0.00%	YES
		4M19	13.8	Future			
		4M20	13.8	Future			
	72B82	4M21	13.8	6,812	0	0.00%	YES
		4M22	13.8	Future			
		4M23	13.8	Future			
		4M24	13.8	6,812	0	0.00%	YES
		4M25	13.8	6,812	0	0.00%	YES
		4M26	13.8	6,812	0	0.00%	YES
		4M27	13.8	6,812	0	0.00%	YES
		4M28	13.8	6,812	0	0.00%	YES
Kitchener 5TS	91B101	5M11	13.8	6,812	6,742	99.00%	NO
		5M13	13.8	6,812	6,735	98.90%	NO
		5M14	13.8	6,812	6,779	99.50%	NO
		5M15	13.8	6,812	6,409	94.10%	NO
		5M16	13.8	6,812	6,440	94.50%	NO
		5M17	13.8	6,812	6,609	97.00%	NO
		5M18	13.8	Future			
		5M19	13.8	Future			
		5M20	13.8	Future			
	92B102	5M21	13.8	6,812	6,750	99.10%	NO
		5M22	13.8	6,812	6,698	98.30%	NO
		5M23	13.8	6,812	5,117	75.10%	NO
		5M24	13.8	Future			
		5M25	13.8	6,812	6,722	98.70%	NO
		5M26	13.8	6,812	6,715	98.60%	NO
		5M27	13.8	6,812	6,472	95.00%	NO
		5M28	13.8	6,812	6,801	99.80%	NO

Table A-1d: Enova REG Feeder Capacities (continued)

Transformer Station	Bus	Feeder	Voltage (kV)	Total Generation Capacity (kW)	Remaining Generation Capacity (kW)	Remaining Capacity (%)	Restricted Feeder (Yes / No)
Kitchener 6TS	**111B121**	6M11	13.8	6,812	6,597	96.80%	NO
		6M12	13.8	Future			
		6M13	13.8	6,812	6,357	93.30%	NO
		6M14	13.8	6,812	6,405	94.00%	NO
		6M15	13.8	6,812	5,472	80.30%	NO
		6M16	13.8	Future			
		6M17	13.8	6,812	6,474	95.00%	NO
		6M18	13.8	6,812	6,647	97.60%	NO
	112B122	6M21	13.8	6,812	6,691	98.20%	NO
		6M22	13.8	6,812	6,802	99.90%	NO
		6M23	13.8	6,812	6,632	97.40%	NO
		6M24	13.8	6,812	6,562	96.30%	NO
		6M25	13.8	6,812	6,695	98.30%	NO
		6M26	13.8	6,812	6,494	95.30%	NO
		6M27	13.8	6,812	6,619	97.20%	NO
		6M28	13.8	6,812	6,812	100.00%	NO
Kitchener 7TS	**13B14**	7M1	13.8	6,812	6,812	100.00%	NO
		7M2	13.8	6,812	6,280	92.20%	NO
		7M3	13.8	6,812	6,812	100.00%	NO
		7M4	13.8	Future			
		7M5	13.8	6,812	6,688	98.20%	NO
		7M6	13.8	Future			
		7M7	13.8	6,812	6,812	100.00%	NO
		7M8	13.8	6,812	6,604	96.90%	NO
		7M9	13.8	6,812	6,140	90.10%	NO
		7M10	13.8	6,812	6,812	100.00%	NO
Kitchener 8TS	**15B16**	8M0	13.8	Future			
		8M1	13.8	Future			
		8M2	13.8	6,812	6,692	98.20%	NO
		8M3	13.8	6,812	6,812	100.00%	NO
		8M4	13.8	6,812	6,785	99.60%	NO
		8M5	13.8	6,812	6,638	97.50%	NO
		8M6	13.8	Future			
		8M7	13.8	6,812	6,532	95.90%	NO
		8M8	13.8	Future			
		8M9	13.8	6,812	6,296	92.40%	NO
		8M10	13.8	6,812	6,545	96.10%	NO
		8M11	13.8	Future			

Table A-1e: Enova REG Feeder Capacities (continued)

Transformer Station	Bus	Feeder	Voltage (kV)	Total Generation Capacity (kW)	Remaining Generation Capacity (kW)	Remaining Capacity (%)	Restricted Feeder (Yes / No)
Kitchener 9TS	17B18	9M2	27.6	13,624	12,814	94.10%	NO
		9M3	27.6	13,624	13,374	98.20%	NO
		9M4	27.6	13,624	12,717	93.30%	NO
		9M5	27.6	Future			
		9M6	27.6	Future			
		9M7	27.6	13,624	13,199	96.90%	NO
		9M8	27.6	Future			
		9M9	27.6	13,624	13,439	98.60%	NO

APPENDIX B - Enova 20 Largest Embedded Generators

Table B-1: Enova 20 Largest Embedded Generators

Ranking	Fuel Type	Feeder #	Year Installed	Generator Size (kW)	Category
1	Land Fill Gas	9M7	2007	6225	RESOP
2	Gas Turbine	3M210	1997	4075	Load Displacement
3	Gas Turbine	3M11	2013	3300	Load Displacement
4	Biomass	33M1	2013	2850	FIT
5	Battery	21M25	2021	2600	Load Displacement
6	Gas Turbine/Solar	8M5	2021	2496	Load Displacement/NET
7	Battery	HS-10	2019	2470	Load Displacement
8	Battery	33M3	2021	2300	Load Displacement
9	Battery	5TS	2018	2000	BESS
10	Battery	33M1	2017	2000	Load Displacement
11	Gas Turbine	HS-12	2021	2000	Load Displacement
12	Battery	HS-12	2021	2000	Load Displacement
13	Battery	HS-11	2021	2000	Load Displacement
14	Steam Turbine	33M3	2020	960	Load Displacement
15	Biogas	3M18	2018	800	Load Displacement
16	Combined Heat and Power	HS-22	2021	600	Load Displacement
17	Solar	9M4	2019	500	FIT
18	Solar	7M2	2012	500	FIT
19	Solar	33M3	2014	500	FIT
20	Solar	33M1	2017	450	FIT

APPENDIX D-2
IESO REG Letter of Comment

IESO response to Enova Power Corp REG Investments Plan

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) Investments Plan, which is part of its Distribution System Plan. On February 24th, 2026, Enova Power Corporation (Enova) sent its REG Investments Plan to the IESO for comment. The IESO has reviewed Enova Power's Plan and reports that it contains no investments specific to connecting REG over 2026 to 2031.

The IESO notes that Enova Power's service territory falls within the Kitchener-Waterloo-Cambridge-Guelph (KWCG) region for regional planning purposes. The IESO published the KWCG Scoping Assessment in July 2024,[1] which recommended an IRRP be undertaken for the region. The IRRP is currently ongoing, and Enova Power is a member of the Technical Working Group.

On Page 19 of its Plan, under the heading Proposed Investments to Facilitate Renewable Energy Generation Connections, Enova Power states that "Enova is not proposing any capital investments specifically to accommodate the connection of generation over the forecast period".

As Enova has determined it requires no system investments to connect REG over the 2026-2031 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.[2]

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

[1] IESO's 2024 Kitchener Waterloo Cambridge Guelph Scoping Assessment Outcome Report

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

APPENDIX E
System Supply and Capacity Study

ENOVA SYSTEM SUPPLY & CAPACITY REPORT



May 28, 2026

TABLE OF CONTENTS

TABLE OF CONTENTS i
LIST OF TABLES ii
LIST OF FIGURES iii
GLOSSARY iv
1. Introduction 1
2. Overview of Enova's Distribution System 2
3. Enova System Demand 6
3.1. Historical Load 6
3.2. Load Forecasting 7
3.3. Impact of Embedded Generation 11
4. Enova Electrical Supply 12
5. Enova Capacity Utilization 14
5.1. HONI Transmission Lines (115 kV & 230 kV) 14
5.2. Enova Transmission Connected Stations (115 kV & 230 kV) 17
5.3. Transformer Station Feeders (13.8 kV and 27.6 kV) 20
5.4. Distribution Station (DS) Capacity Utilization 28
5.5. Distribution Feeder (8 kV) Capacity Utilization 29
5.6. Distribution Transformers 31

LIST OF TABLES

Table 2-1: Enova Service Area Population Demographics 2
Table 2-2: Enova Service Area Customer Demographics 2
Table 2-3: Enova Transmission Connected Stations 3
Table 4-1: Enova Gross Summer Peak Load MW (2024) 12
Table 4-2: Enova Peak Load by Delivery Point (2024) 12
Table 4-3: Enova Embedded Generation at System Peak (2024) 13
Table 5-1: Enova Transmission Supply 14
Table 5-2: Capacity Utilization - Station Transformers 18
Table 5-3: Station Feeder Utilization HMSTS"A" 21
Table 5-4: Station Feeder Utilization HMSTS"B" 21
Table 5-5: Station Feeder Utilization MTS#3 22
Table 5-6: Station Feeder Utilization ERTS 22
Table 5-7: Station Feeder Utilization ELTS 22
Table 5-8: Station Feeder Utilization Kitchener 1TS 23
Table 5-9: Station Feeder Utilization Kitchener 3TS 23
Table 5-10: Station Feeder Utilization Kitchener 4TS 24
Table 5-11: Station Feeder Utilization Kitchener 5TS 24
Table 5-12: Station Feeder Utilization Kitchener 6TS 25
Table 5-13: Station Feeder Utilization Kitchener 7TS 25
Table 5-14: Station Feeder Utilization Kitchener 8TS 26
Table 5-15: Station Feeder Utilization Kitchener 9TS 26
Table 5-16: Delivery Point Feeder Utilization (< 50 kV) (2020 – 2024) 27
Table 5-17: Enova DS Station Capacity Utilization 28
Table 5-18: Enova DS Station Feeder Capacity Utilization 29
Table 5-19: Distribution Transformer Loading by Type 32
Table 5-20: Distribution Transformer Average Loading above 100% 32

LIST OF FIGURES

Figure 2-1: Enova Service Area....4
Figure 3-1 Enova Historical Demand (MW) 6
Figure 3-2: Enova Load Forecast 9
Figure 3-3: Enova Load Forecast (+ Data Centre Load) 10
Figure 3-4: Historical and Forecast Growth in Generation 11
Figure 5-1: Enova Distribution Transformer Utilization (%) 31

GLOSSARY

1) AM – Asset Management
2) AMP – Asset Management Plan
3) DS – Distribution Station
4) DSC – Distribution System Code
5) DSP – Distribution System Plan
6) Enova – Waterloo North Hydro Inc. / Kitchener Wilmot Hydro Inc.
7) EOL – End-of-Life
8) HONI – Hydro One Networks Inc.
9) IESO – Independent Electricity System Operator
10) KWCG – Kitchener – Waterloo – Cambridge – Guelph
11) KWH – Kitchener-Wilmot Hydro Inc.
12) LDC – Local Distribution Company
13) LOS – Loss of Supply
14) LTR - Limited Time Rating
15) MS – Municipal Station
16) MVA - Motor Vehicle Accident
17) O/H or OH - Overhead
18) O&M – Operation & Maintenance
19) OEB – Ontario Energy Board
20) REG – Renewable Energy Generation
21) SCADA – Supervisory Control and Data Acquisition
22) TS – Transmission Station or Transformer Station
23) TUL – Typical Useful Life
24) U/G or UG – Underground
25) WNH – Waterloo North Hydro Inc.
26) XFMR / Tx – Transformer

1. Introduction

Enova's System Supply and Capacity Report (SSCR) provides a consolidated view of Enova's distribution system's ability to supply current and forecasted load customers. The SSCR informs Enova's senior executive team (Executive) and aids in the development of Enova's business plans, capital budgets, and load forecasting. The SSCR also provides key information to allow Enova to develop, utilize and manage its major distribution system assets and to provide a safe, secure, reliable, efficient and cost-effective service to its customers.

This SSCR supports Enova's Distribution System Plan (DSP) and complements information found in the Renewable Energy Generation Investments (REGI) Plan. Unless otherwise stated, the information contained in this report is current as of December 31, 2025.

The report examines Enova's historical and forecast growth in electrical demand. In addition, the report also examines the capacity and load supplied by Enova's key infrastructure components including:

1) delivery points, both at the transmission and distribution level;
2) grid-connected power transformers and feeders;
3) distribution station transformers and feeders;
4) distribution transformers.

2. Overview of Enova's Distribution System

Enova delivers electricity and related energy services to approximately 510,000 residents in the Region of Waterloo. With a service area of approximately 1,108 sq. km, Enova currently serves approximately 165,000 business and residential customers.

Table 2-1 provides a breakdown of the population base Enova serves.

Table 2-1: Enova Service Area Population Demographics

Municipality	Population	%	Service Area (sq. km)	%	Population Density (per sq. km)	Urban Population	Rural Population
City of Kitchener	292,240	57.3%	138.3	12.5%	2,113	292,240	
City of Waterloo	154,440	30.3%	65.3	5.9%	2,365	154,440	
Township of Woolwich	28,530	5.6%	329.3	29.7%	87		28,530
Township of Wilmot	23,010	4.5%	266.1	24.0%	86		23,010
Township of Wellesley	11,650	2.3%	278.5	25.1%	42		11,650
Service Area Amendments	142	0.0%	30.7	2.8%	5		142
Total	510,012	100%	1,108	100%	460	446,680	63,332
Total (%)						88%	12%

Table 2-2 provides a breakdown of Enova's customer base by municipality.

Table 2-2: Enova Service Area Customer Demographics

Municipality	Customers	%	Service Area (sq. km)	%	Customer Density (per sq. km)	Urban Customers	Urban Area (sq.km.)	Rural Customers	Rural Area (sq.km.)
City of Kitchener	95,372	57.8%	138.3	12.5%	690	95,372	138.3		
City of Waterloo	46,080	27.9%	65.3	5.9%	706	46,080	65.3		
Township of Woolwich	11,086	6.7%	329.3	29.7%	34			11,086	329
Township of Wilmot	8,651	5.2%	266.1	24.0%	33			8,651	266
Township of Wellesley	3,559	2.2%	278.5	25.1%	13			3,559	279
Service Area Amendments	142	0.1%	30.7	2.8%	5			142	31
Total	164,890	100%	1,108	100%	149	141,452	204	23,438	905
Total (%)						86%	18%	14%	82%

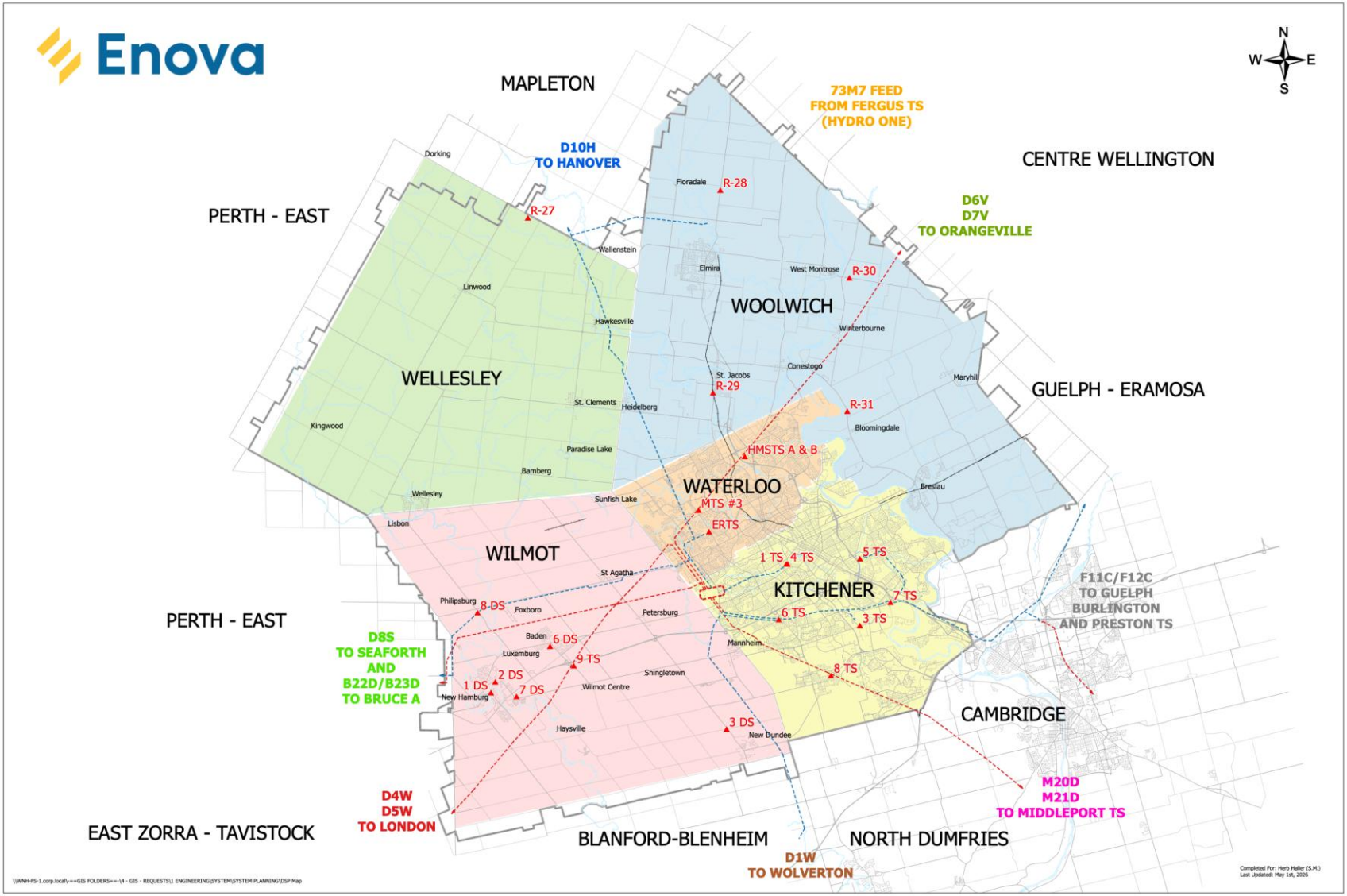
In the Province of Ontario, Enova is ranked 7th by customer base, 6th by total service area and 4th by rural service area size. Although 82% of its service area is rural, it accounts for only 14% of its customer base. **Figure 2-1** provides a map illustrating the extent of Enova's service area.

Enova is connected to the Hydro One Networks Inc. (HONI) Transmission System (HONI Tx) through 13 grid-connected Transformer Stations as illustrated in **Table 2-3**. Twelve of these stations are owned and operated by Enova and are Dual Element Spot Network (DESN) stations. The Elmira Transformer Station (ELTS), which is owned and operated by HONI, is embedded inside Enova's service territory. ELTS is fed from a radial, single circuit, 115 kV transmission line. Enova owns two feeders and portions of the third feeder emanating from the ELTS. Approximately 80% of the ELTS load is supplied to Enova customers with the remaining load supplied to HONI Dx customers in nearby Wellington County.

Table 2-3: Enova Transmission Connected Stations

#	Transformer Stations	Owned & Operated by	Supplied By	HONI Tx Line	HV (kV)	Station Location	LV (kV)	Tx ID
1	HMSTS 'A'	Enova	HONI Tx	D6V	230	Waterloo	13.8	T1
				D7V	230		13.8	T2
2	HMSTS 'B'	Enova	HONI Tx	D7V	230	Waterloo	13.8	T3
				D6V	230		13.8	T4
3	MTS #3	Enova	HONI Tx	D6V	230	Waterloo	27.6	T1
				D7V	230		27.6	T2
4	ERTS	Enova	HONI Tx	D10H	115	Waterloo	13.8	T1
				D8S	115		13.8	T2
5	ELTS	HONI	HONI Tx	D10H	115	Woolwich Twp	27.6	T1
				D10H	115		27.6	T2
6	1TS	Enova	HONI Tx	D12K	115	Kitchener	13.8	T1
				D11K	115		13.8	T2
7	3TS	Enova	HONI Tx	D9F	115	Kitchener	13.8	T5
				D7F	115		13.8	T6
8	4TS	Enova	HONI Tx	D12K	115	Kitchener	13.8	T7
				D11K	115		13.8	T8
9	5TS	Enova	HONI Tx	F12C	115	Kitchener	13.8	T9
				F11C	115		13.8	T10
10	6TS	Enova	HONI Tx	M21D	230	Kitchener	13.8	T11
				M20D	230		13.8	T12
11	7TS	Enova	HONI Tx	D7F	230	Kitchener	13.8	T13
				D9F	230		13.8	T14
12	8TS	Enova	HONI Tx	M21D	230	Kitchener	13.8	T15
				M20D	230		13.8	T16
13	9TS	Enova	HONI Tx	D4W	230	Wilmot Twp	27.6	T17
				D5W	230		27.6	T18

Figure 2-1: Enova Service Area



Enova's stations are connected to 14 HONI transmission lines which directly supply approximately 95% of Enova's load. The remaining 5% of Enova's supply is provided by < 50kV feeders from HONI DX, GrandBridge Energy and embedded generation.

From the 13 transmission connected transformer stations, Enova distributes electricity at voltages of 13.8 kV and 27.6 kV via 127 feeders. Additionally, Enova utilizes 10 distribution stations and 28 feeders to deliver power at the 8.32 kV level.

Overall, Enova's distribution network is comprised of approximately 2,049 km of overhead lines and 1,626 km of underground lines.

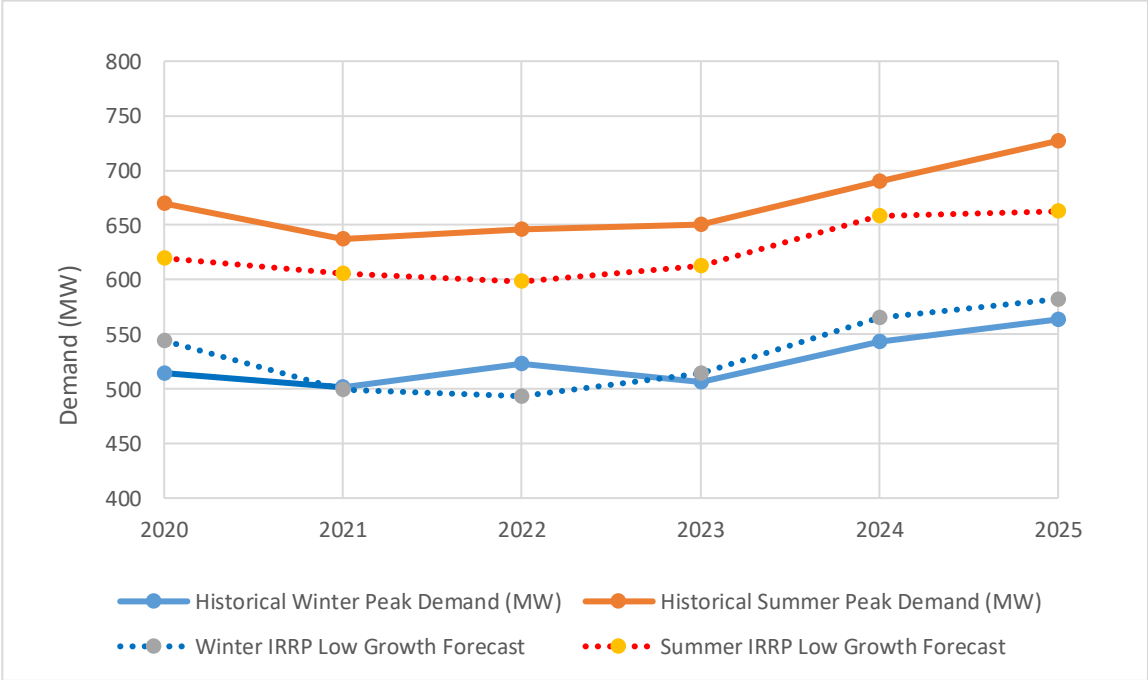
Finally, approximately 19,000 low voltage distribution transformers deliver load to Enova's customers at 240/120V, 120/208V, and 347/600V levels.

3. Enova System Demand

3.1. Historical Load

Enova is a summer peaking utility and weather still remains the main factor impacting volatility in Enova's peak demand. The Region of Waterloo has been and continues to be a growing community. From 2020 to 2025, Enova has seen a growth in its customer base of just under 1%. Over the same period, Enova's annualized Summer System Peak Demand has grown at approximately 3.0% while its annualized Winter System Peak Demand has grown at approximately 0.9%. **Figure 3-1** illustrates Enova's actual historical Summer and Winter peak demands from 2020 – 2025 as compared to previous IRRP forecasts.

Figure 3-1 Enova Historical Demand (MW)



3.2. Load Forecasting

Enova continually monitors and reviews its load and load forecasts to ensure adequate supply and capacity exists for its current and future customers.

Enova also works with the organizations listed below to develop the Kitchener-Waterloo-Cambridge-Guelph (KWCG) Integrated Regional Resources Plans (IRRP) and the Regional Infrastructure Plans (RIP).

i. GrandBridge Energy Inc. (Cambridge area)
ii. Alectra Utilities Corporation (Guelph area)
iii. Hydro One Distribution (HONI Dx),
iv. Hydro One Transmission, (HONI Tx)
v. Independent Electricity System Operator (IESO)

The second cycle of the Regional Planning process for the KWCG region was completed in December 2021. The last IRRP for the KWCG region, dated May 6, 2021, is provided in **Appendix C-3** and the last RIP for the KWCG region, dated Dec 10, 2021, is provided in **Appendix C-4** of this DSP.

The third regional planning cycle is currently underway for the KWCG region. Enova has participated in the planning meetings and consulted with all of the aforementioned stakeholders. The KWCG Needs Assessment was completed in April 2024 (**Appendix C-1**). The Needs Assessment concluded that further regional coordination was required. As a result, the IESO completed a Scoping Assessment in June 2024 (**Appendix C-2**). The IESO also initiated the KWCG IRRP process, which was scheduled for completion in Q2 of 2026.

The IESO has since adjusted the timing of the KWCG IRRP regional planning study to allow for the completion of the IESO's South Central Bulk Planning Study (SCBPS). The IESO recognizes that, with the forecasted load growth, additional 500 kV transmission may be needed in the KWCG area. The SCBPS has developed several options; however, at the time of this report, the preferred option has not yet been selected. The final selection and

engagement stages for the proposed options are scheduled for Q3 of 2026.

The final phase of the regional planning process, the Regional Infrastructure Plan (RIP) phase, will follow the completion of the IRRP.

Enova's load forecast has been developed in conjunction with the IESO, KWCG regional planning group, and is supported by the Grid Smart City Hatch Electrification Strategy Report (Dec 15, 2022). Since that Hatch report was published, changes in government policy and regulations regarding electrification, the carbon tax, the repeal of mandates in transportation & EV targets have occurred, all aimed to at balancing ambitious climate targets with the need for economic competitiveness. The full impact of these changes on electrification is not yet known.

Coming out of COVID-19, Enova has seen a steady rise in both summer and winter peak loads. From 2026 to 2031, Enova forecasts the annual growth in its customer base to remain in the range of 1%. Enova's annualized Summer System Peak Demand is forecasted to grow at approximately 2.5% while its annualized Winter System Peak Demand is forecasted to grow at approximately 5.2%. The main drivers of the load increase include further adoption of electric vehicles, electric hot water heaters and electric heat pumps, albeit at a slower pace than forecast under previous federal government programs. In addition, developers are proposing that 150 MVA of data centre load be connected within Enova's service area in or around the year 2030.

Figure 3-2 illustrates Enova's forecast demand should the data centre load not materialize. Enova normally operates its stations between 50% loading and the Limited Time Rating (LTR) value of the station. This allows the stations to maintain load in an N-1 contingency such as the loss of a transmission line, transformer or bus. The slight increase in transformation capacity in 2030 coincides with the planned replacement of the HMSTS "B" transformers.

Figure 3-2: Enova Load Forecast

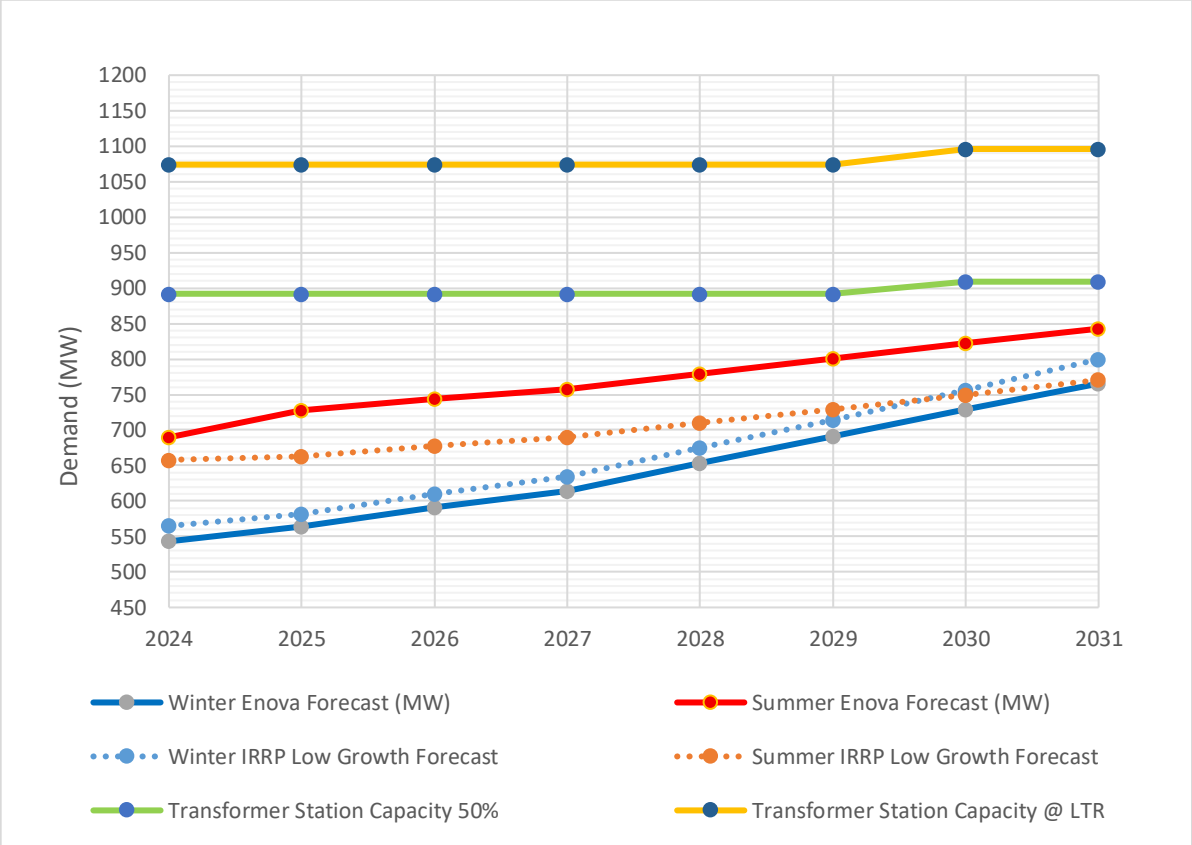
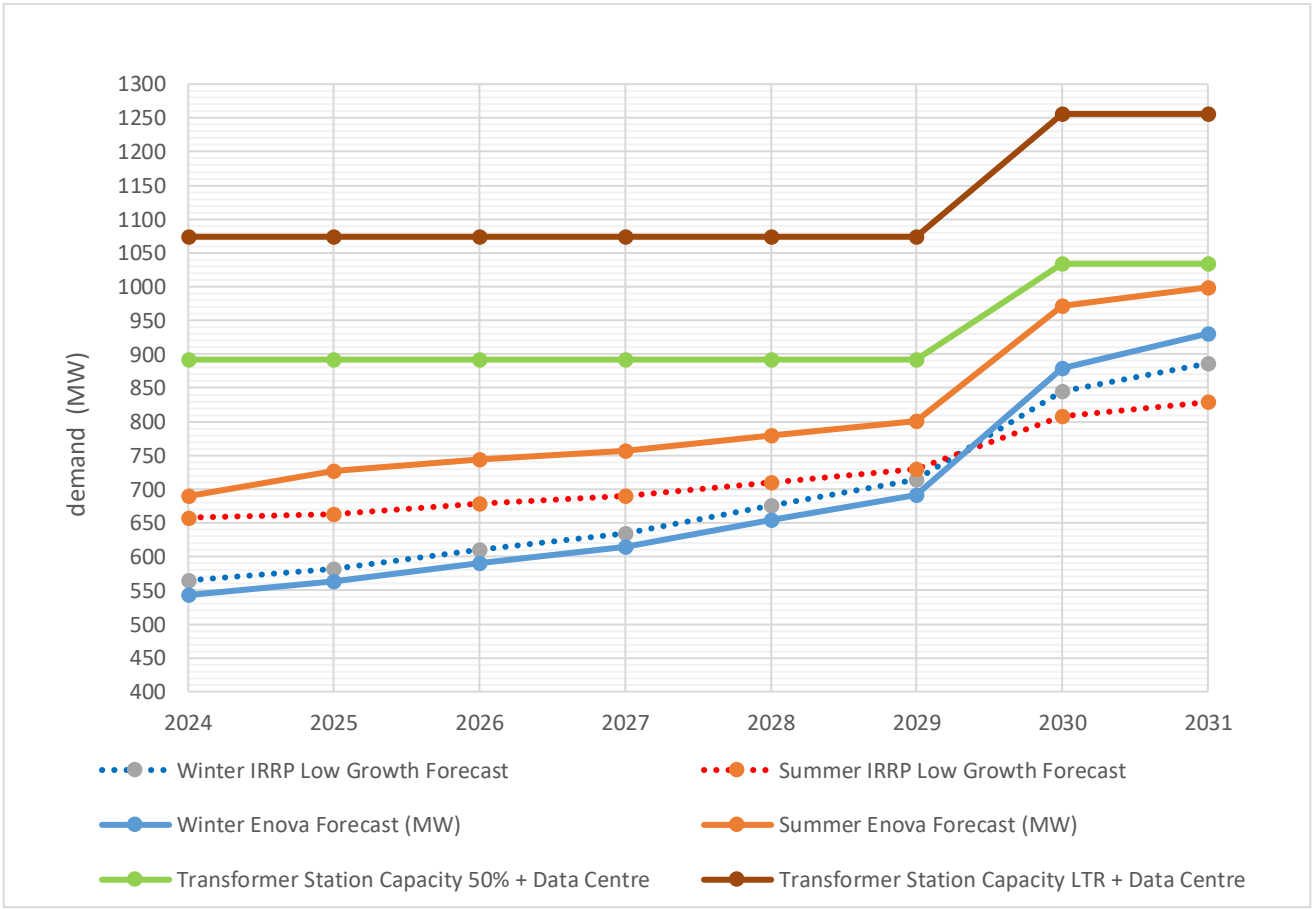


Figure 3-3 illustrates Enova's forecast demand including the proposed 150 MVA of data centre load. Enova's annualized Summer System Peak Demand will jump to 5.7% while its annualized Winter System Peak Demand will jump to 9.0%. If the data centre project moves forward, a new Enova-owned transformer station will be required to provide the additional capacity.

Figure 3-3: Enova Load Forecast (+ Data Centre Load)



Just outside the current forecast window, Enova is also planning for the Region of Waterloo's new state-of-the-art acute care hospital with an initial in-service date of 2035 and full completion in 2039. This 2-million square-foot acute care facility, which is expected to have a load of 50 MW to 60 MW, and forecast load increases due to electrification, will require Enova to expand its transformer station capacity. Construction power, if required within the current forecast window, will be provided by Enova's existing distribution system.

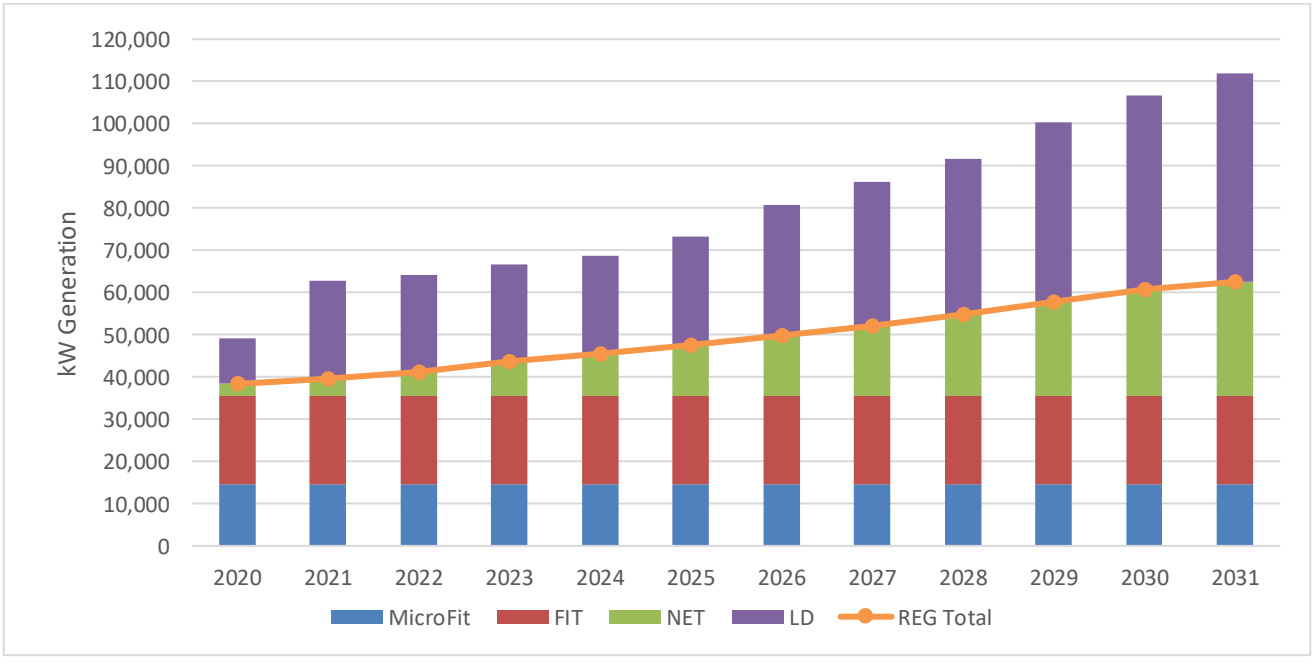
3.3. Impact of Embedded Generation

As of December 31, 2024, 1,934 generators were connected to the Enova distribution system for a total connected capacity of 71,462 kW. Of these, 1,912 were REG connections totalling 42,832 kW.

On June 19th, 2024, at approximately 17:00 hours EST, Enova experienced a gross summer system peak demand of 689.7 MW. At the time of Enova's system peak, total embedded generation supplied approximately 28.9 MW or 4.2% of the system peak. This represents 40.5% of installed generation capacity. REGs contributed 14 MW or 2% of the system peak. This represents 32.8% of the total REG installed capacity. The remainder of Enova's peak demand was supplied through IESO wholesale transmission and < 50 kV points of supply.

Figure 3-4 illustrates Enova's historical and forecast growth of embedded generation. More information on generation can be found in the DSP, **Appendix D-1 - Enova Renewable Energy Generation (REG) Investment Plan**.

Figure 3-4: Historical and Forecast Growth in Generation



4. Enova Electrical Supply

Enova's electrical supply is sourced from four major areas:

1. HONI 230 kV Transmission
2. HONI 115 kV Transmission
3. < 50 kV Feeders, (27.6 kV & 44 kV)
4. Embedded Generation

Table 4-1 illustrates the division of load through each of these four areas with 95.8% being supplied through IESO wholesale points and 4.2% being provided by embedded generation.

Table 4-1: Enova Gross Summer Peak Load MW (2024)

Supply Voltage (kV)	2024 Load (MW)	% Total Load by Delivery Point
230	322.0	46.7%
115	333.0	48.3%
< 50	5.8	0.8%
Embedded Gen.(various)	28.9	4.2%
Total	689.7	100%

Table 4-2 provides a breakdown of Enova's 2024 Gross Summer Peak Load by transmission and distribution delivery points.

Table 4-2: Enova Peak Load by Delivery Point (2024)

Supply	Supply Voltage (kV)	HMSTS A & B (MW)	MTS #3 (MW)	ERTS (MW)	ELTS (MW)	1TS (MW)	3TS (MW)	4TS (MW)	5TS (MW)	6TS (MW)	7TS (MW)	8TS (MW)	9TS (MW)	< 50 kV (MW)	Total Tx (MW)	% Total Load
D6V/D7V	230	140	51												191	29.0%
M20D/M21D	230									58		40			98	14.9%
D4W/D5W	230												32		32	4.9%
D8S/D10H	115			46	36										82	12.5%
D11K/D12K	115					28		63							91	13.8%
D7F/D9F	115						48				38				86	13.0%
F11C/F12C	115								74						74	11.2%
73M7 PME	44													2.7	2.7	0.4%
21M25 PME	27.6													3.1	3.1	0.5%
TOTAL		140	51	46	36	28	48	63	74	58	38	40	32	5.8	660	100%
% Total Tx Load		21.2%	7.8%	7.0%	5.5%	4.2%	7.2%	9.6%	11.2%	8.8%	5.8%	6.1%	4.9%	0.9%	100.0%	

Table 4-3 provides a breakdown of embedded generation's total contribution of 28.9 MW (4.2%) at the time of system peak.

Table 4-3: Enova Embedded Generation at System Peak (2024)

Generation Type	Connections	Total Gen Capacity (kW)	Gen Output at System Peak (kW)	% Output at System Peak (kW)
microFIT	1,375	11,273	3,419	12%
FIT	82	16,827	5,104	18%
Net Metering	448	7,295	2,212	8%
Load Displacement	27	27,842	15,563	54%
Others	2	8,225	2,637	9%
Total	1,934	71,462	28,935	100%

5. Enova Capacity Utilization

5.1. HONI Transmission Lines (115 kV & 230 kV)

From 2020 – 2025 approximately 95% of Enova's load was supplied by 14 HONI transmission lines. During this time, Enova did not experience any constraints in its transmission supply.

Table 5-1: Enova Transmission Supply

HONI Tx	Supply Voltage (kV)
D6V	230
D7V	230
D8S	115
D10H	115
M20D	230
M21D	230
D4W	230
D5W	230
D11K	115
D12K	115
D7F	115
D9F	115
F11C	115
F12C	115

Through the course of the current KWCG IRRP process, Enova has raised concerns about the IESO's presentation of significant reductions in available transmission capacity and potential reliability issues that have arisen since the last IRRP & RIP.

These issues are due in part to the following.

1. Significant growth in the region driven by LDCs in the KWCG area.
2. Large industrial loads such as data centres seeking connection directly to Hydro One's transmission system, bypassing Enova or other LDCs.
    a. Two large data centres in the GrandBridge Energy service area are in the queue for IESO System Impact Assessments.
    b. In Wilmot Twp, 500 MW of transmission-connected data centres are in the queue for IESO System Impact Assessments.

3. With each evolution of the regional planning process, the IESO is becoming more detailed with its analysis and finding constraints or reliability issues that were not previously identified. Transmission constraints under contingency situations, such as breaker failure at transmission stations, have been identified.

Enova cannot adequately comment on transmission constraints over the forecast period until there is greater certainty regarding the outcome of the IRRP and RIP. At the time of preparing this report, a draft of the IRRP report has not yet been completed, however, Hydro One's Regional Planning Status letter dated April 9th, 2026, provides some context surrounding the transmission issues known at this time.

Transmission Line Capacity Needs:

1. **D11K/D12K (Detweiler x Kitchener #1 & 4 JCT) – Mid Term**

   D11K/D12K is a 115 kV supply to Kitchener MTS #1 and MTS #4. Based on current load forecasts, both circuits are expected to experience overloads under loss-of-companion circuit in the mid-term. This need is currently under assessment as part of the ongoing IRRP. A recommendation to address this need will be provided in the IRRP and RIP reports once completed.

2. **D10H – Long term**

   The 115 kV D10H circuit between Detweiler TS and Hanover TS supplies Rush MTS and Elmira TS. A normally open motorized switch south of Palmerston TS provides emergency supply to Palmerston, with the northern section fed radially from Hanover TS and the southern section from Detweiler TS, supplying Elmira TS load. Rush MTS also receives dual supply via the 115 kV D8S circuit. Under an outage of D8S, the D10H section between Detweiler and Leong JCT is forecasted to approach its supply capacity in the long term. This need is currently under assessment as part of the ongoing IRRP. A recommendation to address this need will be provided in the IRRP and RIP reports once completed.

Transmission Reliability, Operation and Restoration Needs :

1. **D11K/D12K (Detweiler x Kitchener #1 & 4 JCT) – Mid Term**

   A double-circuit outage on the M20D/M21D 230 kV line would leave insufficient capability to restore required load within 30 minutes per Ontario Resource and Transmission Assessment Criteria (ORTAC). This affects multiple stations supplied by the corridor, including Kitchener MTS #6, Kitchener MTS #8, Galt TS, Preston TS, Energy+ Inc., and a customer CTS. Current restoration options only recover partial load, resulting in both load security and load restoration criteria not being met. This need is currently under assessment as part of the ongoing IRRP. A recommendation to address this need will be provided in the IRRP and RIP reports once completed.

The full text of Hydro One's letter can be found in **Appendix C-5** of this DSP.

The IESO has adjusted the timing of the KWCG IRRP regional planning study to allow for the completion of the IESO's South Central Bulk Planning Study (SCBPS). The IESO recognizes that, with the forecasted load growth, additional 500 kV transmission may be needed in the KWCG area. The SCBPS has developed several options; however, at the time of this report, the preferred option has not yet been selected. The final selection and engagement stages for the proposed options are scheduled for Q3 of 2026.

Lastly, it is also important to note that Hydro One has stated throughout the IRRP process, that "Capital contribution may be required by Hydro One Networks Inc. from Enova Power Corp for some of the projects recommended through regional planning in the KWCG Region." It is Enova's position that the cost of transmission related solutions to transmission capacity, reliability, operation and restoration shortcomings is the responsibility of the transmitter and should be recovered through the Network Pool and not downloaded to the LDC's through capital contribution requirements.

5.2. Enova Transmission Connected Stations (115 kV & 230 kV)

Enova is connected to the Hydro One Networks Inc. (HONI) Transmission System (HONI Tx) through 13 grid connected Transformer Stations. Twelve of these stations are owned and operated by Enova and are Dual Element Spot Network (DESN) stations.

Under normal operating conditions, the two main power transformers at a DESN station share the load equally through a normally closed secondary bus tie system. The loss of a single transmission line, power transformer or station bus, referred to as an N-1 event, requires the remaining transformer to immediately carry the entire station load without interruption. Enova prepares for such contingencies by purchasing station transformers with overload capabilities known as a Limited Time Rating (LTR). Enova uses 10-day or 60-day summer LTR's in its capacity and contingency planning. Enova also maintains an operating strategy for its DESN stations to limit station loading to no more than the summer 10-day LTR rating of a single transformer. The in-service transformer can be operated at the elevated load for up to 10 consecutive days. During this time the utility must reduce the load or find an alternative solution to prevent catastrophic failure or excessive loss-of-life.

Enova maintains a margin of capacity at its other stations to accept excess load during such contingencies and to ensure individual transformers operate at or below their normal full-load rating. To that end, Enova continually reviews loading data and trends to forecast when capacity limits will be reached and additional supply is needed.

Table 5-2 provides the capacities, average peak loading and percent utilization for the grid-connected stations supplying Enova.

Table 5-2: Capacity Utilization - Station Transformers

Transformer Station	Tx ID	Transformer ONAF/OFAF Rating (MVA)	Station Capacity LTR (MW)	5 Year Avg.	Avg. % Capacity Utilization	2020 - 2024 Avg. Peak Demand (MW)	% Capacity Utilization at Peak Demand	Comments
Waterloo HMSTS 'A'	T1	50	49	51	104%	54	109%	Note (1)
	T2	50						
Waterloo HMSTS 'B'	T3	83	98	91	93%	97	99%	Note (2)
	T4	83						
Waterloo MTS #3	T1	67	77	53	69%	55	71%	
	T2	67						
Waterloo ERTS	T1	50	69	44	64%	51	74%	Note (3)
	T2	50						
HONI ELTS	T1	42	56	39	70%	47	83%	Note (4)
	T2	42						
Kitchener 1TS	T1	50	60	27	45%	29	48%	
	T2	50						
Kitchener 3TS	T5	100	120	50	42%	53	44%	
	T6	100						
Kitchener 4TS	T7	83.3	102	62	61%	68	67%	
	T8	83.3						
Kitchener 5TS	T9	100	120	70	58%	75	63%	
	T10	100						
Kitchener 6TS	T11	83.3	102	55	54%	66	65%	
	T12	83.3						
Kitchener 7TS	T13	50	61	35	57%	38	62%	
	T14	50						
Kitchener 8TS	T15	50	60	38	63%	41	68%	
	T16	50						
Kitchener 9TS	T17	83	100	32	32%	33	33%	
	T18	83						
Total		1783	1,074	647	60%	707	66%	

(Note1) - HMSTS 'A' is currently load-limited by the thermal rating of the station transformers' secondary bushings to a summer LTR of 49 MVA. The LTR of the power transformers is 69 MVA. Percent utilization is calculated based on 49 MVA.

(Note2) - HMSTS 'B' is currently load limited by the thermal rating of the station transformers' secondary bushings to a summer LTR of 98 MVA. The LTR of the power transformers is 110 MVA. Percent utilization is calculated based on 98 MVA.

(Note3) - ERTS is currently load limited by the thermal rating of the station transformers' secondary cables to a summer LTR of 69 MVA. The LTR of the power transformers is 75 MVA. Percent utilization is calculated based on 69 MVA.

(Note 4) - ELTS Summer LTR is 55.8 MW or 62 MVA at 0.9 power factor. Enova has historically utilized approximately 80% of the available station capacity. Enova's percent utilization is calculated based on 80% of the ELTS capacity.

The replacement of HMSTS “B” T3 and T4 transformers, due to condition, is forecast to begin in 2026 with an in-service date of 2029 and 2030. Enova will use the replacement of these transformers as a cost effective opportunity to increase transformer size and station capacity.

Similarly, the replacement of HMSTS “A” T1 and T2 transformers due to age and condition is forecast to begin in 2031 with an in-service date of 2033 and 2034. Enova will use the replacement of these transformers as a cost effective opportunity to increase transformer size and station capacity.

As previously mentioned, should the proposed 150 MVA of data centre load proceed in Enova’s service area, a new transformer station would be required. If this load does not materialize, the existing transformation will have sufficient capacity to serve load and generation customers over the forecast period. Some localized constraints within the distribution system may occur over time and will be addressed on a case-by-case basis.

5.3. Transformer Station Feeders (13.8 kV and 27.6 kV)

From the transmission-connected transformer stations, Enova distributes electricity to its customers through its 127 feeders at distribution voltages of 13.8 kV and 27.6 kV. Enova's transformer stations have an additional 30 switchgear cells that are designated for future feeder positions.

Enova's 13.8 kV and 27.6 kV feeder capacities are rated at 600 A, the limiting factor being the rating of the station feeder cables or overhead line conductors. All of Enova's station feeder breakers are rated for 1,200 A and do not present a limiting factor in supplying load.

Enova uses a planning criterion of 400 A (66%) for average feeder loading. This allows the load of a feeder, that is planned or forced out of service, to be moved to at least of two adjacent feeders and remain within loading limits. The installation of automated switching as part of Enova's grid modernization investments are assisting in Enova meeting this goal.

Enova also receives approximately 1% of its electrical supply at < 50 kV through feeders from 2 neighbouring LDCs; Hydro One Distribution (HONI Dx) and GrandBridge Energy (GBE).

From 2020 – 2024, Enova experienced an average station feeder utilization of approximately 45% and a maximum peak utilization of approximately 63%.

Although not in an overload state, summer loads can push individual feeder peak utilization above Enova's 66% planning criteria target. Excess feeder capacity is not available in every combination of feeder contingencies. Enova must take care with system configuration and planned equipment outages during these times. Enova regularly reviews feeder loading and rebalances the system when needed. When rebalancing is not possible within the existing configuration parameters, grid improvement solutions are proposed and evaluated. Enova grid modernization investments over the historic period have allowed for better utilization of feeder capacity.

The following tables provide capacity utilizations for Enova's TS feeders. All feeders are in service unless otherwise noted.

Table 5-3: Station Feeder Utilization HMSTS"A"

Facility	Feeder	Rating (Amps)	Average Peak (Amps)	Average Utilization (%)	Max Peak (Amps)	Peak Utilization (%)
HMSTS"A" Station	HS07	600	422	70%	529	88%
	HS08	600	392	65%	515	86%
	HS09	600	402	67%	474	79%
	HS10	600	413	69%	470	78%
	HS11	600	388	65%	503	84%
	HS12	600	430	72%	693	115%
	HS13	600	498	83%	568	95%
	HS14	600	344	57%	418	70%
Average Feeder Loading	8	600	411	69%	521	87%

Table 5-4: Station Feeder Utilization HMSTS"B"

Facility	Feeder	Rating (Amps)	Average Peak (Amps)	Average Utilization (%)	Max Peak (Amps)	Peak Utilization (%)
HMSTS"B" Station	HS15	600	352	59%	402	67%
	HS16	600	336	56%	455	76%
	HS17	600	349	58%	539	90%
	HS18	600	229	38%	304	51%
	HS19	600	527	88%	676	113%
	HS20	600	453	76%	528	88%
	HS21	600	422	70%	478	80%
	HS22	600	358	60%	410	68%
	HS23	600	317	53%	379	63%
	HS24	600	238	40%	418	70%
	HS25	600	348	58%	480	80%
	HS26	600	668	111%	744	124%
	HS27	600	334	56%	393	66%
	HS28	600	395	66%	495	82%
	HS29	600	426	71%	655	109%
	HS30	600	421	70%	479	80%
	HS31	Future				
	HS32	Future				
Average Feeder Loading	18	600	386	64%	490	82%

Table 5-5: Station Feeder Utilization MTS#3

Facility	Feeder	Rating (Amps)	Average Peak (Amps)	Average Utilization (%)	Max Peak (Amps)	Peak Utilization (%)
MTS#3	3F60	600	79	13%	207	35%
	3F61	600	311	52%	366	61%
	3F62 (3F50)	600	153	25%	169	28%
	3F63	600	317	53%	367	61%
	3F64	600	31	5%	31	5%
	3F65	600	262	44%	405	67%
	3F66	600	161	27%	222	37%
	3F67 (3F51)	600	186	31%	256	43%
	3F68	600	284	47%	379	63%
	3F69	600	85	14%	313	52%
Average Feeder Loading	10	600	187	31%	272	45%

Table 5-6: Station Feeder Utilization ERTS

Facility	Feeder	Rating (Amps)	Average Peak (Amps)	Average Utilization (%)	Max Peak (Amps)	Peak Utilization (%)
ERTS	ER41	600	249	41%	332	55%
	ER42	600	398	66%	489	82%
	ER43	600	242	40%	337	56%
	ER44	600	326	54%	431	72%
	ER45	600	370	62%	490	82%
	ER46	600	279	46%	369	62%
	ER47	600	378	63%	462	77%
	ER48	600	252	42%	346	58%
Average Feeder Loading	8	600	312	52%	407	68%

Table 5-7 provides a summary of ELTS feeder utilization. The ELTS station is owned and operated by HONI. The 33M1 and 33M3 feeders are dedicated to Enova. The 33M2 feeder is shared with HONI Dx.

Table 5-7: Station Feeder Utilization ELTS

Facility	Feeder	Rating (Amps)	Average Peak (Amps)	Average Utilization (%)	Max Peak (Amps)	Peak Utilization (%)
ELTS	33M1	525	487	93%	585	111%
	33M2	525	433	82%	552	105%
	33M3	525	370	71%	584	111%
Average Feeder Loading	3	525	384	73%	506	96%

Table 5-8: Station Feeder Utilization Kitchener 1TS

Facility	Feeder	Rating (Amps)	Average Peak (Amps)	Average Utilization (%)	Max Peak (Amps)	Peak Utilization (%)
Kitchener 1TS	1M1	600	351	58%	393	65%
	1M2	Future				
	1M3	600	353	59%	524	87%
	1M4	600	87	14%	103	17%
	1M5	600	73	12%	86	14%
	1M6	600	64	11%	79	13%
	1M7	600	101	17%	267	44%
	1M8	600	254	42%	407	68%
	1M9	600	278	46%	418	70%
	1M10	Future				
Average Feeder Loading	10	600	195	33%	285	47%

Table 5-9: Station Feeder Utilization Kitchener 3TS

Facility	Feeder	Rating (Amps)	Average Peak (Amps)	Average Utilization (%)	Max Peak (Amps)	Peak Utilization (%)
Kitchener 3TS	3M11	600	378	63%	434	72%
	3M13	600	213	36%	355	59%
	3M14	600	211	35%	344	57%
	3M15	600	253	42%	279	47%
	3M16	600	240	40%	440	73%
	3M18	600	165	28%	387	65%
	3M20	600	187	31%	268	45%
	3M21	600	150	25%	261	43%
	3M22	600	274	46%	326	54%
	3M23 (1)	600	0	0%	0	0%
	3M24	Future				
	3M25	Future				
	3M26	600	318	53%	457	76%
	3M27	600	185	31%	381	64%
	3M28	600	183	30%	347	58%
	3M29	Future				
	3M210	600	308	51%	447	74%
	3M211	Future				
	3M212	Future				
Average Feeder Loading	19	600	219	36%	338	56%

(1) backup feeder

Table 5-10: Station Feeder Utilization Kitchener 4TS

Facility	Feeder	Rating (Amps)	Average Peak (Amps)	Average Utilization (%)	Max Peak (Amps)	Peak Utilization (%)
Kitchener 4TS	4M10	Future				
	4M11	600	338	56%	470	78%
	4M12	600	314	52%	405	68%
	4M13	600	281	47%	358	60%
	4M14	600	224	37%	324	54%
	4M15	600	262	44%	416	69%
	4M16	600	238	40%	389	65%
	4M17	600	67	11%	104	17%
	4M18	600	258	43%	350	58%
	4M19	Future				
	4M20	Future				
	4M21	600	349	58%	479	80%
	4M22	Future				
	4M23	Future				
	4M24	600	304	51%	416	69%
	4M25	600	121	20%	338	56%
	4M26	600	321	53%	463	77%
	4M27	600	358	60%	449	75%
	4M28	600	118	20%	180	30%
Average Feeder Loading	19	600	254	42%	387	61%

Table 5-11: Station Feeder Utilization Kitchener 5TS

Facility	Feeder	Rating (Amps)	Average Peak (Amps)	Average Utilization (%)	Max Peak (Amps)	Peak Utilization (%)
Kitchener 5TS	5M11	600	361	60%	446	74%
	5M13	600	216	36%	484	81%
	5M14	600	303	50%	401	67%
	5M15	600	450	75%	554	92%
	5M16	600	244	41%	463	77%
	5M17	600	446	74%	486	81%
	5M18	Future				
	5M19	Future				
	5M20	Future				
	5M21	600	352	59%	509	85%
	5M22	600	382	64%	568	95%
	5M23	600	383	64%	451	75%
	5M24	Future				
	5M25	600	303	51%	433	72%
	5M26	600	238	40%	304	51%
	5M27	600	350	58%	390	65%
	5M28	600	66	11%	140	23%
Average Feeder Loading	17	600	315	52%	433	72%

Table 5-12: Station Feeder Utilization Kitchener 6TS

Facility	Feeder	Rating (Amps)	Average Peak (Amps)	Average Utilization (%)	Max Peak (Amps)	Peak Utilization (%)
Kitchener 6TS	6M11	600	228	38%	285	48%
	6M12	Future				
	6M13	600	257	43%	376	63%
	6M14	600	235	39%	470	78%
	6M15	600	255	42%	453	75%
	6M16	Future				
	6M17	600	292	49%	350	58%
	6M18	600	360	60%	469	78%
	6M21	600	330	55%	449	75%
	6M22	600	65	11%	113	19%
	6M23	600	243	41%	353	59%
	6M24	600	146	24%	200	33%
	6M25	600	312	52%	448	75%
	6M26	600	280	47%	310	52%
	6M27	600	255	43%	395	66%
	6M28	600	179	30%	283	47%
Average Feeder Loading	16	600	246	41%	354	59%

Table 5-13: Station Feeder Utilization Kitchener 7TS

Facility	Feeder	Rating (Amps)	Average Peak (Amps)	Average Utilization (%)	Max Peak (Amps)	Peak Utilization (%)
Kitchener 7TS	7M1	600	15	2%	59	10%
	7M2	600	226	38%	266	44%
	7M3	600	282	47%	437	73%
	7M4	Future				
	7M5	600	291	49%	352	59%
	7M6	Future				
	7M7 (1)	600	145	24%	249	42%
	7M8	600	369	62%	446	74%
	7M9	600	381	64%	486	81%
	7M10	600	171	28%	271	45%
Average Feeder Loading	10	600	248	41%	321	53%

(1) backup feeder

Table 5-14: Station Feeder Utilization Kitchener 8TS

Facility	Feeder	Rating (Amps)	Average Peak (Amps)	Average Utilization (%)	Max Peak (Amps)	Peak Utilization (%)
Kitchener 8TS	8M0	Future				
	8M1	Future				
	8M2	600	164	27%	377	63%
	8M3	600	267	45%	420	70%
	8M4	600	273	46%	288	48%
	8M5	600	365	61%	523	87%
	8M6	Future				
	8M7	600	404	67%	523	87%
	8M8	Future				
	8M9	600	274	46%	346	58%
	8M10	600	192	32%	319	53%
	8M11	Future				
Average Feeder Loading	12	600	277	46%	399	67%

Table 5-15: Station Feeder Utilization Kitchener 9TS

Facility	Feeder	Rating (Amps)	Average Peak (Amps)	Average Utilization (%)	Max Peak (Amps)	Peak Utilization (%)
Kitchener 9TS	9M2	600	38	6%	66	11%
	9M3	600	202	34%	386	64%
	9M4	600	228	38%	361	60%
	9M5	Future				
	9M6	Future				
	9M7	600	178	30%	382	64%
	9M8	Future				
	9M9	600	343	57%	411	69%
Average Feeder Loading	8	600	198	33%	321	54%

Enova's two, < 50 kV delivery points are listed in **Table 5-16**. Although not major points of supply, these two delivery points are strategically important to Enova due to their geographic locations.

The 73M7 feeder from HONI Dx feeds into the north-east area of Woolwich Township and is Enova's only 44 kV delivery point. At the end of a long radial feeder, the 44 kV from HONI is out-of-phase with Enova's 27.6 kV system and has had relatively poor historical reliability. Enova has been gradually migrating load over to its 27.6 kV system through voltage conversion measures as part of System Renewal projects in the area.

The 21M25, 27.6 kV feeder from GrandBridge Energy, which feeds into the south-east area of Woolwich Township, is an area of increasing residential and industrial load. At or near capacity, Enova is working to increase supply by strengthen feeder ties with Enova's MTS #3 and other GrandBridge Energy feeders.

Table 5-16: Delivery Point Feeder Utilization (< 50 kV) (2020 – 2024)

Host LDC	Feeder	Feeder Voltage (kV)	Capacity Available to Enova (Amps)	Capacity Available to Enova (MVA)	Average Peak (Amps)	Average Utilization (%)	Max Peak (Amps)	Peak Utilization (%)
HONI Dx	73M7	44	66	5	36	54%	44	66%
GrandBridge Energy	21M25	27.6	300	14.3	300	100%	359	120%
Average Feeder Loading			366		336	92%	403	110%

Enova does not forecast any significant constraints or lack of capacity over the forecast period.

5.4. Distribution Station (DS) Capacity Utilization

Table 5-17 provides a listing of Enova's DS stations in service at the end of 2024. Also included in the table are the capacities and peak station demands from 2020 - 2024. In total, Enova has 50.6 MVA of 8 kV station capacity in service. Overall, station capacity utilization is approximately 70%.

Table 5-17: Enova DS Station Capacity Utilization

#	Station	Supplied By	Location	HV (kV)	LV (kV)	Tx ID	Tx Full Cooled Rating (MVA)	2020 - 2024 Peak Demand (MW)	% Capacity Utilization
1	DS#27	Enova Dx	Wallenstein	27.6	8.32	T1	5.0	2.78	56%
2	DS#28	Enova Dx	Floradale	27.6	8.32	T1	5.0	2.71	54%
3	DS#30	Enova Dx	Zuber Corners	44	8.32	T1	5.0	3.27	65%
4	DS#31	Enova Dx	Bloomingdale	27.6	8.32	T1	5.0	3.84	77%
5	1DS	Enova Dx	New Hamberg	27.6	8.32	T1	5.0	5.15	103%
6	2DS	Enova Dx	New Hamberg	27.6	8.32	T1	5.0	5.16	103%
7	3DS	Enova Dx	New Dundee	27.6	8.32	T1	5.0	2.79	56%
8	6DS	Enova Dx	Baden	27.6	8.32	T1	5.6	4.18	75%
9	7DS	Enova Dx	New Hamberg	27.6	8.32	T1	5.0	4.67	93%
10	8DS	Enova Dx	Philipsburg	27.6	8.32	T1	5.0	4.95	99%

Enova's System Renewal programs in overhead lines have allowed for a gradual shift in load from 8.32 kV to 27.6 kV, resulting in the retirement of 4 stations since 2020. This trend will continue over the forecast period, as Enova is plans to retire 3DS in the 2025-2026 timeframe. Although there are no other stations planned for retirement before 2031, ultimately the entire 8.32 kV station and distribution system will be phased out for the more efficient and cost-effective 27.6kV system.

Measures Enova has taken to support this aging infrastructure to its end-of-life include;

1. Enova owns and maintains two mobile unit substations (MUS) to provide temporary supply to any 8.32 kV station within 4 hours.
2. Enova maintains spare 44 kV and 27.6 kV transformers that can be pressed into service in case of an in-service failure.
3. Enova salvages serviceable equipment from retired stations to maintain operability.

5.5. Distribution Feeder (8 kV) Capacity Utilization

Enova uses a planning criterion of 50% feeder rating for maximum feeder loading. This allows for the load of a feeder that is planned or forced out of service to be moved to adjacent feeders and remain within loading limits.

Table 5-18 provides a listing of Enova's 28, 8.32 kV DS feeders in service at the end of 2024. Included in the table are the feeder capacities, average and peak feeder loading and percent utilization from 2020 - 2024.

Table 5-18: Enova DS Station Feeder Capacity Utilization

Facility	Feeder	Rating (Amps)	Average Peak (Amps)	Average Utilization (%)	Max Peak (Amps)	Peak Utilization (%)
DS 27	1	200	95.7	48%	108.7	54%
	2	200	54.7	27%	88.0	44%
DS 28	1	200	110.7	55%	126.3	63%
	2	200	102.9	51%	128.3	64%
DS 30	1	200	82.2	41%	112.0	56%
	2	200	131.3	66%	173.0	87%
	3	200	71.0	36%	119.7	60%
DS 31	1	200	85.3	43%	154.3	77%
	2	200	121.5	61%	147.0	74%
	3	200	75.7	38%	131.7	66%
1DS	1DS1	400	219.4	55%	280.2	70%
	1DS2	400	80.3	20%	173.1	43%
	1DS3	400	106.9	27%	162.9	41%
2DS	2DS1	400	131.0	33%	204.0	51%
	2DS2	400	112.0	28%	140.6	35%
	2DS3	400	153.4	38%	183.4	46%
3DS	3DS1	400	146.9	37%	174.2	44%
	3DS2	400	0.0	0%	0.0	0%
	3DS3	400	35.2	9%	85.0	21%
6DS	6DS1	400	102.0	25%	138.2	35%
	6DS2	400	136.4	34%	156.4	39%
	6DS3	400	34.7	9%	61.4	15%
7DS	7DS1	400	82.3	21%	150.8	38%
	7DS2	400	121.7	30%	192.4	48%
	7DS3	400	116.6	29%	146.6	37%
8DS	8DS1	400	48.3	12%	145.6	36%
	8DS2	400	120.3	30%	163.9	41%
	8DS3	400	91.8	23%	180.6	45%

Overall, feeder loading averaged approximately 30% with a peak loading of 44%. Enova does not forecast any significant constraints or capacity issues in its 8.32 kV system over the forecast period.

5.6. Distribution Transformers

Enova has approximately 18,972 distribution transformers connected to its system for a total installed capacity of 1,698 MVA. Enova calculates a rolling average of 24 consecutive monthly peaks (kW) for each distribution transformer in its system. Data gathered from Enova's AMI system indicates that the average loading over the entire distribution transformer population is approximately 35%.

Figure 5-1 provides a loading profile of Enova's distribution transformer population.

Figure 5-1: Enova Distribution Transformer Utilization (%)

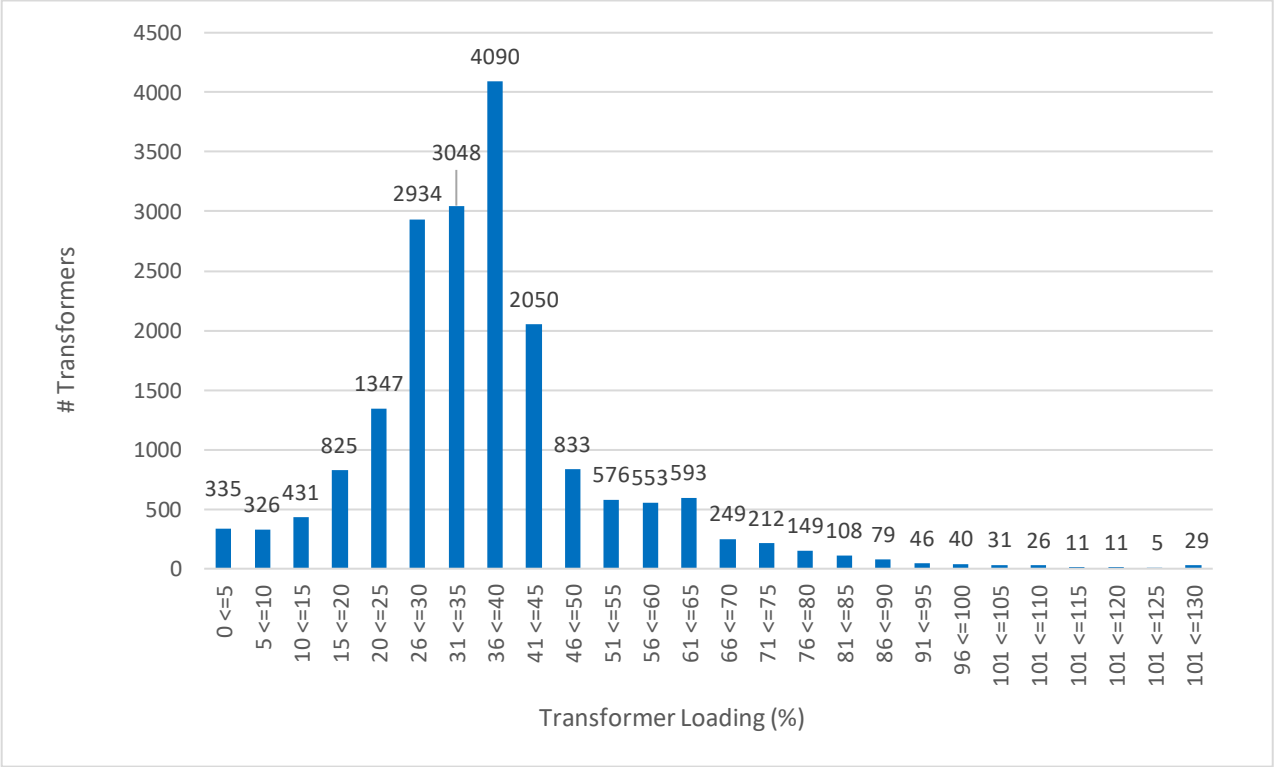


Table 5-19 provides a breakdown of Enova's distribution transformer loading by transformer type.

Table 5-19: Distribution Transformer Loading by Type

Transformer Population	Total	% Loading
Polemount	8,555	34.2%
Padmount	5,627	37.7%
Submersible	4,085	35.6%
Vault	673	34.4%
Network	32	N/A
Total Overhead	8,555	34.2%
Total Underground / Vault / Network	10,417	35.7%
Total Transformers in Service	18,972	35.2%

Enova follows a loading policy that allows distribution transformers with a normal residential load profile can be loaded up to 150% of nominal rating. For other types of loads, 130% of the nominal rating is followed.

Table 5-20 provides a breakdown of distribution transformers with an average loading above 100%. These transformers represent approximately 0.8% of the population.

Table 5-20: Distribution Transformer Average Loading above 100%

Loading Factor (%)	# Units
> 100%	113
> 130%	23
> 150%	9

Transformers exceeding Enova Loading guidelines are target for remedial action.

Enova forecasts sufficient capacity in its population of distribution transformers to serve the forecasted load, including the connection of electric vehicles.

APPENDIX F-1
Distribution System Reliability Report

2024

Distribution System Reliability Report



July 1, 2026

(Page Intentionally left blank)

CONTENTS

CONTENTS ii

LIST OF TABLES iii

LIST OF FIGURES v

GLOSSARY vi

1. Introduction 1
   - 1.1. Purpose of this Report 1
   - 1.2. Description of the Utility Company 1
   - 1.3. Reliability Overview 3
2. Operational Effectiveness – SAIDI, SAIFI and MAIFI 5
   - 2.1. Reliability Performance Overview (2020 - 2024) 5
   - 2.2. System Average Interruption Duration Index (SAIDI) 5
   - 2.3. System Average Interruption Frequency Index (SAIFI) 6
   - 2.4. Momentary Interruptions (MAIFI) 8
3. Sustained Interruptions 10
   - 3.1. Customer Hours of Interruption (CHI) (Overview) 10
   - 3.2. Major Event Days (MED) 13
   - 3.3. Top Contributing Interruption Events 16
4. Sustained Interruption Cause Codes 24
   - 4.1. Overview 24
   - 4.2. Cause Code 0: Unknown / Other 27
   - 4.3. Cause Code 1: Scheduled Outages 29
   - 4.4. Cause Code 2: Loss of Supply 31
   - 4.5. Cause Code 3: Tree Contacts 33
   - 4.6. Cause Code 4: Lightning Contacts 35
   - 4.7. Cause Code 5: Defective Equipment 37
   - 4.8. Cause Code 6: Adverse Weather 39
   - 4.9. Cause Code 7: Adverse Environment 41
   - 4.10. Cause Code 8: Human Element 43
   - 4.11. Cause Code 9: Foreign Interference 45
5. Impact of Grid Modernization on Reliability 48
6. 2024 Worst Performing Feeders 49

LIST OF TABLES

Table 1-1: Historical Reliability Performance 3
Table 1-2: Historical Annual CHI (Total - MED) by Rank 4
Table 2-1: Enova Reliability Performance 2020-2024 5
Table 2-2: Momentary Interruption Events 8
Table 3-1: Sustained Interruptions (CHI) 10
Table 3-2: Customer & Event Data 11
Table 3-3: Historical Sustained Interruptions 12
Table 3-4: MEDs Ranked by CHI 13
Table 3-5a: MED 2020 - 2021 14
Table 3-5b: MED 2022 15
Table 3-6: Top Contributing Sustained Events 2020 16
Table 3-7a: CS Top Contributing Sustained Events 2021 17
Table 3-7b: VS Top Contributing Sustained Events 2021 17
Table 3-8a: CS Top Contributing Sustained Events 2022 18
Table 3-8b: VS Top Contributing Sustained Events 2022 19
Table 3-9a: CS Top Contributing Sustained Events 2023 20
Table 3-9b: VS Top Contributing Sustained Events 2023 21
Table 3-10a: CS Top Contributing Sustained Events 2024 22
Table 3-10b: VS Top Contributing Sustained Events 2024 23
Table 4-1: Historical Annual Interruption Events 24
Table 4-2: Historical Annual CHI (Total) 25
Table 4-3: Historical Annual CHI (Total) by Rank 25
Table 4-4: Historical Annual CHI (Total - MED) by Rank 26
Table 4-5: CC_0 Unknown Cause 28
Table 4-6: CC_1 Scheduled Outages 30
Table 4-7: CC_1 Scheduled Outages by Sub-cause Codes (2024) 30
Table 4-8: CC_2 Loss of Supply 32
Table 4-9: CC_2 Loss of Supply by Sub-cause Codes 32
Table 4-10: CC_3 Tree Contacts 34
Table 4-11: CC_3 Tree Contacts by Sub-cause Codes 34
Table 4-12: CC_4 Lightning Contacts 36

Table 4-13: CC_5 Defective Equipment 38
Table 4-14: CC_5 Defective Equipment by Sub-cause Codes 38
Table 4-15: CC_6 Adverse Weather 40
Table 4-16: CC_6 Adverse Weather by Sub-cause Codes 40
Table 4-17: CC_7 Adverse Environment 42
Table 4-18: CC_8 Human Element 44
Table 4-19: CC_8 Human Element by Sub-cause Codes 44
Table 4-20: CC_9 Foreign Interference 46
Table 4-21a: CC_9 Foreign Interference by Sub-cause Codes (2024) 46
Table 4-21b: CC_9 Foreign Interference by Sub-cause Codes (2024) 46
Table 6-1: Worst Performing Feeders 49
Table 6-2: Worst Performing Feeder Action Plans (2024) 50
Table 6-3: Enova Feeder Performance Excluding Planned & Major Event Days 51

LIST OF FIGURES

Figure 1-1: Enova Service Territory 2
Figure 2-1: SAIDI (2020 – 2024) 6
Figure 2-2: SAIFI (2020 – 2024) 7
Figure 2-3: MAIFI (2020 - 2024) 8
Figure 3-1: Enova Sustained Interruptions (CHI) 10
Figure 3-2: CMI / Customer Trending 11
Figure 3-3: Interruption Events Trending (2020 – 2024) 12
Figure 4-1: CC_0 Unknown / Other Causes 27
Figure 4-2: CC_1 Scheduled Outage Cause Trending 29
Figure 4-3: CC_2 Loss of Supply Cause Trending 31
Figure 4-4: CC_3 Tree Contacts 33
Figure 4-5: CC_4 Lightning Events Cause 35
Figure 4-6: CC_5 Defective Equipment 37
Figure 4-7: CC_6 Adverse Weather 39
Figure 4-8: CC_7 Adverse Environment 41
Figure 4-9: CC_8 Human Element 43
Figure 4-10: CC_9 Foreign Interference (2020 – 2024) 45

GLOSSARY

1) ACA – Asset Condition Assessment
2) AM – Asset Management
3) AMP – Asset Management Plan
4) CAIDI – Customer Average Interruption Duration Index
5) CC – Cause Codes
6) CEA – Canadian Electrical Association
7) CI – Customers Interrupted
8) CHI – Customer Hours Interrupted
9) CMI – Customer Minutes of Interruption
10) CSA – Canadian Standard Association
11) DS – Distribution Station
12) DSC – Distribution System Code
13) DSP – Distribution System Plan
14) EOL – End-of-Life
15) ESA – Electrical Safety Authority
16) FLISR – Fault Location, Isolation and Service Restoration
17) GIS – Geographic Information System
18) GM – Grid Modernization
19) HONI – Hydro One Networks Inc.
20) ICM - Incremental Capital Module
21) IESO – Independent Electricity System Operator
22) KFP – Kitchener Fire Department
23) KPI – Key Performance Indicator
24) KWCG – Kitchener – Waterloo – Cambridge – Guelph Area
25) KWHI – Kitchener-Wilmot Hydro Inc.
26) LDC – Local Distribution Company
27) LOS – Loss of Supply
28) LTLT – Long Time Load Transfer customer

29) MAIFI – Momentary Average Interruption Frequency Index
30) MED – Major Event Day
31) MS – Municipal Station
32) MVA Motor Vehicle Accident
33) O/H or OH – Overhead
34) OEB – Ontario Energy Board
35) O&M – Operation & Maintenance
36) OMS – Outage Management System
37) REG – Renewable Energy Generation
38) RRFE – Renewed Regulatory Framework for Electricity Distributors
39) SAIDI – System Average Interruption Duration Index
40) SAIFI – System Average Interruption Frequency Index
41) SCADA – Supervisory Control and Data Acquisition
42) SEI – Serious Electrical Incidents
43) TS – Transmission Station or Transformer Station
44) U/G or UG – Underground
45) Enova - Enova Power Corporation Inc.
46) WNH - Waterloo North Hydro Inc.
47) WPF - Worst Performing Feeder
48) WFD – Waterloo Fire Department
49) XFMR / Tx – Transformer

1. Introduction

1.1. Purpose of this Report

Good reliability performance is consistently at or near the top of Enova Power Corporation's (Enova) customer stated preferences. It is one of Enova's top Corporate Strategic Objectives and Asset Management Objectives. Good reliability helps support the achievement of the OEB's key performance outcome of Operational Effectiveness as established in the Renewed Regulatory Framework for Electricity (RRFE).

This is Enova's first harmonized "Distribution System Reliability Report". Reliability data from Enova's legacy utilities have been harmonized to provide a consolidated view of Enova's reliability performance over the period 2020 to 2024 inclusive.

This report provides historical data and trends in reliability performance. Starting with the year 2024, the report includes all Sub-cause Codes, consistent with the OEB's RRR filing requirements. Enova constantly monitors reliability performance indicators such as SAIDI, SAIFI and MAIFI. Performances of all Enova feeders are reviewed annually and the worst performing feeders, based on three-year rolling CMI averages, are identified and flagged for action. Reliability issues, including leading causes, are identified and recommendations for action are provided.

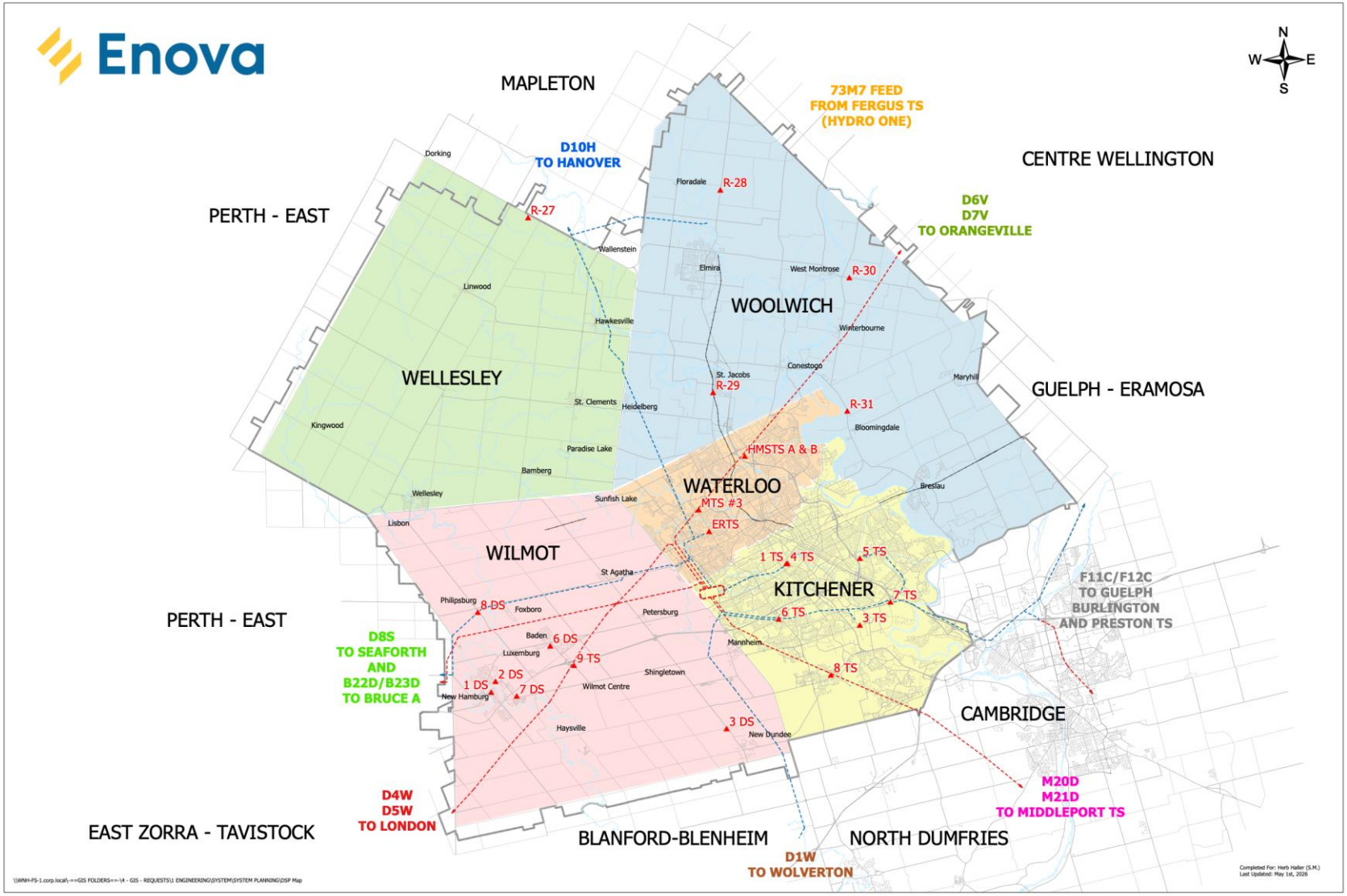
The information in this report informs Enova's senior executive team (Executive) and aides in the development of Enova's business plans, budgets and Distribution System Plan (DSP). This report also informs the system reliability portion of the OEB's RRR filing and has been prepared to support Enova's 2027 ICM application (Application).

1.2. Description of the Utility Company

A current map of Enova's Service Area is provided in **Figure 1-1**.

Please refer to Enova's Distribution System Plan, **Section 1.6** for a complete description of the utility. All information contained in this report is current as of December 31, 2024.

Figure 1-1: Enova Service Territory



1.3. Reliability Overview

Table 1-1 provides a summary of Enova's reliability performance from 2020 to 2024 inclusive. The OEB's reliability targets for Enova are SAIDI (0.84), SAIFI (1.10) and were set in 2022.

Enova's 5-year average reliability performance metrics for SAIDI (0.77) and SAIFI (0.88) are below the OEB targets. Individual years' metrics are all at or below target except for 2022 and 2024 SAIDI.

Enova's 2022 reliability performance was severely impacted by Adverse Weather and Defective Equipment. Enova's 2024 reliability performance was impacted almost equally by Adverse Weather, Defective Equipment and Foreign Interference. More information is provided in the following sections of this report.

Enova's SAIDI and SAIFI performance have also trended well below the industry averages over the period.

Table 1-1: Historical Reliability Performance

Measures	2020	2021	2022	2023	2024	Average	Targets
Sustained Events (ALL)	1,312	1,388	1,427	1,296	1,082	1,301	
Momentary Events (ALL)	398	364	438	411	359	394	
Momentary Events (excluding LOS & MED)	366	336	404	407	354	373	
Average # of Customers	157,405	159,013	160,937	162,585	164,118	160,812	
Total Customer Sustained Interruptions	172,508	153,736	198,708	122,840	214,603	172,479	
Number of Customer Sustained Interruptions (excluding LOS & MED)	150,283	113,397	144,151	119,617	180,894	141,668	
Customer Hours Interrupted (CHI) (Total)	125,929	167,620	357,741	109,000	161,693	184,397	
CHI (excluding LOS & MED)	99,022	92,608	165,828	107,725	157,341	124,505	
SAIDI (All)	0.80	1.05	2.22	0.67	0.99	1.15	
SAIDI (excluding LOS & MED)	0.63	0.58	1.03	0.66	0.96	0.77	0.84
SAIFI (All)	1.10	0.97	1.23	0.76	1.31	1.07	
SAIFI (excluding LOS & MED)	0.95	0.71	0.90	0.74	1.10	0.88	1.10
MAIFI (All)	2.68	2.57	3.03	2.94	2.70	2.78	
MAIFI (excluding LOS & MED)	2.58	2.53	2.88	2.91	2.41	2.66	

Table 1-2 illustrates Enova's Historical Annual CHI (Total - MED) by Rank. Defective Equipment (30.1%), Foreign Interference (28%) and Scheduled Interruptions (14.8%) rank as the top three causes of sustained customer interruptions over the 2020 to 2024 time period.

Table 1-2: Historical Annual CHI (Total - MED) by Rank

	Interruption	2020	2021	2022	2023	2024	Total	Avg.	%
CC #	Cause Code	CHI	CHI	CHI	CHI	CHI		2020-2024	2020-2024
5	Defective Equipment	36,974	28,598	65,982	20,815	38,439	190,808	38,162	30.1%
9	Foreign Interference	27,787	23,023	42,443	47,018	37,118	177,390	35,478	28.0%
1	Scheduled Outage	12,357	20,117	26,077	18,371	16,680	93,602	18,720	14.8%
3	Tree Contacts	12,501	12,222	14,586	12,402	17,319	69,030	13,806	10.9%
6	Adverse Weather	4,161	1,060	2,340	611	32,406	40,579	8,116	6.4%
0	Unknown/Other	2,864	3,636	2,761	6,529	12,536	28,325	5,665	4.5%
7	Adverse Environment	-	-	10,637	625	386	11,648	2,330	1.8%
2	Loss of Supply	1,601	1,700	2,070	1,275	4,352	10,998	2,200	1.7%
4	Lightning	2,277	3,935	638	431	892	8,173	1,635	1.3%
8	Human Element	101	17	364	922	1,566	2,969	594	0.5%
	Total	100,623	94,308	167,898	109,000	161,693	633,522	126,704	100.0%
	AVG	10,062	9,431	16,790	10,900	16,169	63,352		

Enova continues to make prudent system-renewal investments to limit the negative impacts of defective equipment on customer reliability. Approximately 50% of Enova's distribution feeders do not yet fully benefit from the grid modernization technologies deployed to date. Opportunities for reliability improvement exist with the further rollout of these technologies.

Enova is preparing its distribution system for the larger integration of electric vehicles, electric heat pumps, Distributed Energy Resource Systems (DERs) and data centers. Even where grid modernization technologies have been implemented, regular re-examination of feeder reliability performance is performed to identify further opportunities for improvement.

2. Operational Effectiveness – SAIDI, SAIFI and MAIFI

2.1. Reliability Performance Overview (2020 - 2024)

Table 2-1 provides Enova's 2020 to 2024 reliability performance exclusive of Loss of Supply and Major Event Days. Enova's reliability targets for Enova SAIDI (0.84) and SAIFI (1.10) were set in 2022.

It can be observed from **Table 2-1,** that Enova's 5-year average reliability performance metrics are below the OEB targets for SAIDI and SAIFI. Individual years metrics are all at or below target except for 2022 (SAIDI, 1.03) and 2024 (SAIDI, 0.96).

Table 2-1: Enova Reliability Performance 2020-2024

MEASURES	2020	2021	2022	2023	2024	AVG.	Enova Targets
SAIDI (Excluding Loss of Supply and Major Events	0.63	0.58	1.03	0.66	0.96	0.77	0.84
SAIFI Excluding Loss of Supply and Major Events	0.95	0.71	0.90	0.74	1.10	0.88	1.10

2.2. System Average Interruption Duration Index (SAIDI)

SAIDI is generally defined as the system average sustained interruption duration (CHI) for customers served per year (hours/year). It is calculated as follows:

$$\text{SAIDI} = \frac{\text{sum of all customer interruption durations}}{\text{total number of customers served}}$$

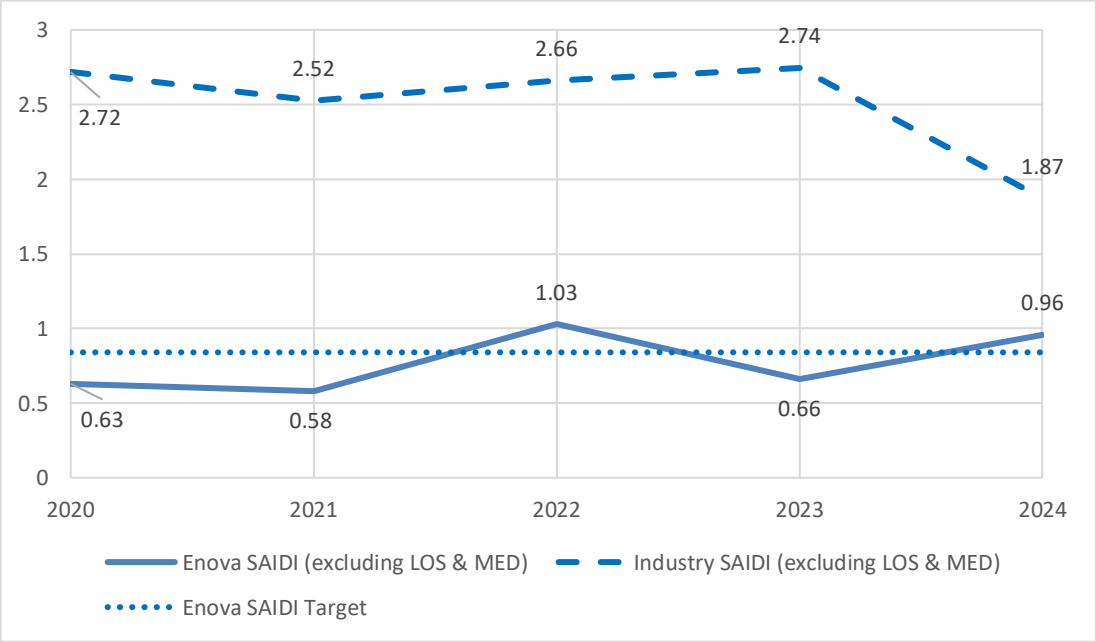
SAIDI(Adjusted) which is filed with Enova's OEB RRR report, represents a version of SAIDI excluding Loss of Supply (LOS) and Major Event Days MED). This normalized version is tracked against Enova's OEB targets.

$$\text{SAIDI (Adjusted)} = \frac{\text{Total CHI - LOS - MED}}{\text{Total number of customers served}}$$

Figure 2-1 illustrates Enova's annual SAIDI from 2020 to 2024 benchmarked against Enova's OEB target and LDC industry SAIDI averages. Although Enova's 5-year average SAIDI was below the OEB target, exceedances occurred in 2022 and 2024. Enova's 2022 reliability performance was severely impacted by Adverse Weather and Defective Equipment. Enova's 2024 reliability performance was impacted almost equally by Adverse Weather, Defective Equipment and Foreign Interference. More information is provided in following sections of this report.

Enova's SAIDI performance has performed better than the industry average over the period.

Figure 2-1: SAIDI (2020 – 2024)



2.3. System Average Interruption Frequency Index (SAIFI)

SAIFI is defined as the average number of sustained interruptions per customer per year. It is calculated as follows:

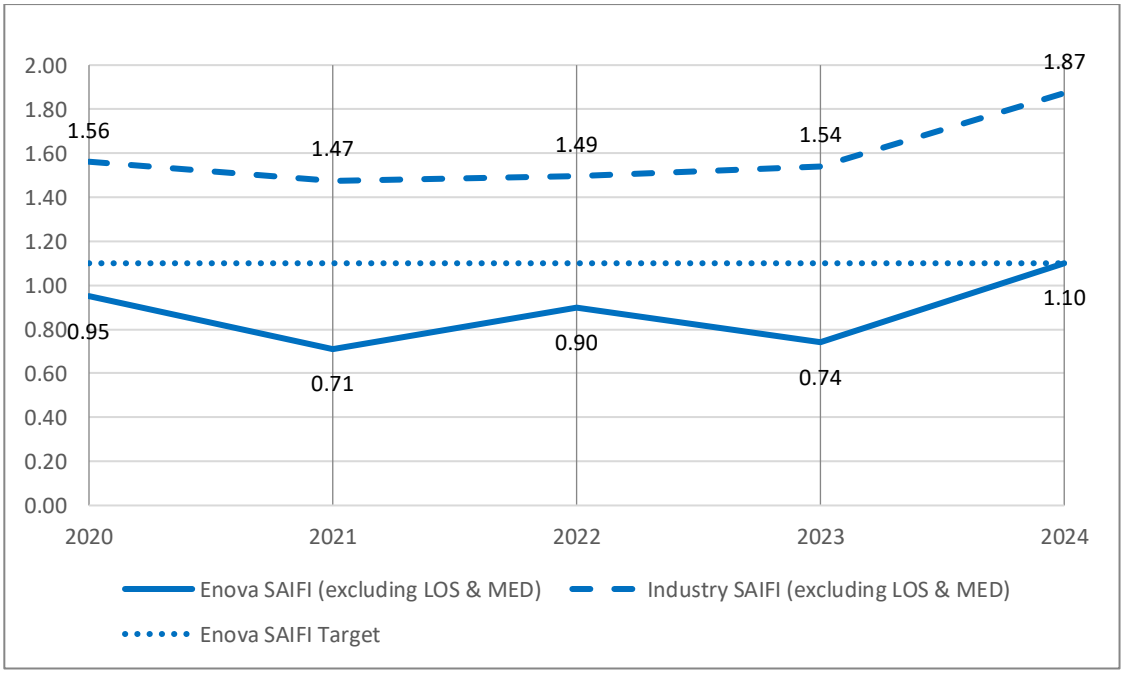
$$\text{SAIFI} = \frac{\text{total number of customer interruptions}}{\text{total number of customers served}}$$

SAIFI(Adjusted) which is filed with Enova's OEB RRR report, represents a version of SAIFI excluding Loss of Supply and Major Event Day events. This normalized version is tracked against Enova's OEB targets.

$$\text{SAIFI(Adjusted)} = \frac{\text{Number of Customer Interruptions - LOS - MED}}{\text{Total number of customers served}}$$

Figure 2-2 illustrates Enova's annual SAIFI from 2020 to 2024 benchmarked against Enova's OEB target and LDC industry SAIDI averages. Enova's 5-year average SAIFI was at or below the OEB target. Enova's SAIFI performance has trended well below the industry averages over the period.

Figure 2-2: SAIFI (2020 – 2024)



2.4. Momentary Interruptions (MAIFI)

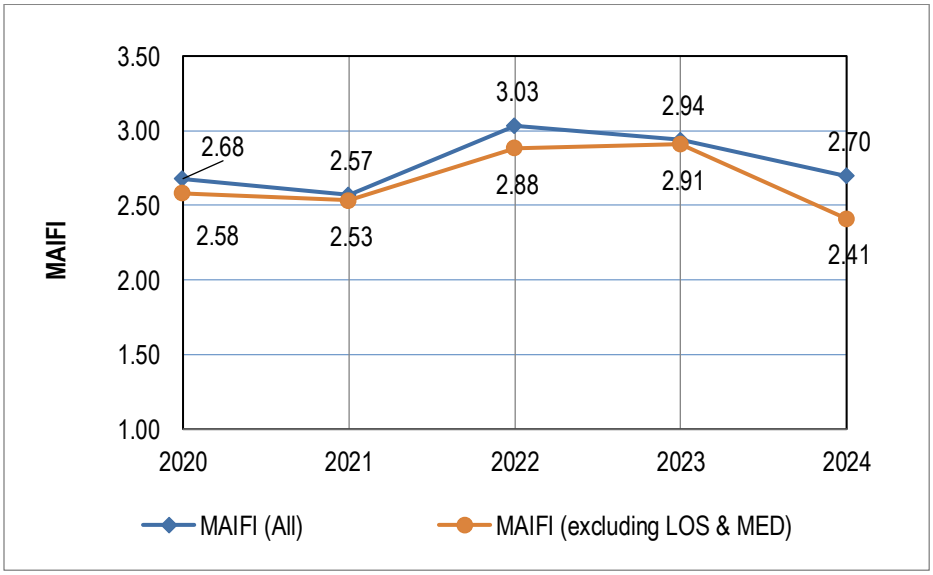
A momentary interruption is defined as an interruption with a duration of less than one minute. Enova customers have averaged approximately 400 momentary interruptions annually between 2020 and 2024. **Table 2-2** provides a summary of Enova's annual momentary interruptions over the historic period.

Table 2-2: Momentary Interruption Events

Year	# Momentary Operations (All Inclusive)	# Momentary Operations (Excluding LOS & MED)
2020	398	366
2021	364	336
2022	438	404
2023	411	407
2024	359	354
Avg.	394	373

Momentary Average Interruption Frequency Index (MAIFI) represents the average number of momentary interruptions that a customer would experience annually. **Figure 2-3** illustrates Enova's annual MAIFI.

Figure 2-3: MAIFI (2020 - 2024)



Although not an OEB target, Enova monitors its MAIFI performance due to the impact momentary outages have on customers. Enova's experience points to animal contact as a major cause of momentary events.

Enova has an active animal guarding program in an attempt to mitigate momentary events. Animal guarding is installed at known problematic areas. New construction standards incorporate animal guarding at vulnerable locations such as transformers and load break switches. Enova also utilizes increased line-to-ground clearances in problematic areas to mitigate the effects of animal contact.

3. Sustained Interruptions

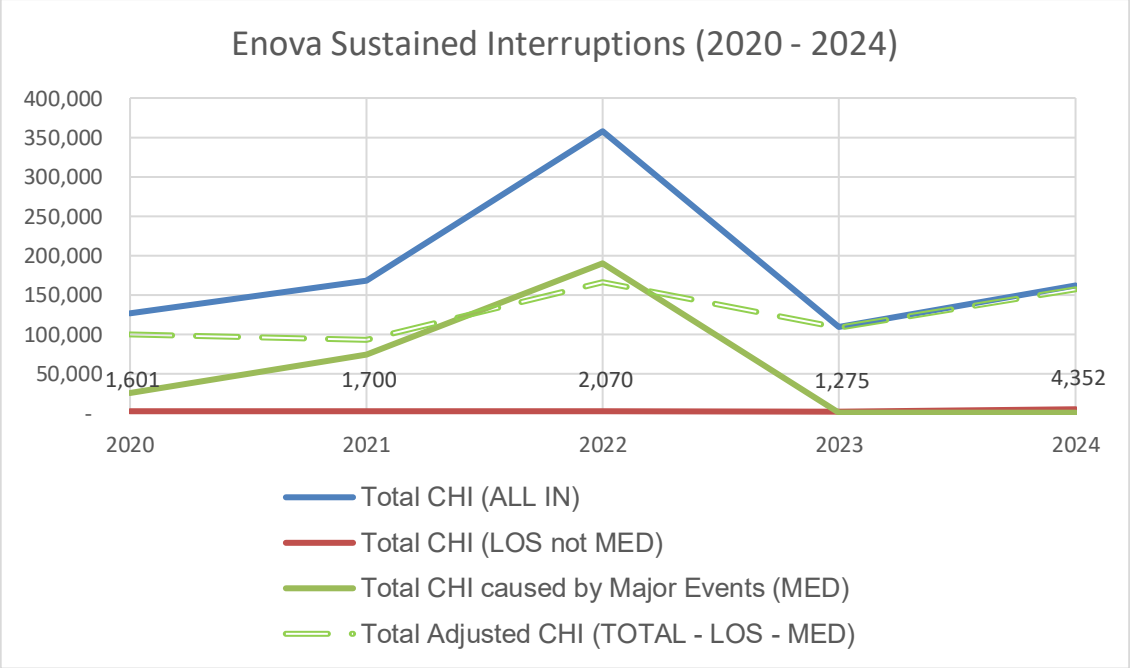
3.1. Customer Hours of Interruption (CHI) (Overview)

Table 3-1 provides a breakdown of Enova's sustained interruption data from 2020 to 2024. Illustrated further in **Figure 3-1**, Enova experienced a significant, weather-related MED in 2022. This event is explained in greater detail in **Section 3.2** of this report. Loss of Supply was not a major factor during this period.

Table 3-1: Sustained Interruptions (CHI)

Measures	2020	2021	2022	2023	2024	Total	Average
Total CHI (ALL IN)	125,929	167,620	357,741	109,000	161,693	921,984	184,397
Total CHI (LOS not MED)	1,601	1,700	2,070	1,275	4,352	10,998	2,200
Total CHI caused by Major Events (MED)	25,306	73,312	189,843	-	-	288,461	57,692
Total Adjusted CHI (TOTAL - LOS - MED)	99,022	92,608	165,828	107,725	157,341	622,525	124,505
Average # of Customers	157,405	159,013	160,937	162,585	164,118	804,058	160,812
SAIDI (Total)	0.80	1.05	2.22	0.67	0.99		1.15
SAIDI (Adjusted) (RRR)	0.63	0.58	1.03	0.66	0.96		0.77

Figure 3-1: Enova Sustained Interruptions (CHI)



The increase in CHI is attributed mainly to adverse weather and tree contacts. More detailed information is provided in **Section 3.2** and **Section 4.8.**

Table 3-2 provides a breakdown of CHI on a customer and event basis. The annual average customer count is calculated consistent with the OEB's RRR filing requirements.

Table 3-2: Customer & Event Data

Measures	2020	2021	2022	2023	2024	Total	Average
	CHI	CHI	CHI	CHI	CHI	CHI	CHI
Total CHI (ALL IN)	125,929	167,620	357,741	109,000	161,693	921,984	184,397
Total Adjusted CHI (TOTAL - LOS - MED)	99,022	92,608	165,828	107,725	157,341	622,525	124,505
Average # of Customers	157,405	159,013	160,937	162,585	164,118	804,058	160,812
Total # Events	1,312	1,388	1,427	1,296	1,082	6,505	1,301
CHI / Customer (SAIDI all in)	0.80	1.05	2.22	0.67	0.99		1.15
CHI / Customer (SAIDI adjusted)	0.63	0.58	1.03	0.66	0.96		0.77
CHI / Event	96.0	120.8	250.7	84.1	149.4		141.7

Figure 3-2: CMI / Customer Trending

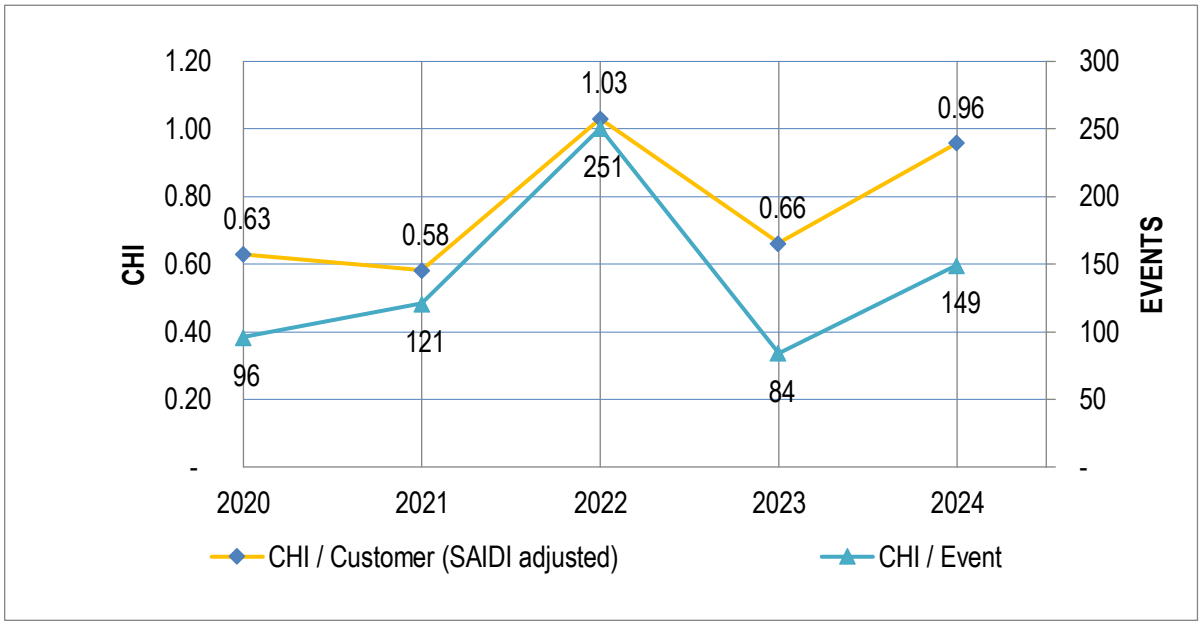
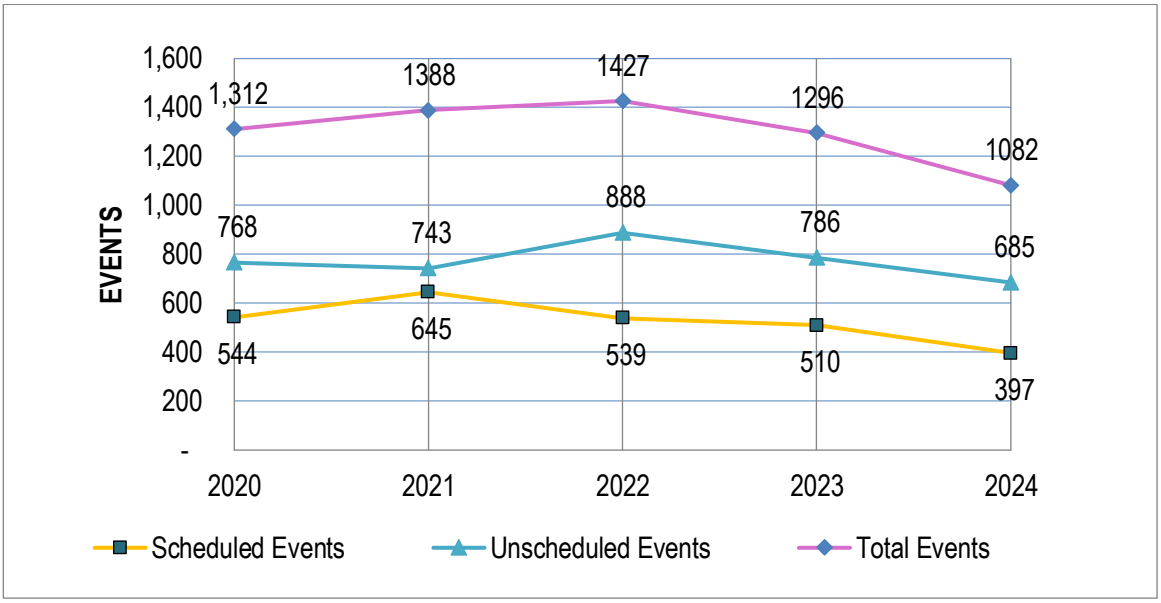


Table 3-3 and **Figure 3-3** illustrate the breakdown of scheduled and unscheduled events over that historic period. Scheduled and unscheduled events have both exhibited a downward trend since the merger in 2022. More detailed information is provided in **Section 4.3** of this report.

Table 3-3: Historical Sustained Interruptions

Measures	2020	2021	2022	2023	2024	TOTAL	AVERAGE
	Events	Events	Events	Events	Events	2020-2024	2020-2024
Scheduled Events	544	645	539	510	397	2,635	527
% of Total	41.5%	46.5%	37.8%	39.4%	36.7%	40.5%	40.5%
Unscheduled Events	768	743	888	786	685	3,870	774
% of Total	58.5%	53.5%	62.2%	60.6%	63.3%	59.5%	59.5%
Total Events	1,312	1388	1427	1296	1082	6505	1301

Figure 3-3: Interruption Events Trending (2020 – 2024)



3.2. Major Event Days (MED)

Table 3-4 ranks Enova's Major Event Days (MEDs) by CHI. The majority of MEDs are driven by adverse weather conditions and tree contacts.

In May of 2022, Southern Ontario experienced a high impact Derecho; a widespread, fast-moving, and long-lived windstorm associated with a band of severe thunderstorms. During the storm, which affected the Quebec City-Windsor Corridor, wind speeds up to 147 km/hr were measured in Kitchener, making this the largest single power outage event over the historical period.

Table 3-4: MEDs Ranked by CHI

	MEDs	2020	2021	2022	2023	2024	TOTAL	AVERAGE	%
#	Cause Code	CHI	CHI	CHI	CHI	CHI		2020-2024	2020-2024
6	Adverse Weather	15,458	35,161	128,781	-	-	179,400	35,880	62.2%
3	Tree Contacts	-	37,865	54,045	-	-	91,910	18,382	31.9%
9	Foreign Interference	9,800	49	36	-	-	9,886	1,977	3.4%
4	Lightning	-	-	4,202	-	-	4,202	840	1.5%
2	Loss of Supply	-	215	2,727	-	-	2,942	588	1.0%
1	Scheduled Interruption	48	-	52	-	-	100	20	0.0%
5	Defective Equipment	-	22	-	-	-	22	4	0.0%
0	Unknown/Other	-	-	-	-	-	-	-	0.0%
7	Adverse Environment	-	-	-	-	-	-	-	0.0%
8	Human Element	-	-	-	-	-	-	-	0.0%
Total	Total	25,306	73,312	189,843	-	-	288,461	57,692	100.0%
AVG	AVG	2,531	7,331	18,984	-	-	28,846		

Tables 3-5 (a & b) provide a listing of individual MEDs experienced by Enova over the historical period. There were no MEDs reported for the years 2023 and 2024.

Table 3-5a: MED 2020 - 2021

Day of Year	Customer Minutes of Sustained Interruptions Today	Customer Affected by Sustained Interruptions Today	Number of Events	Total Customers Served	SAIDI	MED Description
2.5ß T(MED) for 2020	VS					
2020-07-19	930,668	6,893	17	99,235	0.16	Adverse Weather - Severe windstorm
	0	0	0	0	0.00	
	0			MED	0.16	
	930,668			All Incl	0.60	
	0			Excl MED	0.53	
	930,668	6,893	17	99,235	0.16	
2.5ß T(MED) for 2020	CS					
2020-08-14	590,879	4,785	3	58,181	0.17	Foreign Interference - Vehicle - Union St
	590,879	4,785	3	MED	0.17	
	3,453,401			All Incl	0.98	
	2,862,522			Excl MED	0.81	
2.5ß T(MED) for 2021	VS					
2021-05-21	2,772,600	14,035	27	100,317	0.46	Adverse Weather - Severe windstorm
2021-12-11	1,110,286	11,871	17	100,317	0.18	Adverse Weather - Severe windstorm
	489,077			MED	0.14	
	2,720,341			All Incl	0.77	
	2,231,264			Excl MED	0.63	
2.5ß T(MED) for 2021	CS					
2021-12-11	489,077	7,039	15	58,710	0.14	Adverse Weather
	489,077	7,039	15	MED	0.14	
	2,720,341			All Incl	0.77	
	2,231,264			Excl MED	0.63	

Table 3-5b: MED 2022

Day of Year	Customer Minutes of Sustained Interruptions Today	Customer Affected by Sustained Interruptions Today	Number of Events	Total Customers Served	SAIDI	MED Description
2.5ß T(MED) for 2022	VS					
2022-05-14	9,629,008	26,404	68	101,261	1.58	Adverse Weather - Derecho windstorm
		0	0	MED		
	5,274,934			All Incl	1.49	
	5,274,934			Excl MED	1.49	
2.5ß T(MED) for 2022	CS					
2022-05-14	254,301	3,384	2	58,832	0.07	Lightning
2022-05-21	1,507,297	8,925	16	58,832	0.43	Extreme Winds
	1,761,598	12,309	18	MED	0.50	
	5,274,934			All Incl	1.49	
	3,513,336			Excl MED	0.99	

3.3. Top Contributing Interruption Events

Enova reviews the top interruption events each year in order to understand their nature and cause.

Table 3-6: Top Contributing Sustained Events 2020

ID	Event Date	2.5ß MED	Feeder Impact	Cause	CMI	Comments
59450	2020-08-14	Yes	HS27	Foreign Interference - Vehicle	572,367	Motor Vehicle Accident - Request to drop lines. Additional isolation required due to broken insulator that kept crew from properly isolating area. Expanded affected area.
59360	2020-07-23	No	HS7	Equipment Failure- Other	167,381	Wire dropped into lower circuit across expressway. Required Highway closure.
59220	2020-06-23	No	3F61	Tree Contact - Falling Tree	152,977	Pine tree found across both VS circuit and CS circuit on Wilmot Line.
59305	2020-07-11	No	3F61	Tree Contact - Falling Tree	152,090	Tree contact on Wilmot line affecting VS circuit and CS circuit
59343	2020-07-19	No	33M1	Foreign Interference - Vehicle	136,630	Motor Vehicle Accident resulting opening feeder breaker due to live lines on road.
59298	2020-07-10	No	ER42	Tree Contact - Falling Tree	111,876	Falling Tree causing ER42 breaker to open. Asplund required to remove tree
59237	2020-06-28	No	ER48	Foreign Interference-Wildlife	111,761	Faulted underground cable. Blown arrestors, issues under H1 Easement.
59331	2020-07-17	No	HS20	Foreign Inference - Customer Equipment	108,581	HS 20 opened due to high fault no close attempt made. Animal contact found at customer owned equipment.
59508	2020-08-25	No	HS27	Foreign Interference-Wildlife	90,638	Animal contact found a FC-14-2730. Switch required repairs.
58804	2020-03-02	No	HS27	Foreign Interference - Customer Equipment	78,826	Moser Landscape contacted guy wire and front loader damaging customer owned equipment

Table 3-7a: CS Top Contributing Sustained Events 2021

ID	Event Date	2.5ß MED	Feeder Impact	Cause	CMI	Comments
61414	2021-01-11	No	3F63	Equipment Failure: Defective Equipment	125,668	3F63 Riser sustained large fault. No evidence of wildlife but all arrestors blown and D-27-3789 needed to be repaired.
60987	2021-09-05	No	ER45	Equipment Failure: Defective Equipment	113,912	Leaking insulator causing damage to streetlight covers and high close in fault on upstream EVR
60043	2021-08-29	No	HS17	Lightning: Lightning	112,674	Lightning strike damage to SV 81 communications.
61009	2021-12-11	Yes	3F63	Adverse Weather-Extreme Winds	103,378	Trees uprooted by >90km winds along with galloping lines.
60967	2021-06-08	No	ER48	Foreign Interference-Wildlife	83,930	Wildlife contact at ER48 dip. Two arrestors blown due to contact.
61410	2021-09-07	No	R30-2	Tree Contact: Falling Tree	73,406	Falling tree brought BØ 4800V (8320V) primary to ground. Station breaker locked out.
60575	2021-09-07	No	3F68	Tree Contact: Falling Tree	71,812	Falling tree across 3Ø 27600v circuit. Required contact forestry department to respond.
61018	2021-12-11	Yes	R31-3	Tree Contact: Falling Tree	64,260	Feeder patrol found tree affecting 1Ø 4800V (8320V) tripping upstream EVR.

Table 3-7b: VS Top Contributing Sustained Events 2021

ID	Event Date	2.5ß MED	Feeder Impact	Cause	CMI	Comments
26640	2021-06-29	Yes	5M21	STORM/WEATHER 3 - TREE CONTACT	700,649	Feeder Lockout. Summer storm, downed tree into primary (multiple outages at the time, details sparse)
26618	2021-06-29	Yes	5M25	STORM/WEATHER 3 - ADVERSE WEATHER	656,742	Feeder Lockout. Summer storm, high winds and tree contact (multiple outages at the time, details sparse)
25155	2021-01-29	No	7M8	DEFECTIVE EQUIPMENT	607,175	Feeder Lockout. broken top pin insulator let go on Lackner 1 pole north of LBD-2533
26613	2021-06-29	Yes	6M17	Adverse Weather-Extreme Winds	103,378	Feeder Lockout. Summer storm, high winds along with galloping lines and tree contacts
26610	2021-06-29	Yes	4M14	STORM/WEATHER 3 - TREE CONTACT	400,457	Feeder Lockout. 2 downed trees onto primary, David/Whitney/Dill st area
28822	2021-12-11	Yes	6M13	Storm /Weather 3 - Tree Contact	391,534	Feeder Lockout. Winter Storm; Tree limbs on lines, Trussler Rd
28829	2021-12-11	Yes	9M7	Storm/Weather 3 -Tree contact	272,678	Feeder Lockout. Winter Storm; downed tree on Berletts Rd @ Notre Dame
25753	2021-04-07	No	RCL120	Motor Vehicle Accident	270,704	Feeder Lockout. Impact of vehicle into pole resulted in 2-primary phases wrapping together, Caryndale @ Hydro ROW.

Table 3-8a: CS Top Contributing Sustained Events 2022

ID	Event Date	2.5ß MED	Feeder Impact	Cause	CMI	Comments
61946	2022-05-21	Yes	HS20	Tree Contacts-Falling Tree	423,168	3Ø Fault due to tree on 13.8 kV cut. Required contract Forestry company to respond and clear tree.
61986	2022-05-21	Yes	ER48	Tree Contacts-Broken Branch	325,919	Large tree branch located on all 3Ø of 13860V. Required contract Forestry company to respond and clear branch
61912	2022-05-14	Yes	33M3	Lightning: Lightning	252,131	Lightning caused porcelain switch to melt and lock out 33M3. Patrol was completed before requesting close attempt by Hydro One.
61519	2022-01-15	No	9M4 (Normal Feed)	Equipment Failure: Mechanical Failure	213,100	Quick sleeve broke apart causing 1600V conductor (27600V) to fall into bottom cct energizing isolated line after EVR operated. Patrol found broken conductor on Nafzinger Rd.
62915	2022-12-27	No	3F61	Foreign Interference: Foreign Objects	195,876	3F61 3Ø fault on 27600V cct due to large amounts of snow and debris built up on dip switch at TS3
61985	2022-05-21	Yes	21M25 (Normal Feed)	Loss of Supply - Other	163,609	Loss of supply from Grand Bridge due to weather related issues. EVS lost communication resulting in prolonged outage.
61956	2022-05-21	Yes	HS30	Tree Contacts-Falling Tree	130,594	Patrol found large branch on 3Ø 13860V circuit. Required contract tree company to remove branch.
62514	2022-09-04	No	ER44	Foreign Interference: Wildlife	115,000	Animal contact found at damaged switch. Station breaker locked out due to damage.
61950	2022-05-21	Yes	R30-1	Tree Contacts-Falling Tree	113,848	Tree reported on 3Ø 8320V circuit. Required contract forestry to clear lines before customers could be picked up. Due to number of calls, second forestry crew was dispatched to area.
62495	2022-09-07	No	HS12	Scheduled Outage-Construction	101,600	Planned work to move large section of King St N to new circuit.

Table 3-8b: VS Top Contributing Sustained Events 2022

ID	Event Date	2.5ß MED	Feeder Impact	Cause	CMI	Comments
30584	2022-05-21	Yes	5M15	Storm/Weather - High Winds	2,135,905	Feeder Lockout. Multiple Poles down on River Rd @ Rennie (Spring storm, multiple outages at time)
30586	2022-05-21	Yes	5M26	Storm/Weather - High Winds	973,837	Feeder Lockout. broken tree limbs, caused damage to crossarms, insulators, neutral. (Spring storm, multiple outages at time)
30530	21/052022	Yes	3DS1	Storm/Weather - High Winds	880,650	Feeder Lockout. broken poles on Queen St - North of New Dundee. Contractor replacing
31584	2022-06-19	No	VIPER-276	Defective Equipment	760,549	Bad Comms RCL-276 Lockout. RCL-275 tripped and reset. no comm with RCL-276, manually verified tripped. Damaged arrestor lead at FLI -27-5 (1DS)
30564	2022-05-21	Yes	4M18	Storm/Weather - High Winds	628,300	Feeder Lockout. No cause found (Spring storm, multiple outages at time)
30566	2022-05-21	Yes	6M17	Storm/Weather - High Winds	595,572	Feeder Lockout. tree came down and didn't blow fuse on Pattandon Ave, caused 6m17 lockout.-Wind storm at time
30590	2022-05-21	Yes	7M9	Storm/Weather - High Winds	591,709	Feeder Lockout. No cause found (Spring storm, multiple outages at time)
31884	2022-07-09	No	4M14	Forced Outage - KFD Emerg	581,164	Dumped 4M14 for KFD to fight structure fire st 46 St. George St. Aerial device into primary to fight fire. called in tr 12, Crew to cut in openers to isolate the fire. leaving small part of Benton, st. George st and peter st. out of power
30558	2022-05-21	Yes	6M13	Storm/Weather - High Winds	497,015	Feeder Lockout. Downed tree, heavy rain and windstorm spruce tree cut from line on Mannheim Rd
30580	2022-05-21	Yes	7M5	Storm/Weather - High Winds	496,979	Feeder Lockout. Tree Limbs on lines. (Spring storm, multiple outages at time)

Table 3-9a: CS Top Contributing Sustained Events 2023

ID	Event Date	2.5ß MED	Feeder Impact	Cause	CMI	Comments
64204	2023-12-07	No	ER44	Foreign Interference: Vehicle	309,586	Concrete truck struck pole cause outage on 13860V circuit.
63436	2023-06-01	No	ER48	Foreign Interference: Wildlife	298,690	Crew found squirrel at LB, fault caused SC147 to need replacement and multiple fused cut outs to be replaced.
64094	2023-11-08	No	3F63	Tree Contacts: Falling Tree	155,566	Tree on 3Ø 27600V circuit. Required assistance from VS forestry department to clear tree.
63783	2023-08-28	No	R31-2	Foreign Interference: Vehicle	125,560	MVA reported at Shantz Station Rd and Menno St. EVRs operated to isolate fault repairs made to 27600V circuit and poles.
63838	2023-09-09	No	HS20	Foreign Interference: Vehicle	108,486	MVA suspected as freshly damage ground wire was found during a feeder patrol at the normally open point between the station breaker and EVR that operated after seeing a fault.
62948	2023-01-06	No	33M1	Foreign Interference: Vehicle	93,275	MVA involving pole causing 27600V circuit to break at taps. Station breaker operated to isolate fault.
63325	2023-05-04	No	HS20	Equipment Failure: Mechanical Failure	92,066	HS20 breaker had linkage fail causing to remain open after clearing fault but appear closed on SCADA. P&C immediately dispatched when breaker showed closed but no load.
63056	2023-02-08	No	R30-3	Scheduled Outage: Construction	91,587	Planned outage to transfer customers to new 8320V circuit that was built on Kathrine St N .
64024	2023-10-22	No	33M1	Scheduled Outage: Customer Requested	88,716	Customer requested isolation to build new plaza.
63430	2023-05-30	No	HS24	Equipment Failure: Electrical Failure	86,555	Loss of 1Ø of 13860V resulting in protections to operate. Found LB-14-42 will not close and D-14-5640 were failing and sleeved out.

Table 3-9b: VS Top Contributing Sustained Events 2023

ID	Event Date	2.5ß MED	Feeder Impact	Cause	CMI	Comments
35612	2023-06-10	No	8M9	Motor Vehicle Accident	319,844	Feeder Lockout. Broken Pole. Waterloo Regional Police (WRP)report MVA, Huron at Trussler, broken pole
37533	2023-12-11	No	8M9	Motor Vehicle Accident	301,940	Feeder Lockout. WRP report MVA on Trussler north of Plains Rd
34970	2023-04-14	No	5M16	Equipment Failure: Broken Switch	205,700	Truck 38 reports LBD-278 switch is broken, cause of outage.
37188	2023-11-06	No	7M9	Tree Contact: Broken Tree	183,954	Vines around centre phase insulator on King St E and River Rd
35208	2023-05-09	No	8M9	Foreign Interference: Vehicle	163,975	Call from WRP. MVA at 1853 Trussler, pole fire wires down
34229	2023-01-27	No	5M14	Equipment Failure: Underground cable	150,127	5M14 lockout. Manual close x1. no cause found on patrol and down wire call on 28 mansion was a not the cause. Li-491 opened and 5M14 closed, bkr held but current climbed on blue phase until it tripped 5M14 bkr. Cause found, u/g primary cable fault
34486	2023-02-17	No	9M7	Tree Contact: Broken Tree	126,412	Truck 38 reports freezing rain as cause, heavy branches laying across 27kv circuit
34523	2023-02-18	No	6M21	Defective Equipment: Insulator	102847	6M21 feeder lockout, upper circuit (grounded lines to Detweiller) insulator broke and landed on the lower 6M21 circuit . Truck 62 made repairs
36138	2023-08-05	No	4M27	Tree Contact: Broken Tree	89,467	4M27 feeder lockout, 1 x manual reclose, and open KFD reports tree branch has fallen on the lines and started fire
34837	2023-03-29	No	3M15	Defective Equipment: Insulator	86,547	3M13 lockout. attempted a close on 3M13: 3M13 lockout, 3M15 lockout & RCL-115 lockout. Cause found at 149 Pioneer Dr: Broken insulator & riser

Table 3-10a: CS Top Contributing Sustained Events 2024

ID	Event Date	2.5ß MED	Feeder Impact	Cause	CMI	Comments
64309	2024-01-09	No	HS19	Equipment Failure: Mechanical Failure	254,434	EVS-27-3819 blew up with no known cause. Tie point between two 27600V circuits, both were initially affected.
65383	2024-11-05	No	HS20	Foreign Interference: Vehicle	179,054	2 MVAs resulting in broken poles and 13860V cct to break fall to ground.
64767	2024-05-25	No	HS26	Equipment Failure: Electrical Failure	138,646	D-27-4313 found to have melted terminations on 2 phases. No apparent cause for resulting in failures.
64985	2024-07-14	No	33M2	Tree Contacts-Falling Tree	127,303	Falling tree causing 27600V cct to fall into 8320V cct and cause multiple issues on 8320V cct. Hydro One was delayed picking up 33M2 breaker while proper isolation was established on 8320V circuit.
64524	2024-03-15	No	HS20	Foreign Inference: Vehicle	118,814	MVA involving concrete pole resulting in fault on 3Ø 27600V circuit.
64398	2024-02-03	No	3F61	Equipment Failure: Electrical Failure	109,956	EVR locked out due to high fault current. Leads damaged on downstream EVS requiring replacement.
64730	2024-05-17	No	R30-2	Scheduled Outage: Customer Requested	99,208	Customer requested for tree trimming, this also affected the power to EVR-8-508 taking it out of service.
65330	2024-10-20	No	HS20	Unknown: Truly Unknown	92681	No cause for lockout found after feeder patrol.
65295	2024-10-07	No	HS26	Foreign Interference: Vehicle	90,784	MVA involving 27600V causing fuse to operate dropping customers. Larger outage required for safety when crew began making repairs.
65488	2024-12-03	No	T2B2	Loss of Supply-Transmission Inadvertent	90,488	Transfer Trip sent the D8S from Hydro one by accident. Approval required by IESO as T2B2 did not reclose for unknown reason. B2 bus breakers opened due to tap changer readings but were closed in once voltage confirmed good.

Table 3-10b: VS Top Contributing Sustained Events 2024

ID	Event Date	2.5ß MED	Feeder Impact	Cause	CMI	Comments
40886	2024-11-10	No	8M7	Adverse Weather: Heavy Rain	535,981	Report of tree on lines at 154 OLD HURON
37823	2024-01-12	No	7M9	Adverse Weather: Ice / freezing rain	479,820	3ph primary on the ground on Morrison and King St, south of LBD-2861
38684	2024-04-17	No	5M22	Adverse Weather: Heavy Rain	294,020	Fire Department called to report a 3 phase line down on the ground @ Old Chicopee & Huntingdale dr.
39716	2024-07-21	No	1M9	Foreign Interference: Squirrel	293,001	Feeder lockout. Truck 71 found blown insulators @ 151 Madison. Will need a crew to make repairs
41073	2024-12-06	No	3M18	Foreign Inference: Vehicle	210,353	MVA reported by Kitchener fire @ pioneer dr & Bechtel dr pole hit
37716	2024-01-03	No	6M17	Equipment Failure: Insulator	170,105	KFD call in a fire at 429 Ottawa st Concordia club. broken insulator on imperial dr.
38575	2024-04-11	No	8M9	Tree Contact: Broken Tree	143,659	Tree on live on Trussler Rd and Betherl Rd with line down
38094	2024-02-09	No	4M11	Equipment Failure: Insulator	140,666	Broken insulator @ 379 Gage Ave
39442	2024-07-06	No	6DS2	Under Investigation: No Cause found	126,017	FLI-27-1 damaged
38626	2024-04-13	No	8M4	Under Investigation: No Cause found	117,222	Auto 1x lockout. Attempted one close but locked out. customer reports tree limb close to line near 820 Trillium Dr. Truck 71 reports cap bank on Trillium CF-15-2040 blown, lots of damage. cap bank removed from service

4. Sustained Interruption Cause Codes

4.1. Overview

Enova logs, categorizes and tracks sustained interruption events data by CEA cause code. Each event is also logged with geographic coordinates in order to perform spatial analysis and gain additional insights from the data. **Table 4-1** provides data on Enova's annual interruption events by cause code from 2020 to 2024. The leading cause of power interruption events were due to Scheduled Interruptions (40.5%) to allow for planned capital and maintenance work followed by Foreign Interference (21.7%) and Defective Equipment (16.5%).

Table 4-1: Historical Annual Interruption Events

	Interruption	2020	2021	2022	2023	2024	Total	Avg.	%
CC #	Cause Code	Events	Events	Events	Events	Events	2020-2024	2020-2024	2020-2024
0	Unknown/Other	83	92	132	168	68	543	109	8.3%
1	Scheduled Outage	544	645	539	510	397	2,635	527	40.5%
2	Loss of Supply	7	7	9	3	16	42	8	0.6%
3	Tree Contacts	66	108	87	49	90	400	80	6.1%
4	Lightning	19	65	17	33	14	148	30	2.3%
5	Defective Equipment	272	178	225	183	213	1,071	214	16.5%
6	Adverse Weather	52	52	64	9	38	215	43	3.3%
7	Adverse Environment	-	-	4	6	3	13	3	0.2%
8	Human Element	6	3	5	3	8	25	5	0.4%
9	Foreign Interference	263	238	345	332	235	1,413	283	21.7%
Total		1,312	1,388	1,427	1,296	1,082	6,505	1,301	100.0%
AVG		131	139	143	130	108			

Table 4-2 provides data on Enova's annual total interruption CHI by cause code from 2020 to 2024. The leading contributor to CHI for Enova was Adverse Weather (23.9%) followed by Defective Equipment (20.7%) and Foreign Interference (20.3%).

Table 4-2: Historical Annual CHI (Total)

	Interruption	2020	2021	2022	2023	2024	Total	Avg.	%
CC #	Cause Code	CHI	CHI	CHI	CHI	CHI	2020-2024	2020-2024	2020-2024
0	Unknown/Other	2,864	3,636	2,761	6,529	12,536	28,325	5,665	3.1%
1	Scheduled Outage	12,405	20,117	26,129	18,371	16,680	93,702	18,740	10.2%
2	Loss of Supply	1,601	1,915	4,797	1,275	4,352	13,940	2,788	1.5%
3	Tree Contacts	12,501	50,087	68,631	12,402	17,319	160,941	32,188	17.5%
4	Lightning	2,277	3,935	4,840	431	892	12,375	2,475	1.3%
5	Defective Equipment	36,974	28,620	65,982	20,815	38,439	190,830	38,166	20.7%
6	Adverse Weather	19,619	36,221	131,121	611	32,406	219,979	43,996	23.9%
7	Adverse Environment	-	-	10,637	625	386	11,648	2,330	1.3%
8	Human Element	101	17	364	922	1,566	2,969	594	0.3%
9	Foreign Interference	37,587	23,072	42,479	47,018	37,118	187,275	37,455	20.3%
Total		125,929	167,620	357,741	109,000	161,693	921,984	184,397	100.0%
AVG		12,593	16,762	35,774	10,900	16,169			

Table 4-3 provides a ranking of Enova's CHI by cause code from 2020 to 2024. Although Scheduled Interruptions were the leading cause of interruption events, they only accounted for approximately 10% of the total CHI. Adverse weather, defective equipment, and foreign interference are the three leading causes of total CHI.

Table 4-3: Historical Annual CHI (Total) by Rank

	Interruption	2020	2021	2022	2023	2024	Total	Avg.	%
CC #	Cause Code	CHI	CHI	CHI	CHI	CHI	2020-2024	2020-2024	2020-2024
6	Adverse Weather	19,619	36,221	131,121	611	32,406	219,979	43,996	23.9%
5	Defective Equipment	36,974	28,620	65,982	20,815	38,439	190,830	38,166	20.7%
9	Foreign Interference	37,587	23,072	42,479	47,018	37,118	187,275	37,455	20.3%
3	Tree Contacts	12,501	50,087	68,631	12,402	17,319	160,941	32,188	17.5%
1	Scheduled Outage	12,405	20,117	26,129	18,371	16,680	93,702	18,740	10.2%
0	Unknown/Other	2,864	3,636	2,761	6,529	12,536	28,325	5,665	3.1%
2	Loss of Supply	1,601	1,915	4,797	1,275	4,352	13,940	2,788	1.5%
4	Lightning	2,277	3,935	4,840	431	892	12,375	2,475	1.3%
7	Adverse Environment	-	-	10,637	625	386	11,648	2,330	1.3%
8	Human Element	101	17	364	922	1,566	2,969	594	0.3%
Total		125,929	167,620	357,741	109,000	161,693	921,984	184,397	100.0%
AVG		12,593	16,762	35,774	10,900	16,169			

Table 4-4 provides a ranking of Enova's Total CHI – MED cause codes. Adverse weather drops from 1st to 5th place ranking, when major event days are excluded. Defective Equipment and Foreign Interference are the two major contributors to CHI.

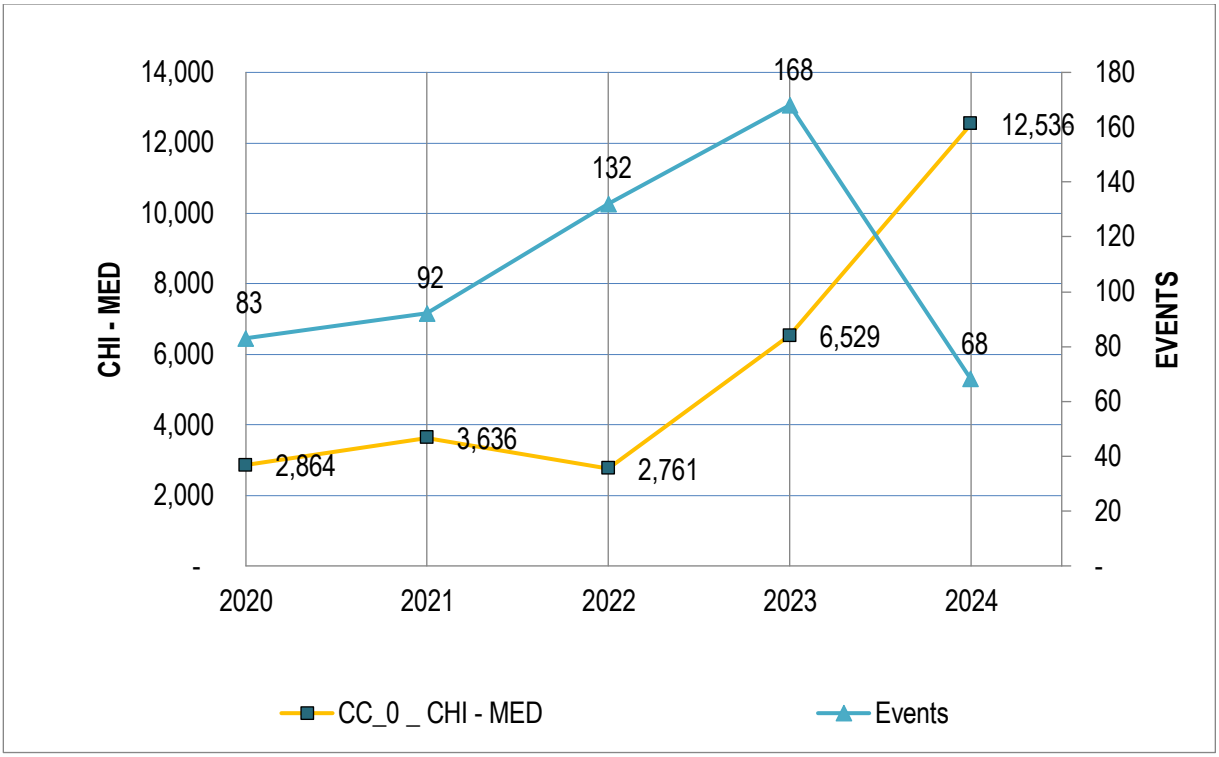
Table 4-4: Historical Annual CHI (Total - MED) by Rank

CC #	Interruption Cause Code	2020 CHI	2021 CHI	2022 CHI	2023 CHI	2024 CHI	Total	Avg. 2020-2024	% 2020-2024
5	Defective Equipment	36,974	28,598	65,982	20,815	38,439	190,808	38,162	30.1%
9	Foreign Interference	27,787	23,023	42,443	47,018	37,118	177,390	35,478	28.0%
1	Scheduled Outage	12,357	20,117	26,077	18,371	16,680	93,602	18,720	14.8%
3	Tree Contacts	12,501	12,222	14,586	12,402	17,319	69,030	13,806	10.9%
6	Adverse Weather	4,161	1,060	2,340	611	32,406	40,579	8,116	6.4%
0	Unknown/Other	2,864	3,636	2,761	6,529	12,536	28,325	5,665	4.5%
7	Adverse Environment	-	-	10,637	625	386	11,648	2,330	1.8%
2	Loss of Supply	1,601	1,700	2,070	1,275	4,352	10,998	2,200	1.7%
4	Lightning	2,277	3,935	638	431	892	8,173	1,635	1.3%
8	Human Element	101	17	364	922	1,566	2,969	594	0.5%
	Total	100,623	94,308	167,898	109,000	161,693	633,522	126,704	100.0%
	AVG	10,062	9,431	16,790	10,900	16,169	63,352		

The following sections provide greater detail surrounding sustained interruptions by cause code. MED related outages and momentary interruptions are excluded from CHI values to better understand the typical volume of sustained interruptions experienced by Enova customers. In addition, MEDs are discussed in greater detail in **Section 3.2** of this report.

4.2. Cause Code 0: Unknown / Other

Figure 4-1: CC_0 Unknown / Other Causes



Cause Code 0: Unknown / Other - are customer interruptions with no apparent cause**.** Enova suspects that most interruptions of unknown origin are caused by Foreign Interference, namely wildlife; however, it is not always possible to find evidence to allow for this categorization. Unless animal remains are found at or downstream of the protective device, the interruption is logged as an unknown cause.

Figure 4-1 illustrates the trend in CHI and total events for all interruptions logged with an unknown cause. Typically, this cause code has ranked approximately 6th (3.1%) in total CHI. Excluding MEDs, Unknown / Other remained as the 5th leading cause of CHI.

Although this category represents a small percentage of the overall CHI, there has been an increasing trend in this category since 2022. Enova management is aware of this trend and plans to improve training for field and system operating teams tasked with identifying potential interference causes. These steps aim to reduce uncertainty and provide for more accurate categorization of sustained outages.

Table 4-5 provides an overview of Enova's historical performance regarding this cause code.

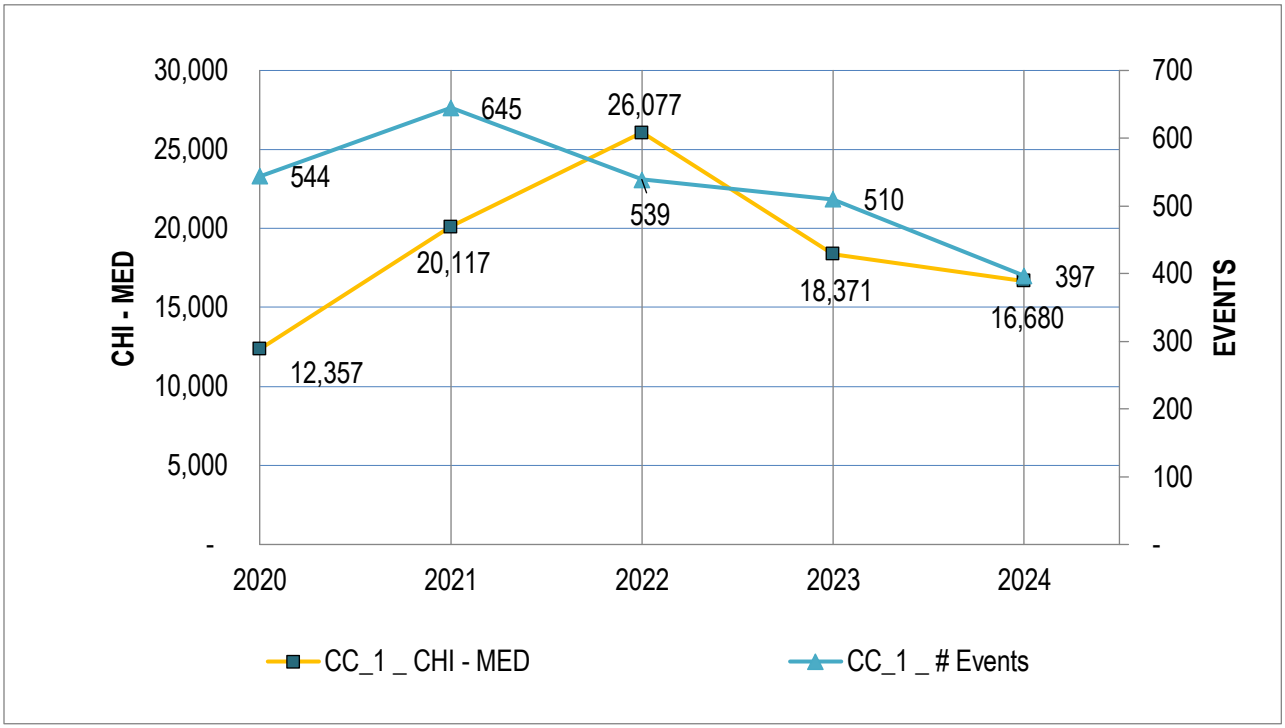
Table 4-5: CC_0 Unknown Cause

MEASURES	2020	2021	2022	2023	2024	Average
Total CHI - MED	100,623	94,308	167,898	109,000	161,693	126,704
CC_0 _ CHI - MED	2,864	3,636	2,761	6,529	12,536	5,665
CC_0 % of Total CHI	2.8%	3.9%	1.6%	6.0%	7.8%	4.5%
Total Events	1,312	1,388	1,427	1,296	1,082	1,301
CC0 _ # Events	83	92	132	168	68	109
CC_0 % of Total Events	6.3%	6.6%	9.3%	13.0%	6.3%	8.3%
CHI / Event	35	40	21	39	184	64
Total Customer-Interruptions	11,290	15,783	13,694	15,442	18,222	14,886

There are no sub-cause codes on which to report in the section.

4.3. Cause Code 1: Scheduled Outages

Figure 4-2: CC_1 Scheduled Outage Cause Trending



Cause Code 1: Scheduled Outage - represents intentional, pre-planned customer interruptions where power is disconnected at a selected time to safely complete electrical work.

Scheduled Outages ranked 5th (10.2%) in sustained interruption causes over the historical period. Excluding MEDs, Scheduled Outages moved to 3rd (14.8%) on the list of leading causes of CHI.

Figure 4-2 illustrates the trend in CMI and total events for all interruptions logged under Scheduled Outages. Since 2022, both scheduled events and total CHI have declined. Planned work was deferred in the first two years of the merger as priorities and resources were adjusted and harmonized.

Table 4-6 provides an overview of Enova's historical performance regarding this cause code.

Table 4-6: CC_1 Scheduled Outages

MEASURES	2020	2021	2022	2023	2024	Average
Total CHI - MED	100,623	94,308	167,898	109,000	161,693	126,704
CC_1 _ CHI - MED	12,357	20,117	26,077	18,371	16,680	18,720
CC_1 % of Total CHI	12.3%	21.3%	15.5%	16.9%	10.3%	15.3%
Total Events	1,312	1,388	1,427	1,296	1,082	1,301
CC1 _ # Events	544	645	539	510	397	527
CC_1 % of Total Events	41.5%	46.5%	37.8%	39.4%	36.7%	40.3%
CHI / Event	23	31	48	36	42	36
Total Customer-Interruptions	11,290	15,783	13,694	15,442	18,222	14,886

Scheduled Outages are further divided into two categories of sub-cause codes.

- **Code 1.1 — Scheduled Non-Distributor Activities**: Outages requested to accommodate third-party work completely unrelated to the utility's own assets. Examples include municipal road widening, bridge/building construction, or third-party telecommunication line attachments.
- **Code 1.2 — Scheduled Distributor Activities**: Planned outages initiated directly by the local utility to safely execute its own maintenance, network upgrades, expansions, or system modifications.

Table 4-7 provides a breakdown of the Scheduled Outage CHI contributions by sub-cause code.

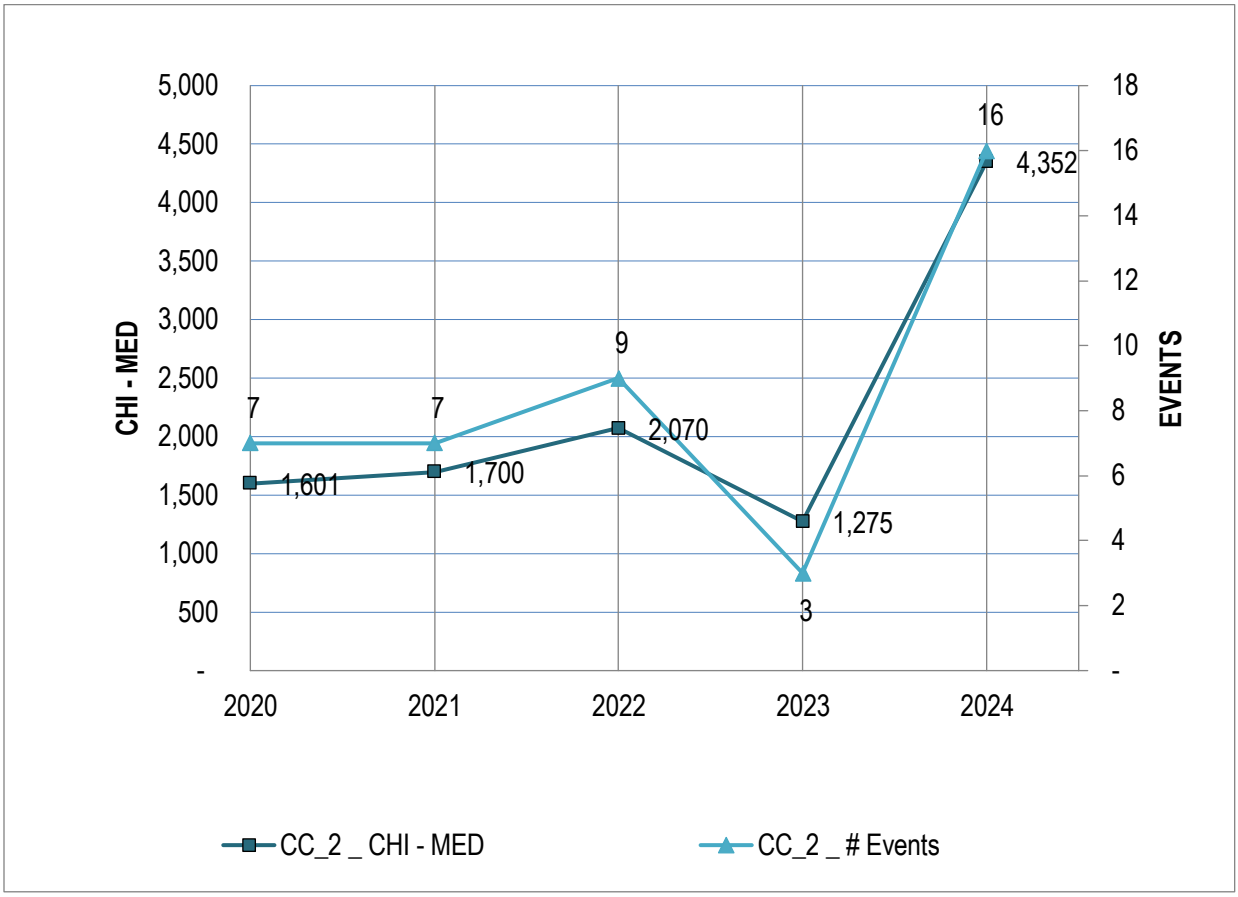
Table 4-7: CC_1 Scheduled Outages by Sub-cause Codes (2024)

Measure	1.1 Scheduled - Non-Distributor Activities	%	1.2 Scheduled - Distributor Activities	%	Total
# of Interruptions	125	31%	272	69%	397
Customer-Interruptions	581	9%	5,821	91%	6,402
Customer-Hours of Interruption	4,667	28%	12,014	72%	16,680
Average Customer Numbers	164,118		164,118		164,118
SAIDI Contribution from this Cause Code	0.03		0.07		0.10
SAIFI Contribution from this Cause Code	0.00		0.04		0.04
Total # of Interruptions Caused by Major Event(s)	-		-		-
Total Customer Interruptions caused by Major Event(s)	-		-		-
Total Customer Hours of Interruptions caused by Major Event(s)	-		-		-

In 2024, distributor activities accounted for 69% of all scheduled interruptions and 72% of the CHI attributed to this cause code.

4.4. Cause Code 2: Loss of Supply

Figure 4-3: CC_2 Loss of Supply Cause Trending



Cause Code 2: Loss of Supply – are customer interruptions due to problems associated with assets owned and/or operated by another party, and/or in the bulk electricity supply system. For this purpose, the bulk electricity supply system is distinguished from the distributor's system based on ownership demarcation.

Figure 4-3 illustrates the trend in CMI and total events for all interruptions logged under Loss of Supply (LOS). Over the historical period, this cause code has ranked approximately 7th (1.5%) in total CHI. Excluding MEDs, Loss of Supply dropped to the 8th leading cause of CHI (1.7%).

Table 4-8: CC_2 Loss of Supply

Measures	2020	2021	2022	2023	2024	Total	Average
Total CHI - MED	100,623	94,308	167,898	109,000	161,693	633,522	126,704
CC_2 _ CHI - MED	1,601	1,700	2,070	1,275	4,352	10,998	2,788
CC_2 % of Total CHI	1.6%	1.8%	1.2%	1.2%	2.7%	1.7%	
Total Events	1,312	1,388	1,427	1,296	1,082	6,505	1,301
CC_2 _ # Events	7	7	9	3	16	42	8
CC_2 % of Total Events	0.5%	0.5%	0.6%	0.2%	1.5%	0.6%	
CHI / Event	229	274	533	425	272	1,732	346
Total Customer-Interruptions					12,755	12,755	12,755
Average # of Customers	157,405	159,013	160,937	162,585	164,118		

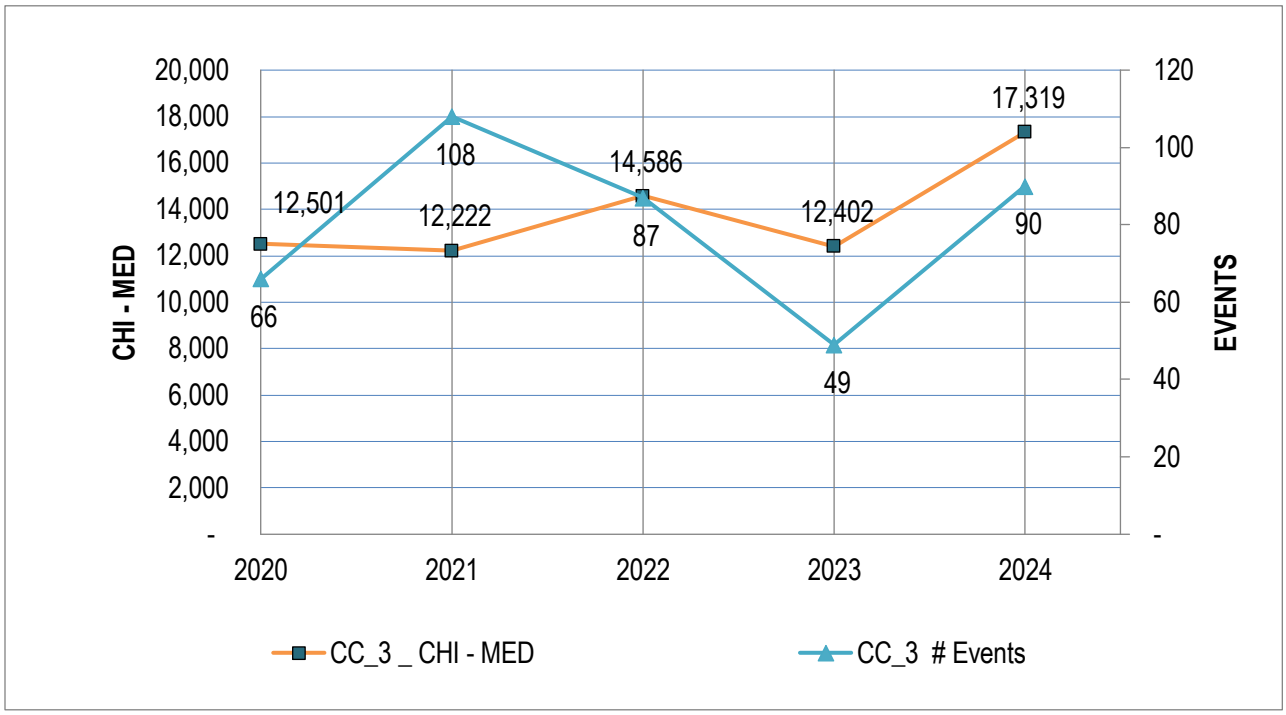
Loss of Supply events are further divided into two categories of sub-cause codes. **Table 4-9** further divides LOS events into Transmission and Distribution related causes. In 2024, Enova experienced two transmission and 14 distribution related LOS events. On a per-event basis, the two transmission related events were much more impactful on Enova customers as they accounted for 47% of the total CHI attributed to LOS.

Table 4-9: CC_2 Loss of Supply by Sub-cause Codes

Measure	2.1 Loss of Supply - Loss of Supply Transmission	%	2.2 Loss of Supply - Loss of Supply Distribution	%	Total
# of Interruptions	2	13%	14	88%	16
Customer-Interruptions	12,755	38%	20,954	62%	33,709
Customer-Hours of Interruption	2,049	47%	2,302	53%	4,352
Average Customer Numbers	164,118		164,118		164,118
SAIDI Contribution from this Cause Code	0.01		0.01		0.03
SAIFI Contribution from this Cause Code	0.08		0.13		0.21
Total # of Interruptions Caused by Major Event(s)	-		-		-
Total Customer Interruptions caused by Major Event(s)	-		-		-
Total Customer Hours of Interruptions caused by Major Event(s)					-

4.5. Cause Code 3: Tree Contacts

Figure 4-4: CC_3 Tree Contacts



Cause Code 3: Tree Contacts – are customer interruptions caused by faults resulting from tree contact with energized circuits. The CEA defines an Adverse Weather-Extreme Wind condition when wind speeds exceed 90 km/hr. Under these conditions, Enova categorizes a tree contact as an Adverse Weather event (Cause Code 6).

Tree Contacts ranked 4th (17.5%) in sustained interruption causes over the historical period. Excluding MEDs, Tree Contacts remained as the 4th (10.9%) leading cause of CHI.

Between 2020 and 2024, approximately 32% of MED CHI were due to tree contacts. Tree contact incidents typically average 80 per year. Enova attempts to strike a balance between customers' stated desires to limit the amount of tree trimming due to aesthetics and tree trimming practices to minimize contact with energized lines.

Table 4-10 provides an overview of Enova's historical performance regarding this cause code.

Table 4-10: CC_3 Tree Contacts

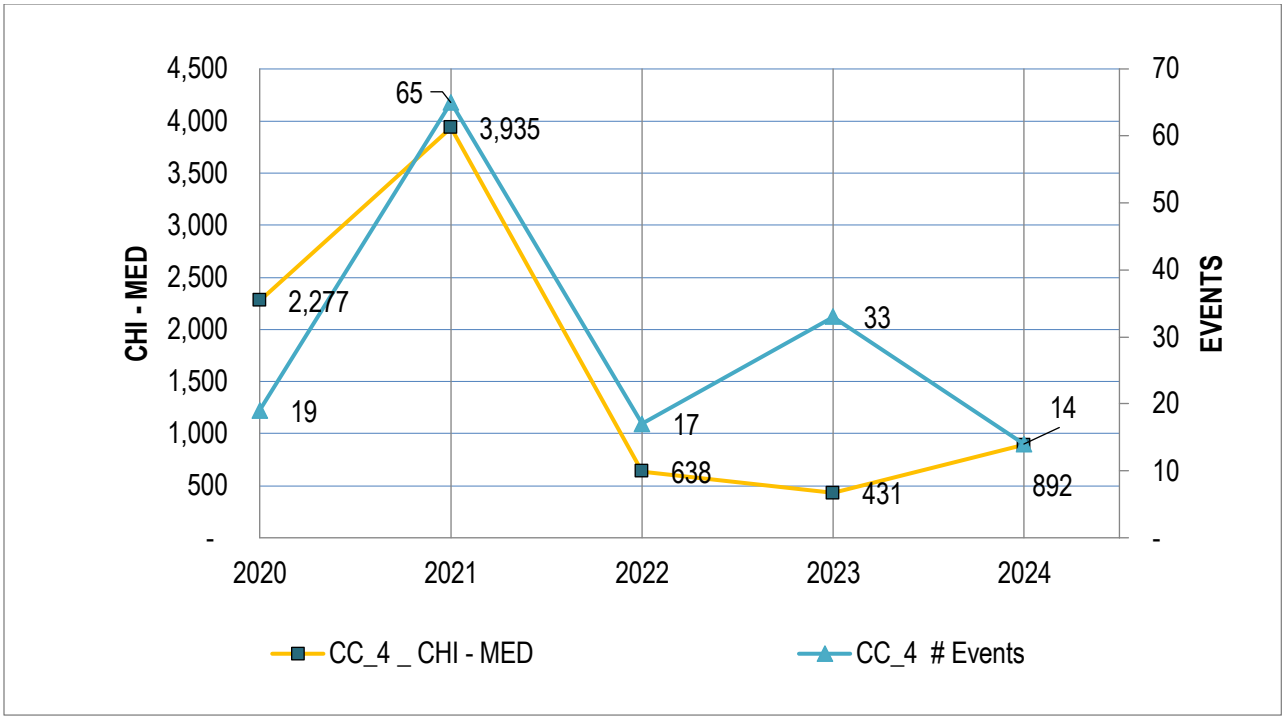
Measures	2020	2021	2022	2023	2024	Total	Average
Total CHI - MED	100,623	94,308	167,898	109,000	161,693	633,522	126,704
CC_3 _ CHI - MED	12,501	12,222	14,586	12,402	17,319	69,030	13,806
CC_3 % of Total CHI	12.4%	13.0%	8.7%	11.4%	10.7%	10.9%	
Total Events	1,312	1,388	1,427	1,296	1,082	6,505	1,301
CC_3 # Events	66	108	87	49	90	400	80
CC_3 % of Total Events	5.0%	7.8%	6.1%	3.8%	8.3%	6.1%	
CHI / Event	189	113	168	253	192	916	183
Total Customer-Interruptions	15,209	22,814	20,475	10,675	27,082	96,255	19,251
Average # of Customers	157,405	159,013	160,937	162,585	164,118		

Table 4-11: CC_3 Tree Contacts by Sub-cause Codes

Measure	3.1 Tree Contacts - Fallen Tree on Right-of-Way	%	3.2 Tree Contacts - Broken Branch/Tree Growth/Untrimmed Tree	%	3.2 Tree Contacts - Broken Branch/Tree Growth/Untrimmed Tree	%	Total
# of Interruptions	18	20%	72	80%	-	0%	90
Customer-Interruptions	1,561	6%	25,521	94%	-	0%	27,082
Customer-Hours of Interruption	2,691	16%	14,628	84%	-	0%	17,319
Average Customer Numbers	164,118		164,118		-	0%	164,118
SAIDI Contribution from this Cause Code	0.02		0.09		-	0%	0
SAIFI Contribution from this Cause Code	0.01		0.16		-	0%	0
Total # of Interruptions Caused by Major Event(s)	-		-		-	-	-
Total Customer Interruptions caused by Major Event(s)	-		-		-	-	-
Total Customer Hours of Interruptions caused by Major Event(s)	-		-		-	-	-

4.6. Cause Code 4: Lightning Contacts

Figure 4-5: CC_4 Lightning Events Cause



Cause Code 4: Lightning – are customer interruptions due to lightning striking the distribution system, resulting in an insulation breakdown and/or flashovers.

Lightning related CHI has ranked 8th (1.3%) in total sustained interruption hours over the last 5 years. Excluding MEDs, Lightning is the 9th leading cause of CHI (1.3%). Although lighting event CHI history has decreased over the most recent 3 years, historically lightning events remain highly variable from year to year.

Table 4-12 provides an overview of Enova's historical performance regarding this cause code.

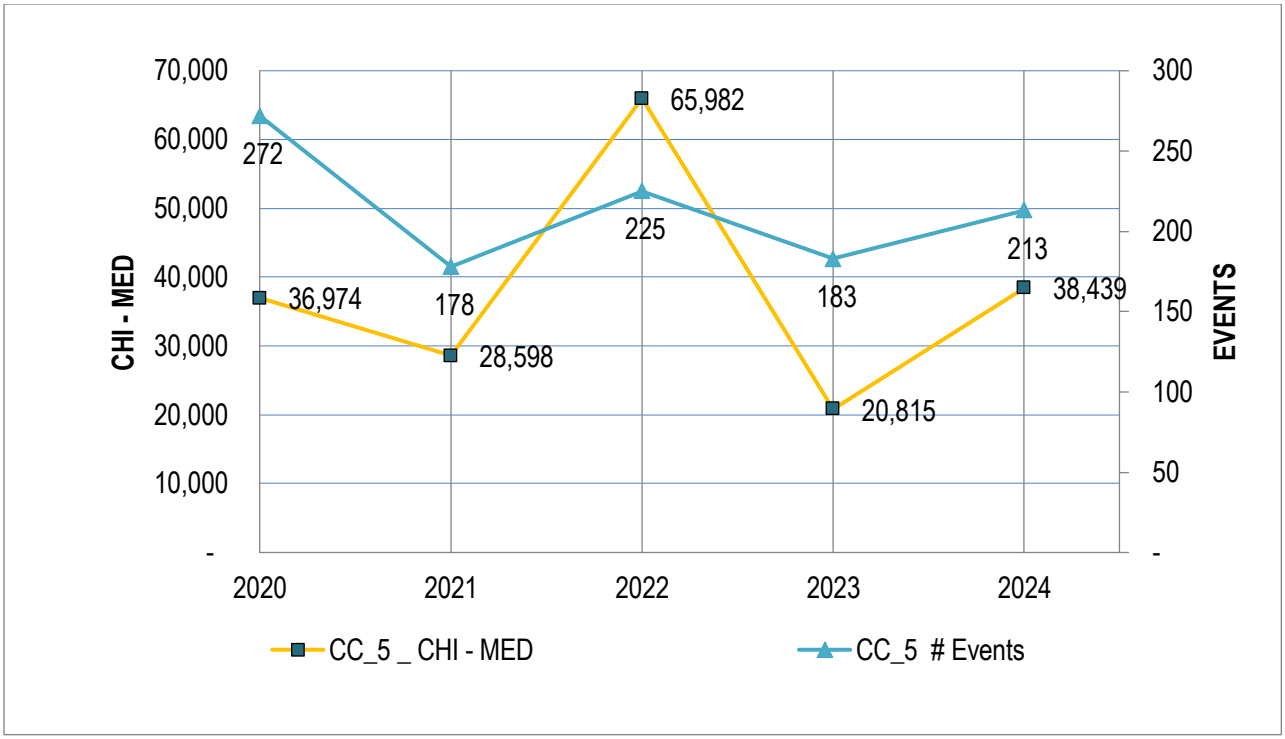
There are no sub-cause codes on which to report in the section.

Table 4-12: CC_4 Lightning Contacts

Measures	2020	2021	2022	2023	2024	Total	Average
Total CHI - MED	100,623	94,308	167,898	109,000	161,693	633,522	126,704
CC_4 _ CHI - MED	2,277	3,935	638	431	892	8,173	1,635
CC_4 % of Total CHI	2.3%	4.2%	0.4%	0.4%	0.6%	1.3%	
Total Events	1,312	1,388	1,427	1,296	1,082	6,505	1,301
CC_4 # Events	19	65	17	33	14	148	30
CC_4 % of Total Events	1.4%	4.7%	1.2%	2.5%	1.3%	2.3%	
CHI / Event	120	61	38	13	64	295	59
Total Customer-Interruptions	6,769	10,964	4,277	1,406	4,679	28,095	5,619
Average # of Customers	157,405	159,013	160,937	162,585	164,118		

4.7. Cause Code 5: Defective Equipment

Figure 4-6: CC_5 Defective Equipment



Cause Code 5: Defective Equipment – are customer interruptions resulting from distributor equipment failures due to deterioration from age, incorrect maintenance, or imminent failures detected by maintenance.

Defective Equipment related CHI has ranked 2nd (20.7%) in total sustained interruption hours over the last 5 years. Excluding MEDs, Defective Equipment is the leading cause (30.1%) of CHI.

In 2024, the largest contributors to this category were:

- Underground station feeder cable failures
- Submersible transformer failures.
- Station feeder breaker failure.

Enova has increased investments in its Asset Renewal program over the forecast period, specifically to reduce the impact of Defective Equipment CHI on its customers. More detailed information can be found in **Appendix B-1 Asset Condition Assessment Report.**

Table 4-13: CC_5 Defective Equipment

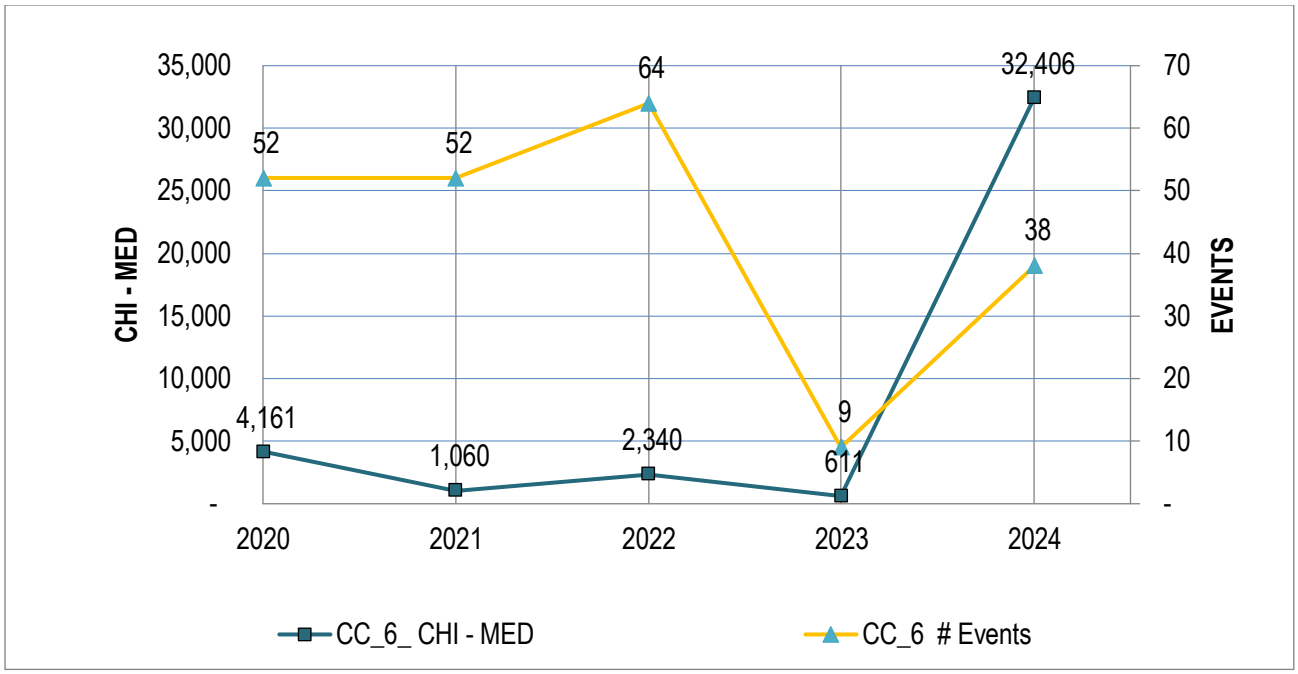
Measures	2020	2021	2022	2023	2024	Total	Average
Total CHI - MED	100,623	94,308	167,898	109,000	161,693	633,522	126,704
CC_5 _ CHI - MED	36,974	28,598	65,982	20,815	38,439	190,808	190,808
CC_5 _% of Total CHI	36.7%	30.3%	39.3%	19.1%	23.8%	30.1%	
Total Events	1,312	1,388	1,427	1,296	1,082	6,505	1,301
CC_5_ # Events	272	178	225	183	213	1,071	214
CC_5_ % of Total Events	20.7%	12.8%	15.8%	14.1%	19.7%	16.5%	
CHI / Event	136	161	293	114	180	884	177
Total Customer-Interruptions	41,255	26,606	46,471	18,130	43,012	175,474	35,095
Average # of Customers	157,405	159,013	160,937	162,585	164,118		

Table 4-14: CC_5 Defective Equipment by Sub-cause Codes

Measure	5.1 Equipment Failure - Equipment Failure	%	5.2 Equipment Failure - Distributed Energy Resource (DER)* Failure	%	5.3 Equipment Failure - Defective Equipment / Material	%	Total
# of Interruptions	209	98%	-	0%	4	2%	209
Customer-Interruptions	42,919	100%	-	0%	93	0%	42,919
Customer-Hours of Interruption	38,385	100%	-	0%	55	0%	38,385
Average Customer Numbers	164,118		-		164,118	100%	164,118
SAIDI Contribution from this Cause Code	0.23		-		0.00	0%	0
SAIFI Contribution from this Cause Code	0.26		-		0.00	0%	0
Total # of Interruptions Caused by Major Event(s)	-		-		-	-	-
Total Customer Interruptions caused by Major Event(s)	-		-		-	-	-
Total Customer Hours of Interruptions caused by Major Event(s)	-		-			-	-

4.8. Cause Code 6: Adverse Weather

Figure 4-7: CC_6 Adverse Weather



Cause Code 6: Adverse Weather – are customer interruptions resulting from rain, ice storms, snow, winds > 90km/hr, extreme temperatures, frost, or other extreme weather conditions (exclusive of Code 3: Tree Contact and Code 4: Lightning events).

Adverse Weather-related CHI has ranked 1st (23.9%) in total sustained interruption hours over the last 5 years. Excluding MEDs, Adverse Weather ranking dropped to 5th (6.4%).

Table 4-15 provides an overview of Enova's historical performance regarding this cause code.

Table 4-16 provides a breakdown of the Adverse Weather CHI contributions by sub-cause code. The leading cause sustained interruptions due to Adverse Weather is captured under Cause Code 6.3.

Table 4-15: CC_6 Adverse Weather

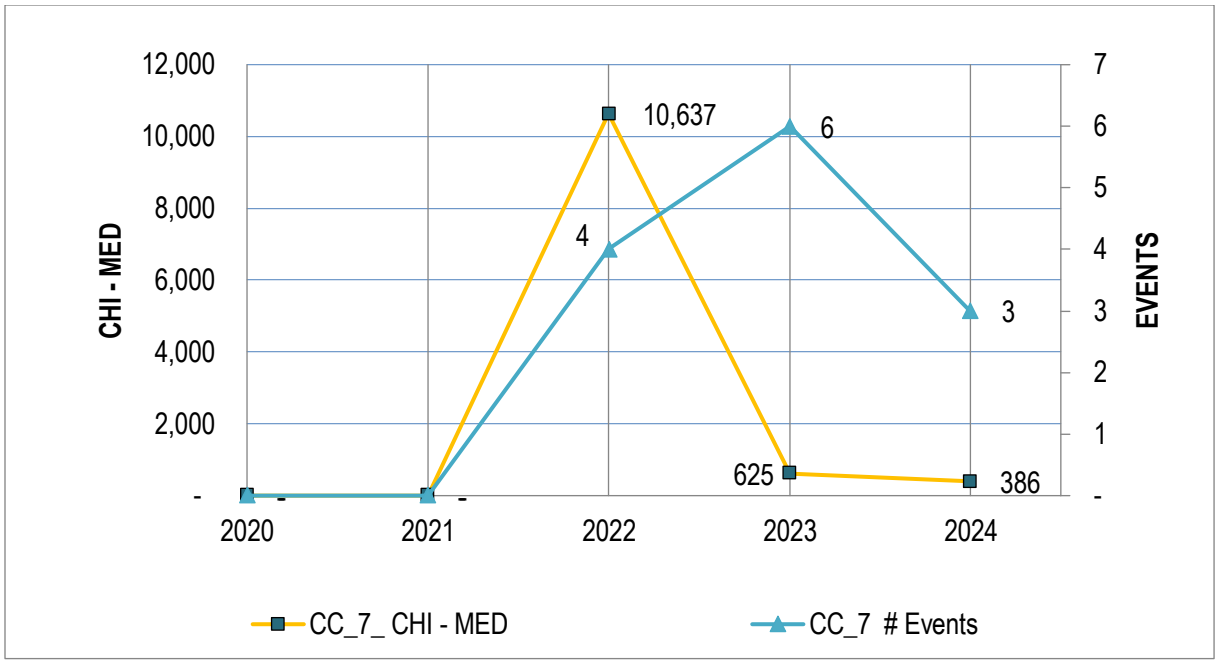
MEASURES	2020	2021	2022	2023	2024	TOTAL
Total CHI - MED	100,623	94,308	167,898	109,000	161,693	633,522
CC_6_ CHI - MED	4,161	1,060	2,340	611	32,406	40,579
CC_6 % of Total CHI	4.1%	1.1%	1.4%	0.6%	20.0%	6.4%
Total Events	1,312	1,388	1,427	1,296	1,082	6,505
CC_6 # Events	52	52	64	9	38	215
CC_6 % of Total Events	4.0%	3.7%	4.5%	0.7%	3.5%	3.3%
CHI / Event	80	20	37	68	853	1,058
Total Customer-Interruptions	41,255	26,606	46,471	18,130	43,012	175,474
Average # of Customers	157,405	159,013	160,937	162,585	164,118	

Table 4-16: CC_6 Adverse Weather by Sub-cause Codes

Measure	6.1 Adverse Weather - Tree Contact Weather	%	6.2 Adverse Weather - Equipment Breakage	%	6.3 Adverse Weather - Other Adverse Weather	%	Total
# of Interruptions	1	2.6%	3	7.9%	34	89%	38
Customer-Interruptions	210	1.4%	1,213	7.8%	14,031	91%	15,454
Customer-Hours of Interruption	672	2.1%	656	2.0%	31,078	96%	32,406
Average Customer Numbers	164,118		164,118		164,118	100%	164,118
SAIDI Contribution from this Cause Code	0.004		0.00		0.19	96%	0.20
SAIFI Contribution from this Cause Code	0.001		0.01		0.09	91%	0.09
Total # of Interruptions Caused by Major Event(s)	-		-		-	-	-
Total Customer Interruptions caused by Major Event(s)	-		-		-	-	-
Total Customer Hours of Interruptions caused by Major Event(s)						-	-

4.9. Cause Code 7: Adverse Environment

Figure 4-8: CC_7 Adverse Environment



Cause Code 7: Adverse Environment – are customer interruptions due to distributor equipment being subject to abnormal environments, such as salt spray, industrial contamination, humidity, corrosion, vibration, fire, or flooding.

Interruptions due to Adverse Environment do not typically impact Enova's annual CMI. From 2020 – 2024, Adverse Environment ranked 9th, (1.3%) in total CHI. Excluding MEDs, Adverse Environment ranking rose to the 7th (1.8%) leading cause of CHI.

Table 4-17 provides an overview of Enova's historical performance regarding this cause code.

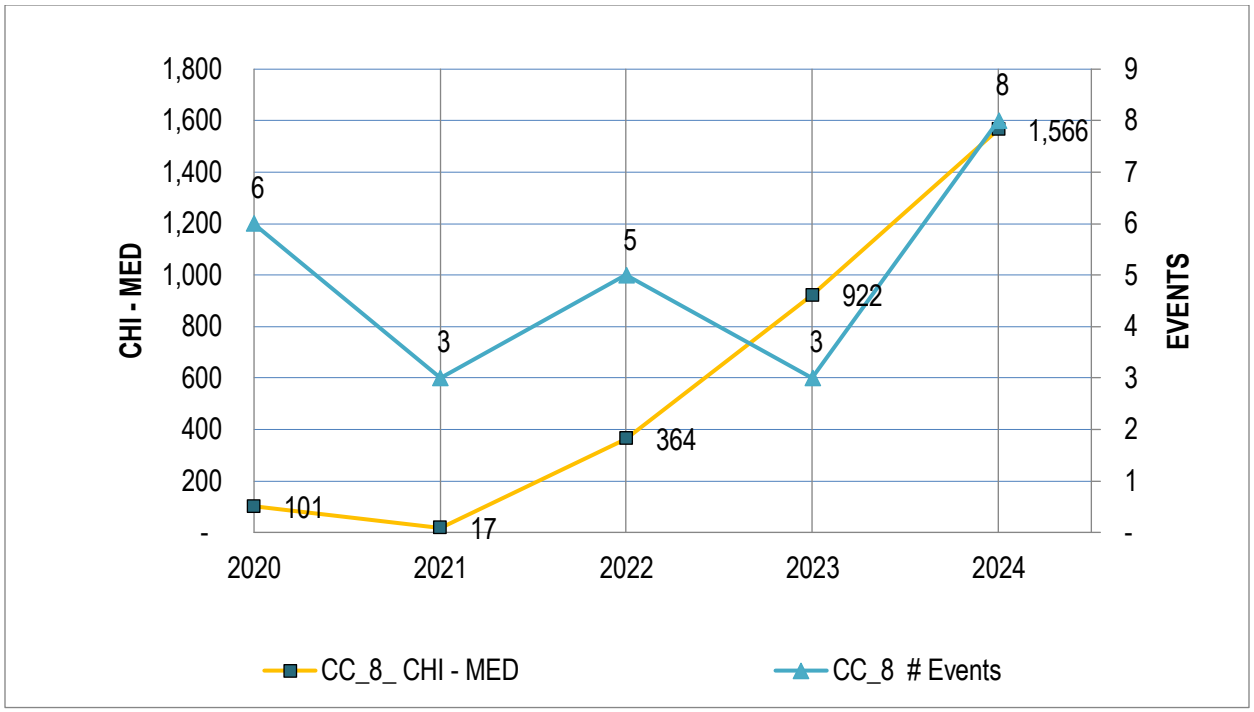
There are no sub-cause codes on which to report in the section.

Table 4-17: CC_7 Adverse Environment

Measures	2020	2021	2022	2023	2024	Total	Average
Total CHI - MED	100,623	94,308	167,898	109,000	161,693	633,522	126,704
CC_7_ CHI - MED	-	-	10,637	625	386	11,648	11,648
CC_7 % of Total CHI	0.0%	0.0%	6.3%	0.6%	0.2%	1.8%	
Total Events	1,312	1,388	1,427	1,296	1,082	6,505	1,301
CC_7 # Events	-	-	4	6	3	13	3
CC_7 % of Total Events	0.0%	0.0%	0.3%	0.5%	0.3%	0.2%	
CHI / Event	-	-	4	6	3	13	3
Total Customer-Interruptions	41,255	26,606	46,471	18,130	43,012	175,474	35,095
Average # of Customers	157,405	159,013	160,937	162,585	164,118		

4.10. Cause Code 8: Human Element

Figure 4-9: CC_8 Human Element



Cause Code 10: Human Element – are customer interruptions due to the interface of distributor staff with the distribution system.

This cause code ranked 10th (0.3%) in total CHI over the last 5 years. Excluding MEDs, the cause code ranking remained as the 10th (0.5%) leading cause of CHI.

Table 4-18 provides an overview of Enova's historical performance regarding this cause code.

Table 4-19 provides a breakdown of the Human Element CHI contributions by sub-cause code. In 2024 there were 8 sustained interruption incidents contributing approximately 1,566 CHI. DERs have had no impact on Enova's Reliability.

The total CHI due to Human Element is not typically impactful on Enova's annual CMI; however, Enova is aware of the increasing trend since 2021 and plans to address this with a review of employee training.

Table 4-18: CC_8 Human Element

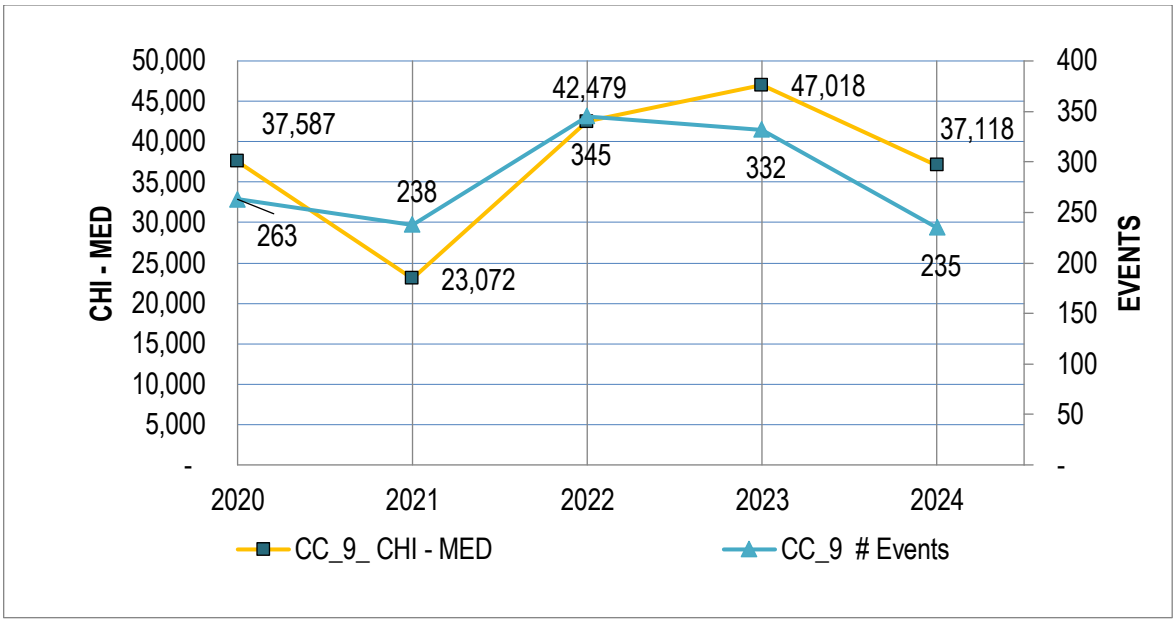
MEASURES	2020	2021	2022	2023	2024	TOTAL	Average
Total CHI - MED	100,623	94,308	167,898	109,000	161,693	633,522	126,704
CC_8_ CHI - MED	101	17	364	922	1,566	2,969	2,969
CC_8_ % of Total CHI	0.1%	0.0%	0.2%	0.8%	1.0%	0.5%	
Total Events	1,312	1,388	1,427	1,296	1,082	6,505	1,301
CC_8 # Events	6	3	5	3	8	25	5
CC_8 % of Total Events	0.5%	0.2%	0.4%	0.2%	0.7%	0.4%	
CHI / Event	-	-	4	6	3	13	3
Total Customer-Interruptions	41,255	26,606	46,471	18,130	43,012	175,474	35,095
Average # of Customers	157,405	159,013	160,937	162,585	164,118		

Table 4-19: CC_8 Human Element by Sub-cause Codes

Measure	8.1 Human Element - Distributed Energy Resource (DER)	%	8.2 Human Element - Other Human Element	%	Total
# of Interruptions	-	0%	8	100%	8
Customer-Interruptions	-	0%	14,302	100%	14,302
Customer-Hours of Interruption	-	0%	1,566	100%	1,566
Average Customer Numbers	-		164,118		164,118
SAIDI Contribution from this Cause Code	-		0.01		0.01
SAIFI Contribution from this Cause Code	-		0.09		0.09
Total # of Interruptions Caused by Major Event(s)	-		-		-
Total Customer Interruptions caused by Major Event(s)	-		-		-
Total Customer Hours of Interruptions caused by Major Event(s)					-

4.11. Cause Code 9: Foreign Interference

Figure 4-10: CC_9 Foreign Interference (2020 – 2024)



Cause Code 9: Foreign Interference – are customer interruptions beyond the control of the distributor, such as those caused by animals, vehicles, dig-ins, vandalism, sabotage, and foreign objects.

Foreign Interference is a major contributor to total CHI ranking 3rd (20.3%) over the last 5 years. Excluding MEDs, Foreign Interference ranking rose to the 2nd leading cause of CHI.

Table 4-20 provides an overview of Enova's historical performance regarding this cause code.

Tables 4-21 (a&b) provide a breakdown of the Foreign Interference CHI contributions by sub-cause code. The leading cause of sustained interruptions due to Foreign Interference is wildlife contacts (52.3%) followed by vehicle accidents (40.4%) although vehicle accidents contributed the largest amount of CHI at 66.3%.

Table 4-20: CC_9 Foreign Interference

MEASURES	2020	2021	2022	2023	2024	TOTAL	Average
Total CHI - MED	100,623	94,308	167,898	109,000	161,693	633,522	126,704
CC_9_ CHI - MED	27,787	23,023	42,443	47,018	37,118	177,390	177,390
CC_9 % of Total CHI	27.6%	24.4%	25.3%	43.1%	23.0%	28.0%	
Total Events	1,312	1,388	1,427	1,296	1,082	6,505	1,301
CC_9 # Events	263	238	345	332	235	1,413	283
CC_9 % of Total Events	20.0%	17.1%	24.2%	25.6%	21.7%	21.7%	
CHI / Event	-	-	4	6	3	13	3
Total Customer-Interruptions	41,255	26,606	46,471	18,130	43,012	175,474	35,095
Average # of Customers	157,405	159,013	160,937	162,585	164,118		

Table 4-21a: CC_9 Foreign Interference by Sub-cause Codes (2024)

Measure	9.1 Foreign Interference - Wildlife	%	9.2 Foreign Interference - Vehicle	%	9.3 Foreign Interference - Dig-in	%	Total
# of Interruptions	123	52.3%	95	40.4%	3	1.3%	235
Customer-Interruptions	15,350	29.7%	34,031	65.8%	35	0.1%	51,716
Customer-Hours of Interruption	10,598	28.6%	24,611	66.3%	83	0.2%	37,118
Average Customer Numbers	164,118		164,118		164,118		164,118
SAIDI Contribution from this Cause Code	0.06	28.6%	0.15	66.3%	0.00	0.2%	0.23
SAIFI Contribution from this Cause Code	0.09	29.7%	0.21	65.8%	0.00	0.1%	0.32
Total # of Interruptions Caused by Major Event(s)	-		-		-	-	-
Total Customer Interruptions caused by Major Event(s)	-		-		-	-	-
Total Customer Hours of Interruptions caused by Major Event(s)	-		-		-	-	-

Table 4-21b: CC_9 Foreign Interference by Sub-cause Codes (2024)

Measure	9.4 Foreign Interference - Customer Equipment	%	9.5 Foreign Interference - Distributed Energy Resource (DER)	%	9.6 Foreign Interference - Other (Non-distributor Staff)	%	Total
# of Interruptions	8	3.4%	-	0.0%	6	2.6%	235
Customer-Interruptions	2,178	4.2%	-	0.0%	122	0.2%	51,716
Customer-Hours of Interruption	1,786	4.8%	-	0.0%	40	0.1%	37,118
Average Customer Numbers	164,118		-		164,118		164,118
SAIDI Contribution from this Cause Code	0.01	4.8%	-	0.0%	0.00	0.1%	0.23
SAIFI Contribution from this Cause Code	0.01	4.2%	-	0.0%	0.00	0.2%	0.32
Total # of Interruptions Caused by Major Event(s)	-		-		-		-
Total Customer Interruptions caused by Major Event(s)	-		-		-		-
Total Customer Hours of Interruptions caused by Major Event(s)							-

Enova has an active animal guarding program in an attempt to mitigate momentary and sustained events. Animal guarding is installed at known problematic areas. New construction standards incorporate animal guarding at vulnerable locations such as transformers and load break switches. Enova also utilizes increased line-to-ground clearances in problematic areas to mitigate the effects of animal contact.

Enova dispatches a crew to all reported dig-ins and Motor Vehicle Accidents (MVA) when Enova infrastructure is involved. This is to ensure public safety; however, this can also increase the length of the outage and increase the CHI in this category. Enova follows a protocol for investigating and reporting such dig-in incidents to the Electrical Safety Authority (ESA) and/or the Ministry of Labour Immigration, Training and Skills Development (MLITSD) as required.

5. Impact of Grid Modernization on Reliability

Grid modernization is an ongoing program at Enova, utilizing technologies, such as SCADA, Outage Management System (OMS), programmable reclosers, and advanced microprocessor-based protection relays.

Fault Location, Isolation, and Service Restoration (FLISR) has been implemented on 58 of its 127 in-service feeders, impacting over 50,000 customers. It is an automated smart grid technology used to automatically detect power line faults, isolate the damaged section, and quickly restore electricity to unaffected areas within seconds. Combined with Survalent's OMS and the aforementioned grid modernization technologies, the duration and scale of outages are reduced.

Enova temporarily paused its grid modernization program due to the merger and subsequent changes in short term priorities; however, over the 2026 to 2031 forecast period, Enova is reimplementing its program and will be rolling out FLISR to additional feeders.

6. 2024 Worst Performing Feeders

Annually, Enova reviews the reliability performance of all feeders. Enova identifies the top 5 Worst Performing Feeders and performs a focused examination to determine the root causes of the interruptions and to look for opportunities to improve reliability.

In total, Enova has 127 in-service feeders at the 13.8 kV and 27.6 kV voltage levels. In addition, there are another 28 feeders at the 8.32 kV level that are planned to be upgraded to 27.6 kV through Enova's System Renewal and grid modernization programs.

Table 6-1 provides a listing of Enova's 5 worst performing feeders at the end of 2024. On average over the last 3 years, the 5 worst performing feeders represent 3.3 % of the feeder population and 21.2% of the total CHI.

Table 6-1: Worst Performing Feeders

Ranking	Feeder #	Distribution Voltage (kV)	# Customers	2022 CHI	2023 CHI	2024 CHI	3 Year Average CHI	% of Total CHI
1	5M15	13.8	3,982	35,873	797	467	12,379	6.5%
2	7M9	13.8	32	14,636	3,456	9,462	9,184	4.8%
3	6M17	13.8	1,851	12,342	1,272	6,542	6,718	3.5%
4	5M26	13.8	2,576	16,696	112	1,870	6,226	3.3%
5	7M5	13.8	1,646	9,160	6,486	1,426	5,691	3.0%
5 WPF CHI			10,087	88,707	12,122	19,767	40,199	21.2%
Total CHI				315,878	108,685	144,756	189,773	100%%
% WPF CHI				28.1%	11.2%	13.7%	21.2%	

Worst Performing Feeder Ranking

Rank	1	2	3	4	5

Table 6-2 provides a listing of action plans developed for the 2024 worst performing feeders.

Table 6-2: Worst Performing Feeder Action Plans (2024)

Ranking	Feeder	Completion Timeline	Plan
1	5M15	2025-2026	• 5M15 was patrolled in 2025. No deficiencies found. • Worst performing feeder due to severe windstorm event in 2022. Performance in 2023-2024 improved substantially. • 5M15 feeder cables scheduled to be replaced in 2026 under System Renewal plan. • Regularly scheduled tree trimming to occur in 2027. • No other action planned at this time.
2	7M9	2025-2026	• 7M9 was patrolled in 2025. No deficiencies found. • Feeder to be reconfigured to balance load and circuit kilometers with other feeders. Sections of feeder to be transferred onto 7M3. • Regularly scheduled tree trimming to occur in 2027/2029. • No other action planned at this time.
3	6M17	2025-2026	• 6M17 was patrolled in 2025. Section of line through wooded area found at high risk for tree contact during ice and windstorms. Remediation tree trimming completed. • A 1 km trunk section on Highland Rd will be rebuilt in 2026. Feeder to be reconfigured with additional tie to feeder 1M9 to improve restoration capability. Two additional reclosers will be installed to reduce number of customers exposed to a single event. • Regularly scheduled tree trimming to occur in 2027. • No other action planned at this time.
4	5M26	2025-2026	• 5M26 patrolled in 2025. Section of line between Station 5TS and Franklin St. found to have several locations at high risk for tree contact during ice and windstorms. Remediation tree trimming completed. • Worst performer due to severe windstorm event in 2022. Performance in 2023-2024 improved substantially. • Regularly scheduled tree trimming to occur in 2027. • No other action planned at this time.
5	7M5	2025-2026	• 7M5 patrolled in 2025. No deficiencies found. • Worst performer due to severe windstorm event in 2022. • Regularly scheduled tree trimming to occur in 2029. • No other action planned at this time.

Of Enova's 127 in-service feeders, 31 contributed 1% or more to the total 3-year average of CHI excluding Scheduled, Loss of Supply and Major Event Day events. These feeders account for approximately 70% of the total CHI Enova customers experienced from 2022 to 2024. **Table 6-3** provides a listing of these feeders.

Table 6-3: Enova Feeder Performance Excluding Planned & Major Event Days

Overall Ranking	Feeder #	Distribution Voltage (kV)	Customers	2022 CHI	2023 CHI	2024 CHI	3 Year Average CHI	Total 3 Year CHI	% of Total CHI
1	5M15	13.8	3,982	35,873	797	467	12,379	37,137	6.5%
2	7M9	13.8	32	14,636	3,456	9,462	9,184	27,553	4.8%
3	6M17	13.8	1,851	12,342	1,272	6,542	6,718	20,155	3.5%
4	5M26	13.8	2,576	16,696	112	1,870	6,226	18,678	3.3%
5	7M5	13.8	1,646	9,160	6,486	1,426	5,691	17,073	3.0%
6	9M7	13.8	454	7,045	4,320	5,651	5,672	17,017	3.0%
7	3DS1	8.32	276	14,862	489	1,223	5,525	16,574	2.9%
8	8M9	13.8	1,495	16	14,027	2,525	5,522	16,567	2.9%
9	4M14	13.8	1,349	14,995	791	172	5,319	15,958	2.8%
10	HS20	13.8	2,182	2,076	3,448	9,399	4,974	14,922	2.6%
11	5M16	13.8	814	9,175	4,774	0	4,650	13,949	2.5%
12	9M9	13.8	2,433	11,613	34	2,294	4,647	13,941	2.4%
13	4M18	13.8	1,093	11,334	412	1,528	4,425	13,274	2.3%
14	9M3	13.8	3,641	12,781	0	0	4,260	12,781	2.2%
15	9M4	13.8	662	11,226	135	1,148	4,170	12,509	2.2%
16	5M11	13.8	1,561	7,161	2,737	621	3,506	10,519	1.8%
17	8M7	13.8	3,059	370	601	9,204	3,391	10,174	1.8%
18	1M9	13.8	1,773	4,386	476	5,107	3,323	9,968	1.8%
19	7M3	13.8	2,044	8,534	373	932	3,279	9,838	1.7%
20	5M25	13.8	1,041	5,232	2	3,926	3,053	9,159	1.6%
21	6M13	13.8	1,911	8,489	148	44	2,894	8,682	1.5%
22	3DS3	8.32	61	8,569	0	0	2,856	8,569	1.5%
23	5M13	13.8	670	7,520	31	387	2,646	7,938	1.4%
24	5M21	13.8	2,200	12	7,183	693	2,629	7,888	1.4%
25	4M11	13.8	2,498	2,596	126	5,013	2,579	7,736	1.4%
26	5M14	13.8	1,350	1,892	2,521	2,858	2,424	7,272	1.3%
27	9M2	13.8	917	4,580	76	2,282	2,312	6,937	1.2%
28	3F61	27.6	3,811	3,855	1,141	1,892	2,296	6,888	1.2%
29	9M4	27.6	1,461	4,803	574	1,017	2,132	6,395	1.1%
30	5M27	13.8	525	2,528	1,566	1,850	1,981	5,944	1.0%
31	HS26	27.6	2,284	927	97	4,846	1,957	5,870	1.0%

APPENDIX F-2
Appendix 2-G SQI & SQR

File Number:
Exhibit:
Tab:
Schedule:
Page:

Date: 06-Jul-26

Appendix 2-G
Service Reliability Indicators
2020 - 2024

Index	Including outages caused by loss of supply					Excluding outages caused by loss of supply				
	2020	2021	2022	2023	2024	2020	2021	2022	2023	2024
SAIDI	0.80	1.05	2.22	0.67	0.99	0.63	0.58	1.03	0.66	0.96
SAIFI	1.10	0.97	1.23	0.76	1.31	0.95	0.71	0.90	0.74	1.10

	5 Year Historical Average	
SAIDI	1.15	0.77
SAIFI	1.07	0.88

SAIDI = System Average Interruption Duration Index
SAIFI = System Average Interruption Frequency Index

Indicator	OEB Minimum Standard	2020 WNH	2020 KWH	2021 WNH	2021 KWH	2022 Enova	2023 Enova	2024 Enova	5 year Average
Low Voltage Connections	90.00%	100.0%	98.8%	100.0%	97.1%	98.5%	96.4%	99.0%	98.6%
High Voltage Connections	90.00%	100.0%	Note 1	100.0%	100.0%	100.0%	100.0%	Note 1	100.0%
Telephone Accessibility	65.00%	86.6%	88.0%	94.7%	74.4%	81.3%	69.8%	75.0%	81.4%
Appointments Met	90.00%	99.7%	98.6%	98.5%	98.6%	99.4%	100.0%	98.7%	99.1%
Written Response to Enquires	80.00%	99.7%	99.9%	99.8%	92.5%	89.6%	92.1%	99.6%	96.2%
Emergency Urban Response	80.00%	97.4%	85.7%	100.0%	100.0%	97.3%	93.1%	92.9%	95.2%
Emergency Rural Response	80.00%	95.0%	100.0%	100.0%	100.0%	100.0%	100.0%	97.0%	98.9%
Telephone Call Abandon Rate	10.00%	0.8%	3.3%	0.3%	17.9%	8.4%	8.3%	1.2%	5.7%
Appointment Scheduling	90.00%	92.9%	94.6%	69.0%	95.5%	84.1%	90.0%	99.2%	89.3%
Rescheduling a Missed Appointment	100.00%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Reconnection Performance Standard	85.00%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Note 1 - There were no requests for HV connection made that year.

APPENDIX G
Operations Maintenance Report

Operations Distribution System Annual Maintenance Report (2025)









TABLE OF CONTENTS

CONTENTS ii
LIST OF FIGURES ii
1. OEB Inspections 1
2. Overhead Systems 2
2.1. Inspections 2
2.2. Load Break Switch Maintenance 3
2.3. Pole Testing 3
2.4. Live-Line Insulator Washing 3
3. Underground Systems 4
4. Vegetation Management 5
5. Appendices 7
5.1. Annual Maintenance Program Progress Sheet 7
5.2. Service Crew Service Call Sheet 8

LIST OF FIGURES

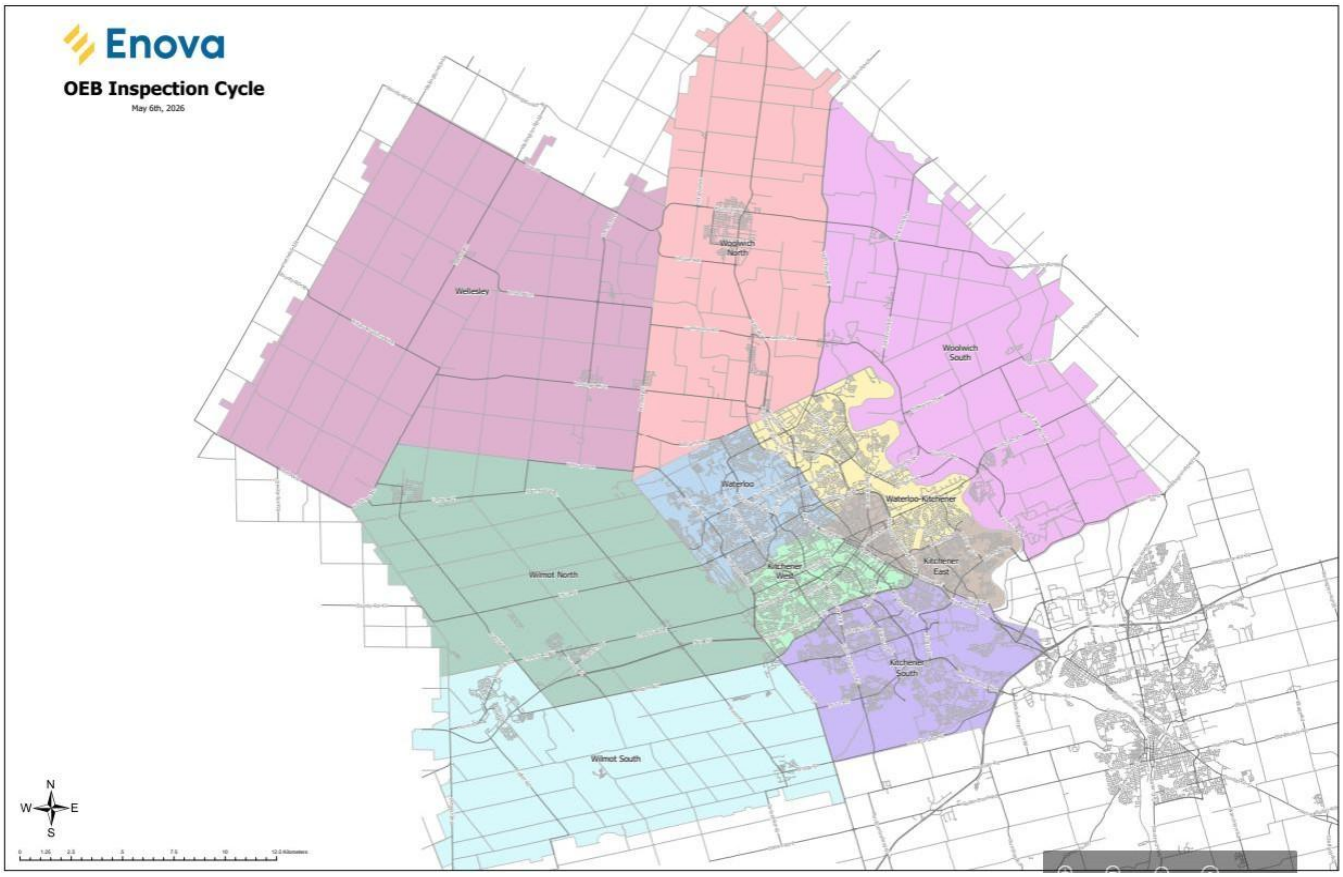
FIGURE 1-1: OEB INSPECTION AREAS 1
FIGURE 1-2: FORESTRY INSPECTION / LINE CLEARING MAP 6

1. OEB Inspections

For the year 2025, Enova's OEB 3-year visual patrol for urban areas consisted of the Waterloo Southwest, Kitchener West, Kitchener East, and Kitchener South areas. The 6-year visual patrol for the rural area consisted of the Wellesley, Woolwich North, and Wilmot South areas. Enova completed 100% of OEB inspections for these areas using qualified Enova staff and a qualified contractor.

In addition to the required OEB visual patrols, Enova completed numerous patrols of lines and equipment for various reasons such as storm damage assessment or prior to reenergization of lines when an interruption has occurred without an identifiable cause or report. These patrols help ensure public safety and often result in corrective and preventative maintenance being performed on overhead plant.

Figure 1-1: OEB Inspection Areas



Included in this report is a sample spreadsheet indicating the types of required tasks with a date range and the group responsible for the inspections. The reports from Geographical Information System (GIS) indicate actual sites and documentation of deficiencies identified during the inspections. Third party attachments and power supplies are also logged and archived in Enova's GIS system.

2. Overhead Systems



2.1. Inspections

The visual overhead patrol consists of the inspection of poles and hardware, transformers, switches, capacitors, regulators, conductors, major road crossings and vegetation. The inspections were completed by qualified Enova staff and contracted powerline maintainers.

Infrared thermographic inspections were conducted by a qualified contractor on all 3-phase overhead lines in the required inspection areas. There were 9 overhead equipment related issues identified. Repairs were completed and documented in the 2025 Electrical Infrared Thermographic Inspection Report.

As part of our OEB inspections, a total of 31,700 poles were inspected, resulting in 537 poor and 103 very poor issues requiring remediation. The identified issues included poles needing replacement, crossarms in poor condition, grounding and guying damage, vegetation proximity to lines, animal contact related damage, hardware replacement, repairs to conductors, and transformers needing maintenance or replacement.

Inspections of expressways, railways, and river crossings are conducted annually, and no major deficiencies were found in 2025.

Inspections of overhead plant located in or adjacent to parks, playgrounds and schoolyards are also completed annually and some minor issues were identified and corrective action taken.

A total of 119 capacitor banks were inspected in 2025, and no deficiencies were identified.

As part of Enova's overall overhead inspection program, staff ensure proper nomenclature is in place for all major equipment, including switches, transformers, capacitors etc. Deficiencies are documented and updated in the GIS system as required. Documented repairs and replacement of identified deficiencies have been completed.

2.2. Load Break Switch Maintenance

A total of 354 load break switches in the designated inspection areas were inspected and as a result 10 required maintenance due to "Fair" condition. The factors determining maintenance versus replacement include the conditions of the switch and pole, damage identified to components of the switch (porcelain insulators, rusted operating devices), and the age of the switch. Four (4) manually operated load break switches were replaced with new SCADA controlled vacuum switches/reclosers (RCLs).

2.3. Pole Testing

In 2025, 6,477 wood poles in the Enova territory were tested by UTS Consultants for remaining wood fiber strength. The contractor identified 256 poles in very poor condition from their inspections. The results of the pole testing are used to inform Enova's Asset Condition Assessments after which a replacement plan is developed by Enova engineering. More information on the results can be found in Enova's Distribution System Plan, **Appendix B-1 - Enova Asset Condition Assessment (ACA) Report.**

2.4. Live-Line Insulator Washing

Insulator washing was completed as part of Enova's annual maintenance program. This is specialized work that is performed by a qualified contractor. High-pressure, low-conductivity water is used to clean insulators in high contamination areas while the power line remains energized.

In 2025, 80 hours of washing was performed on the overhead distribution lines adjacent to high-traffic roadways where salt spray is most severe.

3. Underground Systems

The visual inspection of the underground systems serves to identify obvious structural problems, hazards and is also used in verifying and updating equipment nomenclature. Typical deficiencies identified include rusting pad-mounted equipment, faulty locking mechanisms, hot spots and missing nomenclature.

In 2025, the following work was completed:

- 1,948 transformers were inspected with 10 very poor & 100 poor condition deficiencies identified.
- Vista switches, di-electric switches, and 125 switching cubicles were inspected, with 5 poor / very poor condition issues identified.
- 92 transformer vault room inspections were completed. Transformer vault room inspections also included inspection of school facility vault rooms. Identified issues found included door maintenance/replacement and nomenclature requirements.
- 200 transformers were identified with significant tank corrosion and underwent sandblasting and painting to deal with the issues.
- Submersible vault lid inspections were completed with none found needing replacement.

Documented repairs and the remediation of deficiencies are ongoing.



4. Vegetation Management

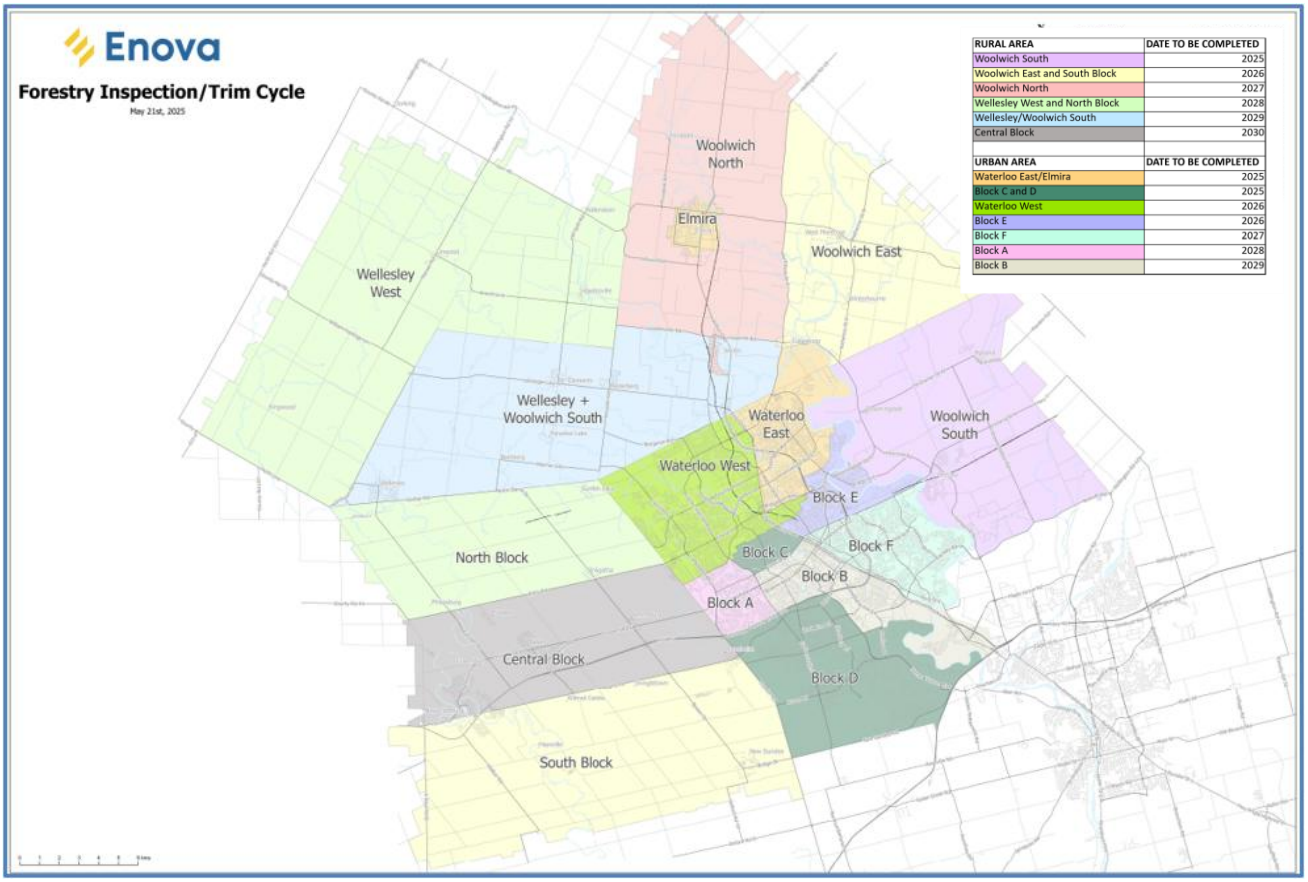
The majority of Enova's vegetation management program is carried out through a planned rotational line-clearing cycle. Annual line clearing typically begins in February and is substantially completed by late November. The work covers a significant portion of Enova's service territory each year and is performed by a combination of Enova forestry staff and qualified third-party contractors.

Figure 1-2 illustrates Enova's vegetation management cycle blocks across its service territory. During 2025, vegetation management activities were completed in the Woolwich South, Waterloo East/Elmira, Wilmot South, Kitchener Block C, and Kitchener Block D cycle areas.

In addition to the scheduled rotational program, Enova undertakes off-cycle vegetation management where conditions warrant earlier intervention. These activities are required where vegetation growth rates exceed the planned maintenance cycle or where access constraints, property owner restrictions, environmental considerations, or other site-specific factors prevent the desired clearances from being achieved during scheduled work. Off-cycle work is prioritized using a risk-based approach that considers vegetation growth, asset criticality, historical reliability performance, and public safety.

Vegetation inspections form part of Enova's ongoing asset inspection and maintenance program. Inspections include overhead distribution lines as well as ground-mounted electrical equipment, including pad-mounted transformers, switching cabinets, and other distribution assets where vegetation may impede safe operation or maintenance activities. Identified deficiencies requiring corrective action are electronically documented using Enova's Urgent Repair Required process and assigned to either Enova's in-house forestry crews or qualified third-party contractors for timely remediation. This process enables Enova to systematically monitor vegetation risks, maintain required electrical clearances, support system reliability, and reduce the likelihood of vegetation-related outages.

Figure 1-2: Forestry Inspection / Line Clearing Map

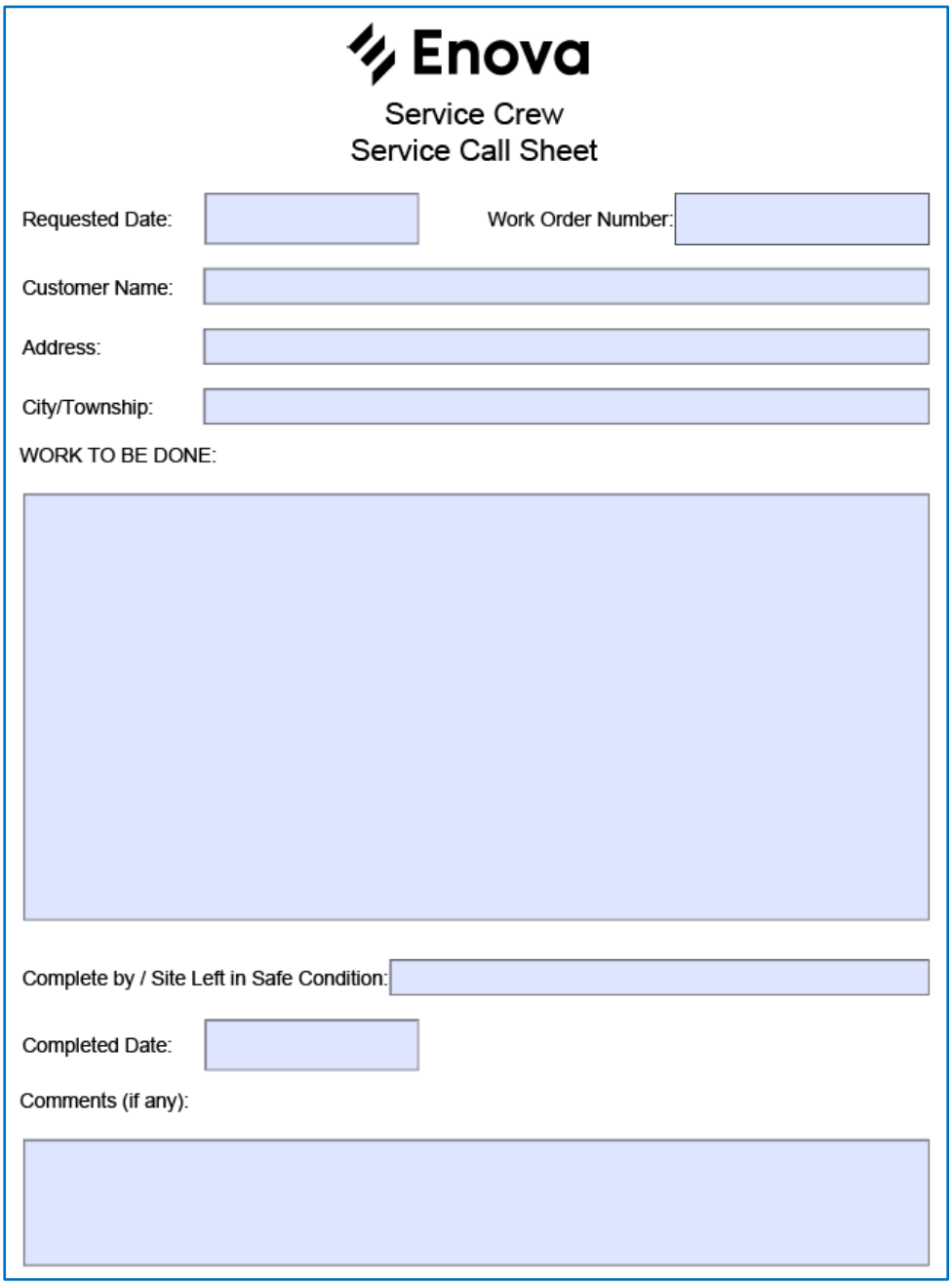


5. Appendices

5.1. Annual Maintenance Program Progress Sheet

	OEB Inspections																			Forestry	
	Plant		Schools/ Playgrounds		Transformers		Infrared Thermographic Analysis		Railway & River Crossings	Expressway Crossings	Capacitors/EVRs	Insulator Washing	Pole Testing	HydroOne 3rd Party Attachments	LB (LI) Maintenance	Dry Ice Cleaning	Meter Calibration	Network TX Oil Samples	Vista Switch Inspections	Rural	Urban
	OH	UG	OH	UG	OH	UG	OH	UG	OH	OH	OH	OH	OH	OH	OH	EQU	EQU	EQU	EQU	% Complete	% Complete
Enova or Contractor	Enova	Enova	Enova	Enova	Enova	Enova	Contractor /Enova	Contractor /Enova	Enova	Enova	Enova	Contractor	Contractor	Enova	Enova	Contractor	Contractor	Contractor	Contractor/ Enova	Contractor	Contractor
January																					
February							100%														
March												100%									
April																					
May																100%	100%				
June																					
July				100%	100%				100%												
August			100%							100%											
September	100%	100%				100%		100%					100%	100%					100%		
October											100%							100%			
November															100%						
December																				100%	100%

5.2. Service Crew Service Call Sheet



Enova

Service Crew
Service Call Sheet

Requested Date:

Work Order Number:

Customer Name:

Address:

City/Township:

WORK TO BE DONE:

Complete by / Site Left in Safe Condition:

Completed Date:

Comments (if any):

APPENDIX H

Information Technology Management Plan



ENOVA POWER CORP.

IT Management Plan

September 8, 2026

CONTENTS

TABLES ii
1. Purpose 1
2. Guiding Principles 1
2.1. Self Service 1
2.2. Digital Literacy 2
2.3. Technical Talent Management 2
2.4. Open Standards and Collaboration 2
3. Long Term Technology Goals 2
4. Service Delivery and KPIs 3
5. Asset Life Cycle and Resource Requirements 3
5.1. Capital Costs and Asset Life-Cycle Planning 3
5.1.1. Inspections and Maintenance 3
5.1.2. IT Hardware Asset Life Cycle 5
5.1.3. Major Software Assets 6
5.2. Business Driven Capital Projects 8
5.3. Move from CapEx to OpEx and Cloud 8
6. Capital Forecast and Distribution 9
6.1. Analysis of historical capital investment 9
6.2. Analysis of Planned Investments during DSP Period 10

LIST OF TABLES

Table 5-1: Inspections - Information Technology 4
Table 5-2: Maintenance - Information Technology 5
Table 5-3: Information Technology Hardware Assets 5
Table 5-4: Information Technology Software Applications 7
Table 6-1: Capital IT Investment Analysis 9
Table 6-2: IT Capital Investment Categories 10
Table 6-3: IT Capital Investment by Program 10

1. Purpose

Enova Power Corp's (Enova) Information Technology Department (IT) includes the planning, design, development, application, implementation, support, and management of computer-based information systems in support of Enova's Mission, Vision and Strategic Objectives.

IT initiatives service both for internal and external Enova customers. These services are provided under the direction of the Vice President of Information and Technology.

The purpose of this report is to provide a consolidated view of Enova's information technology management strategy, objectives, assets under management, asset assessments and investment plans for the years 2027 to 2031 inclusive. The information contained in this report forms the basis on which IT capital investment plans have been formulated.

The information in this report also informs Enova's senior executive team (Executive) and aides in the development of Enova's Distribution System Plan.

2. Guiding Principles

Enova is committed to continuous improvement regarding digital technology and serving customers preferences where possible.

The following is a list of general concepts Enova uses to guide decisions around digital tools and information technology.

2.1. Self Service

Enova believes that end users need smart, efficient and effective self-directed tools in order to accomplish their tasks and extract information from Enova's varied and extensive information systems. Technology should not require specialized technical knowledge to operate.

The following is a summary of our guiding principles for self-service from Enova's digital strategy.

1. Standard System Architecture (consistent and predictable).
2. Data access and control (subject matter experts should have full control of their data).

3. Data accuracy and integrity (define and value “the system or record”).
4. Reproducible standards and systems.

2.2. Digital Literacy

As digital tools and platforms become integrated into all areas of work, Enova recognizes the potential knowledge gap created in the workforce caused by their adoption. Enova utilizes the following strategies to mitigate the potential knowledge gap:

1. Integrate training with day to day work.
2. Invest in digital safety awareness.
3. Process and design thinking as a first principle.
4. Expand staff competence and confidence in technology use.

2.3. Technical Talent Management

The following strategies summarize Enova’s plan to build and maintain a strong information technical team.

1. Maintain a high level of employee engagement.
2. Promote continuous learning.
3. Make room for innovation when possible.

2.4. Open Standards and Collaboration

Open technologies, such as open source software and non-proprietary architecture, foster collaboration through shared practices and enable standard ways of doing work. Enova has demonstrated a preference towards systems of this nature whenever possible in the following ways:

1. Prefer open system and software architecture.
2. Participate in the development, testing and establishment of open systems.
3. Prefer collaboration with other utilities, municipalities and vendors rather than independent development.

3. Long Term Technology Goals

Enova’s long term technology goals are:

1. Full self-service customer experience (able to conduct all business online)

2. Adoption of iterative methods for project management, system architecture and continuous improvement.
3. Increase transparency and visibility of all work (increased use of measures, KPIs, real-time displays of work status).

4. Service Delivery and KPIs

The core functions of Enova's technology group which are measured through KPIs:

1. Help Desk for Break/Fix issues
2. Change Management for Projects, features and unplanned work
3. Security operations with a focus on protecting customer privacy and grid resilience
4. System operations
5. Project delivery

5. Asset Life Cycle and Resource Requirements

Proper management of staff levels, contract resources and asset life-cycling is the foundation of maintaining strong technical resources. This section will discuss the methodology used to manage cost and asset health.

5.1. Capital Costs and Asset Life-Cycle Planning

Enova maintains a range of technology assets such as servers, communications equipment, end user devices and major software assets, such as core business systems.

5.1.1. Inspections and Maintenance

Enova's methodology and inspection schedule for life-cycling of all technology assets are as follows.

Hardware asset replacement factors

1. Mean time to failure (MTTF) as published by the manufacturer.
2. Health events on specific devices through monitoring.
3. Professional judgment of IT staff.

Software asset replacement or update factors

1. Support availability

2. Cost to maintain vs update
3. Obsolescence
4. Market requirements

All assets follow a common life cycle with a defined roadmap

1. Plan: Map out requirements, business process and future state
2. Acquire and Build: Procure, assemble and conduct make ready work for cutover
3. Operate: Shift new asset into operation and integrate with daily workflow
4. Maintain: Perform maintenance during useful life of asset
5. Retire: Decommission gracefully with responsible processes for data and environmental concerns

Table 5-1: Inspections - Information Technology

Technology or Supporting System	Frequency of Inspection
Network and communications health	Automated Hourly
Storage and Compute systems health	Automated Hourly
Physical inspection of servers and server room	As Needed
HVAC and backup HVAC systems	Quarterly
Generator capacity and function	Quarterly
UPS battery life and function	Automated hourly and quarterly full test
Core business software application performance	Real-time monitoring
Software updates and patches	Automated Daily
Network traffic and security events	Real-time monitoring

Table 5-2: Maintenance - Information Technology

Technology or Supporting System	Frequency of Maintenance
Audio/Visual Equipment	Quarterly
End user device patching	Between 30 - 45 days
Server OS patching	As needed (CVEs) or Semi-Annually
Virtual host software version upgrades	Quarterly to Semi-Annually
Server hardware	As needed or part of regular life-cycle
End user device hardware	As needed or part of regular life-cycle

5.1.2. IT Hardware Asset Life Cycle

A list of hardware assets and Enova's current asset life-cycle plan for each is provided in **Table 5-3**. Replacement practice is based on age, failure and professional judgement. During this plan Enova will be introducing real-time health tracking for all hardware assets to improve this process.

Table 5-3: Information Technology Hardware Assets

Hardware	Description	Quantity	Life Cycle (years)
Physical Servers	Compute infrastructure to run virtual or native applications	12	3 – 5
Primary Firewalls	Network security devices that is first and last point of defense for traffic coming into or out of our facilities	4	3 – 5
Storage Systems	Primary storage for virtual machines, files and other business critical records	5	3 – 5
Network Switches and Routers	Backbone for all network traffic including computer, phone and services	52	5 – 7
Wireless access points	Devices to extend network switch communication to wireless	40	3 – 5
Laptops and Desktops	Primary tool for administrative and mobile work forces	230	3 – 4
Mobile connected devices	Smart phones and other devices connected over cellular (LTE, 5G, etc)	210	3 - 4
Network Printers	Multi-function and standard printer devices	20	7 – 10
Plotters	Large form factor printers	4	7 – 10
AV Equipment	Projectors, large presentation screens	22	5 – 7

Enova IT hardware assets are typically acquired or built using parts sourced through a competitive bidding process. Projects replacing IT hardware assets typically take 2-3 months from the acquisition of new assets to the retirement of the outgoing assets.

When IT hardware is retired, all useful parts are kept as well as all sensitive data is securely destroyed

5.1.3. Major Software Assets

There are three primary options when it comes to major software products;

1. **Self-managed**: Typically, self-hosted, managed, updated and are capital intensive as they are “owned”. When managed correctly they can be the most efficient and flexible systems. However, if managed poorly they will cause operational issues and reach obsolesce far too soon. Enova prefers this option for internal facing business systems, especially when critical to daily operation, such as a CIS.
2. **Cloud-hosted**: Software as a Service (SaaS) is managed by a 3rd party and 100% operating expense. When managed correctly this option provides very quick go-live software but sacrifices flexibility. If managed poorly this option will create issues with data presentation data, security and cost. Enova prefers this option for external facing systems such as a corporate website.
3. **Hybrid-hosted**: Software that is a combination of both options 1 & 2 above. When managed properly this option can provide all the benefits of both self and cloud hosted. When managed poorly this option leads to issues with accountability and cost effectiveness.

Enova considers all options as part of its strategy mix.

Most business functions at Enova depend on software applications. These applications are maintained if they continue to be cost effective, are properly supported by their vendor and meet current Enova technology requirements.

Table 5-4 provides a summary of Enova’s major systems by ownership and hosting category.

Table 5-4: Information Technology Software Applications

System Name	System Function	Host Model	Original in Service Date	Last Major Upgrade	Future Direction
Oracle CC&B	Customer Information System (CIS)	Self	2021	2026	Establish roadmap and plan for next major release upgrade
Oracle JDE	Enterprise Resource Planning (ERP)	Self	1998	2025	Routine upgrades 2027 – 2031 with major release upgrade to be considered and planned
JOMAR MDM	Meter Data Management (MDM)	Self	2021	2026	Routine upgrades 2027 – 2031
Survalent	Outage Management System (OMS)	Self	2015	2025	Routine upgrades 2027 – 2031
Survalent	Supervisory Control and Data Acquisition (SCADA)	Self	2011	2025	Routine upgrades 2027 – 2031
Sensus RNI	Advanced Metering Infrastructure (AMI)	Cloud	2009	2026	Routine upgrades 2027 – 2031 with plan to move to AMI 2.0
ESRI GIS	Geographic Information System (GIS)	Self	2005	2025	Routine upgrades 2027 – 2031
ENGIN	Asset Management	Cloud	2019	2025	Routine upgrades 2021 – 2024
Microsoft o365	Business Suite	Cloud	2020	2023	Routine upgrades 2027 - 2031
Enovapower.com	Corporate Website	Self	2022	2025	Routine upgrades 2027 - 2031
Silverblaze	Web Presentment Portal for TOU	Self	2011	2026	Routine upgrades 2027 – 2031 with plan to investigate replacement
UKG Pro	Human Resource Information System (HRIS)	Cloud	2021	2025	Routine upgrades 2027 - 2031
Sangoma PBX	Phone System	Self	2023	2024	Routine upgrades 2027 - 2031
DocOva	Document Management	Self	2009	2022	Routine upgrades 2027 – 2031 with plan for future replacement

While replacement rationale for software across all hosting models is the same, the logistics of the work differ substantially.

1. Self-hosted replacement and upgrade projects are typically longer, capital intensive and infrequent
2. Cloud-hosted replacements and upgrades can involve disruptive business process changes often with little or no consultation from Enova. These projects typically have lower technical staff effort but can sometimes introduce integration and security concerns. Upgrades can be as often as daily with no input or consent from Enova.
3. Enova has concluded that hybrid models are complex, taking 2-3 times the technical resource effort. Hybrid models often require more technical staff effort than self-hosting and more business process change than cloud. For this reason, Enova is gradually moving away from hybrid except in special circumstances.

5.2. Business Driven Capital Projects

During consultations, Enova customers indicated a preference to complete more of their business transactions through self service. Examples of customer preferences for IT initiatives are listed below:

1. An automated outage notification system (automatically sends messages).
2. Reporting issues or making inquiries through an interactive website.
3. Automated alerts when electricity usage exceeds a prearranged threshold.
4. Having an online chat feature on the Enova website during business hours.

Table 5-4 listed in **Section 5.1.3** outlines Enova's core software business applications. As Enova's post-merger integration phase took precedent over planned maintenance during the recent merger between Kitchener Wilmot Hydro (KWH) and Waterloo North Hydro (WNH) some systems will require additional investment during the 2027 – 2031 period.

5.3. Move from CapEx to OpEx and Cloud

Enova continues to monitor the growing trend from the ownership and self-hosted models to a Software as a Service cloud models (SaaS). Examples of this include platforms such as Adobe creative cloud, Microsoft Office 365 and recent availability of large language model driven artificial intelligence.

6. Capital Forecast and Distribution

Enova Power's IT capital program has been operating within the previously filed distribution system plans for KWH (filed in 2019) and WNH (filed in 2020). This section contains details on the plan going forward for the period of 2027 – 2031.

6.1. Analysis of historical capital investment

Table 6-1 below shows a comparison of capital investment for each legacy utility during 2020 – 2022 inclusive as well as Enova's operation during 2023 – 2025 inclusive.

Table 6-1: Capital IT Investment Analysis

Capital Period	Total Spend in Period	Annual Spend in Period
KWH 2020 – 2022	$9,015,567	$3,005,189
WNH 2020 – 2022	$1,894,079	$631,360
Combined 2020 – 2022	$10,909,646	$3,636,549
Enova 2023 – 2025	$14,145,000	$4,715,000
Proposed DSP 2027 – 2031	$26,211,773	$5,242,355

As discussed in section 5.2 Enova has delayed investment in some systems during the merger period. In addition, the following factors contribute to the rise in capital investment during the DSP period of 2027 – 2031.

1. New CIS system is not represented in historical capital baseline as KWH was operating on a home-grown legacy system until late 2021.
2. Cost of IT hardware has risen and in some cases by as much as 90%.
3. New initiatives to support further investment in cyber security, artificial intelligence and improvements to customer experience.

6.2. Analysis of Planned Investments during DSP Period

Enova Power's $26.2M IT Investment plan during the period of 2027 – 2031 has been planned and designed based on the following categories found in **Table 6-2** below

Table 6-2: IT Capital Investment Categories

Category	2027	2031	5-Year Total	Share of Total	2027-2031 Change
Data Centre	$251,632	$295,632	$1,266,162	4.83%	17.49%
AV & Network	$175,048	$175,048	$875,238	3.34%	0.00%
Employee Devices	$713,680	$757,680	$3,576,400	13.64%	6.17%
Major Business Systems	$2,317,000	$2,317,000	$11,585,000	44.2%	0.0%
Corporate IT Projects	$4,988,333	$575,000	$8,908,973	33.99%	-88,47%
Total	$8,445,693	$4,120,360	$26,211,773	100.0%	-51.21%

In **Table 6-3** below the above capital investment categories are bundled into Enova's three IT capital programs contained this DSP's General Plant. These programs are Computer hardware (G-HW-IT), Computer Software (G-SW-IT) and Cyber Security (G-CS)

Table 6-3: IT Capital Investment by Program

Program	2027	2028	2029	2030	2031	Total	Annual
G-HW IT	$1,600,360	$1,612,000	$1,416,360	$1,146,360	$1,503,360	$7,548,440	$1,509,688
G-SW-IT	$6,720,333	$3,247,000	$2,737,000	$2,467,000	$2,367,000	$17,538,333	$3,507,667
G-CS	$125,000	$250,000	$250,000	$250,000	$250,000	$1,125,000	$225,000
Total	$8,445,693	$5,109,000	$4,403,360	$4,133,360	$4,120,360	$26,211,773	$5,242,355

It is worth noting that when viewed through the lens of **Table 6-3,** program G-SW-IT for 2027 is an exceptional investment when compared to the rest of the program. The 2027 GS-SW-IT spend is primarily driven by required upgrades for systems that were purposefully under-invested in to avoid redundant spending during the merger period where two of every system existed at the outset.

APPENDIX I

Facilities Management Plan

FACILITIES MANAGEMENT PLAN

OVERVIEW & FORECAST 2026 - 2031



August 25, 2026

CONTENTS

CONTENTS i

LIST OF TABLES ii

GLOSSARY iii

1. INTRODUCTION 1
   1.1. Purpose of this Report 1
   1.2. Overview 1
2. FACILITIES ASSET MANAGEMENT PLAN (AMP) 3
   2.1. Strategy 3
   2.2. Objectives 4
3. ASSETS UNDER MANAGEMENT 6
4. FACILITIES ASSET CONDITION ASSESSMENTS 7
   4.1. Asset Condition Assessments – Country Squire Facility 8
      4.1.1. Country Squire Facility Asset Condition Scores 8
      4.1.2. HVAC System 9
      4.1.3. Water Systems & Plumbing 9
      4.1.4. Electrical & Lighting 9
      4.1.5. Fire Alarm & Suppression Systems 9
      4.1.6. Security & Access Control (Building & Site) 9
      4.1.7. Roofing 10
      4.1.8. Sanitary Drains & Septic System 10
      4.1.9. Pavement & Concrete 10
      4.1.10. Structural & Interior 11
      4.1.11. Landscaping 11
      4.1.12. Elevators & Lifting Devices 11
      4.1.13. Emergency Power Systems 11
      4.1.14. Other 11
   4.2. Asset Condition Assessments – Victoria Street Facility 12
      4.2.1. Victoria Street Facility Asset Condition Scores 12
      4.2.2. HVAC System 12
      4.2.3. Water Systems & Plumbing 13
      4.2.4. Electrical & Lighting 13
      4.2.5. Fire Alarm & Suppression Systems 14

4.2.6. Security & Access Control (Building & Site) 14
4.2.7. Roofing 14
4.2.8. Sanitary Drains & Septic System 14
4.2.9. Pavement & Concrete 15
4.2.10. Structural & Interior 15
4.2.11. Landscaping 15
4.2.12. Elevators & Lifting Devices 15
4.2.13. Emergency Power Systems 15
4.2.14. Other 16
5. CAPITAL INVESTMENT PLAN 2026 to 2031 17
5.1. Historical Facility Capital Expenditures 2020 to 2026 17
5.2. Forecast Facility Capital Expenditures (2026 to 2031) 17
5.2.1. Victoria Street Facility Renovation Project (2026 - 2027) 18
5.2.2. Country Squire Sanitary Connection (2028) 18
5.2.3. Country Squire, Stations Work Area Mezzanine Addition (2028) 19
5.2.4. Remainder of Forecast Capital Expenditures 19

LIST OF TABLES

Table 3-1: Facility Components & Subsystems 6
Table 4-1: Health Index & Replacement Guidelines 8
Table 4-2: Country Squire Asset Condition Assessments 8
Table 4-3: Victoria Street Asset Condition Assessments 12
Table 5-1: Historical Facility Capital Expenditures (2020-2025) 17
Table 5-2: Annual Forecast Facility Capital Expenditures 18

GLOSSARY

1) ACA – Asset Condition Assessment
2) AM – Asset Management
3) AMP – Asset Management Plan
4) BC – Refrigerant Branch Circuit Box / Branch Controller Box.
5) DSC – Distribution System Code
6) DSP – Distribution System Plan
7) EOL – End-of-Life
8) Enova – Enova Power Corporation
9) FMP – Facility Management Plan
10) GUP – Good Utility Practices
11) HVAC – Heating, Ventilation and Air Conditioning
12) ICM - Incremental Capital Module
13) KPI – Key Performance Indicator
14) KWH - Kitchener Wilmot Hydro Inc.
15) LDC – Local Distribution Company
16) O&M – Operation & Maintenance
17) OEB – Ontario Energy Board
18) SME – Subject Matter Experts
19) TUL – Typical Useful Life
20) WNH - Waterloo North Hydro Inc.

1. INTRODUCTION

1.1. Purpose of this Report

The purpose of this report is to provide a consolidated view of Enova's facilities management strategy, objectives, assets under management, asset condition assessments and investment plan for the years 2026 to 2031 inclusive. The report includes a summary of asset data; condition evaluation criteria and condition assessments that form the basis on which facility capital investment plans have been formulated.

The information in this report also informs Enova's senior executive team (Executive), aides in the development of Enova's Distribution System Plan (DSP) and supports Enova's 2027 Incremental Capital Module (ICM) application.

This is Enova's first harmonized Facility Management Plan (FMP). Unless otherwise noted, all information contained in this report is current as of December 31, 2025.

1.2. Overview

Enova was formed on September 1, 2022, by the merger of Waterloo North Hydro Holding Corporation (WNHHC) and Kitchener Power Corporation (KPC) and subsequently Waterloo North Hydro Inc. (WNH) with Kitchener-Wilmot Hydro Inc. (KWH).

With a total service area of approximately 1,108 sq. km, Enova provides electricity distribution services to approximately 165,000 business and residential customers in the City of Kitchener, the City of Waterloo, the Township of Wellesley, the Township of Wilmot and the Township of Woolwich, all of which are located within the Regional Municipality of Waterloo. As a result of past service area amendments, Enova also provides regulated electricity distribution services to approximately 142 customers in the bordering counties of Wellington, Perth, Oxford and the City of Cambridge.

Enova has the 4th largest rural area and the 6th largest total service area of all LDCs in the province. As a result of its large geographic service area, Enova operates two main facilities out of which approximately 309 employees provide services to its customers. These facilities play a critical role in keeping the Enova staff working efficiently and safely.

1. Country Squire Facility (CS) - 526 Country Squire Road, Waterloo, Ontario.
    a. Formerly Waterloo North Hydro's main work center and administrative offices, this facility occupies 9,755 square metres on two levels. The property consists of 14.2 hectares of agriculturally zoned land located in the Township of Woolwich bordering on the north end of the City of Waterloo.
    b. Built and occupied in 2011, this facility includes a warehouse for inventory, vehicle and equipment storage/repair garage, trades workshops, control room, administrative offices, customer care center and training space.

2. Victoria Street Facility (VS) – 301 Victoria Street South, Kitchener, Ontario.
    a. Formerly the Kitchener Wilmot Hydro's main work center and administrative offices, this facility occupies 10,450 square metres. The property consists of 4.4 hectares of commercially zoned land located near the downtown area of the City of Kitchener.
    b. Built and occupied in 1982, with subsequent additions completed in 1987 and 1992 the building includes a warehouse for inventory, vehicle and equipment storage/repair garage, trades' workshops, administrative offices, customer care center and training space.

Day to day management of these facilities is the responsibility of Enova's Vice President, Corporate Services. There are two management employees responsible for facilities, one for each site. In addition, there are two maintenance persons and two cleaning staff. Contract staff are utilized for work requiring specialized equipment or skills such as snow removal, HVAC & security systems maintenance or where it has been found to be cost effective. Services provided include inspection, maintenance, repair, and replacement of facility assets as well as janitorial and staff support.

Section 2 provides a summary of Enova's Facility Asset Management Plan strategy and objectives. A current listing of Enova's major facility assets can be found in **Section 3** of this report.

2. FACILITIES ASSET MANAGEMENT PLAN (AMP)

2.1. Strategy

Enova performs regular inspection and maintenance on all facility assets. The level of detail and frequency is determined by asset type, regulatory requirements and asset condition. Condition data collected feeds into the facility Asset Condition Assessments which utilize condition parameters, asset condition scoring and relative weighting for each condition parameter to develop a Health Index score (HI) for each asset group. The HI scores are ranked and grouped into 5 categories from Very Good to Very Poor. The condition assessments and ranking help management staff to identify and prioritize worst performing assets and help develop an action plan for facility investments. Actions taken may range from increased inspection and maintenance to capital refurbishment or replacement. The results of asset condition assessments for all facility assets is summarized in **Section 4** of this report.

Enova paces facility capital investments in coordination with its overall capital investment plan. This means that facility investments at times may be lumpy to smooth out Enova's overall capital expenditures. A summary of Enova's facility capital investments proposed for 2026 to 2031 can be found in **Section 5** of this report.

Enova's Asset Management Strategy for facility assets uses a full lifecycle approach like the strategy used for distribution assets. Enova is also focused on evidence-based decision-making when it comes to managing its facility assets.

Plan - Enova prepares and reviews annually a facilities five-year capital and O&M plan which is informed by regular asset condition assessments (ACA). Due to the lead time it takes to plan, budget, contract and place into service, facility assets are typically planned for replacement when assets are approaching the end of their useful life and in Poor condition. By the time the existing assets are upgraded or replaced, they will have normally deteriorated to Very Poor condition.

Plan – Enova prepares and reviews a five-year facilities capital and O&M plan annually. The plan is informed by regular Asset Condition Assessments (ACAs), operational requirements, and long-term asset management objectives. Due to the lead time required to plan, budget, procure, construct, and commission facility projects, assets are generally scheduled for replacement when they are approaching the end of their expected useful lives and have deteriorated to a Poor condition. Given the time required to complete the full project lifecycle, these assets will typically have deteriorated further and be in Very Poor condition by the time they are ultimately replaced or upgraded. This

proactive planning approach enables Enova to manage risk, maintain safe and reliable facilities, and minimize operational disruptions while optimizing the use of capital resources.

Acquire – Enova acquires facility assets in accordance with industry standards, regulatory requirements, and internal specifications. Assets are selected based on lifecycle cost, expected performance, reliability, maintainability, safety, and operational needs. Standardized specifications are used where appropriate to improve asset consistency and reduce lifecycle costs. Purchasing specifications are reviewed and updated periodically to incorporate evolving technologies, industry best practices, and operational experience, while capital planning considers market conditions, lead times, and cost escalation risks.

Operate, Inspect & Maintain – Enova performs regular inspection and maintenance on all facility assets to ensure they continue to meet operational, safety, and reliability requirements throughout their service life. Defects or deficiencies are recorded and flagged for action. The level of detail and frequency is determined by asset type, regulatory requirements and condition of the equipment. These activities are also recorded and inform the asset condition assessments. Health Indices are then developed for each major asset.

2.2. Objectives

Facility operations and investments are key elements in supporting the overall mission of Enova. Enova's Facility Asset Management Strategy is aligned with and supports Enova's overall corporate strategic objectives.

Enova's objectives for maintaining its facilities are as follows;

1) ensure that the buildings and properties are maintained in a safe and efficient manner;
2) ensure that all facilities are fit for their intended use;
3) ensure that the condition of the building meets all statutory requirements;
4) ensure the capital and O&M investments made are prudent, cost effective and timely to maintain the value of the physical assets and support the utility operations;
5) Incorporate sustainability considerations into facility planning, operations, maintenance, and renewal activities by promoting energy efficiency, resource conservation, and environmental stewardship.

6) provide ancillary services such as specialized cleaning and landscape maintenance.

Cost, risk and performance are balanced through a whole life cycle management strategy that takes the assets from procurement to disposal. Enova manages its facilities to ensure these objectives can be achieved consistently and are sustainable over time.

3. ASSETS UNDER MANAGEMENT

Enova has divided its facility assets into 13 separate components and systems at both the VS and CS facilities.

Table 3-1: Facility Components & Subsystems

	Facility Components & Subsystems
1	HVAC
2	Water Systems & Plumbing
3	Electrical & Lighting
4	Fire Alarm & Suppression Systems
5	Security & Access Controls (Building & Site)
6	Roofing
7	Sanitary Drains & Septic Systems
8	Pavement & Concrete
9	Structural & Interior
10	Landscaping
11	Elevators & Lifting Devices
12	Emergency Power Systems
13	Other

4. FACILITIES ASSET CONDITION ASSESSMENTS

In the management of facility assets, Enova uses an asset condition assessment process similar to that used in the management of its distribution network assets.

Facility assets are monitored from acquisition through to disposal and detailed records of all condition assessments are kept. Enova's facility maintenance activities are planned to ensure the operational effectiveness, longevity and safety of facility assets.

Asset condition evaluation parameters have been developed for each asset class. The criteria are based on degradation conditions that lead to the asset's end of life and fall into 3 data type categories:

Registry Data (R): asset registry details including age, operating conditions, operating environment, and nameplate data; may be current and/or historical in nature.

Measurement Data (M): tests which are usually quantitative in nature and assesses the conditions of the asset.

Inspection Data (I): visual inspection and/or other information which is usually qualitative in nature and assesses the conditions of the asset

Condition parameters were developed by Enova, and are a function of manufacturer recommendations, regulatory requirements, industry practices and the expertise and judgment of Enova's facilities SMEs. The evaluation parameters are ranked from A to E, and each rank corresponds to a numerical grade. A weighting factor is applied to each criteria indicating the influence the criteria have on the overall asset health. Asset conditions are compared to the evaluation criteria to develop a Health Score which represents a quantified condition score of the asset. Health Scores are normalized and given as a percentage from 0% to 100%. The asset Health Score is then categorized and assigned a Health Index Category. **Table 4-1** illustrates the relationship between the asset health score, overall health category and replacement guidelines.

Table 4-1: Health Index & Replacement Guidelines

Overall Condition	Health Score	Guidelines
Very Good	85 - 100%	Like New. Replacement generally outside of current 5-year forecast period.
Good	70 - 85%	Normal operation & maintenance. Re-evaluate within 5 years.
Fair	50 - 70%	Normal operation. Increased deterioration and/or maintenance. Expected replacement within current 5-year forecast period.
Poor	30 - 50%	Reduced operation, poor physical condition and/or rapidly escalating maintenance. Order replacement within 12 months.
Very Poor	0 - 30%	Replace as soon as possible. Alternatives may include to restrict operation.

4.1. Asset Condition Assessments – Country Squire Facility

4.1.1. Country Squire Facility Asset Condition Scores

Table 4-2 provides a summary of the asset condition assessments for the 13 components and systems comprising the CS facility. Overall, the facility is in Good condition. The following sections provide more detail regarding the condition of each of these systems.

Table 4-2: Country Squire Asset Condition Assessments

Facility Components & Systems	% Health Score	HI Category
HVAC	50.0%	Fair
Water Systems & Plumbing	100.0%	Very Good
Electrical & Lighting	50.0%	Fair
Fire Alarm & Suppression Systems	50.0%	Fair
Security & Access Controls (Building & Site)	50.0%	Fair
Roofing	75.0%	Good
Sanitary Drains & Septic Systems	75.0%	Good
Pavement & Concrete	75.0%	Good
Structural & Interior	100.0%	Very Good
Landscaping	75.0%	Good
Elevators & Lifting Devices	100.0%	Very Good
Emergency Power Systems	100.0%	Very Good
Other	100.0%	Very Good
	70.0%	Good

4.1.2. HVAC System

The HVAC system is experiencing frequent failures and maintenance issues. Over the past year, multiple refrigerant line leaks and compressor failures have occurred across several BC Controller box locations, with 6 out of 10 compressors already replaced. The remaining compressors are at risk of imminent failure and will likely require replacement soon. These recurring issues affect system reliability, occupant comfort, and equipment protection. The system is functional but on the verge of failing in certain areas, highlighting the need for proactive replacement and upgrades to restore full performance.

4.1.3. Water Systems & Plumbing

The plumbing system is operating as intended with no observed issues or deficiencies. Domestic water is supplied by the municipal system, while a grey water system collects roof and parking drainage, filters it through a Green Turtle system, and stores it for reuse in toilets and shop washdown activities. Both systems are functioning effectively and supporting sustainable water use.

4.1.4. Electrical & Lighting

The electrical distribution is reliable, but the lighting system is outdated and facing operational limitations. The nGWY2 controllers are discontinued, incompatible with newer hardware, and lack support for advanced programming. Clock batteries are failing, causing time synchronization issues and requiring manual reboot after power outages. Additionally, fluorescent lighting is no longer maintainable due to unavailable replacement bulbs. These maintainability factors need to be addressed.

4.1.5. Fire Alarm & Suppression Systems

The fire alarm system is generally operational and detecting events as required; however, the remote annunciator panel display is not working and the main panel display experiences intermittent failures, which can affect monitoring and response. These issues reduce operational effectiveness and indicate aging hardware that is on the verge of failing. The panel requires an upgrade or replacement to ensure the reliability of the system.

4.1.6. Security & Access Control (Building & Site)

The security and access control systems are generally operational; however, the yard access gate is experiencing intermittent failures during closing and requires a system reset to restore normal

operation. These issues create operational inefficiencies and security risk, particularly for controlled yard access. Currently, increased maintenance is being employed to maintain reliable operation. As a permanent solution, replacement of the yard access gate system is planned for 2026.

4.1.7. Roofing

The roofing system is generally in good condition, and previous thermographic scanning did not identify widespread deficiencies or active leaks; however, two skylights experience water leakage during extreme weather conditions due to installation-related issues, not material failure. These leaks are currently localized and not impacting operations, but corrective action is required to prevent deterioration.

4.1.8. Sanitary Drains & Septic System

At the Country Squire facility, the septic system is not connected to the municipal sewer line. Instead, wastewater is collected and treated through a weeping bed system (Class 4 septic system), with the tank requiring pumping annually. The drain and septic systems are generally functional and maintained through regular pumping and quarterly inspections. Recently, a force main disconnection caused by aging components and mechanical strain occurred. Partially corrected, follow-up component repairs/replacements will be required. Enova has engaged MTE, environmental consultants, to perform a feasibility study for connection of the CS facility to the municipal sanitary system. This is considered prudent when considering the City of Waterloo's development plan for the property across the road from the CS facility. The possibility exists that a connection to the sanitary infrastructure at the neighbouring development can be made in a cost-effective manner. Enova is forecasting the connection of the septic system to the municipal sanitary line in 2028, if feasible.

4.1.9. Pavement & Concrete

Pavement and concrete areas are generally in good condition and support normal vehicle and equipment movement; however, localized asphalt settlement and sinkhole type depressions have occurred periodically, requiring corrective repairs. These issues are recurring but manageable through periodic repairing and have not caused operational disruptions.

4.1.10. Structural & Interior

The structural and interior elements of the facility are in good overall condition, with no major damage or structural concerns observed. Minor deficiencies are limited to cosmetic issues and do not impact safety or operations.

The construction of a mezzanine floor in the stations workshop area has been planned for 2028. This will expand the operational functionality within the facility.

4.1.11. Landscaping

Landscaping areas are well maintained and do not present any operational concerns. General grounds maintenance is managed through contracted and internal staff ensuring consistent upkeep during spring, summer and fall seasons. Winter maintenance is managed through a contracted snow ploughing service, supported by the in-house staff. The system is functioning as intended, with routine maintenance sufficient to meet seasonal needs.

4.1.12. Elevators & Lifting Devices

The elevators are fully operational and functioning as intended. Routine inspections confirm that all mechanical and control components are in good condition, with no issues affecting performance or safety. The system is reliable and requires only standard preventive maintenance.

4.1.13. Emergency Power Systems

The emergency power systems, including generators and UPS, are fully operational and performing as designed. All components have been tested quarterly and are functioning reliably, with no observed issues or deficiencies. The system is ready to support life-safety and critical operations during outages.

4.1.14. Other

This category includes general facility support items and does not include any critical operational systems. All items are in Very Good condition, with no functional or safety concerns observed.

4.2. Asset Condition Assessments – Victoria Street Facility

4.2.1. Victoria Street Facility Asset Condition Scores

Table 4-3 provides a summary of the asset condition assessments for the 13 components and systems comprising the VS facility. Overall, the facility is in Poor condition with a number of systems assessed to be in Very Poor condition.

Enova is making major upgrades to the VS facility in 2026 and 2027 to alleviate these issues. Enova's 2027 Incremental Capital Module (ICM) application will be filed with the OEB to support the funding required for this work, details of which, are outlined in the appendices of the ICM application.

The following sections provide more detail regarding the condition of each of these systems.

Table 4-3: Victoria Street Asset Condition Assessments

Facility Components & Systems	% HEALTH SCORE	HI Category
HVAC	25.0%	Very Poor
Water Systems & Plumbing	25.0%	Very Poor
Electrical & Lighting	25.0%	Very Poor
Fire Alarm & Suppression Systems	25.0%	Very Poor
Security & Access Controls (Building & Site)	50.0%	Fair
Roofing	50.0%	Fair
Sanitary Drains & Septic systems	25.0%	Very Poor
Pavement & Concrete	75.0%	Good
Structural & Interior	50.0%	Fair
Landscaping	75.0%	Good
Elevators & Lifting Devices	75.0%	Good
Emergency Power Systems	75.0%	Good
Other	100.0%	Very Good
	43.8%	Poor

4.2.2. HVAC System

The existing HVAC system at Enova's Victoria Street facility is 41 years old and has significantly exceeded its expected service life of 20 to 25 years. As the equipment has aged, its performance, reliability, and operational efficiency have progressively declined. The system now experiences frequent mechanical failures, increasing maintenance requirements, repair costs, and the risk of unexpected service interruptions. Several unplanned breakdowns have occurred in recent years, disrupting normal business operations and customer service.

The aging HVAC system is no longer capable of consistently maintaining acceptable indoor environmental conditions. Employees regularly experience temperature fluctuations that fall outside recognized comfort standards, negatively affecting workplace productivity, employee well-being, and the overall work environment.

In addition to its reliability concerns, the existing system is significantly less energy efficient than current HVAC technologies. Replacement of the system is expected to reduce annual energy costs by approximately $19,000 through improved equipment efficiency and building climate control. The existing natural gas-fired equipment also produces avoidable greenhouse gas emissions that are inconsistent with Enova's corporate sustainability objectives. The proposed replacement will improve energy efficiency, reduce operating costs, enhance occupant comfort, increase system reliability, and support Enova's commitment to environmental stewardship.

Accordingly, Enova proposes to replace the HVAC systems throughout the Victoria Street facility as part of its facilities renewal program. This investment will restore reliable heating and cooling capability, reduce lifecycle costs, improve workplace conditions, and ensure the facility continues to support Enova's operational and customer service requirements over the long term.

4.2.3. Water Systems & Plumbing

The building's plumbing system is similarly aged and nearing the end of its reliable service life, with multiple leaks already experienced. Its condition poses an ongoing risk of water damage, disruption to operations, and increasing maintenance costs. As part of the renovation project, HVAC, ducts and ceilings will need to be removed. This will provide cost-effective access to concealed piping. Replacing the plumbing at the same time avoids future rework, ceiling removal, and additional labour expenses. Coordinating both upgrades now is the most practical and economical approach to reduce risk and ensure long-term system reliability.

4.2.4. Electrical & Lighting

The VS facility suffers from an aging electrical infrastructure. The electrical panels and cabling will need to be replaced, relocated or added to support new equipment and the workspace changes planned for the renovation project. In addition, the building's existing lighting system is poor, particularly in the customer service area. Obsolete fixtures will also need to be replaced.

Coordinating the modernization of the lighting and electrical systems with the upgrades now allows for cost-effective access to concealed wiring, avoids future rework, ceiling removal, and additional

labour expenses. Enova believes this is the most practical and economical approach to reduce risk and ensure long-term system reliability. The complete electrical and lighting system is being replaced in the administrative building as part of the renovation project.

4.2.5. Fire Alarm & Suppression Systems

The existing fire alarm system has become obsolete as replacement parts are no longer readily available from vendors or service contractors. This creates a significant risk to system reliability, as even minor component failures may not be repairable in a timely manner. The lack of manufacturer support and spare parts availability increases the likelihood of prolonged outages. In the event of a fault, the building could be left without a fully functional fire alarm system, posing safety and compliance risks. Replacing the system as part of the renovation ensures long-term reliability, code compliance, and continued vendor support.

4.2.6. Security & Access Control (Building & Site)

Storage yard access needs to be upgraded in order to improve security, safety and reduce operational risks. Part of the facility renovation project planned in 2026 and 2027 is to install new access control gates at both entrances of the site.

4.2.7. Roofing

The roofing system is generally in Fair condition. Previous thermographic scanning identified widespread deficiencies. Enova has also experienced water leakage during extreme weather conditions due to installation-related issues and material failure. These leaks are currently localized and not impacting operations, but corrective action is required to prevent deterioration.

4.2.8. Sanitary Drains & Septic System

The Sanitary Drains and Septic system are similarly aged and nearing the end of its reliable service life, with multiple repairs already completed. Its condition poses an ongoing risk of damage, disruption to operations, and increasing maintenance costs. As part of the renovation project, where the replacement of major systems provides cost-effective access, replacing the drain and septic lines avoids future rework and additional labour expenses. Coordinating both upgrades now is the most practical and economical approach to reduce risk and ensure long-term system reliability.

4.2.9. Pavement & Concrete

Pavement and concrete areas are generally in good condition and support normal vehicle and equipment movement. However, localized asphalt settlement type depressions have been occurred approximately every year, requiring corrective repairs. These issues are recurring but manageable through periodic repairing and have not caused operational disruptions.

4.2.10. Structural & Interior

The Victoria Street office was designed for a smaller workforce, and an outdated organizational model that no longer meets Enova's current workplace needs. As Enova Power has grown and consolidated key functions, the physical layout has not adapted to support a collaborative, team-based work environment. The lack of flexible, ergonomic spaces negatively affects employee engagement. Worn interiors, furniture, and finishes fall short of contemporary office standards and employee expectations. Upgrading the interior of the facility is part of the planned renovation project.

4.2.11. Landscaping

Landscaping areas are well maintained and do not present any operational concerns. General grounds maintenance is contracted out, ensuring consistent upkeep during spring, summer and fall seasons. Winter maintenance is managed by an in-house snow team with snow removal tractor and trucks. The system is functioning as intended, with routine maintenance sufficient to meet seasonal needs.

4.2.12. Elevators & Lifting Devices

The elevators are fully operational and functioning as intended. Routine inspections confirm that all mechanical and control components are in good condition, with no issues affecting performance or safety. The system is reliable and requires only standard preventive maintenance.

4.2.13. Emergency Power Systems

The emergency power systems, including generators and UPS, are fully operational and performing as designed. All components have been tested quarterly and are functioning reliably, with no observed issues or deficiencies. However, while the existing system remains operational, the current generator capacity is not adequate to support the full electrical load of the proposed renovated building, particularly due to the addition of electric heat pumps and the Variable Refrigerant Flow

(VRF) system. A plan to increase generator capacity is forthcoming and is included as part of the administrative building renovation project scheduled for 2026 and 2027.

4.2.14. Other

This category includes general facility support items and does not include any critical operational systems. All items are in Very Good condition, with no functional or safety concerns observed.

5. CAPITAL INVESTMENT PLAN 2026 to 2031

5.1. Historical Facility Capital Expenditures 2020 to 2026

At the time of preparing this report, Enova is three years into the post-merger harmonization of the operations of its legacy companies. **Table 5-1** summarizes Enova's historical facility capital expenditures. For the years 2020 to 2022, combined expenditures from WNH and KWH were used. Values capture the purchase of new and replacement systems and equipment, as well as expenditures for major refurbishments that extend the useful service life of the buildings and their components.

As issues with the VS facility mounted, Enova determined that an annual piecemeal approach to facility upgrades was no longer efficient or effective. A consultant was hired to assist in developing a comprehensive plan to deal with the current deficiencies and future needs of the utility. Expenditures leading up to 2026 were curtailed due to the impending major renovation project being planned for 2026 and 2027. Only necessary work or work outside the scope of the planned renovation was completed.

Table 5-1: Historical Facility Capital Expenditures (2020-2025)

							Total	Avg
Criteria	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2020 -2025**	**2020 -2025**
Planned	1,345,500	867,500	888,000	1,306,000	1,383,409	1,449,240	7,239,649	1,206,608
Actual	1,340,407	714,723	509,754	124,424	474,245	1,748,000	4,911,553	818,592
Variance	(5,093)	(152,777)	(378,246)	(1,181,576)	(909,164)	298,760	(2,328,096)	(388,016)
% Actual Exp	-0.4%	-17.6%	-42.6%	-90.5%	-65.7%	20.6%	-32.2%	-32.2%

5.2. Forecast Facility Capital Expenditures (2026 to 2031)

From Enova's Facility Asset Condition Assessments, an investment plan was developed based on the combination of health, criticality, performance and delivery lead time for asset repair or replacement. Enova's future needs were also factored into forecast plans.

Final adjustments to the plan were made to pace larger facility capital investments in coordination with Enova's overall capital investment plan.

Table 5-2 summarizes Enova's total forecast facility capital expenditures which are comprised of three material projects.

Table 5-2: Annual Forecast Facility Capital Expenditures

							Total	Avg.
Criteria	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2026 -2031**	**2026 -2031**
VS Renovation Costs	5,618,496	7,359,754					12,978,250	
CS Sanitary Connection			480,000				480,000	
CS Stations Mezzanine Addition			500,000				500,000	
Multiple projects below materiality	292,500	285,000	575,000	330,000	305,000	305,000	2,092,500	348,750
Total Planned	5,910,996	7,644,754	1,555,000	330,000	305,000	305,000	16,050,750	2,675,125

5.2.1. Victoria Street Facility Renovation Project (2026 - 2027)

Components of the Victoria St. Property have exceeded their useful lives and require investment to maximize the utility's effectiveness and mitigate risk for employees and customers. Specifically, the Victoria Street Property's Heating, Ventilation and Air Conditioning ("HVAC") system is well past its useful life and requires replacement as soon as practically feasible. At the same time, the employee office space at the Victoria Street Property has not undergone basic updating and renovation since 1987 resulting in a sub-optimal working environment for employees. Finally, the Victoria Street Property is home to Enova Power's customer-facing customer service centre, which (in addition to also requiring basic office updates) currently is compliant, but provides inconvenient and sub-optimal access for customers with accessibility needs. A more readily accessible customer service centre is required to meet expectations of sufficient accessibility for all Enova Power customers in a manner that protects the dignity of those with accessibility needs.

The total project capital cost estimate is $12.978 million. The renovations are scheduled to begin in Q2, 2026, with an in-service date in Q2, 2027.

Details of the renovation project are outlined in the appendices of Enova's **2027 Incremental Capital Module (ICM) application.**

5.2.2. Country Squire Sanitary Connection (2028)

Enova is planning to connect the CS facility sanitary system to the City of Waterloo municipal sanitary system and remove the existing septic system. The estimated cost for this project is approximately $480,000, which is included in this plan.

5.2.3. Country Squire, Stations Work Area Mezzanine Addition (2028)

Also in 2028, Enova is planning the construction of a mezzanine floor in the stations work area to expand the operational functionality within the work area. The estimated cost for this project is approximately $500,000 and is included in this plan.

5.2.4. Remainder of Forecast Capital Expenditures

The remainder of the forecast expenditures are for work on various systems at CS & VS. All are under the materiality threshold.

APPENDIX J
Fleet Management Plan

FLEET MANAGEMENT PLAN

OVERVIEW & FORECAST 2026 - 2031



May 25, 2026

TABLE OF CONTENTS

CONTENTS i
LIST OF TABLES ii
LIST OF FIGURES iii
GLOSSARY iv
1. INTRODUCTION 1
1.1. Purpose 1
1.2. Overview 1
2. FLEET ASSET MANAGEMENT PLAN (AMP) 3
2.1. Strategy 3
2.2. Objectives 6
3. ASSETS UNDER MANAGEMENT 7
3.1. Large Vehicles 7
3.2. Medium Sized Vehicles 10
3.3. Small Sized Vehicles 11
3.4. Rolling Stock 14
4. FLEET ASSET CONDITION ASSESSMENTS 16
4.1. Asset Condition Assessment – Large Vehicles 18
4.2. Asset Condition Assessment – Medium Vehicles 22
4.3. Asset Condition Assessment – Small Vehicles 25
4.4. Asset Condition Assessment – Rolling Stock 29
5. CAPITAL INVESTMENT PLAN 2026 to 2031 32
5.1. Fleet Replacements 2026 to 2031 32
5.2. Fleet Capital Expenditures 2026 to 2031 35
5.3. Fleet Reductions 2026 to 2031 36
5.4. Fleet Additions 2026 to 2031 37

LIST OF TABLES

Table 2-1: Inspections 5
Table 2-2: Maintenance 5
Table 3-1a: Fleet Inventory – Large Vehicles 8
Table 3-1b: Fleet Inventory – Large Vehicles (continued) 9
Table 3-2: Fleet Inventory – Medium Vehicles 10
Table 3-3a: Fleet Inventory – Small Vehicles 11
Table 3-3b: Fleet Inventory – Small Vehicles (continued) 12
Table 3-3c: Fleet Inventory – Small Vehicles (continued) 13
Table 3-4a: Fleet Inventory - Rolling Stock 14
Table 3-4b: Fleet Inventory - Rolling Stock (continued) 15
Table 4-1: Health Index & Replacement Guidelines 17
Table 4-2: Fleet Assets TUL & Order Lead-times 17
Table 4-3: Evaluation Framework – Large Vehicles 18
Table 4-4: Asset Condition Evaluation Criteria – Large Vehicles 19
Table 4-5a: Health Condition Index Results – Large Vehicles 20
Table 4-5b: Health Condition Index Results – Large Vehicles (continued) 21
Table 4-6: Evaluation Framework – Medium Vehicles 22
Table 4-7: Asset Condition Evaluation Criteria – Medium Vehicles 23
Table 4-8: Health Condition Index Results – Medium Vehicles 24
Table 4-9: Evaluation Framework – Small Vehicles 25
Table 4-10: Asset Condition Evaluation Criteria – Small Vehicles 26
Table 4-11a: Health Condition Index Results – Small Vehicles 27
Table 4-11b: Health Condition Index Results – Small Vehicles (continued) 28
Table 4-12: Evaluation Framework – Rolling Stock 29
Table 4-13: Asset Condition Evaluation Criteria – Rolling Stock 29
Table 4-14a: Health Condition Index Results – Rolling Stock 30
Table 4-14b: Health Condition Index Results – Rolling Stock (continued) 31
Table 5-1a: Forecast Fleet Replacements 33
Table 5-1b: Forecast Fleet Replacements (continued) 34
Table 5-1c: Forecast Fleet Replacements (continued) 35
Table 5-2: Historical Fleet Capital Expenditures 35
Table 5-3: Forecast Fleet Capital Expenditures 36

LIST OF FIGURES

Figure 2-1: Enova's Life Cycle approach to Fleet Management 3

GLOSSARY

1) ACA – Asset Condition Assessment
2) AM – Asset Management
3) AMP – Asset Management Plan
4) CSA – Canadian Standards Association
5) DSC – Distribution System Code
6) DSP – Distribution System Plan
7) EOL – End-of-Life
8) Enova – Enova Power Corporation
9) FMP – Fleet Management Plan
10) GIS – Geographic Information System
11) GUP – Good Utility Practices
12) ICM - Incremental Capital Module
13) KPI – Key Performance Indicator
14) KWHI - Kitchener Wilmot Hydro Inc.
15) LDC – Local Distribution Company
16) MTO - Ministry of Transportation of Ontario
17) O&M – Operation & Maintenance
18) OEB – Ontario Energy Board
19) TUL – Typical Useful Life
20) WNH - Waterloo North Hydro Inc.

1. INTRODUCTION

1.1. Purpose

Enova Power Corporation Inc.'s (Enova) fleet services are managed by the Fleet Services section of the Corporate Services Division under the direction of the Manager of Operations Services. Services provided include purchasing, rental, inspection, maintenance, repair, and replacement of vehicles and rolling stock equipment.

The purpose of this report is to provide a consolidated view of Enova's fleet management strategy, objectives, assets under management, asset condition assessments and investment plan for the years 2026 to 2031 inclusive. The report includes a summary of asset data; condition evaluation criteria and condition assessments that form the basis on which fleet capital investment plans have been formulated.

The information in this report also informs Enova's senior executive team (Executive), and aides in the development of Enova's Distribution System Plan (DSP).

This is Enova's first harmonized Fleet Management Plan (FMP). Unless otherwise stated, all information contained in this report is current as of December 31, 2024.

1.2. Overview

Fleet assets play a critical role in keeping the Enova staff working efficiently and safely. These assets are required to be reliable and maintained in a safe and efficient manner. Vehicles not available for service when needed results in a slowdown of the work program, wasted time and labour in reorganizing and rescheduling work. **Section 2** provides a summary of Enova's Fleet Asset Management Plan strategy and objectives.

Enova's fleet assets consist of approximately 131 small, medium and large vehicles as well as 59 pieces of rolling stock comprised mainly of trailers and specialty power operated equipment. Fleet assets have been divided into 4 asset groups, each with their own common set of asset condition parameters. A current listing of all Enova fleet assets can be found in **Section 3** of this report.

Enova performs regular inspection and maintenance on all fleet assets. The level of detail and frequency is determined by asset type, regulatory requirements and asset condition. Condition data collected feeds into the Fleet Asset Condition Assessments which utilize condition parameters, asset condition scoring and relative weighting for each condition parameter to develop a Health Index score

(HI) for each vehicle. The HI scores are ranked and grouped into 5 categories from Very Good to Very Poor. The condition assessments and ranking help management staff to identify and prioritize worst performing assets and also help develop an action plan for fleet investments. Actions taken may range from increased inspection and maintenance to capital refurbishment or replacement. The current health score for all fleet assets is summarized in **Section 4** of this report.

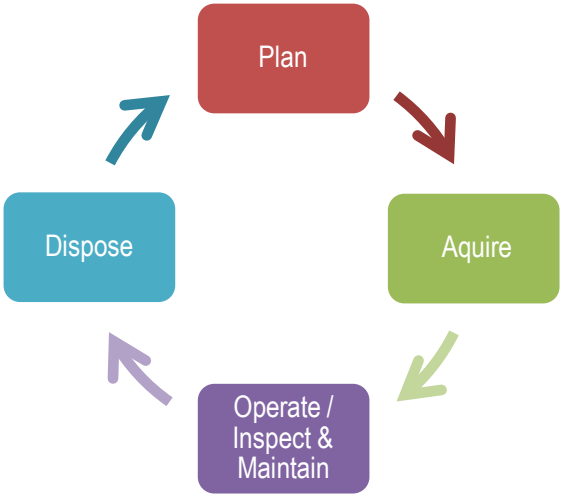
Enova paces fleet capital investments in coordination with Enova's overall capital investment plan. This means that fleet investments at times may be lumpy in order to smooth out Enova's overall capital expenditures. A summary of Enova's fleet capital investments proposed for 2026 to 2031 can be found in **Section 5** of this report.

2. FLEET ASSET MANAGEMENT PLAN (AMP)

2.1. Strategy

Enova's Asset Management Strategy for fleet assets uses a full lifecycle approach similar to the strategy used for distribution assets. Enova is also focused on evidence-based decision-making when it comes to managing its fleet assets.

Figure 2-1: Enova's Life Cycle approach to Fleet Management



Plan - Enova prepares and reviews annually a five-year replacement schedule which is informed by regular asset condition assessments (ACA). Due to the lead time it takes to budget, order, receive and place into service, vehicles are typically planned for replacement when ACAs indicate Fair to Poor condition. By the time the existing assets are removed from service, they will have normally deteriorated to Poor or Very Poor condition.

Replacement of large vehicles are ordered 24 - 36 months or longer in advance of replacement due to manufacturing wait times. Medium sized work vehicles normally are ordered 12 - 18 months and regular small vehicles such as trucks and vans are usually obtainable within a year.

The Rolling Stock asset group is comprised of many diverse pieces of equipment. Although Enova utilizes a generic TUL of 30 years, specific TULs are used for individual assets that significantly vary from the generic value.

Since the last DSPs prepared by predecessor companies KWHI (2019) and WNH (2020), the industry has experienced significant increases in prices and delivery times in its fleet orders. COVID-19 and the resulting supply chain disruptions seemingly have had the greatest impact. The backlog of parts and delays in vehicle production are still felt in the marketplace today. Prices have not appreciably yielded and delivery times have remained extended.

In addition, at the time of preparing this report, a great deal of uncertainty lies ahead in the industry due to two government initiatives expected to increase delivery times and further escalate costs.

1. The extent of the United States (US) tariff pressures is unknown. US manufactured vehicle pricing is expected to rise. Canadian manufactured vehicle prices are also expected to rise as many parts are sourced from the US and demand for Canadian sourced vehicles is expected to rise.

2. Chassis manufacturers have had to prepare for new emission standards requiring design and technology upgrades. Scheduled to come into effect in 2027, the new regulations have been rolled back for now; however, there still remains the possibility of tighter regulations coming into effect during the forecast period.

Acquire – Detailed purchasing specifications are utilized for fleet asset purchases to ensure vehicles meet Enova's operational, safety, regulatory, and performance requirements. Specifications are reviewed and if needed updated before each submittal for tender. Fleet acquisition decisions are based on operational needs, lifecycle cost, reliability, maintainability, utilization, and sustainability considerations, including opportunities to improve fuel efficiency, reduce emissions, and adopt lower-emission technologies where operationally and economically justified. The number and type of vehicles in the fleet at any point in time is determined by the size and scope of Enova’s work program.

Operate, Inspect & Maintain – Enova performs regular inspection and maintenance on all fleet assets. Defects or deficiencies are recorded and flagged for action. The level of detail and frequency is determined by asset type, regulatory requirements and condition of the equipment. **Table 2-1** and **Table 2-2** provide a summary of Fleet Inspection and Maintenance schedules.

Table 2-1: Inspections

FLEET / ROLLING STOCK	FREQUENCY
All commercial vehicles (> 4,500 kg) and all trailers receive an annual MTO safety inspection.	Annual
All commercial vehicles (> 4,500 kg) receive a visual inspection.	12 weeks
All small vehicles (< 4,500 kg) receive a full inspection.	26 weeks
Rolling Stock – receive a full inspection.	26 Weeks

Table 2-2: Maintenance

FLEET / ROLLING STOCK	FREQUENCY
All commercial vehicles (> 4,500 kg) receive a lube, oil, filter.	26 weeks
All aerial devices and cranes have a visual boom inspection and preventative maintenance.	12 weeks
All aerial devices and cranes have a full boom inspection including rotation bearing checks and preventative maintenance completed.	Annual
All small vehicles (< 4,500 kg) receive preventative maintenance of lube, oil, filter.	26 weeks
Rolling Stock Maintenance	Annual

Vehicle operating and maintenance costs are tracked and reviewed annually. At regular intervals or as operations require, these activities are performed, recorded and inform the vehicle asset condition assessments. Health indices are then developed for each vehicle.

Day to day fleet management is the responsibility of Enova's Manager of Operations Services. Enova maintains four licenced vehicle mechanics and two maintenance repair facilities to perform inspections and to correct deficiencies in a timely manner. Enova also utilizes external contractors for specialized work or where it has been found to be cost effective.

Disposal – Enova disposes of its fleet assets when they are normally in Poor or Very Poor condition and are no longer economical, safe or reliable enough to withstand the daily rigors of utility operations or construction on high voltage lines. Vehicles for disposal are normally sold at auction, donated to colleges offering powerline maintenance programs or scrapped.

2.2. Objectives

Fleet operations and investments are key elements in facilitating the overall mission of Enova. Enova's Fleet Asset Management Strategy is aligned with and supports Enova's corporate strategic objectives.

Cost, risk and performance are balanced through a whole life cycle management strategy that takes the assets from procurement to disposal.

To support the Fleet Asset Management Strategy and Objectives, the following goals were developed:

- maximize the operational effectiveness of the workforce by maximizing operational functionality and availability of the vehicles;
- maximize asset longevity through effective purchasing specifications, operational inspections and maintenance;
- minimize total lifecycle costs by tracking operational and maintenance costs as well as downtime costs;
- maximize safety of the fleet by minimizing accidents and incidents involving fleet assets.
- incorporate sustainability considerations into fleet planning, operation, maintenance, and renewal activities by improving energy efficiency, reducing greenhouse gas emissions, conserving resources, and evaluating opportunities to adopt lower-emission vehicle technologies where operationally and economically justified.

Enova manages its fleet to ensure these goals can be achieved consistently and are sustainable over time.

3. ASSETS UNDER MANAGEMENT

Fleet assets under management consist of 131 vehicles and 59 trailers and specialty-power operated equipment. Fleet assets have been divided into four asset groups, each with their own common set of asset condition parameters.

3.1. Large Vehicles

Enova normally maintains a fleet of approximately 38 large vehicles equipped with aerial work platforms or lifting devices. These vehicles are equipped with specialized equipment such as articulating insulated booms, rotating turrets, hydraulic systems and more. Designed to safely and quickly lift workers and materials into the air to perform line construction and maintenance functions. In this group are single and double bucket trucks, radial boom derricks and cranes. These vehicles are special ordered, custom made and have long delivery lead times, generally around 24-36 months.

Table 3-1a: Fleet Inventory – Large Vehicles

Vehicle ID	VEHICLE DESCRIPTION (1)	VEHICLE DESCRIPTION (2)	Asset Condition	Health Score	%TUL	TUL	Purchased year	Current Age
B060	Bucket	Single Bucket Service	Poor	32%	108%	12	2011	13
B341	Bucket	Single Bucket Service	Poor	36%	108%	12	2011	13
B014	Bucket	Single Bucket Material Handler	Poor	37%	83%	12	2014	10
B092	Bucket	Double Bucket Elevator Material Handler	Poor	38%	125%	12	2009	15
B069	Bucket	Single Bucket Material Handler	Poor	38%	83%	12	2014	10
O023	Box Truck	Cable-pulling Truck	Poor	38%	100%	12	2012	12
B119	Bucket	Single Bucket Material Handler	Poor	39%	108%	12	2011	13
D302	Digger Derrick	Radial Boom Derrick	Poor	40%	117%	12	2010	14
B026	Bucket	Single Bucket Service	Poor	42%	92%	12	2013	11
B311	Bucket	Single Bucket Material Handler	Poor	43%	108%	12	2011	13
B006	Bucket	Double Bucket Elevator Material Handler	Poor	44%	100%	12	2012	12
B038	Bucket	Single Bucket Service	Poor	47%	42%	12	2019	5
B355	Bucket	Single Bucket Material Handler	Fair	50%	83%	12	2014	10
D320	Digger Derrick	Radial Boom Derrick	Fair	54%	92%	12	2013	11
B041	Bucket	Single Bucket Service	Fair	54%	42%	12	2019	5
D015	Digger Derrick	Radial Boom Derrick	Fair	57%	50%	12	2018	6

Table 3-1b: Fleet Inventory – Large Vehicles (continued)

Vehicle ID	VEHICLE DESCRIPTION (1)	VEHICLE DESCRIPTION (2)	Asset Condition	Health Score	%TUL	TUL	Purchased year	Current Age
F081	Bucket	Single Bucket Forestry	Fair	60%	42%	12	2019	5
B342	Bucket	Single Bucket Material Handler	Fair	60%	92%	12	2013	11
B033	Bucket	Single Bucket Material Handler	Fair	60%	67%	12	2016	8
B353	Bucket	Single Bucket 68 ft Elevator Material Handler	Fair	65%	83%	12	2014	10
D360	Digger Derrick	Radial Boom Derrick	Fair	66%	75%	12	2015	9
D019	Digger Derrick	General Boom Derrick	Fair	66%	58%	12	2017	7
B095	Bucket	Single Bucket Material Handler	Fair	68%	50%	12	2018	6
F080	Bucket	Single Bucket Forestry	Fair	68%	33%	12	2020	4
B087	Bucket	Single Bucket Material Handler	Good	76%	50%	12	2018	6
C073	Crane	Flatbed Knuckle Boom	Good	77%	33%	12	2020	4
B035	Bucket	Single Bucket Material Handler	Good	80%	33%	12	2020	4
O370	Crane	Flatbed c/w Knuckle Boom	Good	82%	58%	12	2017	7
B371	Bucket	Single Bucket Material Handler	Very Good	90%	25%	12	2021	3
B009	Bucket	Single Bucket Material Handler	Very Good	93%	25%	12	2021	3
B303	Bucket	Single Bucket Service	Very Good	93%	17%	12	2022	2
B064	Bucket	Single Bucket Service	Very Good	96%	67%	12	2016	8
B075	Bucket	Single Elevator Material Handler	Very Good	96%	25%	12	2021	3
B323	Bucket	Single Bucket Service	Very Good	96%	17%	12	2022	2
B034	Bucket	Single Bucket Material Handler	Very Good	96%	8%	12	2023	1
D070	Digger Derrick	Radial Boom Derrick	Very Good	96%	0%	12	2024	0
B004	Bucket	Single Bucket Service	Very Good	96%	0%	12	2024	0
B072	Bucket	Double Bucket Elevator Material Handler	Very Good	96%	-8%	12	2024	0

3.2. Medium Sized Vehicles

Enova normally maintains a fleet of approximately 19 vehicles in this category. They are normally larger vehicles used to transport workers, equipment, tools & test equipment to work sites. Used by underground line and stations departments, they do not have any aerial lifting devices or work platforms. These vehicles are special ordered, custom made and have long delivery lead times, generally around 12-18 months.

Table 3-2: Fleet Inventory – Medium Vehicles

Vehicle ID	VEHICLE DESCRIPTION (1)	VEHICLE DESCRIPTION (2)	Asset Condition	Health Score	%TUL	TUL	Purchased year	Current Age
C059	Dump Truck	Dump Body	Very Poor	29%	108%	12	2011	13
O042	Box Truck	Work Body- Underground	Poor	31%	100%	12	2012	12
O066	Box Truck	Work Body- Underground	Poor	35%	125%	12	2009	15
F007	Box Truck	Wood Chips Hauler	Poor	36%	75%	12	2015	9
C029	Box Truck	Work Body- Construction	Poor	44%	100%	12	2012	12
O099	Dump Truck	Dump Body	Poor	47%	125%	12	2009	15
C024	Box Truck	Work Body- Construction	Poor	47%	92%	12	2013	11
C020	Construction	¾ Ton Heavy Duty Pickup	Poor	49%	67%	12	2016	8
O343	Box Truck	Work Body- Underground	Fair	50%	83%	12	2014	10
C204	Equipment	Backhoe	Fair	54%	58%	12	2017	7
S090	Bucket	Squirt Boom Services	Fair	56%	125%	12	2009	15
O027	Box Truck	Work Body- Underground	Fair	60%	42%	12	2019	5
C203	Equipment	Backhoe	Fair	67%	67%	12	2016	8
S319	Box Truck	Work Body- Stations	Good	70%	33%	12	2020	4
O025	Dump Truck	Dump Body	Good	73%	33%	12	2020	4
O056	Dump Truck	Dump Body	Good	73%	33%	12	2020	4
C022	Box Truck	Work Body- Construction	Good	84%	33%	12	2020	4
S028	Box Truck	Work Body- Stations	Very Good	88%	33%	12	2020	4
S321	Box Truck	Work Body- Stations	Very Good	90%	25%	12	2021	3

3.3. Small Sized Vehicles

This category is normally comprised of approximately 74 small vehicles for the transportation of staff, light tools and equipment. Made up of pickup trucks, vans, SUVs and cars, they are normally ordered from local dealerships and have delivery times of less than 12 months. Most however do require special outfitting before they can be placed into service and function in their role as a utility fleet vehicle.

Table 3-3a: Fleet Inventory – Small Vehicles

Vehicle ID	VEHICLE DESCRIPTION (1)	VEHICLE DESCRIPTION (2)	Asset Condition	Health Score	%TUL	TUL	Purchased year	Current Age
M063	Metering	Cargo Van	Very Poor	28%	110%	10	2013	11
L008	Locate	Cargo Van	Poor	36%	130%	10	2011	13
O001	Operation	½ Ton Light Duty Pickup	Poor	42%	120%	10	2012	12
R047	Collection	SUV	Poor	42%	80%	10	2016	8
O132	Pickup	½ Ton Light Duty Pickup	Poor	42%	110%	10	2013	11
M125	Metering	Cargo Van	Poor	42%	120%	10	2012	12
M013	Metering	Cargo Van	Poor	44%	120%	10	2012	12
M124	Metering	Cargo Van	Poor	44%	120%	10	2012	12
O128	Pickup	½ Ton Light Duty Pickup	Poor	44%	120%	10	2012	12
O048	Operation	½ Ton Light Duty Pickup	Poor	46%	90%	10	2015	9
S067	Stations	Cargo Van	Poor	48%	80%	10	2016	8
E334	Engineering	Cargo Van	Poor	48%	110%	10	2013	11
O045	Operation	Car	Poor	48%	110%	10	2013	11
M031	Metering	Cargo Van	Poor	48%	130%	10	2011	13
O372	Operation	Cargo Van	Poor	48%	170%	10	2007	17
S018	Stations	½ Ton Light Duty Pickup	Fair	52%	80%	10	2016	8
O062	Operation	Pickup	Fair	52%	80%	10	2016	8
C058	Construction	½ Ton Light Duty Pickup	Fair	54%	80%	10	2016	8
O057	Operation	Pickup	Fair	54%	120%	10	2012	12
O194	Operations On-Call	½ Ton Light Duty Pickup	Fair	56%	50%	10	2019	5
O196	Operations On-Call	½ Ton Light Duty Pickup	Fair	56%	50%	10	2019	5
O317	Operation	Minivan	Fair	56%	140%	10	2010	14
S118	Stations	Full size Van	Fair	58%	130%	10	2011	13
E165	Engineering	Cargo Van	Fair	58%	80%	10	2016	8
S050	Stations	Cargo Van	Fair	58%	80%	10	2016	8

Table 3-3b: Fleet Inventory – Small Vehicles (continued)

Vehicle ID	VEHICLE DESCRIPTION (1)	VEHICLE DESCRIPTION (2)	Asset Condition	Health Score	%TUL	TUL	Purchased year	Current Age
O065	Operation	½ Ton Light Duty Pickup	Fair	58%	50%	10	2019	5
E010	Engineering	Minivan	Fair	60%	90%	10	2015	9
E144	Engineering	Cargo Van	Fair	62%	100%	10	2014	10
E135	Engineering	Cargo Van	Fair	62%	110%	10	2013	11
O312	Transportation	SUV	Fair	62%	120%	10	2012	12
O198	Operation	½ Ton Light Duty Pickup	Fair	62%	40%	10	2020	4
O130	Pickup	½ Ton Light Duty Pickup	Fair	64%	120%	10	2012	12
E123	Engineering	Minivan	Fair	66%	120%	10	2012	12
L011	Locate	Cargo Van	Fair	66%	60%	10	2018	6
H061	HSE	Minivan	Fair	68%	90%	10	2015	9
O012	Operation	½ Ton Light Duty Pickup	Fair	68%	40%	10	2020	4
F082	Forestry	½ Ton Light Duty Pickup	Fair	68%	30%	10	2021	3
M271	Metering	Cargo Van	Fair	68%	70%	10	2017	7
O040	Operation	½ Ton Light Duty Pickup	Good	70%	50%	10	2019	5
C049	Construction	½ Ton Light Duty Pickup	Good	72%	30%	10	2021	3
O002	Operation	½ Ton Light Duty Pickup	Good	74%	50%	10	2019	5
R199	Collection	SUV	Good	76%	50%	10	2019	5
E037	Engineering	Minivan	Good	76%	50%	10	2019	5
O017	Operation	½ Ton Light Duty Pickup	Good	76%	40%	10	2020	4
E068	Engineering	SUV	Good	80%	50%	10	2019	5
E373	Engineering	Minivan	Good	80%	70%	10	2017	7
O197	Operation	½ Ton Light Duty Pickup	Good	84%	50%	10	2019	5
M044	Metering	SUV	Very Good	86%	40%	10	2020	4
S192	Stations	Cargo Van	Very Good	86%	50%	10	2019	5
O193	Operation	½ Ton Light Duty Pickup	Very Good	88%	50%	10	2019	5
L036	Locate	Cargo Van	Very Good	90%	10%	10	2023	1
O032	Operation	½ Ton Light Duty Pickup	Very Good	90%	0%	10	2024	0
O043	Operation	½ Ton Light Duty Pickup	Very Good	90%	0%	10	2024	0
E200	Engineering	SUV	Very Good	94%	40%	10	2020	4
O046	Operation	SUV	Very Good	94%	30%	10	2021	3
O212	Operation	½ Ton Light Duty Pickup	Very Good	94%	30%	10	2021	3
L055	Locate	Cargo Van	Very Good	94%	10%	10	2023	1
M211	Metering	Cargo Van	Very Good	94%	30%	10	2021	3

Table 3-3c: Fleet Inventory – Small Vehicles (continued)

Vehicle ID	VEHICLE DESCRIPTION (1)	VEHICLE DESCRIPTION (2)	Asset Condition	Health Score	%TUL	TUL	Purchased year	Current Age
O210	Operation	½ Ton Light Duty Pickup	Very Good	94%	30%	10	2021	3
L016	Locate	Cargo Van	Very Good	96%	20%	10	2022	2
O084	Operation	½ Ton Light Duty Pickup	Very Good	96%	0%	10	2024	0
W005	Warehouse	Pickup	Very Good	96%	20%	10	2022	2
O003	Operation	Fleet Pickup	Very Good	96%	10%	10	2023	1
O039	Operation	½ Ton Light Duty Pickup	Very Good	96%	0%	10	2024	0
O112	Operation	Pickup	Very Good	96%	0%	10	2024	0
O224	Operation	Electric Car	Very Good	100%	10%	10	2023	1
O225	Operation	Electric Car	Very Good	100%	10%	10	2023	1
O220	Operation	Pickup	Very Good	100%	20%	10	2022	2
O222	Operation	Electric Car	Very Good	100%	10%	10	2023	1
O223	Operation	Electric Car	Very Good	100%	10%	10	2023	1
I221	IT	Minivan	Very Good	100%	20%	10	2022	2
E052	Engineering	SUV	Very Good	100%	10%	10	2023	1
E053	Engineering	SUV	Very Good	100%	10%	10	2023	1
R051	Collection	Electric SUV	Very Good	100%	10%	10	2025	0

3.4. Rolling Stock

This group makes up the remainder of Enova's Fleet assets and is comprised of an assortment of pole & material trailers, tension stringers and other custom pieces of rolling equipment. The approximately 59 pieces of equipment are special ordered, custom made and each have unique delivery lead times.

The Rolling Stock asset group is comprised of many diverse pieces of equipment. Enova utilizes a generic TUL of 30 years for most trailers. Specialty assets such as forklifts, chippers and sweepers have TULs that vary significantly from the generic value.

Table 3-4a: Fleet Inventory - Rolling Stock

Vehicle ID	VEHICLE DESCRIPTION (1)	VEHICLE DESCRIPTION (2)	Asset Condition	Health Score	%TUL	TUL	Purchased year	Current Age
T137	Trailer	Brush Chipper	Poor	36%	90%	10	2015	9
T127	Trailer	Cable Reel Trailer	Poor	40%	87%	30	1998	26
T154	Trailer	Brush Chipper	Poor	42%	90%	10	2015	9
T141	Trailer	Oil filtration unit	Poor	44%	137%	30	1983	41
T551	Trailer	Mobile Substation (CS)	Poor	44%	80%	30	2000	24
T113	Trailer	Box Trailer	Poor	46%	77%	30	2001	23
T541	Trailer	Box Trailer	Poor	47%	77%	30	2001	23
T542	Trailer	Box Trailer	Poor	47%	77%	30	2001	23
T140	Trailer	Mobile Substation (VS)	Poor	48%	133%	30	1984	40
T155	Trailer	12 ft Cargo Trailer	Poor	49%	60%	30	2006	18
T138	Trailer	Network Cable Trailer	Fair	55%	33%	30	2014	10
T134	Trailer	Tri-axle Trailer	Fair	55%	60%	30	2006	18
T136	Trailer	Tri-axle Trailer	Fair	55%	60%	30	2006	18
T121	Trailer	Cable Reel Trailer	Fair	56%	97%	30	1995	29
T521	Trailer	Cable Reel Trailer	Fair	56%	80%	30	2000	24
T533	Trailer	Box Trailer	Fair	56%	117%	30	1989	35
T505	Trailer	Tension Stringer	Fair	60%	37%	30	2013	11
T133	Trailer	Box Trailer	Fair	60%	50%	30	2009	15
T540	Trailer	Box Trailer	Fair	60%	83%	30	1999	25
T148	Equipment	Scissor Lift	Fair	61%	106%	16	2007	17
T550	Trailer	Pole Trailer	Fair	61%	40%	30	2012	12
T545	Trailer	Cargo Trailer	Fair	61%	50%	30	2009	15
T552	Trailer	Pole Trailer	Fair	61%	27%	30	2016	8
T172	Trailer	Pole Trailer	Fair	63%	30%	30	2015	9
T546	Trailer	Box Trailer	Fair	63%	47%	30	2010	14
T105	Trailer	Portable Generator	Fair	64%	87%	30	1998	26

Table 3-4b: Fleet Inventory - Rolling Stock (continued)

Vehicle ID	VEHICLE DESCRIPTION (1)	VEHICLE DESCRIPTION (2)	Asset Condition	Health Score	%TUL	TUL	Purchased year	Current Age
T504	Trailer	Tension Stringer	Fair	65%	37%	30	2013	11
T114	Trailer	Air compressor	Fair	65%	60%	30	2006	18
T149	Trailer	Tension Stringer	Fair	66%	20%	30	2018	6
T159	Trailer	Cargo Trailer	Fair	66%	37%	30	2013	11
T157	Trailer	Cargo Trailer	Fair	66%	47%	30	2010	14
T158	Trailer	Cargo Trailer	Fair	66%	40%	30	2012	12
T548	Trailer	Pole Trailer	Fair	66%	43%	30	2011	13
W207	Equipment	Forklift	Fair	66%	100%	12	2012	12
W724	Equipment	Forklift	Fair	66%	43%	30	2011	13
T544	Trailer	Cargo Trailer	Fair	66%	53%	30	2008	16
W713	Equipment	Forklift	Fair	66%	27%	30	2016	8
C205	Equipment	Mini excavator	Fair	67%	83%	12	2014	10
T173	Trailer	Arrowhead Trailer	Fair	67%	30%	30	2015	9
T538	Trailer	Cable Trailer	Fair	68%	120%	30	1988	36
O734	Equipment	Forklift	Fair	69%	140%	30	1982	42
T501	Trailer	Tension Stringer	Fair	69%	113%	30	1990	34
T502	Trailer	Tension Stringer	Fair	69%	113%	30	1990	34
C206	Equipment	Tractor	Fair	69%	17%	30	2019	5
T547	Trailer	Pole Trailer	Good	71%	43%	30	2011	13
T151	Trailer	Flatbed	Good	71%	30%	30	2015	9
T161	Trailer	Scene lighting Trailer	Good	74%	33%	30	2014	10
T150	Trailer	Tension Stringer	Good	76%	20%	30	2018	6
T171	Trailer	Cargo Trailer	Good	76%	30%	30	2015	9
T553	Trailer	Pole Trailer	Good	76%	17%	30	2019	5
W201	Equipment	Forklift	Good	76%	25%	16	2020	4
W736	Equipment	Forklift	Good	81%	20%	30	2018	6
T122	Trailer	Pole Trailer	Good	82%	7%	30	2022	2
G702	Equipment	Lawn mowing tractor	Good	82%	3%	30	2023	1
W706	Equipment	Forklift	Very Good	86%	10%	30	2021	3
T115	Trailer	10 ft Cargo Trailer	Very Good	86%	0%	30	2024	0
G701	Equipment	Tractor	Very Good	90%	0%	30	2024	0
T153	Trailer	Box Trailer	Very Good	92%	3%	30	2023	1
C160	Equipment	Scrubber Sweeper	Very Good	100%	17%	12	2022	2

4. FLEET ASSET CONDITION ASSESSMENTS

In the management of fleet assets, Enova uses an asset condition assessment process similar to that used in the management of its distribution network assets.

Fleet assets are monitored from acquisition through to disposal and detailed records of all condition assessments are kept. Enova's fleet maintenance activities are planned to ensure the operational effectiveness, longevity and safety of fleet assets.

Asset condition evaluation parameters have been developed for each asset class. The criteria are based on degradation conditions that lead to the asset's end-of-life and fall into 3 data type categories:

Registry Data (R): asset registry details including age, operating conditions, operating environment, and nameplate data; may be current and/or historical in nature.

Measurement Data (M): tests which are usually quantitative in nature and assesses the conditions of the asset.

Inspection Data (I): visual inspection and/or other information which is usually qualitative in nature and assesses the conditions of the asset

Condition parameters were developed by Enova, and are a function of manufacturer recommendations, regulatory requirements, industry practices and the expertise and judgment of Enova's licenced vehicle maintenance staff. The evaluation parameters are ranked from A to E and each rank corresponds to a numerical grade. A weighting factor is applied to each criteria indicating the influence the criteria have on the overall asset health. Asset conditions are compared to the evaluation criteria to develop a Health Score which represents a quantified condition score of the asset. Health Scores are normalized and given as a percentage from 0% to 100%.

Table 4-1 illustrates the relationship between the asset health score, overall health category and replacement guidelines.

Table 4-1: Health Index & Replacement Guidelines

Overall Condition	Health Score	Guidelines
Very Good	85 - 100%	Like New. Replacement outside of current 5-year forecast period.
Good	70 - 85%	Normal operation & maintenance. Re-evaluate within 5 years.
Fair	50 - 70%	Normal operation. Increased deterioration and/or maintenance. Expected replacement within current 5-year forecast period.
Poor	30 - 50%	Reduced operation, poor physical condition and/or rapidly escalating maintenance. Order replacement within 12 months.
Very Poor	0 - 30%	Replace as soon as possible. Alternatives may include to restrict operation, rent, lease, or purchase used.

Enova also uses historical information in assessing the condition of the vehicles. From past experience, Enova has found that the typical life expectancy has been 12 years for large and medium vehicles and 10 years for small vehicles. Although vehicles are replaced based on condition and not strictly on age, historical typical useful lives (TUL) present a target by which the degradation of vehicle condition can be benchmarked.

Table 4-2: Fleet Assets TUL & Order Lead-times

Asset Type	KINECTRICS REPORT			Enova TUL	Leadtime for Replacement (months)	Comments
	Min UL	TUL	Max UL			
Large Vehicles	5		15	12	24 - 36	
Medium Vehicles	5		15	12	12 - 18	
Small Vehicles	5		10	10	<=12	
Rolling Stock	5		20	8 - 30	12	Depends on type and use

4.1. Asset Condition Assessment – Large Vehicles

Large vehicle condition assessments are based on the eight condition parameters listed in **Table 4-3**.

Table 4-3: Evaluation Framework – Large Vehicles

Data Type	#	Asset Condition Evaluation Criteria	Weight	Ranking	Numerical Grade	Max Grade
R	1	Service Age TUL = 12 yrs	20	A,B,C,D,E	5,4,3,2,1	100
R	2	Service Duty	5	A,B,C,D,E	5,4,3,2,1	25
M	3	Mileage TUL = 100,000 km	10	A,B,C,D,E	5,4,3,2,1	50
M	4	Engine Hours	20	A,B,C,D,E	5,4,3,2,1	100
M	5	Annual Maintenance Costs	15	A,B,C,D,E	5,4,3,2,1	75
I	6	Chassis Condition	10	A,B,C,D,E	5,4,3,2,1	50
I	7	Arial Device Condition	10	A,B,C,D,E	5,4,3,2,1	50
I	8	Body Condition	10	A,B,C,D,E	5,4,3,2,1	50
		Total Max Score	100			500

In **Table 4-4**, each condition parameter is broken down into five levels of degradation and assigned a value. Each condition parameter is scored and multiplied by the weighting of that parameter. The total of all parameters is normalized and given a percentage health index score.

Table 4-4: Asset Condition Evaluation Criteria – Large Vehicles

Criteria	Weight	
Service Age	**20%**	**Scoring**
Ranking	**Corresponding Condition**	
A	0 <= 3 years	5
B	> 3 <= 6 years	4
C	>6 <= 9 years	3
D	>9 <= 12 years	2
E	> 12 years	1
Service Duty	**5%**	**Scoring**
Ranking	**Corresponding Condition**	
A	Light	5
B		
C	Medium	3
D		
E	Heavy	1
Mileage TUL	**10%**	**Scoring**
Ranking	**Corresponding Condition**	
A	0 to 25,000 km	5
B	25,001 to 50,000 km	4
C	50,001 to 75,000 km	3
D	75,001 to 100,000 km	2
E	> 100,000 km	1
Engine Hours	**20%**	**Scoring**
Ranking	**Corresponding Condition**	
A	0 to 2,500	5
B	2,501 to 5,000	4
C	5,001 to 7,500	3
D	7501 to 10,000	2
E	> 10,000	1

Criteria	Weight	
Annual Maintenance Costs	**15%**	**Scoring**
Ranking	**Corresponding Condition**	
A	0 - $10,000	5
B	$10,001 - $12,500	4
C	$12,501 - $15,000	3
D	$15,001 - $17,500	2
E	> $17,501	1
Chassis Condition	**10%**	**Scoring**
Ranking	**Corresponding Condition**	
A	Very Good (New)	5
B	Good	4
C	Fair	3
D	Poor	2
E	Very Poor	1
Arial Device Condition	**10%**	**Scoring**
Ranking	**Corresponding Condition**	
A	Very Good (New)	5
B	Good	4
C	Fair	3
D	Poor	2
E	Very Poor	1
Body Condition	**10%**	**Scoring**
Ranking	**Corresponding Condition**	
A	Very Good (New)	5
B	Good	4
C	Fair	3
D	Poor	2
E	Very Poor	1

Tables 4-5(a, b) provides a summary of all large vehicle conditions assessments. Overall, the average condition rating for Enova's fleet of 37 large vehicles is 64.4% (Fair). The average age of these assets is 7.2 years or 60.4% of TUL.

Table 4-5a: Health Condition Index Results – Large Vehicles

Vehicle ID	VEHICLE DESCRIPTION (1)	VEHICLE DESCRIPTION (2)	Asset Condition	Health Score	%TUL
B060	Bucket	Single Bucket Service	Poor	32%	108%
B341	Bucket	Single Bucket Service	Poor	36%	108%
B014	Bucket	Single Bucket Material Handler	Poor	37%	83%
B092	Bucket	Double Bucket Elevator Material Handler	Poor	38%	125%
B069	Bucket	Single Bucket Material Handler	Poor	38%	42%
O023	Box truck	Cable pulling Truck	Poor	38%	100%
B119	Bucket	Single Bucket Material Handler	Poor	39%	108%
D302	Digger Derrick	Radial Boom Derrick	Poor	40%	117%
B026	Bucket	Single Bucket Service	Poor	42%	92%
B311	Bucket	Single Bucket Material Handler	Poor	43%	108%
B006	Bucket	Double Bucket Elevator Material Handler	Poor	44%	100%
B038	Bucket	Single Bucket Service	Poor	47%	42%
B355	Bucket	Single Bucket Material Handler	Fair	50%	83%
D320	Bucket	Single Bucket Material Handler	Fair	54%	92%
B041	Bucket	Single Bucket Service	Fair	54%	42%
D015	Digger Derrick	Radial Boom Derrick	Fair	57%	50%
B342	Bucket	Single Bucket Material Handler	Fair	60%	92%
B033	Bucket	Single Bucket Material Handler	Fair	60%	67%
F081	Bucket	Single Bucket Forestry	Fair	60%	42%
B353	Bucket	Single Bucket 68 ft Elevator material Handler	Fair	65%	83%
D360	Digger Derrick	Radial Boom Derrick	Fair	66%	75%
D019	Digger Derrick	General boom derrick	Fair	66%	58%
B095	Bucket	Single Bucket Material Handler	Fair	68%	50%
F080	Bucket	Single Bucket Forestry	Fair	68%	33%
B087	Bucket	Single Bucket Material Handler	Good	76%	50%
C073	Crane	Flatbed knuckle boom	Good	77%	33%
B035	Bucket	Single Bucket Material Handler	Good	80%	33%
B371	Bucket	Single Bucket Material Handler	Very Good	90%	25%
B303	Bucket	Single Bucket Service	Very Good	93%	17%
B009	Bucket	Single Bucket Material Handler	Very Good	93%	25%
B323	Bucket	Single Bucket Service	Very Good	96%	17%
B072	Bucket	Double Bucket Elevator Material Handler	Very Good	96%	0%
B004	Bucket	Single Bucket Service	Very Good	96%	0%
B034	Bucket	Single Bucket Material Handler	Very Good	96%	8%
B064	Bucket	Single Bucket Service	Very Good	96%	67%
D070	Digger Derrick	Radial Boom Derrick	Very Good	96%	0%
B075	Bucket	Single Elevator Material Handler	Very Good	96%	25%

Table 4-5b: Health Condition Index Results – Large Vehicles (continued)

Vehicle ID	VEHICLE DESCRIPTION (1)	VEHICLE DESCRIPTION (2)	Asset Condition	Health Score	%TUL
B342	Bucket	Single Bucket Material Handler	Fair	60%	92%
B033	Bucket	Single Bucket Material Handler	Fair	60%	67%
B353	Bucket	Single Bucket 68ft Elevator material Handler	Fair	65%	83%
D360	Digger Derrick	Radial Boom Derrick	Fair	66%	75%
D019	Digger Derrick	General boom derrick	Fair	66%	58%
B095	Bucket	Single Bucket Material Handler	Fair	68%	50%
F080	Bucket	Single Bucket Forestry	Fair	68%	33%
B087	Bucket	Single Bucket Material Handler	Good	76%	50%
C073	Crane	Flatbed Knuckle Boom	Good	77%	33%
B035	Bucket	Single Bucket Material Handler	Good	80%	33%
B371	Bucket	Single Bucket Material Handler	Very Good	90%	25%
B009	Bucket	Single Bucket Material Handler	Very Good	93%	25%
B303	Bucket	Single Bucket Service	Very Good	93%	17%
B064	Bucket	Single Bucket Service	Very Good	96%	67%
B075	Bucket	Single Elevator Material Handler	Very Good	96%	25%
B323	Bucket	Single Bucket Service	Very Good	96%	17%
B034	Bucket	Single Bucket Material Handler	Very Good	96%	8%
D070	Digger Derrick	Radial Boom Derrick	Very Good	96%	0%
B004	Bucket	Single Bucket Service	Very Good	96%	0%
B072	Bucket	Double Bucket Elevator Material Handler	Very Good	96%	0%

4.2. Asset Condition Assessment – Medium Vehicles

Medium vehicle condition assessments are based on the seven condition parameters listed in **Table 4-6**.

Table 4-6: Evaluation Framework – Medium Vehicles

Data Type	#	Asset Condition Evaluation Criteria	Weight	Ranking	Numerical Grade	Max Grade
R	1	Service Age TUL = 12 yrs	30	A,B,C,D,E	5,4,3,2,1	150
R	2	Service Duty	5	A,B,C,D,E	5, 3, 1	25
M	3	Mileage TUL = 100,000 km	10	A,B,C,D,E	5,4,3,2,1	50
M	4	Engine Hours	15	A,B,C,D,E	5,4,3,2,1	75
M	5	Annual Maintenance Costs	20	A,B,C,D,E	5,4,3,2,1	100
I	6	Chassis Condition	10	A,B,C,D,E	5,4,3,2,1	50
I	7	Body Condition	10	A,B,C,D,E	5,4,3,2,1	50
		Total Max Score	100			500

The same process described in the previous section is applied to medium sized vehicles. In **Table 4-7**, each condition parameter is broken down into five levels of degradation and assigned a value. Each condition parameter is scored and multiplied by the weighting of that parameter. The total of all parameters is normalized and given a percentage health index score.

Table 4-7: Asset Condition Evaluation Criteria – Medium Vehicles

Criteria	Weight	
Service Age	**30%**	**Scoring**
Ranking	**Corresponding Condition**	
A	0 <= 3 years	5
B	> 3 <= 6 years	4
C	>6 <= 9 years	3
D	>9 <= 12 years	2
E	> 12 years	1
Service Duty	**5%**	**Scoring**
Ranking	**Corresponding Condition**	
A	Light	5
B	Light Medium	4
C	Medium	3
D	Medium Heavy	2
E	Heavy	1
Mileage	**10%**	**Scoring**
Ranking	**Corresponding Condition**	
A	0 to 25,000 km	5
B	25,001 to 50,000 km	4
C	50,001 to 75,000 km	3
D	75,001 to 100,000 km	2
E	> 100,000 km	1
Engine Hours	**15%**	**Scoring**
Ranking	**Corresponding Condition**	
A	0 to 2,500	5
B	2,501 to 5,000	4
C	5,001 to 7,500	3
D	7501 to 10,000	2
E	> 10,000	1

Criteria	Weight	
Annual Maintenance Costs	**20%**	**Scoring**
Ranking	**Corresponding Condition**	
A	0 - $10,000	5
B	$10,001 - $12,500	4
C	$12,501 - $15,000	3
D	$15,001 - $17,500	2
E	> $17,501	1
Chassis Condition	**10%**	**Scoring**
Ranking	**Corresponding Condition**	
A	Very Good (New)	5
B	Good	4
C	Fair	3
D	Poor	2
E	Very Poor	1
Body Condition	**10%**	**Scoring**
Ranking	**Corresponding Condition**	
A	Very Good (New)	5
B	Good	4
C	Fair	3
D	Poor	2
E	Very Poor	1

Table 4-8 provides a summary of all medium vehicle conditions assessments. Overall, the average condition rating for Enova's fleet of 20 medium vehicles is 58.3% (Fair). The average age of these assets is 8.5 years or 70.8% of TUL.

Table 4-8: Health Condition Index Results – Medium Vehicles

Vehicle ID	VEHICLE DESCRIPTION (1)	VEHICLE DESCRIPTION (2)	Asset Condition	Health Score	%TUL
C059	Dump Truck	Dump Body	Very Poor	29%	108%
O042	Box Truck	Work Body- Underground	Poor	31%	100%
O066	Box Truck	Work Body- Underground	Poor	35%	125%
F007	Box Truck	Wood chips hauler	Poor	36%	75%
C029	Box Truck	Work Body- Construction	Poor	44%	100%
O099	Dump Truck	Dump Body	Poor	47%	125%
C024	Box Truck	Work Body- Construction	Poor	47%	92%
C020	Construction	¾ Ton Heavy Duty Pickup	Poor	49%	67%
O343	Box Truck	Work Body- Underground	Fair	50%	83%
C204	Equipment	Backhoe	Fair	54%	58%
S090	Bucket	Squirt boom service	Fair	56%	125%
O027	Box Truck	Work Body- Underground	Fair	60%	42%
C203	Equipment	Backhoe	Fair	67%	67%
S319	Box Truck	Work Body- Stations	Good	70%	33%
O025	Dump Truck	Dump Body	Good	73%	33%
O056	Dump Truck	Dump Body	Good	73%	33%
O370	Crane	Flatbed knuckle boom	Good	82%	58%
C022	Box Truck	Work Body- Construction	Good	84%	33%
S028	Box Truck	Work Body- Stations	Very Good	88%	33%
S321	Box Truck	Work Body- Stations	Very Good	90%	25%

4.3. Asset Condition Assessment – Small Vehicles

Small vehicle condition assessments are based on the six parameters listed in **Table 4-9**.

Table 4-9: Evaluation Framework – Small Vehicles

Data Type	#	Asset Condition Evaluation Criteria	Weight	Ranking	Numerical Grade	Max Grade
R	1	Service Age	30	A,B,C,D,E	5,4,3,2,1	150
R	2	Service Duty	10	A,B,C,D,E	5, 3, 1	50
M	3	Mileage TUL	20	A,B,C,D,E	5,4,3,2,1	100
M	4	Annual Maintenance Costs	20	A,B,C,D,E	5,4,3,2,1	100
I	5	Chassis Condition	10	A,B,C,D,E	5,4,3,2,1	50
I	6	Body Condition	10	A,B,C,D,E	5,4,3,2,1	50
		Total Max Score	100			500

The same process described in the previous sections on large and medium vehicles also applies to small vehicles. In **Table 4-10**, each condition parameter is broken down into five levels of degradation and assigned a value. Each condition parameter is scored and multiplied by the weighting factor of that parameter. The total of all parameters is normalized and given a percentage Health Index score.

Table 4-10: Asset Condition Evaluation Criteria – Small Vehicles

Criteria	Weight	
Service Age	**30%**	**Scoring**
Ranking	**Corresponding Condition**	
A	0 to 3 years	5
B	3 to 6 years of service	4
C	6 to 8 years of service	3
D	8 to 10 years of service	2
E	> 10 years	1
Service Duty	**10%**	**Scoring**
Ranking	**Corresponding Condition**	
A	Light	5
B	Light Medium	4
C	Medium	3
D	Medium Heavy	2
E	Heavy	1
Mileage TUL	**20%**	**Scoring**
Ranking	**Corresponding Condition**	
A	0 to 50,000 km	5
B	50,001 to 100,000 km	4
C	100,001 to 150,000 km	3
D	150,001 to 200,000 km	2
E	> 200,000 km	1

Criteria	Weight	
Annual Maintenance Costs	**20%**	**Scoring**
Ranking	**Corresponding Condition**	
A	0 - $10,000	5
B	$10,001 - $12,500	4
C	$12,501 - $15,000	3
D	$15,001 - $17,500	2
E	> $17,501	1
Chassis Condition	**10%**	**Scoring**
Ranking	**Corresponding Condition**	
A	Very Good (New)	5
B	Good	4
C	Fair	3
D	Poor	2
E	Very Poor	1
Body Condition	**10%**	**Scoring**
Ranking	**Corresponding Condition**	
A	Very Good (New)	5
B	Good	4
C	Fair	3
D	Poor	2
E	Very Poor	1

Tables 4-11(a, b) provide a summary of all small vehicle condition assessments. Overall, the average condition rating for Enova's fleet of 74 small vehicles is 71.6% (Good). The average age of these assets is 6.1 years or 61.5% of TUL.

Table 4-11a: Health Condition Index Results – Small Vehicles

Vehicle ID	VEHICLE DESCRIPTION (1)	VEHICLE DESCRIPTION (2)	Asset Condition	Health Score	%TUL
M063	Metering	Cargo Van	Very Poor	28%	110%
L008	Locate	Cargo Van	Poor	36%	130%
O001	Operation	½ Ton Light Duty Pickup	Poor	42%	120%
R047	Collection	SUV	Poor	42%	80%
O132	Pickup	½ Ton Light Duty Pickup	Poor	42%	110%
M125	Metering	Cargo Van	Poor	42%	120%
M013	Metering	Cargo Van	Poor	44%	120%
M124	Metering	Cargo Van	Poor	44%	120%
O128	Pickup	½ Ton Light Duty Pickup	Poor	44%	120%
O048	Operation	½ Ton Light Duty Pickup	Poor	46%	90%
S067	Stations	Cargo Van	Poor	48%	80%
E334	Engineering	Cargo Van	Poor	48%	110%
O045	Operation	Car	Poor	48%	110%
M031	Metering	Cargo Van	Poor	48%	130%
O372	Operation	Cargo Van	Poor	48%	170%
S018	Stations	½ Ton Light Duty Pickup	Fair	52%	80%
O062	Operation	Pickup	Fair	52%	80%
C058	Construction	½ Ton Light Duty Pickup	Fair	54%	80%
O057	Operation	½ Ton Light Duty Pickup	Fair	54%	120%
O194	Operation	On-call Pickup	Fair	56%	50%
O196	Operation	On-call Pickup	Fair	56%	50%
O317	Operation	Minivan	Fair	56%	140%
S118	Stations	Full size van	Fair	58%	130%
E165	Engineering	Cargo Van	Fair	58%	80%
S050	Stations	Cargo Van	Fair	58%	80%

Table 4-11b: Health Condition Index Results – Small Vehicles (continued)

Vehicle ID	VEHICLE DESCRIPTION (1)	VEHICLE DESCRIPTION (2)	Asset Condition	Health Score	%TUL
O065	Operation	½ Ton Light Duty Pickup	Fair	58%	50%
E010	Engineering	Minivan	Fair	60%	90%
E144	Engineering	Cargo Van	Fair	62%	100%
E135	Engineering	Cargo Van	Fair	62%	110%
O312	Transportation	SUV	Fair	62%	120%
O198	Operation	½ Ton Light Duty Pickup	Fair	62%	40%
O130	Pickup	½ Ton Light Duty Pickup	Fair	64%	120%
E123	Engineering	Minivan	Fair	66%	120%
L011	Locate	Cargo Van	Fair	66%	60%
H061	HSE	Minivan	Fair	68%	90%
O012	Operation	½ Ton Light Duty Pickup	Fair	68%	40%
F082	Forestry	½ Ton Light Duty Pickup	Fair	68%	30%
M271	Metering	Cargo Van	Fair	68%	70%
O040	Operation	½ Ton Light Duty Pickup	Good	70%	50%
C049	Construction	½ Ton Light Duty Pickup	Good	72%	30%
O002	Operation	½ Ton Light Duty Pickup	Good	74%	50%
R199	Collection	SUV	Good	76%	50%
E037	Engineering	Minivan	Good	76%	50%
O017	Operation	½ Ton Light Duty Pickup	Good	76%	40%
E068	Engineering	SUV	Good	80%	50%
E373	Engineering	Minivan	Good	80%	70%
O197	Operation	½ Ton Light Duty Pickup	Good	84%	50%
M044	Metering	SUV	Very Good	86%	40%
S192	Stations	Cargo Van	Very Good	86%	50%
O193	Operation	½ Ton Light Duty Pickup	Very Good	88%	50%
L036	Locate	Cargo Van	Very Good	90%	10%
O032	Operation	½ Ton Light Duty Pickup	Very Good	90%	0%
O043	Operation	½ Ton Light Duty Pickup	Very Good	90%	0%
E200	Engineering	SUV	Very Good	94%	40%
O046	Operation	SUV	Very Good	94%	30%
O212	Operation	½ Ton Light Duty Pickup	Very Good	94%	30%
L055	Locate	Cargo Van	Very Good	94%	10%
M211	Metering	Cargo Van	Very Good	94%	30%

4.4. Asset Condition Assessment – Rolling Stock

Rolling stock is a catchall category for the remainder of Enova's Fleet assets. These units tend to be unique custom ordered, custom made and have varying TULs. Enova's condition assessments are based on four condition parameters listed in **Table 4-12**.

Table 4-12: Evaluation Framework – Rolling Stock

Data Type	#	Asset Condition Evaluation Criteria	Weight	Ranking	Numerical Grade	Max Grade
R	1	Service Age	25	A,B,C,D,E	5,4,3,2,1	125
R	2	Service Duty	20	A,B,C,D,E	5, 3, 1	100
M	3	Annual Maintenance Costs	25	A,B,C,D,E	5,4,3,2,1	125
I	4	Chassis Condition	30	A,B,C,D,E	5,4,3,2,1	150
		Total Max Score	100			500

In **Table 4-13**, each condition parameter is broken down into five levels of degradation and assigned a value. Each condition parameter is scored and multiplied by the weighting factor of that parameter. The total of all parameters is normalized and given a percentage Health Index score.

Table 4-13: Asset Condition Evaluation Criteria – Rolling Stock

Criteria	Weight	
Service Age	**25%**	**Scoring**
Ranking	**Corresponding Condition**	
A	0 to 5 years	5
B	5 to 10 years	4
C	10 to 15 years	3
D	15 to 20 years	2
E	> 20 years	1
Service Duty	**20%**	**Scoring**
Ranking	**Corresponding Condition**	
A	Light	5
B	Light Medium	4
C	Medium	3
D	Medium Heavy	2
E	Heavy	1

Criteria	Weight	
Annual Mtce Costs	**25%**	**Scoring**
Ranking	**Corresponding Condition**	
A	0 - $1,000	5
B	$1,001 - $1,500	4
C	$1,501 - $2,000	3
D	$2,001 - $2,500	2
E	> $2,500	1
Chassis Condition	**30%**	**Scoring**
Ranking	**Corresponding Condition**	
A	Very Good (New)	5
B	Good	4
C	Fair	3
D	Poor	2
E	Very Poor	1

Tables 4-14(a, b) provide a summary of all rolling stock condition assessments. Overall, the average condition rating for Enova's fleet of 59 rolling stock assets is 64.6% (Fair). The average age of these assets is 15.2 years or 55.8% of TUL.

Table 4-14a: Health Condition Index Results – Rolling Stock

Vehicle ID	VEHICLE DESCRIPTION (1)	VEHICLE DESCRIPTION (2)	Asset Condition	Health Score	%TUL
T137	Trailer	Brush Chipper	Poor	36%	90%
T127	Trailer	Cable Reel Trailer	Poor	40%	87%
T154	Trailer	Brush Chipper	Poor	42%	90%
T141	Trailer	Oil filtration unit	Poor	44%	137%
T551	Trailer	Mobile Substation (CS)	Poor	44%	80%
T113	Trailer	Box Trailer	Poor	46%	77%
T541	Trailer	Box Trailer	Poor	47%	77%
T542	Trailer	Box Trailer	Poor	47%	77%
T140	Trailer	Mobile Substation (VS)	Poor	48%	133%
T155	Trailer	Trailer – 12 ft Cargo	Poor	49%	60%
T138	Trailer	Network Cable Trailer	Fair	55%	33%
T134	Trailer	Tri-axle Trailer	Fair	55%	60%
T136	Trailer	Tri-axle Trailer	Fair	55%	60%
T121	Trailer	Cable Reel Trailer	Fair	56%	97%
T521	Trailer	Cable Reel Trailer	Fair	56%	80%
T533	Trailer	Box Trailer	Fair	56%	117%
T505	Trailer	Tension Stringer	Fair	60%	37%
T133	Trailer	Box Trailer	Fair	60%	50%
T540	Trailer	Box Trailer	Fair	60%	83%
T148	Equipment	Scissor Lift	Fair	61%	106%
T550	Trailer	Pole Trailer	Fair	61%	40%
T545	Trailer	Cargo Trailer	Fair	61%	50%
T552	Trailer	Pole Trailer	Fair	61%	27%
T172	Trailer	Pole Trailer	Fair	63%	30%
T546	Trailer	Box Trailer	Fair	63%	47%
T105	Trailer	Portable Generator	Fair	64%	87%

Table 4-14b: Health Condition Index Results – Rolling Stock (continued)

Vehicle ID	VEHICLE DESCRIPTION (1)	VEHICLE DESCRIPTION (2)	Asset Condition	Health Score	%TUL
T504	Trailer	Tension Stringer	Fair	65%	37%
T114	Trailer	Air Compressor	Fair	65%	60%
T149	Trailer	Tension Stringer	Fair	66%	20%
T159	Trailer	Cargo Trailer	Fair	66%	37%
T157	Trailer	Cargo Trailer	Fair	66%	47%
T158	Trailer	Cargo Trailer	Fair	66%	40%
T548	Trailer	Pole Trailer	Fair	66%	43%
W207	Equipment	Forklift	Fair	66%	100%
W724	Equipment	Forklift	Fair	66%	43%
T544	Trailer	Cargo Trailer	Fair	66%	53%
W713	Equipment	Forklift	Fair	66%	27%
C205	Equipment	Mini excavator	Fair	67%	83%
T173	Trailer	Arrowhead Trailer	Fair	67%	30%
T538	Trailer	Cable Trailer	Fair	68%	120%
O734	Equipment	Forklift	Fair	69%	140%
T501	Trailer	Tension Stringer	Fair	69%	113%
T502	Trailer	Tension Stringer	Fair	69%	113%
C206	Equipment	Tractor	Fair	69%	17%
T547	Trailer	Pole Trailer	Good	71%	43%
T151	Trailer	Flatbed	Good	71%	30%
T161	Trailer	Scene Lighting Trailer	Good	74%	33%
T150	Trailer	Tension Stringer	Good	76%	20%
T171	Trailer	Cargo Trailer	Good	76%	30%
T553	Trailer	Pole Trailer	Good	76%	17%
W201	Equipment	Forklift	Good	76%	25%
W736	Equipment	Forklift	Good	81%	20%
T122	Trailer	Pole Trailer	Good	82%	7%
G702	Equipment	Lawn mowing tractor	Good	82%	3%
W706	Equipment	Forklift	Very Good	86%	10%
T115	Trailer	10 ft Cargo Trailer	Very Good	86%	0%
G701	Equipment	Tractor	Very Good	90%	0%
T153	Trailer	Box Trailer	Very Good	92%	3%
C160	Equipment	Scrubber Sweeper	Very Good	100%	17%

5. CAPITAL INVESTMENT PLAN 2026 to 2031

5.1. Fleet Replacements 2026 to 2031

From Enova's Fleet Asset Condition Assessments, a vehicle replacement program is developed based on the combination of health, criticality, performance and delivery lead time for asset replacement. Final adjustments to the plan are made to pace fleet capital investments in coordination with Enova's overall capital investment plan. This means that fleet investments at times may be lumpy in order to smooth out overall capital spending. All vehicles assessed in Very Poor condition were replaced by the end of 2025. Enova fleet plans are to replace 62 fleet assets of which 30 are currently in Poor condition and 32 are currently assessed in Fair condition but are expected to become Poor during the 2026 – 2031 time frame.

The 62 assets scheduled to be replaced are comprised of 14 large, 7 medium, 24 small and 17 pieces of rolling stock. Currently this group of assets have a combined health score of 50.2% with the average age of 12.7 years or 86% TUL. **Tables 5-1(a, b, c)** list the units recommended for replacement over this period.

Table 5-1a: Forecast Fleet Replacements

Vehicle ID	VEHICLE DESCRIPTION (1)	VEHICLE DESCRIPTION (2)	Asset Condition	Health Score	%TUL
F007	Box Truck	Wood chips hauler	Poor	36%	75%
T137	Trailer	Brush Chipper	Poor	36%	90%
B014	Bucket	Single Bucket Material Handler	Poor	37%	83%
B069	Bucket	Single Bucket Material Handler	Poor	38%	83%
O023	Box Truck	Cable pulling Truck	Poor	38%	100%
T127	Trailer	Cable Reel Trailer	Poor	40%	87%
B026	Bucket	Single Bucket Service	Poor	42%	92%
T154	Trailer	Brush Chipper	Poor	42%	90%
O132	Pickup	½ Ton Light Duty Pickup	Poor	42%	110%
O001	Operation	½ Ton Light Duty Pickup	Poor	42%	120%
R047	Collection	SUV	Poor	42%	80%
M125	Metering	Cargo Van	Poor	42%	120%
B311	Bucket	Single Bucket Material Handler	Poor	43%	108%
B006	Bucket	Double Bucket Elevator Material Handler	Poor	44%	100%
T141	Trailer	Oil filtration unit	Poor	44%	137%
M124	Metering	Cargo Van	Poor	44%	120%
O128	Pickup	½ Ton Light Duty Pickup	Poor	44%	120%
T113	Trailer	Box Trailer	Poor	46%	77%
O048	Operation	½ Ton Light Duty Pickup	Poor	46%	90%
B038	Bucket	Single Bucket Service	Poor	47%	42%

Table 5-1b: Forecast Fleet Replacements (continued)

Vehicle ID	VEHICLE DESCRIPTION (1)	VEHICLE DESCRIPTION (2)	Asset Condition	Health Score	%TUL
C024	Box Truck	Work Body- Construction	Poor	47%	92%
T541	Trailer	Box Trailer	Poor	47%	77%
T542	Trailer	Box Trailer	Poor	47%	77%
S067	Stations	Cargo Van	Poor	48%	80%
O372	Operation	Cargo Van	Poor	48%	170%
M031	Metering	Cargo Van	Poor	48%	130%
O045	Operation	Car	Poor	48%	110%
E334	Engineering	Cargo Van	Poor	48%	110%
C020	Construction	3/4 Ton Heavy Duty Pickup	Poor	49%	67%
T155	Trailer	12 ft Cargo Trailer	Poor	49%	60%
B355	Bucket	Single Bucket Material Handler	Fair	50%	83%
O343	Box Truck	Work Body- Underground	Fair	50%	83%
S018	Stations	½ Ton Light Duty Pickup	Fair	52%	80%
O062	Operation	½ Ton Light Duty Pickup	Fair	52%	80%
D320	Bucket	Single Bucket Material Handler	Fair	54%	92%
C204	Equipment	Backhoe	Fair	54%	58%
B041	Bucket	Single Bucket Service	Fair	54%	42%
O057	Operation	½ Ton Light Duty Pickup	Fair	54%	120%
C058	Construction	½ Ton Light Duty Pickup	Fair	54%	80%
T134	Trailer	Tri-axle Trailer	Fair	55%	60%
T136	Trailer	Tri-axle Trailer	Fair	55%	60%
T138	Trailer	Network Cable Trailer	Fair	55%	33%
S090	Bucket	Squirt boom service	Fair	56%	125%
O194	Operation	On-call Pickup	Fair	56%	50%
O196	Operation	On-call Pickup	Fair	56%	50%
O317	Operation	Minivan	Fair	56%	140%
T521	Trailer	Cable Reel Trailer	Fair	56%	80%
T533	Trailer	Box Trailer	Fair	56%	117%
T121	Trailer	Cable Reel Trailer	Fair	56%	97%
D015	Digger Derrick	Radial Boom Derrick	Fair	57%	50%
S118	Stations	Full size van	Fair	58%	130%
E165	Engineering	Cargo Van	Fair	58%	80%
S050	Stations	Cargo Van	Fair	58%	80%
O065	Operation	½ Ton Light Duty Pickup	Fair	58%	50%
O027	Box Truck	Work Body- Underground	Fair	60%	42%

Table 5-1c: Forecast Fleet Replacements (continued)

Vehicle ID	VEHICLE DESCRIPTION (1)	VEHICLE DESCRIPTION (2)	Asset Condition	Health Score	%TUL
B342	Bucket	Single Bucket Material Handler	Fair	60%	92%
B033	Bucket	Single Bucket Material Handler	Fair	60%	67%
F081	Bucket	Single Bucket Forestry	Fair	60%	42%
E010	Engineering	Minivan	Fair	60%	90%
T505	Trailer	Tension Stringer	Fair	60%	37%
T540	Trailer	Box Trailer	Fair	60%	83%
T133	Trailer	Box Trailer	Fair	60%	50%

5.2. Fleet Capital Expenditures 2026 to 2031

Table 5-2 summarizes Enova's historical capital fleet expenditures. This program captures the purchase of new and replacement vehicles and equipment, as well as expenditures for major refurbishments that extend the useful service life of vehicles and equipment.

Table 5-2: Historical Fleet Capital Expenditures

							Total	Avg	Total	Avg
Criteria	2020	2021	2022	2023	2024	2025	2020 - 2024	2020 - 2024	2020 - 2025	2020 - 2025
Planned Fleet Expenditure	1,716,740	1,849,745	1,856,500	1,937,000	2,100,000	2,787,000	9,459,985	1,891,997	12,246,985	2,041,164
Actual Fleet Expenditure	1,093,947	1,492,906	1,794,058	2,011,257	2,077,641	2,813,000	8,469,810	1,693,962	11,282,810	1,880,468
Variance	(622,793)	(356,839)	(62,442)	74,257	(22,359)	26,000	(990,175)	(198,035)	(964,175)	(160,696)
% Actual Exp	64%	81%	97%	104%	99%	101%	90%	90%	92%	92%

Notably, from 2020 to 2022 there was a shortfall in vehicle replacements. Substantial delivery delays and unavailability of vehicles were experienced as suppliers faced major supply chain disruptions during and coming out of the COVID-19 pandemic. Some vehicle delivery times have increased by as much as one year and have not returned to pre-COVID conditions.

Enova has also seen substantial increases in vehicle pricing that has not abated since the impacts of COVID-19. On average, vehicle pricing is 40% above pre-COVID procurements with some vehicles, such as pickup trucks, doubling in cost since the last DSP.

Table 5-3 summarizes Enova's Forecast capital fleet expenditures. This program captures the replacement of all fleet assets currently in Poor condition. It also includes assets currently in Fair condition assessed with a Health Score of 60% or less. These assets are forecast to deteriorate to a state of Poor or Very Poor over that timeframe.

Table 5-3: Forecast Fleet Capital Expenditures

Estimate in 2025 $			HI <= 60%				Total	Avg
Vehicle Category	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2026-2031**	**2026-2031**
Large Vehicles	2,500,000	1,550,000	950,000	1,800,000	2,500,000	1,650,000	10,950,000	1,825,000
Medium Vehicles	-	930,000	380,000	580,000	-	760,000	2,650,000	441,667
Small Vehicles	260,000	295,000	520,000	165,000	260,000	-	1,500,000	250,000
Rolling Stock	-	540,000	1,075,000	450,000	200,000	575,000	2,840,000	473,333
Total Planned Fleet Expenditure	2,760,000	3,315,000	2,925,000	2,995,000	2,960,000	2,985,000	17,940,000	2,990,000

Enova is proposing an annual fleet capital expenditure program of approximately $3.0 million over the 2027–2031 planning period. The proposed investment is supported by Enova's asset condition assessments, lifecycle replacement strategies, and operational requirements necessary to safely and efficiently execute its capital construction, maintenance, and emergency response programs. The forecast annual expenditures exceed historical average spending primarily due to the combined effects of increased vehicle and equipment acquisition costs resulting from inflation and supply chain pressures, together with a growing number of fleet assets that have reached the end of their useful lives and require replacement based on age, condition, reliability, and maintenance history. The proposed expenditure level is intended to maintain a safe, reliable, and operationally effective fleet while minimizing lifecycle costs and reducing the risk of service disruptions associated with aging equipment.

5.3. Fleet Reductions 2026 to 2031

At the time of preparing this Distribution System Plan, Enova is three years into the post-merger harmonization of the operations of its legacy local distribution companies. As operational practices,

fleet management processes, and resource sharing continue to be integrated, Enova has identified opportunities to optimize its fleet requirements while maintaining service levels.

Over the 2027–2031 planning period, Enova forecasts a net reduction of four (4) light-duty vehicles. This reduction is expected to result from improved vehicle pooling, greater operational efficiencies, and the elimination of duplicate fleet resources that were previously maintained by the legacy utilities. These efficiencies have been made possible through the continued harmonization of work practices, centralized fleet management, and improved coordination of field operations.

Enova will continue to evaluate fleet utilization throughout the planning period and will pursue additional fleet optimization opportunities where operational experience demonstrates that vehicles can be removed without compromising employee safety, emergency response capability, customer service, or the execution of capital and maintenance programs. This approach supports Enova's objective of maintaining a right-sized fleet while prudently managing capital expenditures and operating costs.

5.4. Fleet Additions 2026 to 2031

Enova is proposing one (1) addition to its rolling stock fleet during the planning period: a narrow tracked, insulated aerial lift device designed specifically for rear-lot and other difficult-to-access urban distribution assets. This specialized equipment will enable crews to safely access overhead electrical infrastructure in locations where conventional bucket trucks cannot operate due to restricted access or terrain constraints. The insulated aerial lift will reduce the need for employees to work from ladders or climb aging utility poles that may be in poor structural condition, thereby improving worker safety and reducing operational risk. The addition will also enhance the efficiency of maintenance, inspection, and emergency restoration activities by providing safe and reliable access to infrastructure in challenging environments. The investment supports Enova's commitment to employee safety, operational effectiveness, and the reliable maintenance of its distribution system.

APPENDIX K
NWS Pre-Assessment

Non-Wires Solutions Pre-Assessment

Benefit-Cost Analysis Framework

Compliance Material Capital Investment Programs (≥$2M)



July 2026

Version 1.0

Table of Contents

Table of Contents i
1. Executive Summary 1
2. Regulatory Framework 2
2.1 OEB BCA Framework and NWS Guidelines 2
2.2 Scope: Distribution System Including Stations 2
2.3 Planning Horizon 2
2.4 Discretionary vs. Non-Discretionary Classification 3
3. Pre-Assessment Methodology 4
4. Distribution Line Program Pre-Assessments 5
4.1. Program R-OL-VU – OH Line Renewal – Voltage Upgrade 5
4.1.1 Description of System Need 5
4.1.2 Assets and Scope 5
4.1.3 NWS Suitability Assessment 6
4.1.4 Pre-Assessment Conclusion 6
4.2. Program R-UL-S – UG Line Renewal – Subdivisions 8
4.2.1 Description of System Need 8
4.2.2 Assets and Scope 8
4.2.3 NWS Suitability Assessment 9
4.2.4 Pre-Assessment Conclusion 9
4.3. Program R-OL-RP – OH Line Renewal – Routine Projects 10
4.3.1 Description of System Need 10
4.3.2 Assets and Scope 10
4.3.3 NWS Suitability Assessment 10
4.3.4 Pre-Assessment Conclusion 11
4.4. Program E-SP – Relocations – Special Projects 12
4.4.1 Description of System Need 12
4.4.2 Assets and Scope 12
4.4.3 NWS Suitability Assessment 13
4.4.4 Pre-Assessment Conclusion 13
5. Station Program Pre-Assessments 14
5.1 Station Equipment – Renewal (R-SE) 14
5.1.1 Description of System Need 14
5.1.2 NWS Suitability Assessment 15
5.1.3 Pre-Assessment Conclusion 15

6. Forward-Looking NWS Consideration (2028–2031) 17
7. Conclusion and Filing Statement 18
8. References 19

1. Executive Summary

This document presents Enova Power Corp.'s ("Enova") pre-assessment of non-wires solutions ("NWS") for material capital investment programs with projected capital costs exceeding $2 million, as required by the Ontario Energy Board's ("OEB") Benefit-Cost Analysis Framework ("BCA Framework") and Non-Wires Solutions Guidelines ("NWS Guidelines").

The NWS pre-assessment requirement applies to all electricity system needs exceeding $2 million across the full DSP planning horizon (2027–2031), excluding general plant. This document assesses material programs in two categories: (a) distribution line programs, and (b) station capital programs.

The following programs exceed the $2 million threshold and require documented NWS consideration:

Code	Program Name	OEB Cat	2027 Budget	5yr Total	Result
R-OL-VU	OH Line Renewal – Voltage Upgrade	SR	$5.89M	$29.43M	NWS Not Viable
R-OL-RP	OH Line Renewal – Routine Projects	SR	$4.11M	$20.54M	NWS Not Viable
R-UL-S	UG Line Renewal – Subdivisions	SR	$11.14M	$72.64M	NWS Not Viable
E-SP	Relocations – Special Projects	SA	$3.13M	$15.66M	NWS Not Viable
R-SE	Station Equipment – Renewal	SR	$7.74M	$41.62M	NWS Not Viable

For all programs, the pre-assessment concludes that NWS is not a viable alternative. Detailed pre-assessments are provided for the distribution line programs in Section 4 and station programs in Section 5.

2. Regulatory Framework

2.1 OEB BCA Framework and NWS Guidelines

On May 16, 2024, the OEB issued the Benefit-Cost Analysis Framework for Addressing Electricity System Needs (EB-2023-0125). The BCA Framework establishes a methodology for electricity distributors to assess the economic feasibility of using distributed energy resources as non-wires solutions when addressing defined electricity system needs.

NWS Guidelines, Section 3.1: *"Distributors are required to document their consideration of NWSs when making investment decisions on electricity system needs with an expected capital cost of $2 million or more as part of distribution system planning, excluding general plant investments."*

The requirement operates as a two-step process:

Step 1 — Pre-Assessment (mandatory): The distributor must conduct a pre-assessment to determine whether NWS could viably meet the identified system need. The pre-assessment must be filed with the OEB regardless of outcome. The OEB has not established a defined format for the pre-assessment.

Step 2 — Full BCA (conditional): Only if the pre-assessment concludes that NWS is a viable approach should the distributor proceed with a full BCA using the Distribution Service Test. If the pre-assessment finds NWS is not viable, a full BCA is not required.

2.2 Scope: Distribution System Including Stations

The BCA Framework applies to all electricity system needs exceeding $2 million in projected capital cost, excluding general plant. This scope explicitly includes distribution station investments (transformer stations, switchgear, protection and control equipment), as stations are part of the distribution system infrastructure. The only exclusion is general plant (land, buildings, vehicles, IT, tools).

The BCA Framework also notes that it "does not apply to determining costs of expansions and connections in relation to connecting new customers. Such evaluations are governed by the DSC" (Section 2.2). This exclusion applies to customer-driven System Access programs including new service connections, subdivision expansions, feeder extensions, and the Enova 11TS station expansion (which is driven by a data centre customer connection obligation). These programs are not assessed in this document as the BCA Framework does not apply; their cost evaluations are governed by the DSC.

2.3 Planning Horizon

The NWS consideration applies across the full DSP planning horizon (2027–2031), not solely the test year. The OEB expects that NWS is embedded in the planning methodology for the entire capital plan.

2.4 Discretionary vs. Non-Discretionary Classification

BCA Framework, Section 3.2.2: *"For the purposes of the BCA Framework, a non-discretionary system need is one with a reference scenario that needs some investment for an electricity distributor to deliver service to its customers and meet its regulatory obligations. For non-discretionary system needs, there is no 'do-nothing' option."*

All programs assessed in this document involve non-discretionary system needs: distribution line renewal programs address assets that have reached end of life and must be replaced to maintain safety and reliability; relocation programs address statutory obligations to relocate facilities at the direction of municipal road authorities; and station renewal programs address deteriorated station equipment.

3. Pre-Assessment Methodology

The OEB has not established a defined approach for the pre-assessment stage (BCA Framework, Section 2.2). Enova has developed this methodology drawing on the system need classifications described in Section 3.1.1 of the BCA Framework, the discretionary/non-discretionary framework in Section 3.2.2, and the screening approach referenced in the NWS Guidelines (Enbridge Gas IRP Framework).

Enova's pre-assessment evaluates each program against five criteria:

#	Criterion	Description
1	**Nature of System Need**	What is the primary driver? Condition-driven, obligation-driven, or capacity-driven?
2	**Physical Replacement Requirement**	Does the need require physical replacement of assets that cannot be substituted by DER?
3	**NWS Technical Applicability**	Could any NWS technology technically address the identified system need?
4	**BCA Framework Alignment**	Does the need align with the BCA Framework's illustrative NWS use-cases (Section 3.1.1)?
5	**Regulatory and Safety Obligations**	Are there statutory or code obligations mandating the physical investment?

A program is determined to be unsuitable for NWS if the system need is fundamentally driven by physical asset condition or external obligations rather than capacity constraints, and no NWS technology can substitute for the physical replacement of the affected assets.

4. Distribution Line Program Pre-Assessments

4.1. Program R-OL-VU – OH Line Renewal – Voltage Upgrade

Program Code:	R-OL-VU
Program Name:	OH Line Renewal – Voltage Upgrade
OEB Investment Category:	System Renewal
2027 Test Year Capital:	$5,886,291 (exceeds $2M BCA Framework threshold)
System Need Classification:	Non-Discretionary (condition-driven asset replacement)
Pre-Assessment Outcome:	NWS is NOT a viable alternative – Full BCA not required

4.1.1 Description of System Need

This program involves the planned rebuilding of overhead distribution lines where the primary driver is the age and deteriorated condition of existing plant combined with the opportunity to convert operating voltage from legacy 8.32 kV to the system standard of 27.6 kV. The 2027 program comprises 11 individual projects across Enova's service territory involving the replacement of poles, conductors, transformers, insulators, and associated equipment on lines originally installed between the 1960s and 1980s. These assets are 40 to 60+ years of age, with Health Index ratings in the Poor and Very Poor categories as determined through Enova's Asset Condition Assessment (ACA) program. The projects include both dedicated voltage conversion sections and combined rebuild-and-conversion sections where deteriorated poles require replacement regardless of the voltage upgrade.

4.1.2 Assets and Scope

The 2027 R-OL-VU program involves 11 overhead line projects totalling $5.89M in capital expenditure. The scope includes replacement of deteriorated wood poles, replacement of conductors with modern CSA compliant cross-arms and insulators, installation of new distribution transformers rated for 27.6 kV operation, and associated civil works. Certain legacy 8.32 kV components (cutouts, insulators, bushings) are no longer manufactured and cannot be sourced for maintenance or refurbishment, making replacement the only technically feasible option.

4.1.3 NWS Suitability Assessment

In accordance with the OEB's BCA Framework and NWS Guidelines, Enova conducted a pre-assessment to determine whether there is a reasonable expectation that a non-wires solution could viably address the system need underlying this program. The assessment considered the following factors:

Assessment Criterion	Finding
Nature of System Need	The primary driver is physical asset deterioration (Poor/Very Poor Health Index) combined with voltage standardization. This is not a capacity-driven need; the existing lines have adequate capacity for current load. The need arises from the physical condition of poles, conductors, and equipment that have reached or exceeded their typical useful life.
Physical Replacement Requirement	The investment requires physical replacement of poles, conductors, transformers, and hardware. No DER technology can substitute for a structurally deficient wood pole that has failed its remaining-strength test, nor can a DER replace deteriorated conductor or obsolete 8.32 kV equipment.
NWS Technical Applicability	NWS technologies (energy storage, distributed generation, demand response, energy efficiency) are designed to manage load, defer capacity upgrades, or improve reliability through alternative energy supply. None of these technologies can address the physical deterioration of pole structures, conductor degradation, or equipment obsolescence that drives this program. A battery energy storage system, for example, cannot prevent a public safety hazard, a weakened pole from failing during an ice storm event.
BCA Framework Reference (Section 3.1.1)	The BCA Framework's illustrative NWS use-cases involve: (1) forecast overload approaching capacity; (2) N-1 contingency; and (3) underperforming circuit reliability. This program is not driven by any of these conditions. The system need is asset condition and standards compliance, which falls outside the scope of NWS applicability.
Regulatory and Safety Obligations	Enova is obligated under O.Reg 22/04 and CSA C22.3 No.1 to maintain overhead construction to current safety standards. Poles failing remaining-strength testing represent public safety risks requiring physical replacement.

4.1.4 Pre-Assessment Conclusion

The R-OL-VU program addresses non-discretionary system needs driven by the physical deterioration of overhead assets and the obsolescence of legacy 8.32 kV equipment. The nature of these needs is fundamentally incompatible with NWS: no distributed energy resource can restore structural integrity to a deteriorated pole, replace degraded conductor, or substitute for obsolete voltage-class equipment. The system need does not involve capacity constraint, load growth, or contingency planning scenarios where NWS technologies are applicable. Enova's obligation to maintain safe and reliable overhead construction under O.Reg 22/04, the ESA Electrical Safety Code, and CSA standards further confirms that physical asset replacement is the only viable response.

Based on the above assessment, Enova concludes that NWS is not a viable alternative for this program. In accordance with Section 2.2 of the BCA Framework, a full benefit-cost analysis using the Distribution Service Test (DST) is therefore not required. This pre-assessment is filed with the OEB as required by the NWS Guidelines.

4.2. Program R-UL-S – UG Line Renewal – Subdivisions

Program Code:	R-UL-S
Program Name:	UG Line Renewal – Subdivisions
OEB Investment Category:	System Renewal
2027 Test Year Capital:	$11,143,755 (exceeds $2M BCA Framework threshold)
System Need Classification:	Non-Discretionary (condition-driven asset replacement)
Pre-Assessment Outcome:	NWS is NOT a viable alternative – Full BCA not required

4.2.1 Description of System Need

This program involves the planned renewal of underground distribution infrastructure in residential subdivision areas. The 2027 program comprises 17 individual projects totalling $11.14M, including underground cable replacement, transformer pad and vault rehabilitation, voltage conversion from legacy voltages to 27.6 kV, and associated civil works (duct bank replacement, surface restoration). The underground assets targeted by this program were installed primarily during the 1970s and 1980s residential development boom and are approaching or past their typical useful life of 35–40 years for direct-buried cable and 40–45 years for duct-bank cable systems. Asset condition has been assessed through a combination of failure history analysis and age-based degradation assumptions.

4.2.2 Assets and Scope

The program scope includes: cable replacement on 17 subdivision circuits; voltage conversion of subdivision loops from legacy 4.16 kV/8.32 kV to 27.6 kV; pad-mounted transformer replacement; submersible vault drain installation; and associated civil restoration. Multiple projects involve complete transformer loop rebuilds including both electrical and civil components.

4.2.3 NWS Suitability Assessment

In accordance with the OEB's BCA Framework and NWS Guidelines, Enova conducted a pre-assessment to determine whether there is a reasonable expectation that a non-wires solution could viably address the system need underlying this program. The assessment considered the following factors:

Assessment Criterion	Finding
Nature of System Need	The primary driver is underground cable and equipment deterioration based on age and failure history. Cable failures are on the rise, and are expected to rise over the forecast period, consistent with industry accepted life expectancy curves for cables. Secondary drivers include voltage standardization and improvement of subdivision loop switching capability. The need is not capacity-driven.
Physical Replacement Requirement	The investment requires physical excavation and replacement of underground cables, duct banks, transformer pads, switching equipment, and associated civil works. Cable replacement is inherently a physical construction activity that cannot be deferred or avoided through demand-side management. Underground cable insulation deterioration is a progressive, irreversible degradation mechanism.
NWS Technical Applicability	NWS technologies cannot address underground cable insulation deterioration, duct bank structural degradation, or transformer equipment wear. Unlike overhead systems where selective component replacement may extend life, underground cable failure modes (insulation breakdown, water treeing, jacket deterioration) require full cable replacement. A distributed energy resource cannot prevent a cable fault caused by insulation failure, nor can demand response reduce the thermal stress that accelerates cable aging on residential subdivision circuits with relatively flat load profiles.
BCA Framework Alignment (Section 3.1.1)	The BCA Framework's illustrative NWS use-cases involve capacity deferral, N-1 contingency management, and reliability improvement through DER backup. Underground subdivision renewal is not driven by capacity constraints but by the physical condition of buried assets. The aging cables present a failure risk regardless of load level, as insulation degradation is driven primarily by time, thermal cycling, and moisture exposure.
Regulatory and Safety Obligations	Enova is obligated under the DSC and ESA Electrical Safety Code to maintain underground infrastructure in safe operating condition. Cable failures pose arc flash and ground potential rise safety risks. Extended repair durations for underground failures make proactive replacement the prudent approach.

4.2.4 Pre-Assessment Conclusion

The R-UL-S program addresses non-discretionary system needs driven by the physical deterioration of underground cable, equipment, and civil infrastructure in residential subdivisions. Cable insulation degradation is an irreversible, progressive failure mechanism that cannot be addressed through demand management, energy storage, or any other NWS technology. The investment requires physical excavation and replacement of buried assets – work that is

fundamentally incompatible with non-wires alternatives. The BCA Framework's illustrative NWS applications involve capacity management scenarios that do not apply to condition-driven underground renewal.

Based on the above assessment, Enova concludes that NWS is not a viable alternative for this program. In accordance with Section 2.2 of the BCA Framework, a full benefit-cost analysis using the Distribution Service Test (DST) is therefore not required. This pre-assessment is filed with the OEB as required by the NWS Guidelines.

4.3. Program R-OL-RP – OH Line Renewal – Routine Projects

Program Code:	R-OL-RP
Program Name:	OH Line Renewal – Routine Projects
OEB Investment Category:	System Renewal
2027 Test Year Capital:	$4,107,173 (exceeds $2M BCA Framework threshold)
System Need Classification:	Non-Discretionary (condition-driven asset replacement)
Pre-Assessment Outcome:	NWS is NOT a viable alternative – Full BCA not required

4.3.1 Description of System Need

This program involves the planned rebuilding of overhead distribution lines in poor condition that are not associated with voltage conversion. These lines involve assets that are past their typical useful life, cannot be refurbished, and if not replaced represent a risk to public safety and customer reliability. The lines were originally installed between the 1960s and 1980s, are 40 to 60+ years of age, and have Health Index ratings in the Poor and Very Poor categories as determined through Enova's Asset Condition Assessment (ACA) program. The 2027 program comprises 7 individual projects totalling $4.11M across the service areas.

4.3.2 Assets and Scope

The program scope includes design, construction, and installation of new poles designed to conform to O.Reg 22/04-compliant standards, as well as new conductors, insulators, transformers, and equipment. Although pole condition is normally the main driver, other assets such as transformers, insulators, wire, and arrestors are also replaced as part of the pole line rebuild. These assets are nearing end of life and would not normally survive a second life cycle. Replacing all assets simultaneously is more cost-effective and less disruptive than waiting until individual assets fail.

4.3.3 NWS Suitability Assessment

In accordance with the OEB's BCA Framework and NWS Guidelines, Enova conducted a pre-assessment to determine whether there is a reasonable expectation that a non-wires solution could viably address the system need underlying this program. The assessment considered the following factors:

Assessment Criterion	Finding
Nature of System Need	The primary driver is physical asset deterioration identified through Enova's ACA program. Poles have Health Index ratings in the Poor and Very Poor categories, with many failing remaining-strength testing. This is a condition-driven need, not a capacity-driven need; the existing lines have adequate capacity for current and forecast load.
Physical Replacement Requirement	The investment requires physical replacement of poles, conductors, transformers, and hardware. No DER technology can substitute for a structurally deficient wood pole, restore strength to a deteriorated cross-arm, or replace corroded conductor. The assets must be physically removed and replaced to eliminate safety hazards.
NWS Technical Applicability	NWS technologies are designed to manage load, defer capacity upgrades, or improve reliability through alternative energy supply. None of these technologies can address the physical deterioration of pole structures, conductor degradation, or equipment wear that drives this program. A battery energy storage system cannot prevent a weakened pole from failing during an adverse weather event.
BCA Framework Alignment (Section 3.1.1)	The BCA Framework's illustrative NWS use-cases involve: (1) forecast overload approaching capacity; (2) N-1 contingency; and (3) underperforming circuit reliability. This program is not driven by any of these conditions. The system need is asset condition and safety compliance, which falls outside the scope of NWS applicability.
Regulatory and Safety Obligations	Enova is obligated under O.Reg 22/04 and CSA C22.3 No.1 to maintain overhead construction to current safety standards. Poles failing remaining-strength testing represent public safety risks requiring physical replacement. Deferral of replacement increases the probability of uncontrolled pole failure.

4.3.4 Pre-Assessment Conclusion

The R-OL-RP program addresses non-discretionary system needs driven by the physical deterioration of overhead assets. The nature of these needs is fundamentally incompatible with NWS: no distributed energy resource can restore structural integrity to a deteriorated pole or replace degraded conductor and equipment. The system need does not involve capacity constraint, load growth, or contingency planning scenarios where NWS technologies are applicable. Enova's obligation to maintain safe and reliable overhead construction under O.Reg 22/04, the ESA Electrical Safety Code, and CSA standards further confirms that physical asset replacement is the only viable response.

Based on the above assessment, Enova concludes that NWS is not a viable alternative for this program. In accordance with Section 2.2 of the BCA Framework, a full benefit-cost analysis using the Distribution Service Test (DST) is therefore not required. This pre-assessment is filed with the OEB as required by the NWS Guidelines.

4.4. Program E-SP – Relocations – Special Projects

Program Code:	E-SP
Program Name:	Relocations – Special Projects
OEB Investment Category:	System Access
2027 Test Year Capital:	$3,131,253 (exceeds $2M BCA Framework threshold)
System Need Classification:	Non-Discretionary (statutory obligation – municipal road authority direction)
Pre-Assessment Outcome:	NWS is NOT a viable alternative – Full BCA not required

4.4.1 Description of System Need

This program represents capital expenditures required to comply with statutory obligations related to the relocation of overhead and underground distribution facilities installed within municipal or provincial road allowances. Unlike routine PSWHA relocations, this program includes projects where an alternative cost-sharing arrangement is followed. An example project type involves overhead-to-underground conversions directed by a municipal road authority in conjunction with road reconstruction or widening projects. Where the road authority directs Enova to replace aged overhead plant with underground, the road authority typically funds the cost difference between overhead and underground systems (75–85% of total project cost). The 2027 program comprises 8 projects totalling $3.13M, driven by municipal road construction schedules in the Region of Waterloo.

4.4.2 Assets and Scope

The program scope includes relocation of existing overhead and underground distribution lines, poles, transformers, and associated equipment to accommodate municipal road construction. Each project is triggered by a specific municipal construction project and must be completed within the municipality’s construction schedule.

4.4.3 NWS Suitability Assessment

In accordance with the OEB's BCA Framework and NWS Guidelines, Enova conducted a pre-assessment to determine whether there is a reasonable expectation that a non-wires solution could viably address the system need underlying this program. The assessment considered the following factors:

Assessment Criterion	Finding
Nature of System Need	The primary driver is the statutory obligation to relocate distribution facilities when directed by municipal road authorities. The timing, scope, and location of each project are determined by the municipality's road construction schedule, which is outside Enova's control. This is an obligation-driven need, not a condition-driven or capacity-driven need.
Physical Replacement Requirement	Each project requires physical removal of existing distribution infrastructure from the road construction zone and reinstallation in a new alignment. For overhead-to-underground conversions, new underground duct bank, cable, and pad-mounted equipment must be constructed. No DER technology can relocate a pole line or duct bank out of a road widening zone.
NWS Technical Applicability	NWS technologies are designed to manage load, defer capacity upgrades, or improve reliability. None of these technologies can address the physical conflict between existing distribution infrastructure and municipal road construction. A battery or demand response program cannot move a pole that is in the path of a road widening project.
BCA Framework Alignment (Section 3.1.1)	The BCA Framework's illustrative NWS use-cases involve capacity deferral, N-1 contingency, and reliability improvement. Municipal road authority-directed relocations are not driven by any of these conditions. The system need is the resolution of a physical conflict between existing infrastructure and municipal construction.
Regulatory and Safety Obligations	Enova is obligated under the Public Service Works on Highways Act (PSWHA) and equivalent municipal cost-sharing arrangements to relocate its facilities when directed by the road authority. This obligation is non-discretionary and cannot be deferred through NWS.

4.4.4 Pre-Assessment Conclusion

The E-SP program addresses non-discretionary system needs driven by statutory obligations to relocate distribution facilities at the direction of municipal road authorities. The nature of these needs is fundamentally incompatible with NWS: no distributed energy resource can resolve the physical conflict between existing infrastructure and municipal road construction. The system need does not involve capacity constraint, load growth, or reliability scenarios where NWS technologies are applicable.

Based on the above assessment, Enova concludes that NWS is not a viable alternative for this program. In accordance with Section 2.2 of the BCA Framework, a full benefit-cost analysis using the Distribution Service Test (DST) is therefore not required. This pre-assessment is filed with the OEB as required by the NWS Guidelines.

5. Station Program Pre-Assessments

5.1 Station Equipment – Renewal (R-SE)

Program Code:	R-SE (Station Equipment – Renewal)
OEB Investment Category:	System Renewal
2027 Capital:	$7,742,259
5-Year Capital (2027–2031):	$41,623,181 (exceeds $2M threshold in every year)
System Need Classification:	Non-Discretionary (condition-driven asset replacement)
Pre-Assessment Outcome:	NWS is NOT a viable alternative – Full BCA not required

5.1.1 Description of System Need

This program involves the planned renewal of transformer and distribution station equipment that has reached or is approaching end of life. Station equipment renewal is identified through Enova's Asset Condition Assessment (ACA) program and includes the replacement of switchgear, power transformers, protection relays, Remote Terminal Units (RTUs), circuit breakers, and associated control and communication equipment at Enova's transformer stations and municipal substations.

5.1.2 NWS Suitability Assessment

In accordance with the OEB's BCA Framework and NWS Guidelines, Enova conducted a pre-assessment to determine whether there is a reasonable expectation that a non-wires solution could viably address the system needs underlying this program. The assessment considered the following factors:

Assessment Criterion	Finding
Nature of System Need	The primary driver is the physical deterioration and obsolescence of station equipment identified through Enova's ACA program. Switchgear, protection relays, and power transformers have reached or exceeded their typical useful life. Replacement parts for legacy equipment (electromechanical relays, certain SF6 breaker types) are no longer available from manufacturers. This is a condition-driven need, not a capacity-driven need — the stations have adequate capacity for current and forecast load.
Physical Replacement Requirement	The investment requires physical removal and replacement of station equipment: switchgear, power transformers, protection relays, RTUs, breakers, and associated control wiring. These are large, complex electromechanical assets that must be physically installed in the station. No DER technology can substitute for a deteriorated switchgear lineup or a power transformer with degraded insulation.
NWS Technical Applicability	NWS technologies (energy storage, distributed generation, demand response) are designed to manage load, defer capacity upgrades, or improve reliability through alternative energy supply. None of these technologies can address the physical deterioration of switchgear, transformer insulation degradation, or the obsolescence of breakers and electromechanical protection relays. A battery energy storage system cannot prevent a switchgear failure caused by contact erosion, nor can it replace a transformer with degraded oil quality.
BCA Framework Alignment (Section 3.1.1)	The BCA Framework's illustrative NWS use-cases involve: (1) forecast overload approaching capacity; (2) N-1 contingency management; (3) underperforming circuit reliability. Station equipment renewal is not driven by any of these conditions. The system need is equipment condition and safety compliance, which falls outside the scope of NWS applicability.
Regulatory and Safety Obligations	Enova is obligated under the Ontario Electrical Safety Code, CSA standards (C22.3), and the Distribution System Code to maintain station equipment in safe operating condition. Station equipment failures can result in catastrophic events (transformer fires, arc flash incidents, loss of supply to thousands of customers). The obligation to maintain safe and reliable station infrastructure is non-discretionary.

5.1.3 Pre-Assessment Conclusion

The Station Equipment Renewal program addresses non-discretionary system needs driven by the physical deterioration and obsolescence of station equipment. The nature of these needs is fundamentally incompatible with NWS: no distributed energy resource can restore degraded transformer insulation, replace worn switchgear contacts, or substitute for obsolete protection

relays. The system need does not involve capacity constraint or load growth scenarios where NWS technologies are applicable.

Based on the above assessment, Enova concludes that NWS is not a viable alternative for this program. A full benefit-cost analysis using the Distribution Service Test is therefore not required. This pre-assessment is filed with the OEB as required by the NWS Guidelines.

6. Forward-Looking NWS Consideration (2028–2031)

Enova will continue to apply NWS screening to all capital programs exceeding $2M across the DSP planning period. As NWS technologies mature and the OEB's Phase 2 BCA Framework is finalized, Enova will incorporate any updates into its planning methodology.

Enova notes the following areas where NWS may warrant more detailed consideration in future DSP periods:

Station capacity thresholds: The stations capital narrative identifies that in the latter part of the 2027–2031 period, early-stage planning is underway for additional station capacity to address forecast load growth. Future capacity additions triggered by general load growth forecasts may be candidates for NWS deferral analysis. Enova will conduct detailed NWS screening for any capacity-driven station expansion that is not triggered by a specific customer connection obligation.

Grid Improvements — Connectivity and Automation: Enova's System Service programs (U-GI-C, U-GI-A) involve the installation of tie-line connections and automated switching equipment. While these programs are below $2M individually, they represent grid modernization investments that could, in principle, be complemented by NWS technologies (e.g., DER-based islanding capability). Enova will monitor the evolution of NWS-grid modernization integration opportunities.

Electrification-driven load growth: The IEP Directive (June 2025) anticipates significant load growth from electrification (EV charging, heat pumps). If future DSP periods identify distribution system capacity constraints driven by electrification load growth, NWS screening will be a standard component of the alternatives analysis for those investments.

7. Conclusion and Filing Statement

Enova has completed pre-assessments for all capital investment programs across its 2027–2031 DSP that exceed the $2 million threshold established by the OEB's NWS Guidelines and BCA Framework. This includes four distribution line programs and one station program, for a total of five programs assessed.

Code	Program	Driver	Why NWS Not Viable	BCA Required?
R-OL-VU	OH Renewal – Voltage Upgrade	Asset condition	Physical pole/conductor replacement	No — pre-assessment filed
R-OL-RP	OH Renewal – Routine Projects	Asset condition	Physical pole/line replacement	No — pre-assessment filed
R-UL-S	UG Renewal – Subdivisions	Cable deterioration	Cable excavation/replacement	No — pre-assessment filed
E-SP	Relocations – Special Projects	Municipal obligation	Physical relocation required	No — pre-assessment filed
R-SE	Station Equipment – Renewal	Asset condition	Physical equipment replacement	No — pre-assessment filed

This document is filed as a standalone appendix to Enova's Distribution System Plan in fulfillment of the OEB's requirement that pre-assessments be filed with related applications regardless of outcome. Enova will continue to evaluate NWS opportunities across its capital programs, particularly for future capacity-driven investments where the BCA Framework's illustrative use-cases may be applicable.

8. References

1. Ontario Energy Board, Benefit-Cost Analysis Framework for Addressing Electricity System Needs, EB-2023-0125, May 16, 2024.

2. Ontario Energy Board, Non-Wires Solutions Guidelines for Electricity Distributors, EB-2024-0118, March 28, 2024.

3. Ontario Energy Board, BCA Framework Issuance Letter, EB-2023-0125, May 16, 2024.

4. Ontario Energy Board, Filing Requirements for Electricity Distribution Rate Applications, Chapter 5, 2026 Edition, December 16, 2025.

5. Ontario Energy Board Act, 1998, S.O. 1998, c. 15, Schedule B, Section 28.

6. Ontario Energy Board, Distribution System Code, March 27, 2024.

7. O.Reg 22/04, Electrical Distribution Safety, under the Electricity Act, 1998.

8. CSA C22.3 No. 1, Overhead Systems.

9. BCA Framework Reporting Template (Excel), May 16, 2024.

APPENDIX M

VASH - Climate Vulnerability of Distribution Pole Assets

Enova

Vulnerability Assessment and System Hardening (VASH)

Engineering Analysis: Climate Vulnerability of Distribution Pole Assets



June 24, 2026

TABLE OF CONTENTS

Contents i
1. Introduction 1
2. Vulnerability Assessment 1
  2.1 Asset Summary and Scope 1
  2.2 Failure Thresholds 2
  2.3 Climate Peril Projections 3
  2.4 Vulnerability Heatmap Results 3
3. Historic Outage Calibration 3
  3.1 Data Analysis Methodology 3
  3.2 Results 4
4. Benefit-Cost Analysis 4
  4.1 Project Characterization 4
  4.2 Economic and Criticality Assumptions 5
  4.3 Project Costs 5
  4.4 BCA Results 6
  4.5 Interpretation 6
5. Path Forward 6

1. Introduction

In October 2025, the Ontario Energy Board (OEB) released the final Vulnerability Assessment and System Hardening (VASH) Report and Toolkit (EB-2024-0199), establishing a standardized framework for distributors to assess climate-related vulnerabilities and evaluate system hardening investments through a benefit-cost analysis (BCA). This document presents Enova Power Corporation's VASH assessment, prepared on a best-efforts basis for inclusion in the Distribution System Plan (DSP).

Enova has been an active participant in the Utilities Standards Forum (USF) VASH working group, a collaborative industry initiative where member utilities jointly examined the VASH Toolkit's methodology, tested pole vulnerability modelling using SPIDAcalc structural analysis software, and developed a shared understanding of appropriate input parameters. This working group engaged directly with the OEB project owners to ensure consistent interpretation of the framework. The findings from this collaborative effort have informed the assumptions and parameters used throughout this assessment.

Enova recognizes that the VASH framework represents a new approach to integrating climate resilience into distribution planning, and that the OEB has indicated it will take into account the time distributors have had to prepare these analyses. This filing reflects Enova's initial assessment and demonstrates its commitment to embedding climate resilience considerations into its asset management and system planning processes. Enova intends to refine its analysis in future filings as data availability, analytical capabilities, and industry experience with the VASH framework mature.

2. Vulnerability Assessment

2.1 Asset Summary and Scope

The VASH assessment focuses on Enova's wood distribution pole fleet, which represents the primary overhead asset class vulnerable to wind-related climate perils.

For the purposes of this initial assessment, Enova analyzed approximately 7,000 degraded wood poles, representing roughly 15% of its total wood pole population. This 10% - 15% of total population assumption was established through the USF working group's SPIDAcalc modelling, which demonstrated that poles at or above 60% remaining strength generally retain sufficient capacity to withstand the design-level climate loads.

Poles are categorized into sub-classes based on their circuit configuration, as this directly affects wind loading and therefore the failure threshold. New poles (those with remaining strength above 60%) are included in the asset inventory for Excel toolkit model to work but show no vulnerability under the modelled climate perils and are excluded from the BCA project scope (i.e., count set to 0).

Table 1: Asset Summary — Pole Sub-Classes Included in VASH Assessment

Asset Class	Sub-Class	Count	Condition	In BCA Scope
Pole	1Ph Degraded	1,960	<60% RS	Yes
Pole	1cct Degraded	3,360	<60% RS	Yes
Pole	2cct Degraded	1,400	<60% RS	Yes
Pole	3cct Degraded	280	<60% RS	Yes
Pole	1Ph New	0	≥60% RS	No
Pole	1cct New	0	≥60% RS	No
Pole	2cct New	0	≥60% RS	No
Pole	3cct New	0	≥60% RS	No

RS = Remaining Strength. Total degraded poles in BCA scope: 7,000; the count distribution among 1Ph, 1cct, 2 cct and 3 cct is based on system wide asset distribution percentage.

2.2 Failure Thresholds

Wind severity thresholds were derived from SPIDAcalc structural modelling conducted by the USF working group. The analysis evaluated standard pole line configurations per USF framing standards for single-phase through three-circuit configurations. Poles were modelled under climate wind loads per CSA C22.3 No. 1:25. The failure threshold is defined as the wind speed at which pole loading exceeds 100% of design capacity.

It is important to note that exceeding the design loading limit does not equate to immediate pole failure; poles exhibit elastic-plastic behaviour and can absorb wind energy beyond their rated capacity. However, the 100% loading threshold represents the accepted engineering design limit and provides a conservative basis for vulnerability assessment consistent with CSA standards.

Table 2: Wind Failure Thresholds from SPIDAcalc Analysis

Asset Class	Sub-Class	Peril	Threshold (kph)	Unit Basis
Pole	1Ph Degraded	Wind	100	kph (10-min avg.)
Pole	1cct Degraded	Wind	100	kph (10-min avg.)
Pole	2cct Degraded	Wind	80	kph (10-min avg.)
Pole	3cct Degraded	Wind	80	kph (10-min avg.)
Pole	1Ph New	Wind	160	kph (10-min avg.)
Pole	1cct New	Wind	120	kph (10-min avg.)
Pole	2cct New	Wind	110	kph (10-min avg.)
Pole	3cct New	Wind	100	kph (10-min avg.)

Multi-circuit poles carry greater wind loading and have lower failure thresholds. New poles show no vulnerability at projected wind speeds.

2.3 Climate Peril Projections

Climate peril probabilities were derived using the OEB-provided climate dataset embedded in the VASH Toolkit, sourced from Environment and Climate Change Canada (ECCC) and CSA C22.3 No. 1:25 wind return period data. The RCP 8.5 scenario was selected as the climate projection pathway, consistent with a conservative approach to long-lived infrastructure planning.

Enova's service territory covering the cities of Kitchener and Waterloo, and the townships of Woolwich, Wilmot, and Wellesley. The Toolkit's Climate Severity Calculator produces identical results for Kitchener and Waterloo, reflecting their geographic proximity and shared climate zone. Accordingly, Kitchener was used as the representative location in the Excel toolkit for value lookup and calculation.

2.4 Vulnerability Heatmap Results

The VA Heatmap summarizes the annual probability of wind speed exceedance for each pole sub-class over the projection period. Key findings are as follows:

- **2-circuit and 3-circuit degraded poles** fall in the Medium vulnerability bin (2%–10% annual probability), with probabilities of approximately 10.5% in 2025 rising to 11.3% by 2090. These poles are the most vulnerable assets in the fleet.
- **1-phase and 1-circuit degraded poles** fall in the Low vulnerability bin (<2%), with probabilities of approximately 1.1% in 2025 rising to 2.0% by 2090.
- **All new pole sub-classes** show no vulnerability (annual probability effectively zero) across the entire projection period, confirming that poles meeting current CSA design standards provide adequate resilience to projected wind perils.

The heatmap results confirm that vulnerability is driven by the combination of asset degradation and circuit loading. The VASH framework does not account for ongoing asset maintenance and inspection cycles, which may mitigate some of the projected risk for poles approaching the 60% threshold.

3. Historic Outage Calibration

3.1 Data Analysis Methodology

The VASH BCA model requires calibration against historic weather-related outage observations to ground the modelled failure probabilities against actual system performance. Per the VASH Report guidance, these outages should reflect those caused by the specific climate perils addressed in the analysis, and inclusion of outages from other causes would inflate results.

Enova's outage management system (OMS) contains records from two legacy systems reflecting its merged service territory: the former Waterloo North Hydro (WHN) system, which uses OEB standard cause codes (e.g., "6 – Adverse Weather"), and the former Kitchener-Wilmot Hydro (KWH) system, which uses detailed descriptive cause codes (e.g., "Adverse Weather – Extreme Winds >90km/h"). Both systems were queried for the analysis period of 2019–2025.

Since the VASH toolkit models wind speed exceedance as the failure mechanism for poles, the outage filtering was restricted to **confirmed pole structural failures** caused by wind events.

3.2 Results

Over the period 2019–2024, yielding an average of approximately 1.2 pole-related outage events per year system-wide. A sensitive analysis is conduct, value from 1.2 to 2 doesn't change the BCR value.

A value of 2 historic annual outage events was used as the BCA calibration input, reflecting a slightly rounded figure appropriate for a system-wide pole replacement project. The median customer interruption per pole failure event is approximately 4 customers, with an average outage duration of approximately 186 minutes.

4. Benefit-Cost Analysis

4.1 Project Characterization

The BCA evaluates an Early Retirement project type, whereby degraded poles are replaced with new poles before their natural end-of-life. The project is characterized as a Frequency impact type, reflecting the expectation that pole replacement will reduce the frequency of wind-related structural failures without changing the duration or customer count of remaining outages. Key project parameters are summarized below.

- **Project Start Year:** 2027
- **Project Expected Lifetime:** 40 years – 45 years (sensitivity analysis range)
- **Remaining Useful Life of Existing Assets:** 1 – 10 years (sensitivity analysis range)
- **Scope:** 7,000 degraded poles (1Ph, 1cct, 2cct, 3cct sub-classes)
- **Replacement Strategy:** Like-for-like replacement of degraded poles with new poles of the same circuit configuration. 100% replacement assumed for all sub-classes.
- **Incremental Project Non-Asset Costs:** $500,000 - $2,000,000 (sensitivity analysis range)
- **Climate Scenario:** RCP 8.5

4.2 Economic and Criticality Assumptions

The following economic variables and criticality parameters were applied. These values represent Enova's current best estimates and are subject to refinement in future filings. Most of them are default values from the Excel toolkit.

Table 4: Economic Variables

Variable	Unit	Value
Inflation	%	3.00%
Nominal Utility Discount Rate (WACC)	%	5.60%
Social Discount Rate	%	4.00%
Baseline & Scenario OM&A Cost	% of costs	1.50%
Tax Rate	%	26.50%
Historic Annual Outage Events	Count	2
Average Outage Duration	Minutes	186
Estimated Customers Interrupted (Res)	Count	200
Estimated Customers Interrupted (Sm C&I)	Count	15
Estimated Customers Interrupted (M/L C&I)	Count	1
Baseline VOLL	$/Outage	$5,000 - $10,000

4.3 Project Costs

Unit repair and replacement costs reflect Enova's current cost experience. A 80% - 100% replacement assumption is applied for sensitivity analysis, consistent with the VASH Report guidance that where CSA-derived severity thresholds are used, the replacement percentage is set to 100%.

Table 5: Replacement Cost Summary

Sub-Class	Count	Repair $/unit	Replace $/unit	Budget ($)	BCA Cost ($)
1Ph Degraded	1,960	~$5,000	~$12,000	$23,520,000	$15,858,278
1cct Degraded	3,360	~$5,000	~$12,000	$40,320,000	$27,185,619
2cct Degraded	1,400	~$5,000	~$20,000	$28,000,000	$18,878,902
3cct Degraded	280	~$5,000	~$25,000	$7,000,000	$4,719,726
Total	**7,000**			**$98,840,000**	**$66,642,525**

BCA Cost reflects the present value of incremental revenue requirement per the Toolkit's methodology.

4.4 BCA Results

Table 6: Project BCA Results

Metric	Unit	Value
Benefit-Cost Ratio (BCR)	Ratio	0.78 - 0.97 (with the sensitivity analysis range)

4.5 Interpretation

The BCA produces a benefit-cost ratio of 0.78 - 0.97, indicating that the present value of quantifiable benefits from avoided asset repairs and customer interruption costs covers approximately 78% - 97% of the present value of project costs.

5. Path Forward

Enova views this VASH assessment as an important first step in integrating climate resilience into its distribution system planning. The analysis has demonstrated that degraded multi-circuit poles represent the relatively more vulnerable segment of the fleet and that proactive replacement delivers meaningful, though not fully cost-justified under the current modelling assumptions, reliability and resilience benefits.

Enova intends to advance its VASH analysis in several areas for future filings:

- **Refined Outage Calibration:** Continue forensic OMS analysis to build a more robust dataset of pole-specific failure events.
- **Feeder-Level Analysis:** Transition from system-wide assessment to project-specific BCAs targeting the highest-vulnerability feeders, where is possible, consistent with the VASH Report's preferred approach of matching outage data to project location.
- **Integration with Asset Management:** Consider VASH vulnerability outputs into Enova's existing asset condition assessment and capital planning processes, ensuring that climate resilience considerations are systematically incorporated alongside other investment drivers.
- **Continued Industry Collaboration:** Maintain participation in the USF VASH working group and ongoing OEB consultations to contribute to and benefit from evolving industry practices.

Enova will continue to exercise its asset management practices with climate resilience as a complementary planning driver, consistent with the OEB's expectations as set out in the VASH Report and the IEP Directive.

APPENDIX N

OEB Appendix 5-A Unit Cost Metrics

Appendix 5-A
Metrics

Metric Category	Metric	Measures	
		1 Year (2025)	5 Year Average
Cost	Total Cost per Customer (1)	414.03	453.03
	Total Cost per km of Line (2)	7,952.71	15,381.16
	Total Cost per MW (3)	96,122.48	110,573.59
CAPEX	Total CAPEX per Customer	286.12	331.36
	Total CAPEX per km of Line	5,495.77	11,303.55
O&M	Total O&M per Customer	127.91	121.67
	Total O&M per km of Line	2,456.94	4,077.60

Notes to the Table:

1 The Total Cost per Customer is the sum of a distributor's capital and O&M costs divided by the total number of customers that the distributor serves.

2 The Total Cost per km of Line is the sum of a distributor's capital and O&M costs divided by the total number of kilometers of line that the distributor operates to serve its customers.

3 The Total Cost per MW is the sum of the distributor's capital and O&M costs divided by the total peak MW that the distributor serves.

Explanatory Notes on Adverse Deviations (complete only if applicable)

Metric Name:

Total Cost per km of Line / Total CAPEX per km of Line / Total O&M per km of Line

Enova Power's 2025 metrics involving cost per kilometer of line, represent a significant reduction compared to prior years. The change is primarily due to the change in method used to calculate the total kilometers of line.

Starting in 2024, the cost per kilometer was calculated using both:
• Primary line kilometers: 3,736 km
• Secondary line kilometers: 4,738 km
This resulted in a lower per-kilometer costs.

In prior years, the calculation only included the primary kilometers of line.

Metric Name:

Metric Name:

APPENDIX O

OEB Chapter 2 Appendix 2-AA

Appendix 2-AA – Capital Projects Table

Projects	2020 Actual			2021 Actual			2022 Actual			2023 Actual	2024 Actual	2025 Actual	2026 Bridge	2027 Test	2028 Forecast	2029 Forecast	2030 Forecast	2031 Forecast
	WNH	KWH	Total	WNH	KWH	Total	WNH	KWH	Total	Enova	Enova	Enova	Enova	Enova	Enova	Enova	Enova	Enova
Reporting Basis	***MIFRS***	***MIFRS***	***MIFRS***	***MIFRS***	***MIFRS***	***MIFRS***	***MIFRS***	***MIFRS***	***MIFRS***	***MIFRS***	***MIFRS***	***MIFRS***	***MIFRS***	***MIFRS***	***MIFRS***	***MIFRS***	***MIFRS***	***MIFRS***
System Access																		
Relocations - Routine Projects	$ 1,308	$ 2,450	$ 3,759	$ 1,540	$ 763	$ 2,303	$ 765	$ 1,734	$ 2,499	$ 597	$ 2,395	$ 3,511	$ 1,388	$ 727	$ 1,227	$ 1,227	$ 1,227	$ 1,227
Relocations - Special Projects	$ 0	$ 0	$ 0	$ 3	$ 0	$ 3	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 3,322	$ 3,131	$ 3,131	$ 3,131	$ 2,831	$ 3,431
Customer Connections - Loads	$ 3,030	$ 2,044	$ 5,074	$ 2,853	$ 2,523	$ 5,376	$ 2,993	$ 2,966	$ 5,959	$ 5,905	$ 5,950	$ 6,858	$ 8,553	$ 8,027	$ 7,527	$ 7,527	$ 7,527	$ 7,527
Customer Connections - Generation	$ 384	$ 30	$ 414	$ 363	$ 72	$ 435	$ 85	$ 70	$ 155	$ 200	$ 199	$ 328	$ 371	$ 299	$ 299	$ 299	$ 299	$ 299
OH Line Expansions	$ 1,425	$ 0	$ 1,425	$ 764	$ 0	$ 764	$ 608	$ 0	$ 608	$ 971	$ 638	$ 3,817	$ 976	$ 729	$ 729	$ 729	$ 729	$ 729
UG Line Expansions - Feeders	$ 946	$ 256	$ 1,201	$ 186	$ 1,810	$ 1,995	$ 1,339	$ 1,209	$ 2,548	$ 2,213	$ 1,252	$ 650	$ 1,055	$ 2,794	$ 2,794	$ 2,794	$ 2,794	$ 2,794
UG Line Expansions - Subdivisions	$ 929	$ 2,549	$ 3,478	$ 1,802	$ 1,163	$ 2,965	$ 1,129	$ 2,305	$ 3,434	$ 3,521	$ 4,143	$ 4,450	$ 5,852	$ 4,165	$ 4,165	$ 4,165	$ 4,165	$ 4,165
Station Buildings - Expansions	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 334	$ 323	$ 0	$ 0	$ 0	$ 0
Station Equipment - Expansions	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 2,357	$ 2,280	$ 2,007	$ 7,249	$ 13,653	$ 10,629
SCADA Equipment - Expansions	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
Meters - Retail	$ 774	$ 409	$ 1,184	$ 690	$ 346	$ 1,036	$ 661	$ 348	$ 1,008	$ 1,120	$ 1,004	$ 1,743	$ 1,363	$ 1,427	$ 1,587	$ 9,814	$ 8,809	$ 8,842
Sub-Total	$ 8,797	$ 7,739	**$ 16,535**	$ 8,200	$ 6,676	**$ 14,876**	$ 7,578	$ 8,633	**$ 16,211**	**$ 14,527**	**$ 15,581**	**$ 21,357**	**$ 25,572**	**$ 23,903**	**$ 23,466**	**$ 36,935**	**$ 42,035**	**$ 39,644**
System Renewal																		
OH Line Renewal - Routine Projects	$ 3,418	$ 3,187	$ 6,605	$ 3,893	$ 5,431	$ 9,324	$ 6,756	$ 4,784	$ 11,540	$ 11,582	$ 6,171	$ 2,415	$ 2,270	$ 4,107	$ 4,107	$ 4,107	$ 4,107	$ 4,107
OH Line Renewal - Failing Conductor	$ 478	$ 0	$ 478	$ 1,493	$ 0	$ 1,493	$ 0	$ 0	$ 0	$ 0	$ 515	$ 171	$ 1,917	$ 1,941	$ 541	$ 541	$ 541	$ 541
OH Line Renewal - Voltage Upgrade	$ 616	$ 1,180	$ 1,796	$ 566	$ 664	$ 1,231	$ 497	$ 1,456	$ 1,953	$ 2,469	$ 3,070	$ 1,090	$ 3,520	$ 6,364	$ 5,364	$ 5,364	$ 5,364	$ 5,364
OH Line Renewal - Proactive	$ 539	$ 0	$ 539	$ 745	$ 0	$ 745	$ 516	$ 0	$ 516	$ 1,762	$ 767	$ 1,675	$ 358	$ 337	$ 337	$ 337	$ 337	$ 337
OH Line Renewal - Reactive	$ 610	$ 0	$ 610	$ 191	$ 0	$ 191	$ 398	$ 0	$ 398	$ 414	$ 772	$ 336	$ 1,055	$ 684	$ 684	$ 684	$ 684	$ 684
UG Line Renewal - Feeders	$ 0	$ 0	$ 0	$ 150	$ 650	$ 799	$ 0	$ 0	$ 0	$ 852	$ 880	$ 116	$ 2,251	$ 185	$ 2,252	$ 1,793	$ 1,118	$ 997
UG Line Renewal - Subdivisions	$ 1,292	$ 3,662	$ 4,954	$ 2,517	$ 3,962	$ 6,480	$ 2,329	$ 4,550	$ 6,879	$ 7,469	$ 6,009	$ 5,251	$ 2,312	$ 8,244	$ 12,930	$ 14,250	$ 13,850	$ 15,050
UG Line Renewal - Customer Connections	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 22	$ 200	$ 200	$ 200	$ 200	$ 200
UG Line Renewal - Network System	$ 0	$ 63	$ 63	$ 0	$ 186	$ 186	$ 0	$ 258	$ 258	$ 214	$ 573	$ 223	$ 0	$ 130	$ 130	$ 130	$ 130	$ 130
UG Line Renewal - Proactive	$ 340	$ 0	$ 340	$ 282	$ 0	$ 282	$ 347	$ 0	$ 347	$ 640	$ 721	$ 807	$ 1,113	$ 934	$ 434	$ 440	$ 441	$ 441
UG Line Renewal - Reactive	$ 0	$ 84	$ 84	$ 11	$ 53	$ 64	$ 0	$ 101	$ 101	$ 102	$ 521	$ 141	$ 957	$ 969	$ 969	$ 969	$ 969	$ 969
Station Building - Renewal	$ 358	$ 100	$ 458	$ 31	$ 0	$ 31	$ 0	$ 76	$ 76	$ 391	$ 596	$ 181	$ 617	$ 848	$ 432	$ 432	$ 432	$ 190
Station Equipment - Renewal	$ 844	$ 1,778	$ 2,622	$ 1,092	$ 974	$ 2,067	$ 675	$ 1,664	$ 2,339	$ 5,921	$ 7,232	$ 6,773	$ 5,769	$ 7,742	$ 8,966	$ 9,424	$ 8,411	$ 7,081
SCADA Equipment - Renewal	$ 137	$ 11	$ 148	$ 103	$ 11	$ 114	$ 14	$ 0	$ 14	$ 40	$ 113	$ 0	$ 63	$ 0	$ 0	$ 0	$ 0	$ 0
Sub-Total	$ 8,631	$ 10,065	**$ 18,696**	$ 11,076	$ 11,931	**$ 23,007**	$ 11,531	$ 12,889	**$ 24,420**	**$ 31,856**	**$ 27,940**	**$ 19,181**	**$ 22,224**	**$ 32,686**	**$ 37,347**	**$ 38,672**	**$ 36,586**	**$ 36,092**
SystemService																		
Grid Improvements - Connectivity	$ 0	$ 99	$ 99	$ 16	$ 287	$ 304	$ 0	$ 363	$ 363	$ 0	$ 2	$ 0	$ 64	$ 928	$ 928	$ 928	$ 928	$ 928
Grid Improvements - Automation	$ 786	$ 1,140	$ 1,926	$ 884	$ 716	$ 1,600	$ 0	$ 636	$ 636	$ 132	$ 304	$ 475	$ 433	$ 615	$ 615	$ 615	$ 615	$ 615
Grid Improvements - Resiliency	$ 0	$ 0	$ 0	$ 30	$ 0	$ 30	$ 251	$ 0	$ 251	$ 0	$ 0	$ 0	$ 307	$ 100	$ 100	$ 100	$ 100	$ 100
Station Building - Upgrades	$ 0	$ 0	$ 0	$ 66	$ 0	$ 66	$ 70	$ 0	$ 70	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
Station Equipment - Upgrades	$ 0	$ 0	$ 0	$ 62	$ 0	$ 62	$ 211	$ 0	$ 211	$ 0	$ 34	$ 115	$ 90	$ 0	$ 0	$ 0	$ 0	$ 0
SCADA Equipment - Upgrades	$ 0	$ 0	$ 0	$ 9	$ 0	$ 9	$ 260	$ 0	$ 260	$ 1,157	$ 728	$ 2,032	$ 1,903	$ 0	$ 0	$ 0	$ 0	$ 0
Meters - Wholesale	$ 41	$ 0	$ 41	$ 0	$ 0	$ 0	$ 52	$ 0	$ 52	$ 67	$ 0	$ 251	$ 58	$ 0	$ 0	$ 0	$ 0	$ 0
Sub-Total	$ 827	$ 1,240	**$ 2,066**	$ 1,068	$ 1,003	**$ 2,071**	$ 845	$ 999	**$ 1,844**	**$ 1,356**	**$ 1,068**	**$ 2,873**	**$ 2,854**	**$ 1,643**	**$ 1,643**	**$ 1,643**	**$ 1,643**	**$ 1,643**
General Plant																		
Fleet	$ 247	$ 847	$ 1,094	$ 569	$ 924	$ 1,493	$ 890	$ 904	$ 1,794	$ 2,011	$ 1,955	$ 3,476	$ 2,975	$ 3,315	$ 2,925	$ 2,995	$ 2,960	$ 2,985
Tools, Equipment, and Instruments	$ 0	$ 229	$ 229	$ 0	$ 92	$ 92	$ 92	$ 226	$ 318	$ 288	$ 451	$ 382	$ 361	$ 399	$ 401	$ 406	$ 406	$ 411
Hardware - IT	$ 296	$ 325	$ 621	$ 146	$ 168	$ 315	$ 281	$ 218	$ 500	$ 690	$ 442	$ 380	$ 1,148	$ 1,049	$ 947	$ 752	$ 752	$ 783
Software - IT	$ 626	$ 4,565	$ 5,191	$ 420	$ 3,507	$ 3,926	$ 126	$ 226	$ 351	$ 278	$ 4,586	$ 7,769	$ 4,875	$ 6,720	$ 3,247	$ 2,737	$ 2,467	$ 2,367
Cyber Security	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 125	$ 250	$ 250	$ 250	$ 250
Software - Distribution Support	$ 406	$ 0	$ 406	$ 575	$ 0	$ 575	$ 346	$ 0	$ 346	$ 267	$ 123	$ 0	$ 1,113	$ 958	$ 1,043	$ 1,619	$ 2,213	$ 1,448
Software - Administration Support	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 250	$ 0	$ 0	$ 0	$ 0	$ 0
Buildings	$ 89	$ 649	$ 738	$ 121	$ 673	$ 794	$ 187	$ 377	$ 564	$ 176	$ 365	$ 1,576	$ 8,093	$ 7,645	$ 1,455	$ 230	$ 205	$ 205
Furniture and Office Devices	$ 152	$ 8	$ 160	$ 118	$ 64	$ 182	$ 231	$ 35	$ 266	$ 174	$ 212	$ 85	$ 62	$ 7	$ 107	$ 107	$ 107	$ 107
Land and Land Rights	$ 47	$ 474	$ 521	$ 16	$ 1,339	$ 1,356	$ 50	-$ 1	$ 49	$ 57	$ 561	$ 24	$ 230	$ 200	$ 200	$ 200	$ 200	$ 200
Station Decommissioning	$ 3	$ 0	$ 3	$ 73	$ 0	$ 73	$ 78	$ 0	$ 78	$ 113	$ 46	$ 85	$ 381	$ 55	$ 57	$ 57	$ 57	$ 57
Sub-Total	$ 1,866	$ 7,097	**$ 8,963**	$ 2,038	$ 6,767	**$ 8,805**	$ 2,282	$ 1,985	**$ 4,266**	**$ 4,053**	**$ 8,741**	**$ 13,776**	**$ 19,489**	**$ 20,473**	**$ 10,632**	**$ 9,353**	**$ 9,617**	**$ 8,813**
Adjustment to CWIP	-$ 417	-$ 218	-$ 635	-$ 733	$ 0	-$ 733	$ 1,985	-$ 380	$ 1,605	$ 116	$ 53	-$ 344	$ 0					
Total	$ 19,704	$ 25,922	**$ 45,626**	$ 21,649	$ 26,377	**$ 48,026**	$ 24,220	$ 24,125	**$ 48,346**	**$ 51,908**	**$ 53,383**	**$ 56,843**	**$ 70,139**	**$ 78,705**	**$ 73,089**	**$ 86,604**	**$ 89,880**	**$ 86,192**