## BOMA-1

**Reference(s): Exhibit 1, Tab 1, Schedule 1, p19**

**Why have you not asked the Board to approve the five year DSP for the Enersource rate zone/division? Do you agree that the Board must approve the DSP prior to approving the ICM module for the first year covered by that DSP? Please discuss fully.**

**Response:**

Please see Alectra Utilities' response to CCC-4.

**BOMA-2**

**Reference(s): DSP**

**When was the initial draft of the Enersource DSP completed? When was the final draft approved by Enersource management, Alectra's management, Alectra's Board of Directors?**

**Response:**

The initial draft of the Enersource DSP was completed December 9th 2015. That version was filed with the OEB as part of Enersource's 2016 Price Cap IR (EB-2015-0065). The revised draft of the Enersource DSP, post Alectra Utilities' consolidation, was completed March 30th 2017.

The penultimate draft DSP, which included adjustments from the Innovative Customer Engagement feedback, was provided to Alectra Utilities executive on June 14th 2017. The DSP was approved on June 20th 2017.

**BOMA-3**

**Reference(s): DSP, p31**

**Alectra's evidence is that Enersource submitted a draft DSP in 2015 (EB-2015-0065) for the 2011 bridge year and the 2017-2021 test period. Please provide a copy of that DSP, or a link where it can be found. Please summarize the principal difference between the two plans, with particular reference to the projects included in the proposed capital module.**

**Response:**

Alectra Utilities provides the Draft DSP for the former Enersource Hydro Mississauga, which was submitted as part of its 2016 Price Cap IR Application (EB-2015-0065), as BOMA-3_Attach 1. Please see Alectra Utilities' response to 4-VECC-24 for the principal difference between the Draft DSP and the DSP included in Exhibit 3, Tab 1, Schedule 1, Attachment 50 – Enersource Rate Zone DSP.




DRAFT

# Enersource Hydro Mississauga Inc.

# Distribution System Plan

# 2015

## Executive Summary

In 2013, Enersource Hydro Mississauga Inc. (Enersource or the Company) established an Asset Management Division (AMD) responsible for the development of the Distribution System Plan (DSP) and Long Term Investment Portfolio (LTIP). The division's first priority was to create a Comprehensive Asset Management Policy (CAMP), stating that Enersource will adopt practices to optimize the performance and lifecycle costs of all of its assets in a safe, reliable, and sustainable manner. The Company's policy for the stewardship and management of these assets is to strike the best possible balance among risk, performance, and costs in a sustainable fashion that maximizes enterprise value while complying with all health, safety, environmental, and regulatory requirements. The objective of the DSP is to ensure the alignment of the LTIP with the CAMP when determining investments in electricity infrastructure, equipment, and general plant.

The DSP and LTIP support Enersource's strategy of adopting a complete lifecycle approach for all asset investments from the initial risk identification, preparation, design, acquisition, operation and maintenance to the decommissioning and removal or disposal of assets. To comply with Enersource's CAMP, the Company will maintain regulatory compliance, monitor risk during the lifecycle of an asset, and establish and maintain a conformance and quality framework to allow for continuous improvement.

Enersource embraces innovation and progressively implements best practices. The Company is committed to fostering a work environment that is committed to the asset management systems and complete lifecycle strategy.

The DSP also describes Enersource's service territory and gives a high level description of the subtransmission and distribution systems. This provides context of the topographical outline before assessing system performance and reliability history.

Where applicable, in the cases of System Service and System Access, Enersource considers Conservation and Demand Management (CDM) programs prior to engaging in any major capital investments (as exemplified in the Downtown Core expansion).

The DSP and LTIP are based on several inputs including, but not limited to, Asset Condition Assessment (ACA), system capacity/load forecast, asset information extracted from testing and inspection reports, information from the Integrated Operating Model (IOM), the Automated Mapping/Facilities Management (AM/FM), as well as Enersource's JD Edwards/Enterprise Resource Planning (JDE), and Customer Care and Billing (CC&B) systems.

Enersource's historical high standard of maintenance and sustainment practices have resulted in most of the distribution system assets being in an acceptable operational state. However, over the course of time and standard use, a large number of assets are expected to require replacement at increasing rates over the near and mid-term, especially transformers and underground cables. This is evidenced by a large number of distribution assets, installed during times of rapid growth in Mississauga, that are soon expected to approach the end of their useful life. This DSP outlines the tactics and activities that

Enersource will undertake in order to address such issues through proactive planning, risk evaluation, and the continuation of existing programs and projects.

The approach applied in the development of the DSP and LTIP is founded on key factors including system planning, prioritization, and the execution of capital projects in a sustainable manner. The objective of these activities is to select the projects and programs that deliver the required functions at the desired level of service and financial performance. These projects and programs have been summarized according to the Ontario Energy Board's (OEB) investment categories that include requirements for System Access, System Renewal, System Service, and General Plant.

System Access investments are modifications (including asset relocation) to a distribution system that a distributor must perform in order to provide customers (including generator customers) with access to electricity services via the distribution system.

System Renewal investments involve replacing and/or refurbishing system assets to extend their original service life and thereby maintain the ability of the distribution system to provide customers with electricity services.

System Service investments ensure the distribution system continues to meet distributor objectives while addressing anticipated future customer electricity service requirements.

Finally, General Plant investments are modifications, replacements, or additions to a distributor's assets that are not part of its distribution system, including land and buildings, tools and equipment, rolling stock, and electronic devices and software used to support day to day business and operations activities.

Enersource evaluates its capital investments, and creates its DSP and LTIP, based on the following business values from the OEB's Renewed Regulatory Framework for Electricity (RRFE):

- Regulatory/Public Policy Responsiveness: the ability to meet obligations mandated by government;
- Operational Effectiveness: the ability to continuously improve productivity and cost performance while delivering on system reliability and quality objectives;
- Customer Focus: services are provided in a manner reflective of identified customer preferences; and
- Financial Performance: financial viability is maintained and operational effectiveness savings are sustainable.

Based on the business value evaluations and numerous identified inputs, program and project business cases are developed under each investment category, which are then used to establish the near to medium term capital expenditure forecasts contained within this DSP. Overall, the DSP recommendations are consistent with previous Enersource investment activities and outline a continuation of programs and System Renewal projects. To address the impending increase in assets that are expected to reach end-of-life in the near and medium terms, this plan also identifies several initiatives under development and consideration that will allow Enersource to continually improve its asset management practices.

To ensure Enersource's DSP considers customer preferences, pursuant to the OEB's RRFE, Enersource has engaged Decision Partners Inc., a third party consultant, to conduct broad, professional, and scientific research on customers' behaviour regarding the DSP. This work is now underway. The customer input will be considered in the final version of the DSP to ensure that distribution services are provided in a manner responsive to customer preferences.

Overall, Enersource plans to significantly increase its System Renewal projects over this DSP's timeframe. The Company has met with potential third-party contractors that are committed to increasing their workforces over the next few years in order to meet Enersource's forecasted renewal project increases. The increase in investment is required due to the age and condition of a significant portion of Enersource's overhead and underground system assets, and to ensure the Company's distribution system continues to remain safe and reliable. Enersource has also seen a significant increase in operating and maintenance costs in recent years and is committed to reversing this trend.

After considering the System Renewal investment increases and what is required for System Service (two new substations for the Downtown Core, one additional substation to meet the 27.6kV electricity demand forecast), and System Access updates to support Light Rail Transit, Enersource reviewed its General Plant investment proposals and re-prioritized many planned activities over the entire DSP period. By more smoothly pacing General Plant investments over the DSP time frame, Enersource was able to maintain a relatively stable year-to-year investment portfolio that ensured sufficient funds would be available, labour resources would not be overly committed, and customer rates would be kept reasonable.

The chart below in **Figure 1** shows Enersource's actual and proposed capital investment portfolio expenditures between 2011-2021:

DRAFT

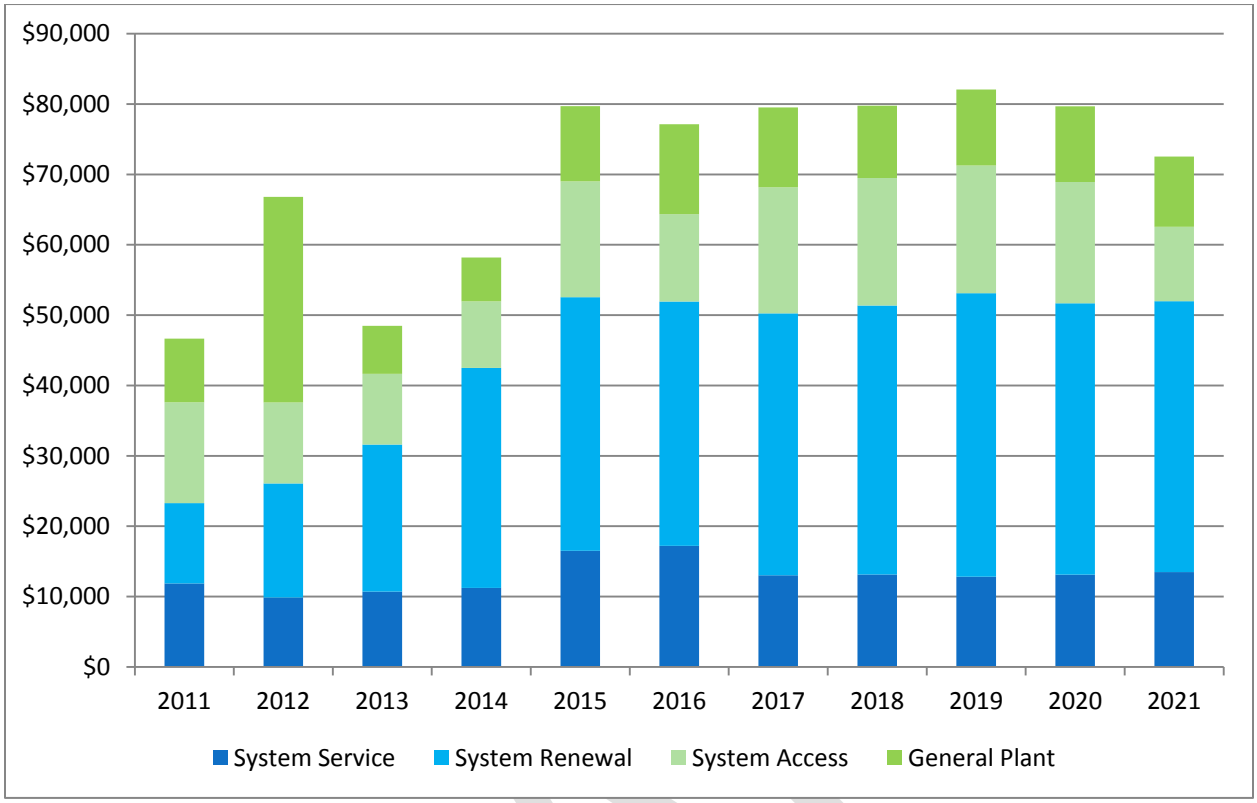



**Figure 1. Enersource's actual and proposed capital investment portfolio expenditures (2011-2021)**

### How the DSP is Organized

The DSP has been divided into three main sections. The first section provides stakeholders with an overview of the information filed in the plan including, but not limited to, key elements that affect the rates, the sources of cost savings, information on coordinated planning with third parties, and performance measurements for continuous improvement. The second section provides an overview of information pertaining to Enersource's asset management processes and the direct links between the asset management system and the proposed capital expenditures outlined in the DSP. The final section explains Enersource's capital investments resulting from the asset management planning processes and the capacity of the distribution system to connect new electricity demand and embedded generation customers.

# Table of Contents

Executive Summary ..... i
List of Tables ..... viii
List of Figures ..... x
Glossary ..... xiii

**1. Distribution System Plan (OEB Chapter 5.2) ..... 1**

**1.1 Distribution System Plan Overview (OEB Chapter 5.2.1) ..... 2**

1.1.1 Key Elements of the DSP ..... 2
1.1.2 Sources of Cost Savings ..... 3
1.1.3 DSP Period ..... 6
1.1.4 Currency of Information ..... 6
1.1.5 Updates from Previous Filing ..... 6
1.1.6 Aspects of the DSP Contingent on Future Events ..... 6

**1.2 Coordinated Planning with Third Parties (OEB Chapter 5.2.2) ..... 7**

1.2.1 Regional Planning ..... 7
1.2.2 Public Utility Coordinating Committee ..... 9
1.2.3 LDC Inter-Utility Standards Working Group ..... 10
1.2.4 HONI - LDC Generation Working Group ..... 11
1.2.5 Customer Consultation ..... 11

**1.3 Performance Measurement for Continuous Improvement (OEB Chapter 5.2.3) ..... 13**

1.3.1 Methods, Measures, and Metrics ..... 13
1.3.2 Performance Trends ..... 14
1.3.3 Impact on the DSP ..... 17

**2. Asset Management Process (OEB Chapter 5.3) ..... 18**

**2.1 Asset Management System Overview (OEB Chapter 5.3.1) ..... 18**

2.1.1 Asset Management Framework – Goals and Objectives ..... 18
2.1.2 Asset Management Implementation and Components ..... 19
Adjustment to Approved Capital Plan - Overview ..... 21

**2.2 Overview of Assets Managed (OEB Chapter 5.3.2) ..... 41**

DRAFT

2.2.1 Description and Explanation of Distribution System Features ..... 41
2.2.2 System Configuration ..... 46
2.2.3 Asset Demographics and Condition ..... 52
2.2.4 Information on General Plant Assets ..... 82
**2.3 Asset Lifecycle Optimization Policies and Practice (OEB Chapter 5.3.3) ..... 87**
2.3.1 Inspection and Maintenance Programs ..... 87
2.3.2 Renewal Programs ..... 97
2.3.3 Expansion Programs ..... 116
2.3.4 Information Technology Assets ..... 130
2.3.5 Facilities Remediation ..... 134
2.3.6 Fleet Replacement ..... 135
**2.4 Asset Lifecycle Risk Management ..... 138**
**3. Capital Expenditure Plan (OEB Chapter 5.4) ..... 142**
**3.1 Summary (OEB Chapter 5.4.1) ..... 142**
3.1.1 Load Connection Capability ..... 142
3.1.2 Total Annual Capital Expenditures by Category ..... 151
3.1.3 Capital Expenditures Description by Category ..... 152
3.1.4 Regional Planning Process or Regional Infrastructure Plan Impact ..... 156
3.1.5 Customer Engagement Activities ..... 156
3.1.6 System Development Expectations ..... 156
**3.2 Capital Expenditures Planning Process Overview (OEB Chapter 5.4.2) ..... 157**
3.2.1 Objectives ..... 157
3.2.2 Policies, Regional Planning and Non-Distribution System Alternatives ..... 157
3.2.3 Prioritization and Pacing of Investments ..... 158
3.2.4 Details of the Mechanisms Used by the Distributor to Engage Customers ..... 160
3.2.5 Method and Criteria Used to Prioritize REG Investments ..... 160
**3.3 System Capability Assessment for Renewable Energy Generation (OEB Chapter 5.4.3) ..... 161**
3.3.1 Applications from Renewable Generators ..... 161
3.3.2 The Number and the Capacity of Renewable Generation Connections Anticipated ..... 162
3.3.3 The Capacity of Enersource's Distribution System to Connect Renewable Energy Generation ..... 163

DRAFT

3.3.4 Constraints Related to the Connection of Renewable Generation ..... 166

3.3.5 Constraints for an Embedded Distributor that may Result from the Connections ..... 167

**3.4 Capital Expenditure Summary (OEB Chapter 5.4.4) ..... 168**

**3.5 Justification of Capital Expenditures (OEB Chapter 5.4.5) ..... 171**

3.5.1 Overall Plan ..... 171

3.5.2 Material Investments ..... 176

DRAFT

# List of Tables

Table 1. Total Capital Expenditures over the DSP Period 3
Table 2. Methods, Measures and Metrics 13
Table 3. Trends in reliability indices 2010-2014 (including Major Event Days ("MED") 15
Table 4. Prioritization drivers 26
Table 5. System Peaks in Overloaded Substations 29
Table 6. Maximum Cable Load and Fusing for Industrial and Commercial Customers 30
Table 7. Residential Distribution Transformers (100 kVA) – Number of Transformers per Feeder per Phase 30
Table 8. Residential Distribution Transformers (100 kVA) – Number of Customers per Transformer 30
Table 9. Single- Phase Transformers and Secondary Cables Reference Sheet for Residential Services 31
Table 10. Load Fusing for Local Distribution Feeders 31
Table 11. Reliability Statistics with Major Event Days (MED's) in 2010-2014 32
Table 12. Reliability Statistics in 2010-2014 (without MED's) 32
Table 13. Cause Code Statistics in 2010-2014 (without MED's) 32
Table 14. Equipment Failure Statistics (2010-2014) 34
Table 15. Worst Performing Feeder Weighting Methodology 37
Table 16. Customer Focus 39
Table 17. Operational Effectiveness 39
Table 18. Financial Performance 40
Table 19. Length of underground and overhead systems 51
Table 20. Number and length of circuits and conductors by voltage level 52
Table 21. Number and capacity of municipal stations 52
Table 22. Asset Health Index Summary 53
Table 23. Asset Management Strategy 53
Table 24. Summary of Enersource Buildings 84
Table 25. Planning Districts, Potential Population, and Estimated Load 119
Table 26. Downtown Core Conservation Estimates 121
Table 27. Hardware Category 130
Table 28. Benefits of Enhancement Initiatives program 133
Table 29. Prioritization Drivers 133
Table 30. Business value weighting. 138
Table 31. Significant asset classes 139
Table 32. Historical expenditures by investment category (2011-2015) ($000's) 151
Table 33. Projected Expenditures by Investment Category (2016-2021) ($000's) 151
Table 34. System Access Expenditures by Capital Program (2016-2021) ($000's) 152
Table 35. System Renewal expenditures by Capital Program (2016-2021) ($000's) 153
Table 36. Condition based replacement schedule by asset category 154
Table 37. System Service expenditures by Capital Program (2016-2021) ($000's) 155
Table 38. General Plant Expenditures by Capital Program (2016-2021) ($000's) 155

DRAFT

Table 39. Number of DEG Connections (as of the end of June, 2015) 162
Table 40. Forecasted Number of DEG Connections 163
Table 41. DEG Station Capacity 164
Table 42. Feeders with No capacity to Accommodate DEG Facilities 166
Table 43. HONI Station Restrictions for DEG Facilities 166
Table 44. Historical Expenditures by Investment Category (2011-2015) ($000's) 171
Table 45. Projected Expenditures by Investment Category (2016-2021) ($000's) 171
Table 46. Investment Drivers by Category 173
Table 47. System Access Expenditures by Capital Program (2016-2021) ($000's) 176
Table 48. System Service Expenditures by Capital Program (2016-2021) ($000's) 184
Table 49. Substation Equipment Replacement by Year. 187
Table 50. System Renewal Expenditures by Capital Program (2016-2021) ($000's) 190
Table 51. Transformers Showing Signs of Leakage and Containing PCB 194
Table 52. General Plant Expenditures by Capital Program (2016-2021) 199

DRAFT

# List of Figures

Figure 1. Enersource's actual and proposed capital investment portfolio expenditures (2011-2021) ..... iv
Figure 2. Enersource's Service Area ..... 8
Figure 3. Trends in SAIDI 2010-2014 ..... 16
Figure 4. Trends in SAIFI 2010-2014 ..... 16
Figure 5. Trends in CAIDI 2010-2014 ..... 17
Figure 6. Enersource Asset Management Framework ..... 19
Figure 7. Continuous Improvement Framework ..... 24
Figure 8. IT Asset Management Plan ..... 26
Figure 9. Customer Minutes by Cause in 2014 (without MED's) ..... 33
Figure 10. Customer Minutes by Cause in 2014 (with MED's) ..... 34
Figure 11. Equipment Failures in 2014 ..... 35
Figure 12. Enersource Underground Reliability Performance (2012-2014) ..... 38
Figure 13. Map of Enersource Territory ..... 42
Figure 14. Daily Maximum Temperature ..... 43
Figure 15. Daily Minimum Temperature ..... 43
Figure 16. Rainfall ..... 44
Figure 17. Snowfall ..... 44
Figure 18. Wind speed ..... 45
Figure 19. Map of Enersource 44kV subtransmission system ..... 46
Figure 20. Map of Enersource distribution system ..... 47
Figure 21. Map of Enersource North 16/27.6kV distribution system ..... 48
Figure 22. Map of Enersource South 16/27.6 and 2.4/4.16kV distribution systems ..... 49
Figure 23. Map of Enersource West 8/13.8kV distribution system ..... 50
Figure 24. Map of Enersource east 8/13.8kV distribution system ..... 51
Figure 25. Station Transformer Age Demographics ..... 54
Figure 26. Station Transformer Condition ..... 55
Figure 27. Circuit Breakers Age Distribution ..... 56
Figure 28. Circuit breakers health index distribution (unit) ..... 57
Figure 29. Pad Mounted Switchgear Age Distribution ..... 58
Figure 30. Pad Mounted Switchgear Health Index Distribution (unit) ..... 59
Figure 31. Age Distribution of 44 kV Load Break Switches ..... 60
Figure 32. Age Distribution 27.6 kV Load Break Switches ..... 60
Figure 33. Motorized Switches Age Distribution ..... 61
Figure 34. In-Line Switch Age Distribution ..... 61
Figure 35. Health Index Distribution of 44 kV Load Break Switches (Unit) ..... 62
Figure 36. Health Index Distribution of 27.6kV Load Break Switches (Unit) ..... 63
Figure 37. Motorized Switches Health Index Distribution (Unit) ..... 63
Figure 38. In Line Switches Health Index Distribution (Unit) ..... 64
Figure 39. Wood Pole Age Distribution ..... 65

DRAFT

Figure 40. Concrete Pole Age Distribution ..... 65
Figure 41. Wood pole Health Index Distribution (Unit) ..... 66
Figure 42. Concrete Pole Health Index Distribution (Unit) ..... 66
Figure 43. Main Feeder Cables Age Distribution ..... 67
Figure 44. Distribution Cables Age Distribution ..... 68
Figure 45. Main Feeder Cables Health Index Distribution (Unit) ..... 69
Figure 46. Distribution Cables Health Index Distribution (Unit) ..... 69
Figure 47. Pole Mounted Transformers Age Distribution ..... 70
Figure 48. Pole Mounted Transformers Health Index Distribution (Unit) ..... 71
Figure 49. Single-Phase Pad Mounted Transformers Age Distribution ..... 72
Figure 50. Single-Phase Pad Mounted Transformers Health Index Distribution (Unit) ..... 73
Figure 51. Three-Phase Pad Mounted Transformers Age Distribution ..... 74
Figure 52. Three-Phase Pad Mounted Transformers Health Index Distribution (Unit) ..... 75
Figure 53. Vault Transformer Age Distribution ..... 76
Figure 54. Vault Transformer Health Index Distribution (Unit) ..... 77
Figure 55. Health Index Results Summary – Condition Based ..... 78
Figure 56. 27.6 kV Switchgear Dry Ice Cleaning ..... 90
Figure 57. Infrared Inspection Report ..... 91
Figure 58. Map of 2015-2018 Vegetation Cut Plan ..... 92
Figure 59. Switchgear Overall Condition ..... 98
Figure 60. Analysis of Underground Areas with Aging Assets and Poor Reliability ..... 100
Figure 61. Pole Condition from Field Inspections ..... 103
Figure 62. List of Pole Mounted Transformers with PCB Content ..... 104
Figure 63. Leaking Pole Mounted Leaking Transformers (Non-PCB) ..... 105
Figure 64. Feeders Supplying Large Customers and Hospitals ..... 106
Figure 65. Location of Poles 35 Years or Older ..... 107
Figure 66. Pole Condition ..... 109
Figure 67. Sample Area Identifying the Location of SMD-20 Switch ..... 111
Figure 68. Porcelain and EPAC Insulator Locations ..... 112
Figure 69. Square One Shopping Centre After and Before Construction ..... 116
Figure 70. Today's Mississauga Downtown Core ..... 117
Figure 71. Downtown 21 Planning Districts ..... 117
Figure 72. Present and future loads in Downtown 21 Planning Districts ..... 118
Figure 73. Existing Loads and Substations ..... 120
Figure 74. Existing Station Location and Developer's Property ..... 122
Figure 75. Existing Substation and Switchgear Locations ..... 123
Figure 76. Existing Substation Location and the Proposed Square One Drive ..... 123
Figure 77. Proposed Duke MS Location ..... 124
Figure 78. Existing and Proposed Substation Locations in the Downtown Core ..... 126
Figure 79. Proposed Location of Webb MS ..... 127
Figure 80. Proposed Supply Points to the Downtown Substations ..... 128

DRAFT

Figure 81. Existing Underground Distribution Infrastructure ..... 129
Figure 82. Existing and proposed underground distribution infrastructure in the Downtown Core. ..... 130
Figure 83. Intel White Paper - PC Total Cost of Ownership by Refresh Rate ..... 131
Figure 84. Fleet distribution by type ..... 136
Figure 85. Enersource Peak Demand Forecast - North 16/27.6kV Distribution System – Extreme Weather Scenario (1996-2035) ..... 143
Figure 86. Enersource Peak Demand Forecast - South 16/27.6kV Distribution System – Extreme Weather Scenario (1996-2035) ..... 144
Figure 87. Enersource Peak Demand Forecast - West 44/13.8kV Distribution System – Extreme Temperature Scenario (1996-2035) ..... 145
Figure 88. Enersource Peak Demand Forecast - East 44/13.8kV Distribution System – Extreme weather scenario (1996-2035) ..... 146
Figure 89. Downtown 21 Initiatives ..... 147
Figure 90. Downtown 21 Framework Plan ..... 148
Figure 91. Lakeview Master Site Plan. ..... 149
Figure 92. LRT Plan ..... 150
Figure 93. Enersource's Investment Portfolio (2011-2021) ..... 152
Figure 94. Currently Connected DEG Facilities ..... 161
Figure 95. DEG Facility Generation Capacity by Fuel Type ..... 162
Figure 96. Enersource's Investment Portfolio (2011-2021) ..... 172
Figure 97. Proposed Locations for New Substations ..... 175
Figure 98. Enersource Underground Reliability Performance (2012-2014) ..... 191

DRAFT

# Glossary

| Acronym | Meaning |
|---|---|
| ACA | Asset Condition Assessment |
| AIC | Asset Investment Council |
| AMD | Asset Management Division |
| AM/FM | Automated Mapping/Facilities Management |
| AMI | Advanced Metering Infrastructure |
| AMRC | Advanced Metering Regional Collectors |
| AOD | Asset Operations Division |
| BCM | Business Continuity Management |
| BRT | Bus Rapid Transit |
| CAIDI | Customer Average Interruption Duration Index |
| CAMP | Comprehensive Asset Management Policy |
| CC&B | Customer Care and Billing |
| CCTV | Closed-Circuit Television |
| CDM | Conservation and Demand Management |
| CEA | Canadian Electricity Association |
| CEATI | Centre for Energy Advancement through Technological Innovation |
| CIA | Connection Impact Assessment |
| COS | Cost of Service |
| CRM | Customer Relationship Management |
| CSA | Canadian Standards Association |
| DEG | Distributed Energy Generation |
| DESN | Dual Element Spot Network |
| DGA | Dissolved Gas Analysis |
| DSC | Distribution System Code |
| DSP | Distribution System Plan |
| EAC | Executive Advisory Committee |
| E&AS | Engineering and Asset Systems |
| EBT | Electronic Business Transactions |
| E&GIA | Electricity and Gas Inspection Act |
| EPAC | Electric Power Accessories Corporation |
| EPSRA | Electric Power System Reliability Assessment |
| ERP | Enterprise Resource Planning |
| ESA | Electrical Safety Authority |
| ESQR | Electrical Service Quality Requirements |
| FCI | Fault Current Indicator |
| FIT | Feed-In-Tariff |
| GE | General Electric |
| GEA | Green Energy Act |
| GIS | Geographic Information System |
| GPS | Global Positioning System |
| GTA | Greater Toronto Area |
| GTAA | Greater Toronto Airports Authority |
| HONI | Hydro One Networks Inc. |

DRAFT

| | |
|---|---|
| HV | High Voltage |
| HVAC | Heating, Ventilation and Air Conditioning |
| ICM | Incremental Capital Module |
| IEEE | Institute of Electrical and Electronics Engineers |
| IESO | The Independent Electricity System Operator |
| IMS | Individual Metered Suite |
| IOM | Integrated Operating Model |
| IR | Infrared |
| IRRP | Integrated Regional Resource Planning |
| IT | Information Technology |
| JDE | JD Edwards (Enterprise Resource Planning) |
| KPI | Key Performance Indicator |
| LDC | Local Distribution Company |
| LRT | Light Rail Transit |
| LTIP | Long Term Investment Portfolio |
| LTR | Limited Time Rating |
| LV | Low Voltage |
| MC | Measurement Canada |
| MDM/R | Meter Data Management and Repository |
| MED | Major Event Date |
| MIST | Metered Inside System Timeframe |
| MPLS | Multiprotocol Label Switching |
| MS | Municipal Substation |
| MSP | Metering Service Provider |
| MTO | Ministry of Transportation of Ontario |
| MWM | Mobile Workforce Management |
| OEB | Ontario Energy Board |
| OH (or O/H) | Overhead |
| OM&A | Operating, Maintenance and Administration |
| OMS | Outage Management System |
| OPA | Ontario Power Authority |
| ORTAC | Ontario Resource and Transmission Assessment Criteria |
| PCB | Polychlorinated Biphenyl |
| PDSB | Peel District School Board |
| PUCC | Public Utility Coordinating Committee |
| PVC | Polyvinyl Chloride |
| QA | Quality Assurance |
| QC | Quality Control |
| RESOP | Renewable Energy Standard Offer Program |
| RIP | Regional Infrastructure Planning Processes |
| RRFE | Renewed Regulatory Framework for Electricity |
| RTU | Remote Terminal Unit |
| SAIDI | System Average Interruption Duration Index |
| SAIFI | System Average Interruption Frequency Index |
| SCADA | Supervisory Control and Data Acquisition |
| SCC | Service Continuity Committee |

DRAFT

| | |
|---|---|
| SD | Solid Dielectric |
| SPF | SmartPlant Foundation |
| TCP/IP | Transmission Control Protocol/Internet Protocol |
| TS | Transformer Station |
| TSC | Transmission System Code |
| UG | Underground |
| XLPE | Cross-Linked Polyethylene |

DRAFT

# 1. Distribution System Plan (OEB Chapter 5.2)

On March 28, 2013, the OEB issued Chapter 5 of the Board's Filing Requirements for Electricity Transmission and Distribution Applications, which outline the OEB's expectations regarding a distributor's asset management processes and long term capital expenditure plans. Enersource has prepared this DSP and organized the required information using the section headings in accordance with the OEB's Chapter 5 Filing Requirements.

The DSP outlines an integrative approach to the cost-effective planning and operation of Enersource's electricity distribution system to ensure the network is managed in an efficient, reliable, and sustainable manner and provides value to its customers. Operating and maintaining an electricity distribution system requires a significant amount of investments and Enersource is committed to undertaking prudent capital projects and maintenance plans in order to ensure customers receive value in the most cost efficient and effective manner.

The DSP is divided into three sections:

## Section 1- Distribution System Plan

The Distribution System Plan section provides a brief description of the information filed in the DSP including, but not limited to, key elements that affect the rates, the sources of cost savings, information on coordinated planning with third parties, and performance measurements for continuous improvement.

## Section 2 - Asset Management Process

The Asset Management Process section provides an overview of the information filed on Enersource's asset management processes and the direct links between the asset management system and the proposed capital expenditures outlined within this DSP.

## Section 3 - Capital Investment Plan

The Capital Investment Plan section outlines Enersource's capital investments derived from the asset management processes as described in Section 2. In addition, detailed information on the Company's capital expenditure planning process and the capacity of the distribution system to connect new load and embedded generation has been included in Section 3.

DRAFT

## 1.1 Distribution System Plan Overview (OEB Chapter 5.2.1)

The purpose of the DSP is to consolidate Enersource's practices as they relate to the planning and execution of capital investments associated to System Access, System Renewal, System Service, and General Plant through its asset management process. The DSP outlines capital expenditures for the forecast years (2016-2021) and other internally driven activities, while considering information received from customer engagement initiatives.

Enersource is committed to continuously enhancing its asset management system and processes, and has made several improvements since its last cost of service (COS) application. In 2013, Enersource created a new Asset Management Division (AMD) to oversee Asset Planning and Analysis. The new division is responsible for assessing the health of Enersource's distribution assets, overseeing the asset management process, outlining the need for capital asset replacements, and ensuring inspections and maintenance are performed to optimize the asset life cycles.

### 1.1.1 Key Elements of the DSP

The objective of the DSP is to make recommendations for the addition, replacement, disposal, and maintenance of Enersource's assets in an efficient manner that realizes value and achieves the Company's performance outcomes. The goal of the DSP is to outline how Enersource effectively manages its assets on a life-cycle basis, with investment plans that are prioritized and aligned with the CAMP.

The DSP supports Enersource's performance objective outcomes with regard to the planning, prioritization, and execution of programs and projects which are identified and classified into the following OEB requirement categories:

*System Access Investments* - modifications (including asset relocation) to Enersource's distribution system that the Company is obligated to perform to provide customers (including generator customers) with access to electricity services via the distribution system.

*System Renewal Investments* - involve replacing and/or refurbishing system assets to extend their original service life and thereby maintain the ability of Enersource's distribution system to provide customers with electricity services.

*System Service Investments* - modifications to Enersource's distribution system to ensure it continues to meet the Company's objectives while addressing anticipated future customer electricity service requirements.

*General Plant Investments* - modifications, replacements or additions to Enersource's assets that are not part of its distribution system, including land and buildings; tools and equipment; rolling stock and electronics devices and software used to support day to day business and operations activities.

**Table 1** below summarizes the proposed investments required to ensure Enersource is able to provide a safe, secure, and reliable supply of electricity, meet system load growth demands and complete all regulatory driven initiatives.

**Table 1. Total Capital Expenditures over the DSP Period**

| Description | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 |
|---|---|---|---|---|---|---|
| System Service | 17,200 | 13,015 | 13,130 | 12,825 | 13,105 | 13,490 |
| System Renewal | 34,735 | 37,243 | 38,240 | 40,280 | 38,570 | 38,490 |
| System Access | 12,408 | 17,916 | 18,123 | 18,162 | 17,238 | 10,568 |
| General Plant | 12,796 | 11,337 | 10,281 | 10,794 | 10,755 | 9,984 |
| **Total** | **77,139** | **79,511** | **79,773** | **82,061** | **79,668** | **72,532** |

### 1.1.2 Sources of Cost Savings

The DSP outlines Enersource's prioritization and optimization of distribution system expenditures. As outlined in Section 2 Asset Management Processes, Enersource aims to smoothly pace capital investments while minimizing the risks associated with reliability, safety, customer impact, environment, and providing value to stakeholders. As shown in Section 3 Capital Expenditure Plan, business cases are created for each investment to evaluate project alternatives that provide the greatest business value and minimize risk in a cost effective manner. Capital expenditures are prioritized in order to minimize overall risk to Enersource's business values while ensuring a balanced level of spending and efficient use of limited resources.

Enersource is focused on improving productivity and developing efficiencies as sources of cost savings in both capital and OM&A programs. For example, asset lifecycle optimization and an increased level of asset management planning would result in real (both capital and OM&A) savings. The following list outlines key areas of cost savings on which Enersource is focusing:

#### Operational Productivity

Enersource strives to create a culture of ongoing improvement. Whether through process improvement or by leveraging new technology, the Company continues to explore new ways to effectively provide the best value to customers. The following is a list of current initiatives:

**Balanced Scorecard** – Implementation of a wide range of Key Performance Indicators (KPIs) across all divisions and departments to measure and monitor productivity across the Company.

**Third Party Coordination** - Planning and coordination of work with third parties provides for potential cost savings.

**4kV to 13.8kV & 27.6kV Conversion Program** – Implementation of projects that replace distribution assets that are beyond end-of-life for specified areas. Enersource also works to proactively eliminate the

need to invest in more expensive substation-class assets and equipment by better utilizing available capacity at higher standard voltages of 13.8kV and 27.6kV systems. In 2007 and 2010, Enersource upgraded a portion of its distribution system in the Streetsville area from 4kV to 13.8kV, thereby allowing the Company to decommission two substations: Alpha Mills Municipal Substation (MS) and Ontario MS. Similar conversion from 4kV to 27.6kV is expected in the future in the south end of Mississauga that will require replacement of distribution assets to allow for greater connection capacity. The eventual decommissioning of 4kV substations will provide operational costs savings in the following areas:

- Reduced labour and expenditures required to maintain the electrical assets within the substations;
- Reduced labour and expenditures related to the cleaning, maintenance, security monitoring and regular inspections of the substations;
- Elimination of potential environmental risks from transformer oil spills associated with a failure of a substation power transformer; and
- Reduced expenditures for utilities and taxes upon disposal of the substation properties.

### Planning Effectiveness

Through an ever-improving inspection, testing and maintenance planning and project prioritization process, Enersource has developed a plan that paces spending while meeting the service requirements of the distribution system and General Plant assets. Two evolving programs aimed at helping the Company achieve this goal are:

- Detailed inspection programs which provide valuable insight into the condition of switchgear units (in the field) that are critical components of Enersource's distribution system. As a result, Enersource is able to develop a more effective maintenance program (e.g., dry-ice cleaning) to target switchgear units that are likely to cause an outage. This ensures outages are minimized, thereby reducing time spent on troubleshooting and switching. Similar inspection programs have been developed for poles and transformers, with a plan to roll existing substation inspection methodologies into the process; and

- Enersource has implemented a pilot project with Microsoft to develop a business intelligence solution that consolidates data from Integrated Operating Model (IOM), the Automated Mapping/Facilities Management (AM/FM), JD Edwards/Enterprise Resource Planning (JDE) and Customer Care and Billing (CC&B) systems. This will allow Enersource to complete better long term planning and asset investment while having detailed and accurate information on various asset data including loading, asset record information, customer information, and asset value, etc.

### Increased Use of New Technology

When replacing assets at the end-of-life or evaluating projects to improve reliability, Enersource incorporates new technologies where feasible. This includes:

- Replacing end-of-life switches with smart, Supervisory Control and Data Acquisition (SCADA) controlled switches capable of remote operation, thus reducing crew and truck time previously required for switching and power restoration;

- By third quarter 2015, Enersource is expected to complete the pole numbering project that will see each pole tagged and numbered with a barcode in order to improve asset management and inspection capabilities. Major benefits include:

    - Recording of all assets attached to the poles, and their condition, including photographs
    - GPS locations to save line crew driving and preparation time
    - Improved tracking of inspections and conditions of poles;

- Installing fault current indicators (FCIs) based on historical reliability information and evaluation of single line diagrams for ideal installation locations. Enersource has partnered with Siemens, BlackBerry, Mohawk College and McMaster University to implement WiMAX. This technology will allow Control Room operators to determine the location of the fault, thus hastening switching and restoration time by reducing time spent on finding the fault;

- Installing various types of equipment such as cut-out cover ups, bolt covering discs and fibreglass cut-out brackets to reduce outages caused by animal contact; and

- Enersource is in the process of implementing the Mobile Workforce Management (MWM) tool for operational crews, trouble trucks and metering field staff. The purpose of MWM is to address three core requirements: centralized dispatching, electronic processing of timesheets, and electronic tracking of work progress. MWM tools will enable the following:

    - Increase in daily job completion rates
    - Decrease kilometers driven and reduce fuel consumption
    - Reduce overtime
    - Reduce administrative load of field service teams
    - Eliminate paper-based timesheets and improve accuracy
    - Improve customer satisfaction
    - Provide better tracking and reporting of work completed.

## Centre for Energy Advancement through Technological Innovation (CEATI)

CEATI is committed to providing technology solutions to its electrical utility participants to advance the industry through the sharing and development of practical and applicable knowledge. These innovations address issues pertinent to day-to-day operations, planning and management of distribution assets.

In addition to enabling information sharing through interest groups and industry conferences, CEATI brings participants together to collaborate on technical projects. The outcome of these projects may have a significant impact on the infrastructure that Enersource plans to use in the future. In 2015, Enersource joined over 120 organizations including electricity and gas utilities, governmental agencies and provincial and state research bodies such as Hydro One Networks Inc. (HONI), PowerStream, Hydro Ottawa, Toronto Hydro-Electric System Limited, National Research Council, Ontario Power Generation, and the Ontario Power Authority (now the Independent Electricity System Operator or IESO).

### 1.1.3 DSP Period

This DSP covers the 2012 to 2015 historical years, the 2016 Bridge Year, and the 2017 to 2021 Test Years.

### 1.1.4 Currency of Information

All asset information, including inspection, maintenance and operating data provided to Kinectrics for the ACA is current as of December 31, 2014. Reliability metrics and analysis presented in this DSP include all outage information up to December 31, 2014.

### 1.1.5 Updates from Previous Filing

Enersource has not previously filed a DSP. Since the most recent cost of service (COS) submission April 27, 2012, the Company has filed an Incremental Capital Module (ICM).

### 1.1.6 Aspects of the DSP Contingent on Future Events

The execution of distribution system capital investment programs often involves co-ordination with external organizations. Enersource has identified several projects that are dependent on external factors for scope and timing. These projects include:

- Municipal Road Relocation / Upgrade Projects
  System Access investments required to facilitate road relocation projects may be dependent upon the City of Mississauga;

- Regional Road Relocation / Upgrade Projects
  System Access investments required to facilitate road relocation projects may be dependent upon the Region of Peel;

- Ministry of Transportation Road Relocation Projects
  System Access investments required to facilitate road relocation projects may be dependent upon the Ministry of Transportation;

- Regional Planning Projects
  Enersource is participating in two Regional Infrastructure Planning Processes (RIP) with HONI. The Company continues to participate in and support both the Integrated Regional Resource Planning (IRRP) and the RIP processes and will make the required investments into projects arising from the plans as identified; and

- Customer Connections
  System Access investments toward the expansion of Enersource's distribution system may be required; the timing of which is dependent on the location and service requirements of new customers, which are outside the Company's control.

DRAFT

## 1.2 Coordinated Planning with Third Parties (OEB Chapter 5.2.2)

### 1.2.1 Regional Planning

On May 17, 2013 the OEB provided notice of proposed amendments to the Transmission System Code (TSC) and the Distribution System Code (DSC). The proposed amendments outlined how to implement the Board's policies set out in its October 18, 2012 Report of the Board – A Renewed Regulatory Framework for Electricity Distributors: A Performance Based Approach (RRFE Board Report). The changes included the framework for a more structured approach to regional infrastructure planning among distributors, HONI and the IESO.

On November 14 and December 3, 2013, HONI launched regional planning efforts with Regional Infrastructure Planning Needs Screening conference calls for two planning regions in which Enersource participates, namely GTA West Southern Sub-Region and GTA North Western Sub-Region. The objective of this is to develop long-term electricity plans that integrate all relevant options such as: CDM, distributed generation, large-scale generation, transmission, and distribution.

Enersource is serviced via 11 transformer stations owned by HONI. Four transformer stations are shared among several utilities, including Hydro One Brampton, Toronto Hydro and Oakville Hydro. **Figure 2** illustrates Enersource's Service Area and the location of HONI transformer stations servicing Enersource territory and municipal substations.

DRAFT

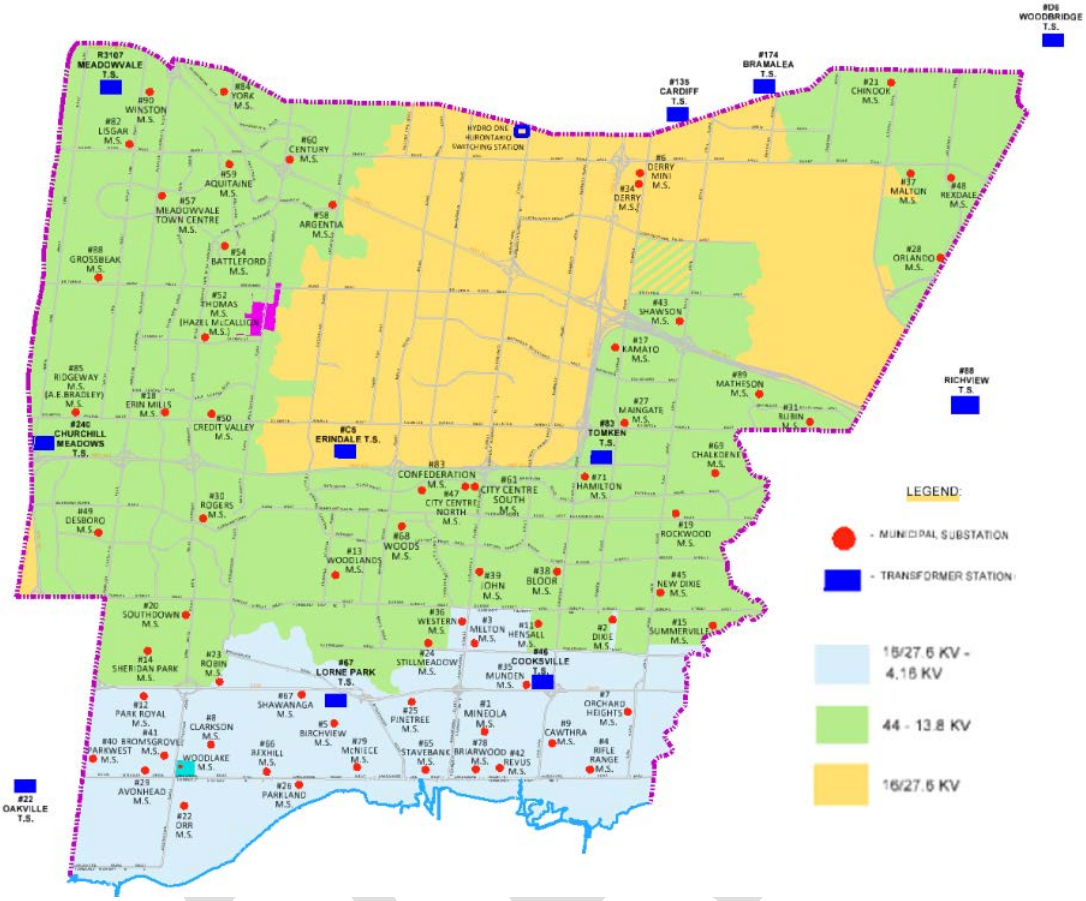



**Figure 2. Enersource's Service Area**

Enersource has provided HONI with a Long Term Load Forecast report within prescribed timelines outlined in the RIP and IRRP processes.

HONI, in collaboration with the study team that included Enersource and other neighbouring utilities, completed the Needs Screening and issued the Final Needs Screening Report for GTA West Southern Sub-Region and GTA North Western Sub-Region on May 30 and June 27, 2014, respectively.

In the Needs Screening Report for GTA West Southern Sub-Region, the study team recommended that further coordinated regional planning will be required to assess the needs identified in the report, namely the Erindale Transformer Stations (TS) T1/T2 27.6kV system which is forecasted to reach normal supply capacity within the next 10 years. It was further recommended that the IESO initiate a Scoping Assessment for this Sub-Region. On September 1, 2014, the IESO completed the Scoping Assessment highlighting two major categories of needs:

**Capacity**

Erindale TS T1/T2 is forecasted to be overloaded above the 10-day Limited Time Rating (LTR) during summer peak. It was also concluded that the capacity needs for Erindale TS T1/T2 should be addressed through available transformation capacity existing adjacent to the limiting assets. Enersource and HONI are currently planning the necessary infrastructure investments for this project, which will be further discussed in this DSP. Also included in this DSP is the investment for securing land and installing a substation comprised of two step-down transformers rated 44/27.6kV, as outlined in Section 3.5. The load will be supplied from HONI's Churchill Meadows TS.

**Load Restoration**

Load restoration needs along the Richview-Trafalgar corridor and west of the Cooksville area were also identified. The current radial transmission supply configuration from Richview and Manby Transformer Stations does not provide operational flexibility. This has considerably impacted the supply of power to the region, specifically the southern part of Mississauga and Oakville. In fact, a large storm on July 8, 2013 highlighted this major risk and lack of operational flexibility. The scoping report recommended that the requirement of further load restoration must be considered within the ongoing Bulk System Planning study currently under way in the Western portion of the GTA. This study is considering electricity needs in the municipalities of Oakville, Mississauga, Toronto, Brampton, Milton, Halton Hills and Caledon, and is being coordinated with other electricity planning studies in these areas. In addition, the scoping assessment has found that regional coordination via an RIP or an IRRP is not needed at this time.

### 1.2.2 Public Utility Coordinating Committee

Enersource participates in the Public Utility Coordinating Committee (PUCC), which provides a forum for communication between utilities, the City of Mississauga (the City) and the Region of Peel, in order to ensure safe and efficient management of the infrastructure within road allowances and other rights-of-way. Regular and effective communication between the City and the owners of infrastructure in the City creates an efficient and coordinated effort for all parties involved.

The PUCC meets on a quarterly basis and discusses common issues, shares information, and develops solutions to concerns or project-related matters. Issues include efficiency enhancements through improved construction scheduling coordination, damage prevention initiatives, and development of standards.

The PUCC was formed to ensure that projects undertaken on any City road allowance are completed using current standards and are recorded for future reference through the Municipal Consent Approval process.

The PUCC is responsible for:

- Approving non-standard locations of utility installations based on the understanding that wherever possible, utilities will be placed in the approved standard corridor locations;
- Developing appropriate policies and procedures regarding construction and utility installations;

- Improve communication and the exchange of information among the road allowance stakeholders;
- Coordinate the scheduling of the road allowance, capital improvement and maintenance projects; and
- Chair quarterly meetings.

Members of the PUCC include:

- MTS-Allstream
- Bell Canada
- City of Mississauga Transportation and Works
- City of Mississauga Recreation and Parks
- Cogeco Data Services
- Enbridge Gas Distribution Inc.
- Enersource
- FCI Broadband (Rogers Communications Partnership Co.)
- GT Fiber Services Inc.
- GTAA/Toronto Pearson International Airport
- Hydro One Network Services
- Hydro One Telecom Inc.
- Region of Peel – Public Works
- Rogers Communications Partnership
- TELUS Communications
- TeraGo Networks
- Union Gas Limited.

### 1.2.3 LDC Inter-Utility Standards Working Group

This working group was created in February, 2012 to provide participating utilities the opportunity to share knowledge and experience in the area of distribution utility design standards, construction practices, and equipment and material standards.

Members include Enersource, London Hydro, PowerStream, Veridian Connections, Toronto Hydro, Horizon Utilities Corporation, Peterborough Distribution, and Whitby Hydro Electric Corporation.

Benefits of this working group include:

- Enables utilities to present an issue in order for the group to provide advice and/or relate their experiences in solving a similar problem;
- To notify others of equipment or material failures within a particular utility in order to alert others or to identify common failures;
- To share experiences regarding the use of new equipment or materials;
- To highlight new technologies or work practices that may benefit others; and
- To share standards among utility members.



DRAFT

### 1.2.4 HONI - LDC Generation Working Group

The LDC Generation Working Group provides an opportunity for its members to discuss, develop and potentially adopt policies and best practices relating to LDC distributed generation connections. This allows for better management of the grid when using distributed energy resources, plus effectively and consistently delivering services to generators.

Current committee representation includes Enersource, HONI, Kingston Hydro, Horizon Utilities, Newmarket-Tay Power Distribution, Greater Sudbury Hydro, PowerStream, and Toronto Hydro.

Some of the working group's current activities include:

- Discussing emerging issues around LDC Distributed Generation connections and sustainment;
- Providing and gathering feedback on proposed enhancements to LDC Distributed Generation processes prior to implementation;
- Allowing LDC representatives to identify emerging issues from their perspectives;
- Identifying emerging operational issues and determining the correct forum for addressing them; and
- Discussing operational issues related to connecting and operating distributed generation.

The working group is designed to assume an advisory role rather than act as a decision-making body. In this role, the HONI - LDC Generation Working Group will provide recommendations to HONI and the IESO. Feedback from the working group will be considered in ongoing business decisions. The IESO participates in these meetings and regularly provides updates on new IESO policies and processes related to generation connections.

Some of the benefits are:

- Aiding in the development of both the IESO's and HONI's distributed generation connection processes;
- Providing input on the IESO's and HONI's distributed generation connections and process sustainment; and
- Sharing and gaining knowledge and experience among utility members.

### 1.2.5 Customer Consultation

Enersource recognizes the importance of customer feedback and regularly engages Simul Corp., an external research firm, to conduct a bi-annual customer satisfaction survey. The survey helps Enersource understand the satisfaction levels of its customers relative to Ontario and national comparators. In addition, it helps Enersource understand how customer perception, issues and concerns are changing over time.

To ensure Enersource's DSP accurately considers customer feedback, Enersource has engaged Decision Partners Inc., a third party consultant, to conduct broad, professional and scientific research on the input of customers regarding the DSP. This work is now underway. The customer feedback will be integrated into the final DSP to ensure that distribution services are provided in a manner responsive to customer preferences. This will be accomplished by:

- Identifying the benefits the DSP represents to customers;
- Considering factors relating to customer preferences that were identified in the course of planning investment projects and activities; and
- Identifying whether consultation(s) have or are expected to affect Enersource's DSP.

Research will be conducted with all customers in three groups, including:

- Residential Customers
- Non-Residential Customers
- Large Use Customers, the City of Mississauga, the hospitals and school boards.

This exercise will confirm Enersource's commitment to educate, and seek the input of, its customers, demonstrate how Enersource has considered that input, and revise its DSP accordingly. Effective customer consultation is based on in-depth insight into people's values, interests and priorities, in short, their mental models. Decision Partners' methodology is based on its proprietary Mental Modeling Technology™ (MMT™ ) which is an evidence-based, science-informed process specifically designed for understanding and influencing judgment, decision making, and behaviour.

The consultant has conducted 46 in-depth research interviews with three cohorts of customers and stakeholders, including: 15 Residential Customers, 15 Non-Residential Customers, and 16 Large Use Customers and Other Stakeholders (key intervenor groups). The consultant has worked closely with the Enersource team to ensure a broad sampling of customers (geographically and along other signification classifications).

The in-depth interviews provided foundational research which identified that Enersource's value proposition – what it takes to deliver electricity safely and reliably – was not understood by most customers. Building on the findings of the foundational research, Decision Partners, and its Interactive Decision Support Technology™ (IDST) partner, MedRespond, proposed an engagement solution that would first clarify Enersource's distribution role within the larger electricity system, then enable engagement of a broad range of residential and non-residential customers in thoughtful "conversations" with Enersource leaders about the DSP, who would listen and respond to customers' questions and comments in an online, virtual customer engagement environment.

Consultation with customers is continuing, currently via a 'video dialogue', accompanied by an online survey at www.enersource.com/survey. The results of the survey will provide Enersource with insights into customer preferences and will be used to align investment planning activities with the DSP.

DRAFT

## 1.3 Performance Measurement for Continuous Improvement (OEB Chapter 5.2.3)

A key consideration of Enersource's performance objectives outcomes, and reflected within this DSP, is the concept of balancing customer expectations and preferences, public policy responsiveness, and stakeholder requirements in the most operational, cost effective, and sustainable manner.

Since most of Enersource's assets are estimated to have a long useful life and are funded or recovered through distribution rates, Enersource must ensure the appropriate funding is available in order to minimize the cash flow constraint that may occur when undertaking long-term investments.

Enersource must ensure that its workforce is committed to the Company's performance objectives outcomes, and be able to identify risks, assess stakeholder requirements, and maintain/replace assets either directly or by overseeing third parties and other subcontracting firms. Since a significant number of Enersource's employees have expertise and are nearing retirement age, industry competition for additional resources is strong and has been identified as a significant constraint within this DSP.

To complement and continuously improve Enersource's strategic and capital expenditure plans, programs and projects are fully assessed and are evaluated to ensure alignment with the Company's CAMP and other corporate strategies. To facilitate the achievement of this goal, Enersource performs quantitative and qualitative analysis and risk assessments on each significant program or project. Enersource then considers the impact investments will have on distribution rates while ensuring the recommendations are prioritized and selected based on customer value, operational performance, stakeholder needs, and risk mitigation.

### 1.3.1 Methods, Measures, and Metrics

**Table 2. Methods, Measures and Metrics**

| Business Outcome | Key Success Factor | Key Indicator Groups | Key Performance Indicators |
|---|---|---|---|
| **Health & Safety** | Keep personnel, service providers and the public safe | • Employee safety incidents<br>• Service provider safety incidents<br>• Public safety incidents | Lost Time Incidents |
| | | | Medical Aid Injuries |
| | | | First Aid Injuries |
| | | | Vehicle Accidents |
| | | | Property Damage |
| | | | Property Theft |
| | | | Public Electrical Safety Measure |

| Business Outcome | Key Success Factor | Key Indicator Groups | Key Performance Indicators |
|---|---|---|---|
| **Distribution System Reliability** | Acceptable long term reliability performance of distribution system | • Reliability | SAIDI |
| | | | SAIFI |
| **Network Asset Operations & Management** | Ensure planned capital expenditure completed on time and budget | • System Access<br>• System Service<br>• System Renewal<br>• General Plan | Discretionary Capital Expenditures on plan |
| | | | Discretionary Capital Expenditures completed on time/as planned |
| **Service Quality Measure** | Meet all compliance standards | • Regulatory service quality indicators results<br>• Legal violations<br>• License conditions violations | Call Centre - ESQRs |
| | | | New Service Connections |
| | | | Appointments |
| | | | Billing Accuracy |
| **Employee Measures** | Ensure healthy and engaged workforce | • Employee absenteeism<br>• Employee retention<br>• Employee driving | Employee Absenteeism |
| | | | Employee Voluntary Turnover |
| | | | Employee Preventable Incidents |

DRAFT

### 1.3.2 Performance Trends

The following sections provide a summary of performance trends over the historical period using the methods and measures identified above.

### *Customer Oriented Performance*

Enersource regularly seeks customer feedback on their satisfaction with the services provided by the Company. Satisfaction levels have proven to be greatly impacted by system reliability. Where gaps are found, the appropriate actions are identified to address the issues. Service reliability is integral to all work undertaken as part of system planning and asset management. Annually, Enersource undertakes a thorough review of system reliability and identifies planned works under applicable investment categories which are designed to directly impact system reliability.

Customer value is at the centre of Enersource's Corporate Strategic Objectives. Customers are engaged on an ongoing basis and their feedback is incorporated into distribution system planning. Enersource engages customers with two surveys: Customer Satisfaction Survey and a DSP Consultation. The results provide the Company with the KPIs which Enersource uses to identify areas of improvement and benchmark its accomplishments against results of other utilities.

### *System Reliability Performance Indicator*

Key measures of reliability are System Average Interruption Frequency Index (SAIFI), System Average Interruption Duration Index (SAIDI) and Customer Average Interruption Duration Index (CAIDI). Frequency relates to the number of outages whereas duration relates to the outage time. Enersource tracks System Reliability Performance Indicators, as shown in **Table 3 and Figures 3-5**, to ensure that power is provided to customers on a reliable basis. Interruption categories such as defective equipment and adverse weather-related outages have been progressively trending upward. Improvements to the asset management processes are underway to enhance the Company's ability to prioritize end-of-life asset replacements. Maintenance, inspection, and testing of existing assets are essential to ensure equipment operates as expected and to identify potential failures before they occur. Enersource's objective is to maintain the System Reliability Performance Indicators year over year.

**Table 4. Trends in reliability indices 2010-2014 (including Major Event Days ("MED")**

| KPI | 2010 | 2011 | 2012 | 2013 | 2014 |
|---|---|---|---|---|---|
| SAIDI | 35 | 53.3 | 41.91 | 320.29* | 40.51 |
| 3-Yr Average SAIDI | 30.41 | 41.65 | 43.4 | 138.5 | 134.24 |
| SAIFI | 1.32 | 1.97 | 1.71 | 2.72 | 1.14 |
| 3-Yr Average SAIFI | 1.08 | 1.49 | 1.67 | 2.13 | 1.86 |
| CAIDI | 26.5 | 27 | 24.6 | 117.9 | 35.6 |
| 3-Yr Average CAIDI | 28.1 | 28.2 | 26.03 | 56.5 | 59.4 |

**includes two MEDs (July storm and flood, and December ice storm)*

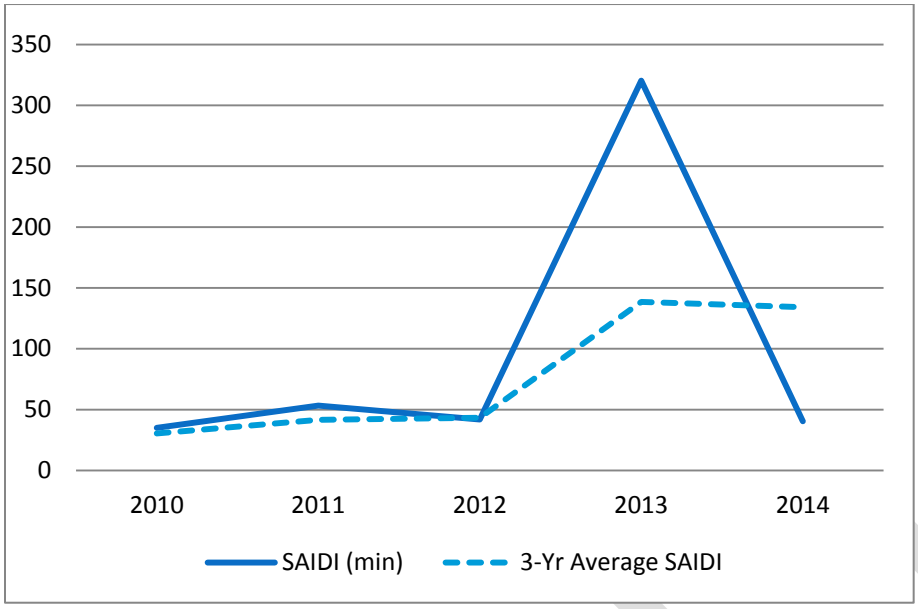



**Figure 3. Trends in SAIDI 2010-2014**

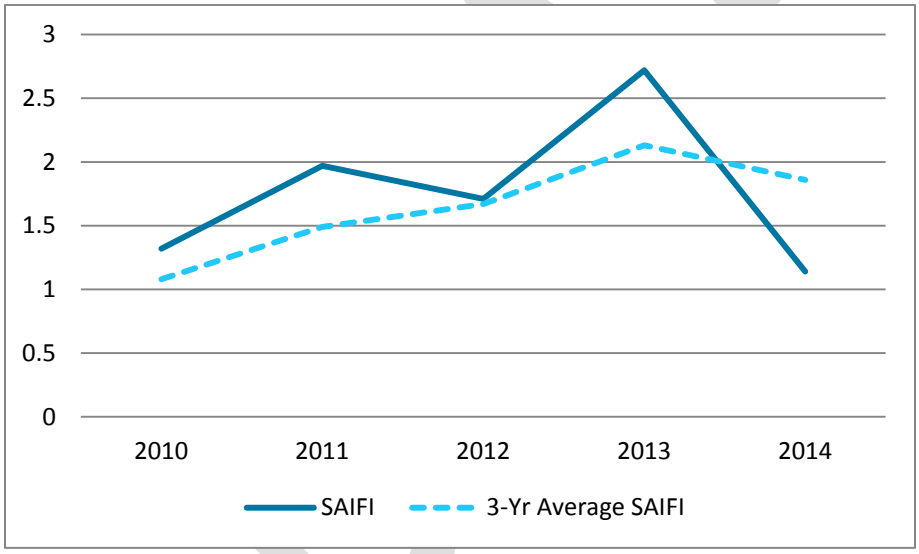



**Figure 4. Trends in SAIFI 2010-2014**

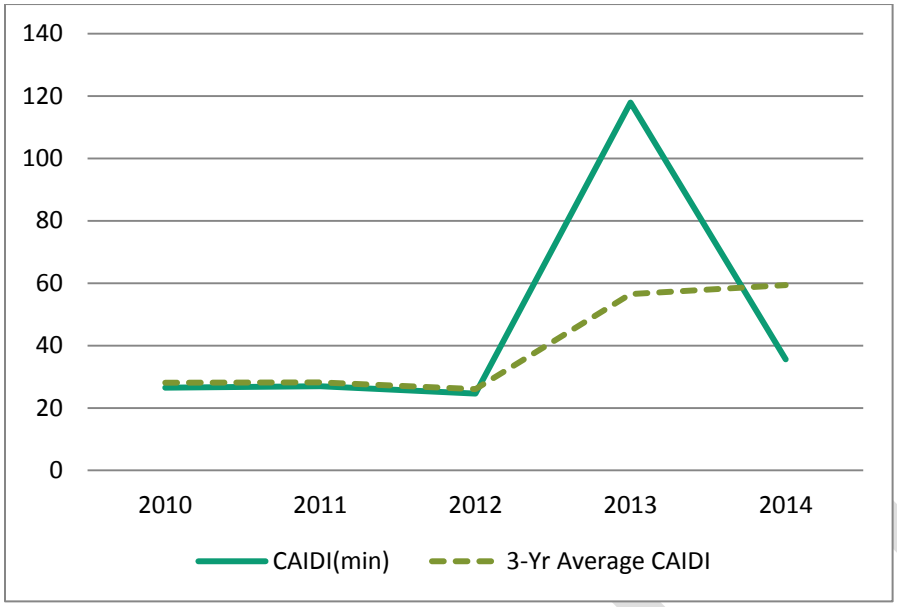



**Figure 5. Trends in CAIDI 2010-2014**

### 1.3.3 Impact on the DSP

Enersource's Corporate Strategic Objectives and targets provide the framework for the DSP. The Company tracks the KPIs listed in previous sections, which are used to set benchmarks to ensure Enersource's objectives of continuous improvement are achieved across all areas of the Company.

DRAFT

# 2. Asset Management Process (OEB Chapter 5.3)

## 2.1 Asset Management System Overview (OEB Chapter 5.3.1)

The objective of the DSP is to make recommendations for additions, replacement, disposal, and maintenance of assets in an efficient manner that realizes value and achieves Enersource's established performance outcomes. The goal of the DSP, updated annually, is to then outline how Enersource effectively manages its assets on a life-cycle basis with investment plans that are prioritized and aligned with the CAMP.

### 2.1.1 Asset Management Framework – Goals and Objectives

The DSP has been based on the following key factors: planning, prioritization and execution of programs and projects. The investments have been identified and classified into the following categories:

***System Access*** - modifications (including asset relocation) to Enersource's distribution system that it is obligated to perform in order to provide customers (including generator customers) with access to electricity services via the distribution system.

***System Renewal*** - involve replacing and/or refurbishing system assets to extend their original service life and thereby maintain the ability of Enersource's distribution system to provide customers with electricity services.

***System Service*** - modifications to Enersource's distribution system to ensure the distribution system continues to meet the Company's objectives while addressing anticipated future customer electricity service requirements.

***General Plant*** - modifications, replacements or additions to Enersource's assets that are not part of its distribution system, including land and buildings, tools and equipment, rolling stock and electronic devices and software used to support day to day business and operations activities.

Asset management is an Enersource-wide discipline guided by the following principles for the development and implementation of asset related programs or projects:

**Risk-based**: Incorporate risk management appropriately into decision making strategy

**Sustainable**: Optimize asset life cycle value

**Multi-disciplinary**: Asset management accountability framework crosses departmental and discipline boundaries

**Integration Oriented**: View assets in their total relative value context

**Optimal**: Strike the right balance among competing objectives such as short-term performance and reliability versus long-term planning and sustainability

DRAFT

**Systematic**: Rigorously applied in a structured management system complete with a monitoring framework and evidentiary structures and tools.

Enersource formalized these guiding principles into its CAMP in 2013, reinforcing that good asset management practices must be an integrated business discipline involving planning, finance, engineering, maintenance and operations.

In order to strike the optimal balance among risks, performance, and costs in a sustainable fashion that maximizes value while complying with all health, safety, environmental and regulatory requirements, Enersource established an asset management framework that will allow it to continuously improve its current asset management system and planning processes, as shown in **Figure 6**.

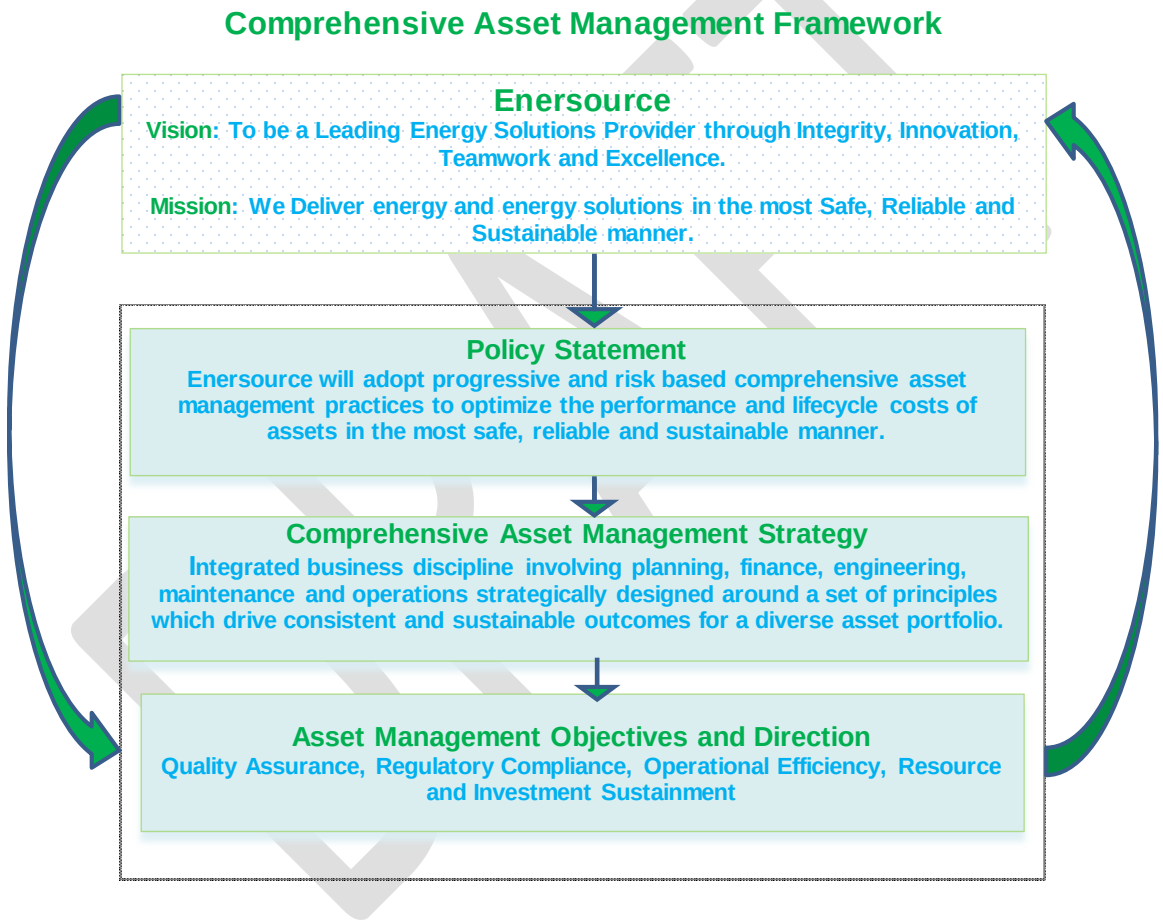



**Figure 6. Enersource Asset Management Framework**

### 2.1.2 Asset Management Implementation and Components

Enersource views its current asset management system as a set of tools, policies, plans, and business processes used to direct, coordinate, and control investment activities. It provides Enersource with a method to reduce risk and give assurance that the asset management objectives will be achieved on a consistent basis.

Enersource has five main focus areas which it takes into account when establishing its yearly business plans:

- Corporate Risk
- Stakeholder Engagement
- Workforce
- Value Creation
- Asset Management.

Enersource uses these focus areas to establish the short and long term organizational objectives which are used to align the business planning activities.

Enersource's Senior Management and Executive Advisory Committee (EAC) establish the Company's objectives and goals, which are then approved, in principle, by the Board of Directors. The EAC consists of the Chief Executive Officer, Executive Vice Presidents, Vice Presidents, and Director-level staff. This top down objective-setting approach is to ensure that when detailed plans are created, they align with the objectives and values set out and approved by the Board of Directors.

Enersource currently evaluates its business plan and investment projects and programs against the following business values:

- Regulatory/Public Policy Responsiveness
- Operational Effectiveness/Safety
- Customer Focus
- Financial Performance.

In order to establish a realistic investment plan that takes into consideration customer expectations and preferences, public policy responsiveness and stakeholder requirements, Enersource prioritizes projects and programs based on the business values listed above. Projects are ranked based on which investments have the greatest impact on the business values. Assuming there were no constraints, all investments with a positive impact on the business values would be approved. Due to resource constraints (e.g., appropriate funding, labour availability, information technology support) and other considerations such as the impact on the customer, other stakeholders and the environment, projects and programs are selected and prioritized based on supplemental quantitative and qualitative analysis.

After the top down objectives have been approved, the detailed capital budgeting process begins with an assessment and evaluation of Enersource's current and future distribution, intangible, and General Plant asset needs and requirements. Recommendations are then made on the timing of asset additions, replacements and disposals. Considerations include strategic or top down objectives, operational requirements and constraints, asset condition, asset age, criticality, reliability information, new capacity or regulatory requirements, environmental and other stakeholder impacts.

Each recommendation is assessed and draft business cases are prepared by the main business unit sponsors, along with other key stakeholders, for each proposed project or program. Each business case includes a description of the investment driver, scope, forecasted cost, and potential benefit/risk mitigation anticipated from each project or program.

Projects and programs are selected by assessing and balancing labour availability and funding with other needs and constraints within each division and across the Company. The recommendations are further prioritized by performing risk evaluations that identify impacts the project or program will have on Enersource's business values.

Each proposal is reviewed to ensure alignment with Enersource's overall asset management strategy and to determine if the project or program is realistically achievable in the timeframe proposed.

After the selected draft proposals have been reviewed, projects and programs are consolidated into the DSP. This selection exercise is conducted annually. The consolidated draft DSP is presented to Enersource's Asset Investment Council AIC (as per Enersource's CAMP). The appropriate signing authority within each line of business approves each of the respective capital asset project or program proposals to be presented to the Board of Directors.

Any single capital or intangible expenditure proposed in the DSP that exceeds $2,500,000 must receive separate approval from the Board of Directors before any action can be taken. Any capital or intangible expenditures that in aggregate exceed $5,000,000 and that are transferred or redirected between established investment categories during the calendar year must also receive separate approval from the Board of Directors before any transfer or action can be undertaken.

After the DSP is approved in principle by the Board of Directors, it is incorporated into the overall annual business plan which receives formal approval through a Board of Directors' resolution. The annual capital investment plan includes all electricity infrastructure, equipment, building improvements, land and intangible asset requirements (e.g., software and permanent easement rights).

### Adjustment to Approved Capital Plan - Overview

While the annually-approved DSP is a consolidation of Enersource's business cases and proposals which have been reviewed, assessed, evaluated, planned and prioritized based on numerous quantitative and qualitative analyses, the actual execution of the plan may vary from the DSP due to:

- Changes in customer and stakeholder requirements (e.g., regional plans, unexpected growth, unplanned road widening, etc.);
- Changes in business priorities from new or evolving information;
- Changes in external requirements (e.g., government directives, new technical standards, environmental regulations); and
- Major events (e.g., storms, equipment failures, etc.).

Adjustment to the approved capital plan process follows the same initial steps as described in the planning process. The next step in the Adjustments to the Approved Plan process is to assess resource requirements of the new or revised proposal against the original Approved Plan.

The following two issues must then be resolved:

1. If the proposal can be executed within the budgeted category by the business unit sponsor and the Vice President, Asset Management Strategy, then the proposal is accepted and communicated to the appropriate signing authority; or
2. If the proposal cannot be executed within the budgeted category by the business unit sponsor and the Vice President, Asset Management Strategy, then an alternative proposal is made to the AIC for consideration. If the recommendation is accepted, the proposal is approved by the appropriate signing authority.

Should an individual adjustment proposal exceed $2,500,000, the revised proposal must be sent to the Board of Directors for approval. If it is determined that the changes, transfers and or redirections are, in aggregate, over $5,000,000, a summary of the proposed Adjustments to the Capital Plan must be sent to the Board of Directors for approval.

### Asset Life Cycle Management – Process and Procedures

The planning process includes evaluations, which are completed for each asset class and for each project or program. The evaluations involve identifying the significance of each asset, project and program and how risk affects the main business value categories. This process also includes gauging the consequences of not proceeding with new capital or sustainment investments. The listing of asset classes is provided under Section 2.4 Asset Lifecycle Risk Management.

### Project Evaluation

In order to effectively prioritize projects and programs included in the DSP, Enersource performs assessments of the associated business values listed above. The objective is to eliminate, control or mitigate risks associated with each business value and to ensure that the highest risks are addressed first. The Project Evaluation phase defines project alternatives and creates business cases in support of the feasible alternatives. Unless mandated, project alternatives are evaluated based on their impact to Enersource's business values.

Project concepts are first reviewed to determine if they are a mandatory project. Such projects are typically dictated by regulatory requirements resulting from changes to the *Electricity Act* or the *Ontario Energy Board Act,* and resulting changes to the OEB's Distribution System Code, and/or other OEB codes or instruments. They range from customer connections to line relocations, to restoring power in a timely fashion.

Non-mandated project concepts are evaluated and possible alternatives are developed to meet the desired objectives of the project. This assessment is done through a business case development. Project alternatives are then scored by identifying their risk and/or benefit as it relates to Enersource's business values.

### Project Prioritization

The Project Prioritization phase ranks projects based on their value and allows for each to be evaluated based on the same criteria in order to determine which will provide the most value to the business while minimizing risks. A Preliminary Project List is created based on the prioritization process and understanding of risk/impact if the proposed project is not approved. The project list considers available funds and resources to complete the work. The proposed investment projects and programs are reviewed by Enersource's Executive Management Team and Board of Directors before proceeding to execution. This ensures that Corporate Strategic Objectives are met through the proposed investment plan.

### Execution

The Execution phase follows Enersource's internal project management methodology which provides specific guidelines, procedures, work instructions, and industry best practices that allow employees to perform project work in an economically efficient, cost effective, and safe manner.

### Continuous Improvement

The next stage of the asset management system is to review the results achieved from the execution of the projects and programs. Enersource has adopted an asset management conformance and continuous improvement framework as illustrated below in **Figure 7**.

DRAFT

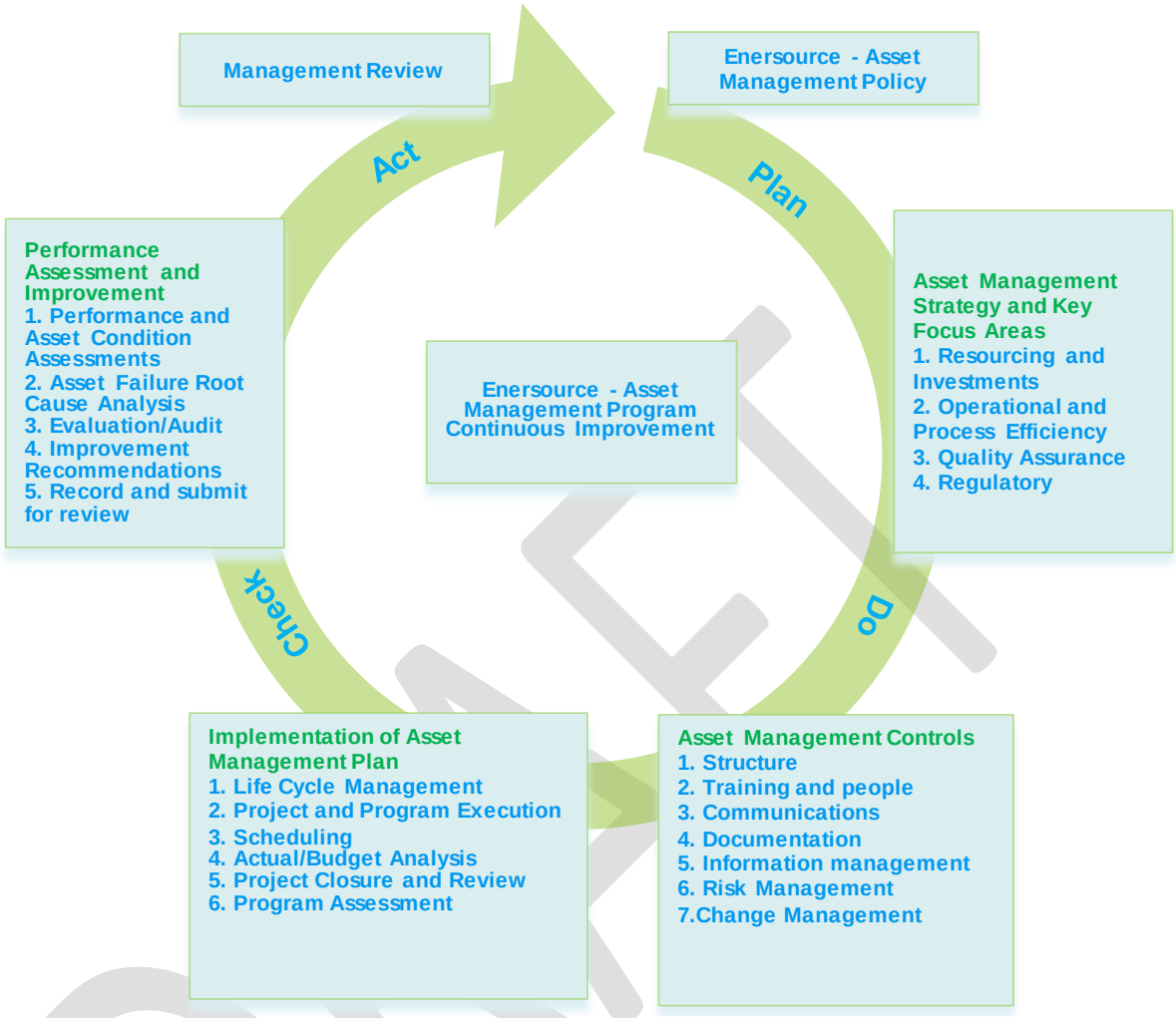



**Figure 7. Continuous Improvement Framework**

### *2.1.2.1 Asset Condition Assessment*

In the past, sustaining capital investments have dominated over other types of capital investments. However, in recent years it has become clear that significant investments are required to address operational, redundancy, safety, non-discretionary, and obsolescence issues.

Conducting an Asset Condition Assessment (ACA) is a process whereby the conditions of all key distribution infrastructure asset categories are assessed. This process employs the health indexing methodology used widely by utilities in Canada and around the world. Health indexing is considered a fundamental element without which an asset management program/plan would be seriously deficient. Conducting an ACA is good practice and the OEB has expressed its expectation that Enersource must be in a position to provide asset condition studies and other analyses which support its capital and investment strategies.

In early 2011, Enersource first engaged Kinectrics Inc. (Kinectrics), an independent third-party expert, to perform an ACA of Enersource's assets and provide an objective opinion on their condition . The results of Kinectrics' 2013 ACA report provided significant input in this DSP. In addition, Enersource is currently working with Kinectrics to finalize the 2014 ACA study and its findings will be used to inform further updates to the DSP.

The ACA provided the Health Index distribution for all infrastructure assets in each class, and a 10-year condition-based replacement plan. As stated above, the ACA report has been used as one of the inputs to this DSP. It has helped Enersource evaluate its existing programs (renewal, sustainment, expansion, and regulatory) and develop new ones in order to address the required replacement rates for all asset groups considered in the ACA. Enersource's six-year capital and investment plan, which addresses some of the issues identified in the ACA, has been included within this DSP under Programs and Projects.

### *2.1.2.2 Information Technology (IT) Asset Management Process*

Information Technology (IT) is an essential division of any organization's operation. IT systems enable businesses to automate and optimize their processes and efficiently execute their operations. Enersource relies on its IT assets and systems to meet its daily operational demands such as control of the electrical grid and enterprise applications (i.e., financial reporting, JDE and CC&B) as well as meeting external operational requirements (i.e., providing Meter Data Management and Repository (MDM/R)) with daily smart meter data.

The IT asset management plan includes asset procurement, operation, maintenance, replacement, and disposition of the assets. The primary objectives of Enersource's IT Asset Management Plan (IT AMP) are as follows:

- Ensure assets are utilized effectively, maximizing their value to the utility and in turn, to ratepayers;
- Ensure high reliability and scalability of assets in order to meet required service levels, minimizing business downtime and lost productivity;
- Minimize life-cycle cost, including the operation, maintenance, replacement and disposal of each asset; and
- Ensure assets conform to IT standards and protocols, minimizing security risks and operational risks.

Enersource's IT AMP includes both hardware and software assets and consists of two main components, as shown in **Figure 8:**

- Sustaining existing systems and business functionality
- Enhancement initiatives.

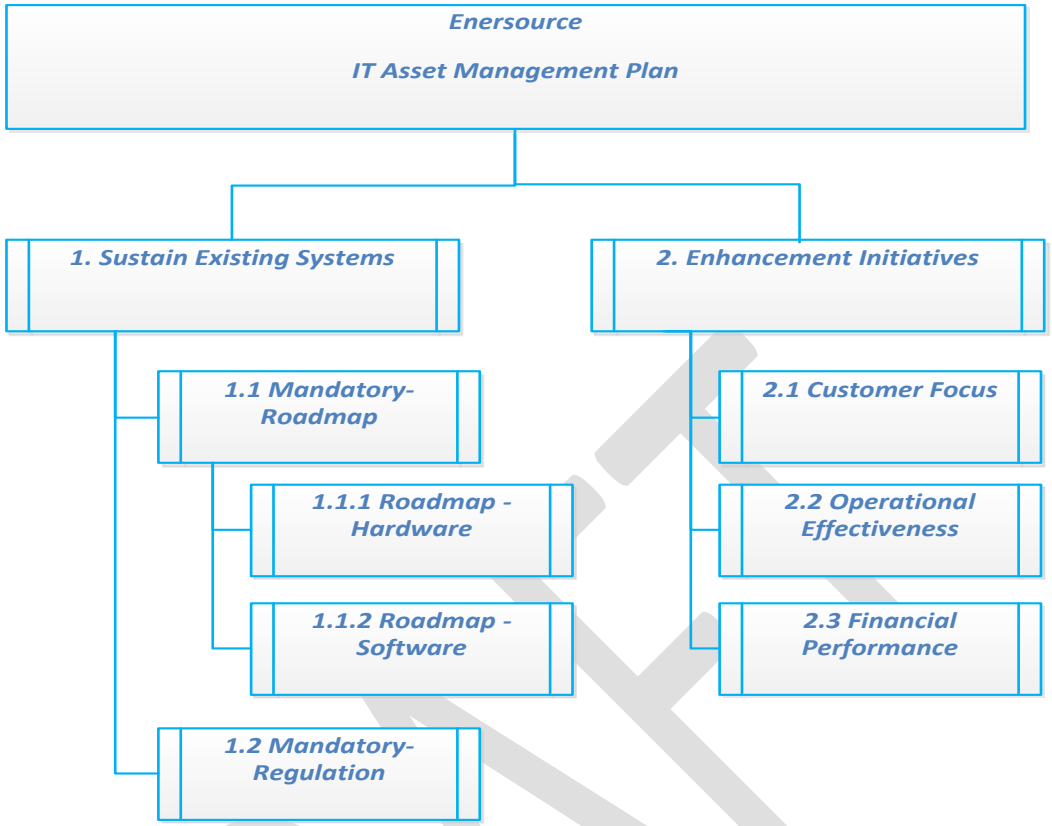



**Figure 8. IT Asset Management Plan**

The planning process for IT assets begins with prioritizing the investments. Prioritization consists of four drivers as shown in **Table 5**.

**Table 5. Prioritization drivers**

| Investment Drivers | Objective |
|---|---|
| Regulatory / Public Policy Responsiveness | Services are provided to address a regulatory requirement or mandate. This category includes IT roadmap projects as they are necessary in order to maintain vendor support. |
| Customer Focus | Services are provided in order to respond to customer needs and/or preferences. |
| Operational Effectiveness | Continuous improvement in productivity and cost performance is achieved, and system reliability and quality improvement are gained. |
| Financial Performance | Financial viability is maintained, and savings from operational effectiveness are achieved. |

## 2.1.2.2.a - Enersource IT Asset Management

Enersource uses multiple IT systems to support its business processes and to ensure continued execution of its daily operations. The IT systems allow employees to effectively perform their daily

functions. These systems are critical tools for all business areas of the organization including but not limited to, accounting, engineering, distribution grid control, and customer care. Most important, the IT infrastructure (i.e., network, servers, etc.) acts as the backbone to the entire IT asset systems.

In today's complex utility environment there is a greater need for sophisticated systems that can provide the business with automation, process optimization, information sharing, and better decision-making using factual data analytics. In addition, over the last few years there has been a paradigm shift in the way customers interact with their utility. There is a need to empower customers with information to help them make informed decisions about matters that could impact them (i.e., usage data, outages, etc.) with one goal being to enhance the culture of conservation. It is anticipated that technology will continue to change the way most customers interact with Enersource.

### 2.1.2.2.b - Asset Register

Asset Registers represent the primary repository sources of storing various assets types and corresponding information associated with those assets. There are several systems used to acquire, update and maintain the diverse set of assets at Enersource.

i. Geographical Information System (GIS) system
ii. Integrated Operating Model (IOM)
iii. Supervisory Control and Data Acquisition (SCADA) system.

#### *i. Geographical Information System (GIS)*

Enersource's Geographical Information System (GIS) holds locational and attributes data on electricity distribution assets within the Company's service territory. Enersource's GIS data is used for operational, maintenance, design, construction, and asset management requirements.

The Asset Management group ensures that an accurate record of the electricity distribution network and connectivity is available on Enersource GIS maps reflecting live conditions of electrical plant in the field. In addition, the key attributes associated with each asset are recorded in forms of intelligent maps. The information can then be queried and extracted to satisfy specific requests for information (e.g., electrical connectivity, age of assets, testing records, equipment types and system feeder analysis).

Maintenance of GIS records is controlled by the Asset Management group which has instituted procedures to capture, update and maintain Enersource's electricity distribution asset data. All GIS data entries including, but not limited to, new plant, attribute updates, plant removal, and any other spatial data are completed in the Intergraph's G/Technology and IOM environments. All GIS data entries undergo a rigorous quality assurance and quality control process by the Asset Management group before they are posted to the GIS production environment.

The majority of GIS information input is from capital projects that result in additions or renewal of the distribution system. Examples include drawings pertaining to new subdivisions, new commercial and residential installations, new substations, and various road work.

The remaining 30% of GIS information input comes from operational sources (e.g., plant energization and in-service processes, device switching open points on feeders, discrepancy verification), maintenance sources (e.g., attribute information arising from inspection or maintenance) and other discrete sources (e.g., joint use, street lighting, land base, orthographic imaging, etc.).

### *ii. Integrated Operating Model (IOM)*

The IOM is a computer-based system that provides a single-user interface for monitoring the grid, allowing for faster, more informed decision-making. The IOM consolidates information on location and attributes of distribution equipment, real-time crew location and active outages. The IOM also performs the core requirements of an Outage Management System (OMS) which uses outage probability modeling to help the Control Room Operators determine the most likely source of an outage and to prioritize restoration efforts.

At Enersource, the type, duration and cause of each outage is recorded based on operations executed by the Control Room Operators into the IOM; this information is the source of reliability statistics. If equipment fails in the field, a follow-up report is created in the IOM and used for tracking and prioritizing follow-up maintenance activities. In addition to providing the basis for reliability statistics, the outage information stored in the IOM is used to investigate the worst-performing feeders and to identify worst reliability areas.

The IOM tracks all activities, outages and problems associated with the distribution system, including information on equipment failures. Outage event records include information on the type of equipment that has failed, its location in the field, the duration and cause of the outage, and the number of customers affected. This application brings together multiple operational inputs and provides a dynamic picture of reliability performance of Enersources's distribution system.

### *iii. Supervisory Control and Data Acquisition (SCADA)*

The SCADA system provides real-time data on key assets in the field (e.g., stations, circuit breakers, automated switches). It allows the Control Room Operators to monitor real-time asset status and performance and to configure (through device switching) the distribution system on an ongoing basis in order to optimize system performance and the supply of power to Enersource's customers. Typical data collected through SCADA is used to operate the distribution system and includes information such as equipment status (on/off), current flow (amps) and alarms related to critical station equipment (relay triggers).

SCADA data is archived and provides an historical record of system performance that allows for detailed engineering and operating analysis to provide future direction and plans for improving system performance. SCADA real-time data is available to operations and engineering staff through the corporate networks via a web browser. Archived SCADA data is available to select users through a data historian application located on the corporate network.

### *2.1.2.3 Asset Capacity Utilization/Constraint Assessment*

Enersource regularly assesses the loading capability of the distribution system in an effort to maintain adequate and reliable supply to customers. System planning is carried out for system additions and upgrades while considering regulatory requirements for the connection of customers and consideration for safety, environment, and reliability. With respect to annual system utilization, Enersource's Control Room monitors substation and feeder loading on a daily basis to ensure that both transformer and feeder loading is maintained within established guidelines. The loading of HONI transformer stations should not exceed the limited time rating (LTR) for that station. The loading of substation transformers should not exceed the nameplate rating for the transformer for prolonged periods of time. Enersource main feeders are typically rated at 600 amps maximum and are monitored and balanced by Control Room Operators to ensure loading of approximately 350 amps at any given time. This ensures that enough capacity contingency is available in the event of a cable fault or major system issue whereby feeder switching is required for restoration or from additional loading that typically occurs during summer months.

Enersource currently owns and operates 66 substations with 109 substation transformers. Listed below in **Table 6** are substations that have exceeded the transformer capacity between the 2013-2014 periods. The overloading at these substations is closely monitored by the Control Room and System Planning group and arrangements are made to balance the loading on adjacent substations to minimize substation overloading. In addition, the System Planning group runs long-term peak demand forecasts to assess if substation additions or upgrades are required to address future loading requirements, as is the case with the Downtown 21 area.

**Table 6. System Peaks in Overloaded Substations**

| Substation | 2012 System Peak Day Load (MVA) | 2013 System Peak Day Load (MVA) | 2014 System Peak Day Load (MVA) | Substation Capacity Limit (MVA) | Exceeding Capacity |
|---|---|---|---|---|---|
| 20 - Southdown | 41.0 | 37.9 | 24.0 | 40 | Yes |
| 39 - John | 23.2 | 23.2 | 15.4 | 20 | Yes |
| 48 - Rexdale | 22.4 | 23.1 | 13.9 | 20 | Yes |
| 50 - Credit Valley | 23.8 | 19.0 | 18.8 | 20 | Yes |
| 52 - Thomas | 40.9 | 39.6 | 21.4 | 40 | Yes |
| 59 - Aquitaine | 21.8 | 24.2 | 15.6 | 20 | Yes |

In order to ensure optimal utilization of its assets, Enersource has developed design guidelines and standards to provide its design technicians with a reference in regards to transformer, cable and foundation sizing, fusing and maximum capacities allowed on sub-transmission, local distribution and main feeder cables. The guide is to ensure that the equipment supplying services is adequate to supply customers' needs and meets Enersource's reliability criteria. This is especially important in high rise

residential buildings and industrial services, where replacement of equipment after initial installation is difficult and much more expensive than installation of proper equipment during initial construction.

**Tables 7-11** outline system planning design criteria which are used for engineering purposes.

**Table 7. Maximum Cable Load and Fusing for Industrial and Commercial Customers**

| Voltage | Preferred 3Φ Transformation – Local Distribution Feeder (1/0) | Matching PMH Fuse – Local Distribution Feeder | Matching Cutout Fuse Local Distribution Feeder | Maximum 3Φ Transformation Distribution Main Feeder (1000 kcmil)* | Maximum 3Φ Transformation Subtransmission Feeder (1000 kcmil) |
|---|---|---|---|---|---|
| 2.4/4.16 kV | 800 | 100 E | 100 K | 3,500 | - |
| 8.0/13.8 kV | 2,400 | 100 E | 100 K | 11,500 | - |
| 16.0/27.6 kV | 4,800 | 100 K | 100 K | 23,000 | - |
| 44 kV | - | - | - | - | 42,700 |

**Table 8. Residential Distribution Transformers (100 kVA) – Number of Transformers per Feeder per Phase**

| Voltage | Optimal Number of Transformers on Local Distribution Feeder per Phase | Maximum Number of Transformers on Local Distribution Feeder per Phase |
|---|---|---|
| 2.4/4.16 kV | 2 | 3 |
| 8.0/13.8 kV | 8 | 10 |
| 16.0/27.6 kV | 12 | 16 |

**Table 9. Residential Distribution Transformers (100 kVA) – Number of Customers per Transformer**

| Voltage | Maximum Number of Connections per 100 kVA U/G Transformer | Optimal Number of Residential Customers per 100 kVA O/H Transformer | Maximum Number of Residential Customers per 100 kVA O/H Transformer | Optimal Number of Townhouse Customers per 100 kVA U/G Transformer | Maximum Number of Townhouse Customers per 100 kVA U/G Transformer |
|---|---|---|---|---|---|
| 2.4/4.16 kV | 14 | 20 | 25 | 20 | 25 |
| 8.0/13.8 kV | 14 | 20 | 25 | 20 | 25 |
| 16.0/27.6 kV | 14 | 20 | 25 | 20 | 25 |

**Table 10. Single- Phase Transformers and Secondary Cables Reference Sheet for Residential Services**

| Service size | Maximum Current | Transformer size | O/H Conductor Size and Number of Runs | Enersource Part Number | U/G Cable Size and Number of Runs | Enersource Part Number |
|---|---|---|---|---|---|---|
| | | 120/240 V | Triplex | | Triplex | |
| 100 A | 80 A | 100 kVA | #4 | 16,840 | 3/0 | 16,857 |
| 200 A | 160 A | 100 kVA | 1/0 | 16,844 | 3/0 | 16,858 |
| 400 A | 320 A | 100 kVA | 2-1/0 or 250SB | 16,844 or 16,815 | 2-3/0 | 16,858 |
| 600 A | 480 A | 167 kVA | - | - | 3-3/0 | 16,858 |

**Table 11. Load Fusing for Local Distribution Feeders**

| Total Transformation | Number of Phases | 2.4/4.16 kV | 8.0/13.8 kV | 16.0/27.6 kV |
|---|---|---|---|---|
| 100 kVA | 1 | 65 | 20 | 10 |
| 167 kVA | 1 | 100 | 30 | 15 |
| 150 kVA | 3 | 30 | 10 | 6 |
| 300 kVA | 3 | 65 | 20 | 10 |
| 500 kVA | 3 | - | 30 | 15 |
| 750 kVA | 3 | - | 50 | 25 |
| 1,000 kVA | 3 | - | 65 | 30 |
| 1,500 kVA | 3 | - | 100 | 50 |
| 2,000 kVA | 3 | - | 100 | 65 |
| 2,500 kVA | 3 | - | 125/140 | 80 |
| 3,000 kVA | 3 | - | - | 100 |

### *2.1.2.4 Historical Period - Customer Interruptions Caused by Equipment Failure*

System reliability is a key system performance measurement of an LDC. The OEB requires that every LDC maintains reliability performance within its own historical three-year range. In order to meet this requirement, Enersource has implemented several system reliability programs.

Enersource uses industry standards to measure and benchmark system reliability performance. The System Reliability Performance definitions are set by the Service Continuity Committee (SCC); a subcommittee of the Canadian Electricity Association (CEA). Enersource follows guidelines set out by the CEA's Electric Power System Reliability Assessment program (EPSRA) which governs system reliability statistics for the entire electricity industry.

Key measures of reliability are System Average Interruption Frequency Index (SAIFI), System Average Interruption Duration Index (SAIDI) and Customer Average Interruption Duration Index (CAIDI). Frequency relates to the number of outages whereas duration relates to the outage time. Enersource implemented the IOM in 2009, which enhanced the ability to track reliability statistics. These indices are used to measure overall system performance and to benchmark against comparable utilities.

Reliability results for the last five years are shown below.

Additional information regarding reliability results, incident cause classification, and equipment statistics of outages from 2010 to 2014 are listed in **Tables 12-15** and **Figures 9-11.**

**Table 12. Reliability Statistics with Major Event Days (MED's) in 2010-2014**

| Metric | 2010 | 2011 | 2012 | 2013 | 2014 |
|---|---|---|---|---|---|
| Interruptions | 2,083 | 1,027 | 923 | 1,310 | 1,203 |
| Customers Affected | 251,366 | 380,771 | 335,736 | 541,642 | 228,251 |
| Customer Minutes | 6,673,600 | 10,277,717 | 8,242,559 | 63,887,058 | 8,134,215 |
| SAIDI (minutes) | 35 | 53.3 | 41.91 | 320.29 | 40.51 |
| SAIFI | 1.32 | 1.97 | 1.71 | 2.72 | 1.14 |
| CAIDI (minutes) | 26.5 | 27 | 24.6 | 117.9 | 35.6 |

**Table 13. Reliability Statistics in 2010-2014 (without MED's)**

| Metric | 2010 | 2011 | 2012 | 2013 | 2014 |
|---|---|---|---|---|---|
| Interruptions | 2,083 | 1,027 | 923 | 1,087 | 1,159 |
| Customers Affected | 251,366 | 380,771 | 335,736 | 280,787 | 195,258 |
| Customer Minutes | 6,673,600 | 10,277,717 | 8,242,559 | 7,182,677 | 6,365,209 |
| SAIDI (minutes) | 35 | 53.3 | 41.91 | 36.01 | 31.7 |
| SAIFI | 1.32 | 1.97 | 1.71 | 1.41 | 0.97 |
| CAIDI (minutes) | 26.5 | 27 | 24.6 | 25.6 | 32.6 |

**Table 14. Cause Code Statistics in 2010-2014 (without MED's)**

| Cause Code | 2010 | 2011 | 2012 | 2013 | 2014 |
|---|---|---|---|---|---|
| Unknown/Other | 100,669 | 180,650 | 64,476 | 112,949 | 86,335 |
| Foreign Interference | 466,580 | 882,668 | 792,130 | 780,569 | 1,041,488 |
| Scheduled | 1,939,026 | 682,740 | 411,417 | 990,732 | 983,108 |
| Loss of Supply (HONI) | 362,222 | 1,893,664 | 236,671 | 964,794 | 19,106 |
| Tree Contacts | 257,916 | 893,379 | 415,925 | 345,010 | 324,014 |
| Lightning | 62,454 | 38,475 | 57,711 | 39,552 | 13,157 |
| Defective Equipment | 3,051,586 | 5,219,938 | 4,869,365 | 3,763,595 | 3,808,219 |

| Cause Code | 2010 | 2011 | 2012 | 2013 | 2014 |
|---|---|---|---|---|---|
| Weather | 422,209 | 49,927 | 1,387,837 | 162,298 | 84,281 |
| Adverse Environment | 0 | 19,492 | 0 | 21,060 | 3,000 |
| Human Element | 10,938 | 416,784 | 7,027 | 2,118 | 2,501 |
| **Total** | **6,673,600** | **10,277,717** | **8,242,559** | **7,182,677** | **6,365,209** |

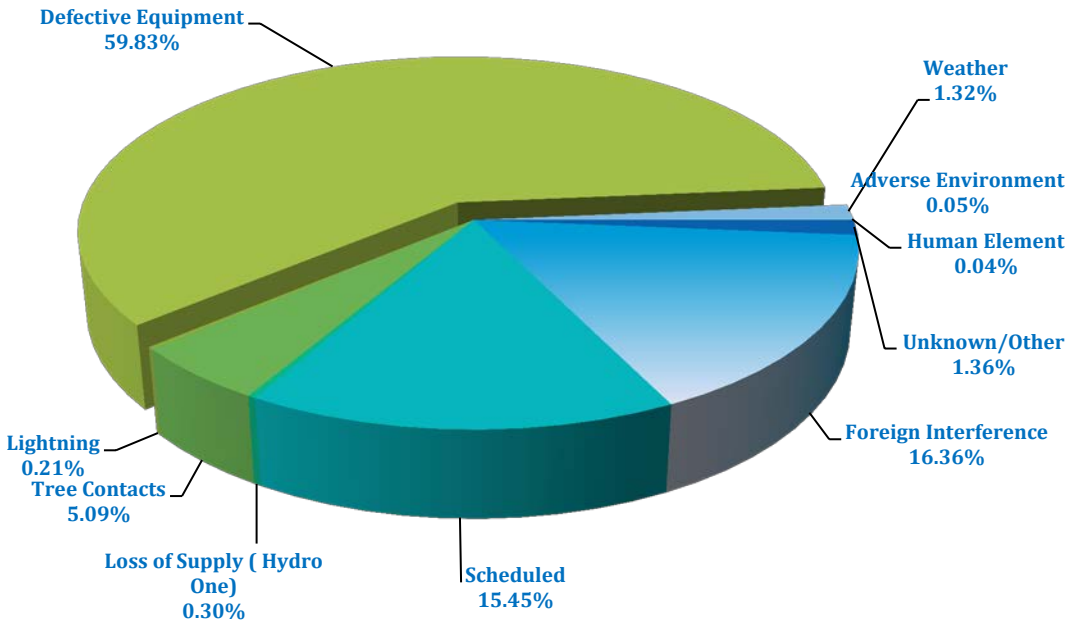



**Figure 9. Customer Minutes by Cause in 2014 (without MED's)**

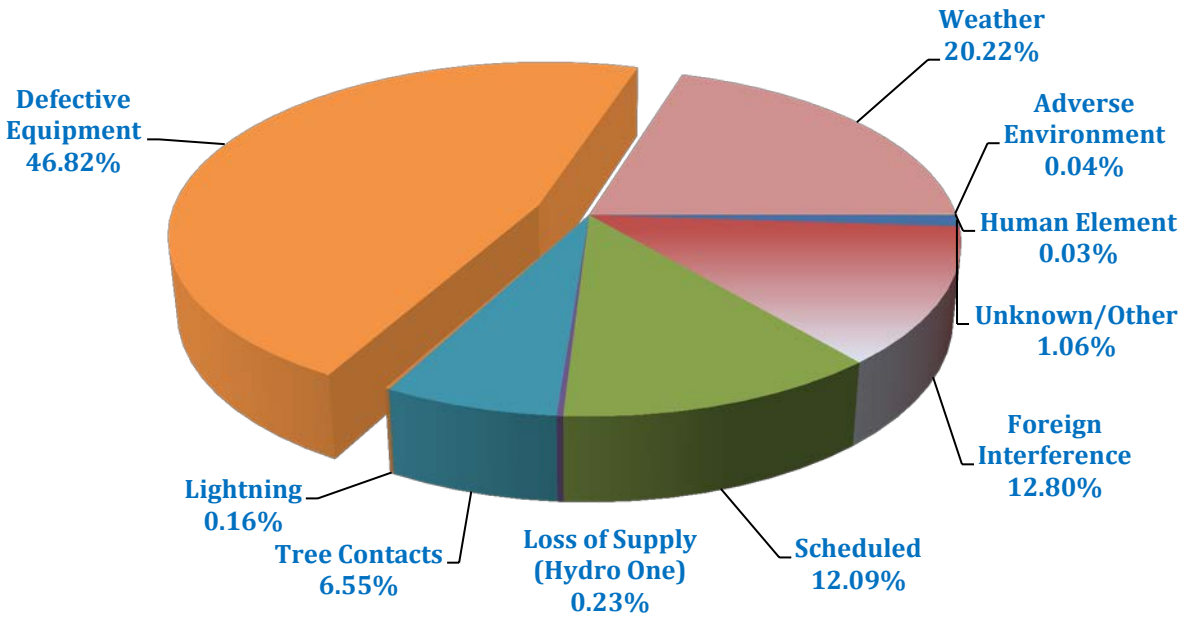



**Figure 10. Customer Minutes by Cause in 2014 (with MED's)**

**Table 15. Equipment Failure Statistics (2010-2014)**

| Cause Codes | 2010 | 2011 | 2012 | 2013 | 2014 |
|---|---|---|---|---|---|
| Underground Cable | 2,120,732 | 2,881,575 | 2,727,177 | 1,720,513 | 1,610,094 |
| Fuse | 39,211 | 38,392 | 50,685 | 27,675 | 7,392 |
| Insulator | 2,687 | 42,884 | 156,102 | 301,820 | 170,207 |
| Switchgears | 68,884 | 421,281 | 49,230 | 221,229 | 544,465 |
| Overhead Equipment | 230,471 | 1,098,335 | 425,638 | 521,462 | 692,494 |
| Others/Unknown | 62,183 | 133,394 | 83,825 | 110,227 | 78,817 |
| Splices | 277,098 | 262,275 | 807,069 | 196,638 | 192,193 |
| Switches | 24,938 | 86,549 | 262,899 | 151,604 | 291,775 |
| Elbows/Terminations | 55,984 | 62,340 | 70,562 | 219,763 | 39,223 |
| Transformers | 169,398 | 192,913 | 236,178 | 292,664 | 181,559 |
| **Total** | **3,051,586** | **5,219,938** | **4,869,365** | **3,763,595** | **3,808,219** |

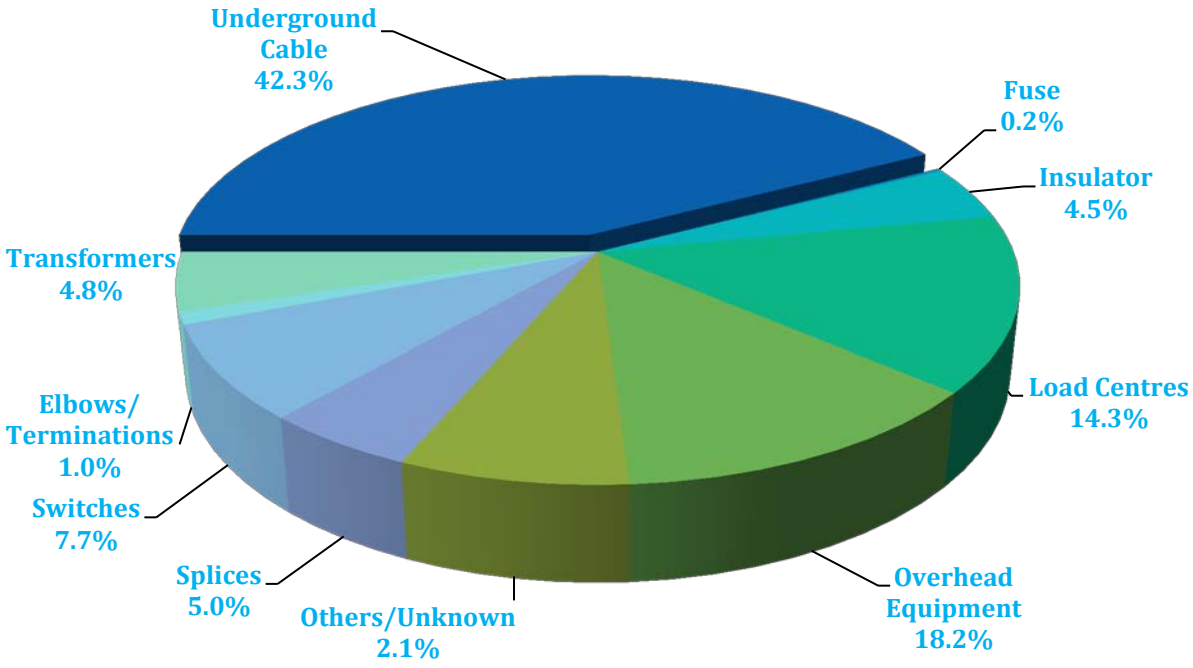



**Figure 11. Equipment Failures in 2014**

### *2.1.2.5 Reliability-Based 'Worst Performing Feeder'*

The programs and projects included in this section deal with the replacement of underground cables and components that have reached their expected end-of-life and have been determined to create unacceptable operational risks.

Underground cable failures are the leading cause of equipment failures in the distribution system and present a significant amount of operational risk to Enersource. To address this issue, the Company executes its ongoing cable replacement program based on a significant amount of qualitative and quantitative analysis. On an annual basis, the worst performing areas of the underground cable system are identified and ranked according to operational risk, impact to customers, and financial consequences, while considering labour availability and other constraints.

Criteria used to identify the worst performing areas include: number of cable failures, age of the cable, cable type installed and how critically customers are affected. Most cables installed before 1989 either do not have a jacket and/or were not installed in ducts and thus, are more susceptible to failure. The typical life expectancy for new or replacement underground cable is approximately 40 years.

Locations for yearly rebuild projects are prioritized by using three years' worth of operational data, ranked by equipment age, and the number and type of customers involved. Once rebuild locations are selected, the projects are included in the following year's capital renewal plans, budgeted for and

designed. To optimize work efficiencies, renewal projects typically involve replacement of the complete underground system including cables, transformers, switchgears and other system components that are also nearing the end of their useful life.

Many utilities use different methods to identify areas with poor performance and implement various programs and improvements. Worst feeder ranking is most commonly used to identify poor performing feeders and many utilities implement programs to improve feeder performance.

Enersource has reviewed several presentations/methods used by other utilities to identify worst feeders in the system. These include:

- Feeder Vulnerability Study - HONI performance analysis
- Feeder Reliability Management - Toronto Hydro
- Worst Performing Feeders - Power System Solutions International
- Worst Feeder Methodology - Presented by Hydro Ottawa at 2012 EDIST conference.

Enersource used an electronic spreadsheet in the past to list the worst feeders. In 2011, Enersource began following the Hydro Ottawa methodology with some variations. This methodology was tested using software spreadsheets before being implemented in Enersource's IOM reporting tool to identify the worst feeders in the system.

Enersource has enhanced its worst feeder reports and applies improved methodology to identify operational impacts at the transformers level in the system. Some of the reasons for this change are identified below:

- Normal system configuration and abnormal configuration can skew reliability measures;
- Worst feeder may not identify worst area of the system;
- IOM statistics are recorded against each transformer (with few exceptions);
- Inspection data and manufacturer information can be used to refine reporting on reliability impacts at the transformer level;
- Transformer outage data helps indicate poor performing areas in the system; and
- History and details of reliability statistics of each transformer remains in the IOM data base for future reference.

DRAFT

**Methodology**

Enersource is using the weighting methodology as shown in Table 16.

**Table 16. Worst Performing Feeder Weighting Methodology**

| Occurrence date | Weight | Customers affected | Customer minutes | Number of sustained outages |
|---|---|---|---|---|
| Current year | 0.4 | 0.3 | 0.3 | 0.4 |
| 1st year prior to current | 0.3 | 0.3 | 0.3 | 0.4 |
| 2nd year prior to current | 0.3 | 0.3 | 0.3 | 0.4 |

Once the rank for each transformer is calculated based on reliability history, additional factors are considered to select poor performance areas and equipment that is at the end-of-life or that must be replaced due to regulatory requirements.

Below are factors that determine areas that need to be rebuilt:

- Reliability – based on the Worst Feeder methodology
- Transformers that are leaking oil
- Transformers that contain PCB
- Health Index of the cables and transformers
- Frequency of cable failures
- Age of the cables and transformers
- Transformers located in rear lots.

Once the projects are selected using the factors shown above, they are scrutinized to ensure the project scope and boundaries are properly defined.

**Figure 12** is an example of one of the detailed visual maps used to indicate where Enersource has had significant reliability issues over the last three years, along with asset health condition.

DRAFT

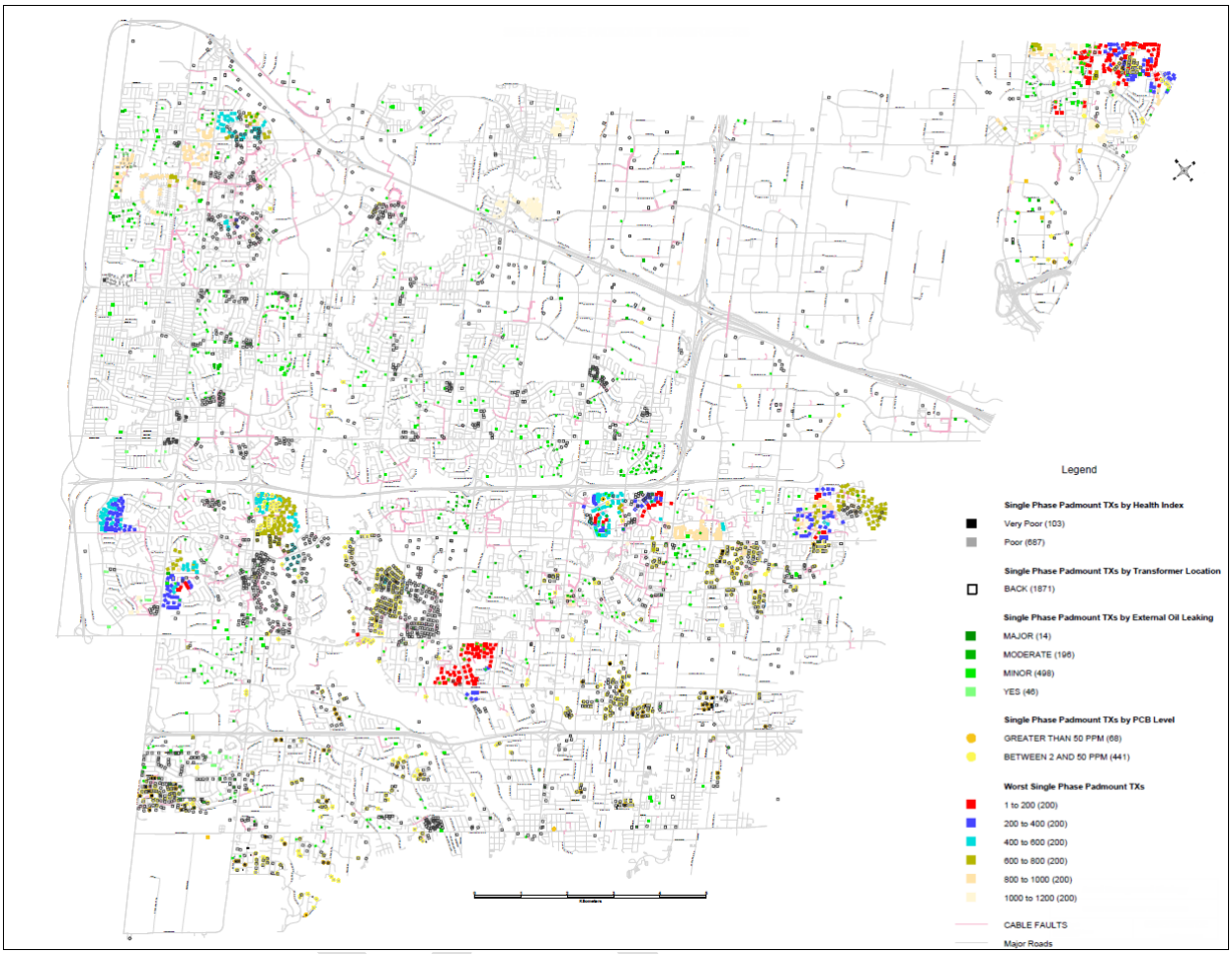



**Figure 12. Enersource Underground Reliability Performance (2012-2014)**

### *2.1.2.6 Reliability Risk/Consequence of Failure Analysis*

Enersource uses a Risk Model Matrix to identify the risk associated with not undertaking an investment. Project concepts are first reviewed to determine if they are a mandatory project. Mandatory projects are typically dictated by the OEB via the DSC or other regulatory instruments. Projects range from customer connections, to line relocations, to restoring power in a timely fashion. These projects are then prioritized based on whether they pose immediate concerns to safety, environment, or constrain the operation of the system. Immediate concerns move directly to the execution phase, may take precedence over planned projects and cause deferral or delays. Otherwise, the projects are prioritized against Enersource's business values and are scheduled to be completed in a timely manner.

Non-mandated projects are evaluated and possible alternatives are developed which meet the desired objectives of the project. This evaluation is done through business case development which evaluates alternatives against pre-defined investment criteria and proposed recommendation(s).

Project alternatives are then scored by identifying their risks and/or benefits as they relate to Enersource's business values through use of the Risk Matrix. The prioritization is shown in **Tables 17-19**.

**Table 17. Customer Focus**

| Score | Service Quality i.e., does the project improve a Customer Service ESQR metric? | Customer Satisfaction i.e., does the project add Customer Value? | Reputational Risk i.e., does the project reduce or eliminate a reputational risk? |
|---|---|---|---|
| **10** | Improvement from non-compliance to compliance | Direct positive impact that will be reflected on next customer survey | Prevents or significantly reduces likelihood of irreparable brand damage |
| **8** | Significant improvement to ESQR | Adds value or service that customers have identified through survey or ~~some~~ other means | Positive impact on brand |
| **5** | Improvement of multiple ESQRs | Improves customer experience (a large user or 1,000 residential customers) | Helps preserve brand |
| **3** | Makes an improvement or prevents degradation of one ESQR | Positive improvement to customer experience (non-quantifiable) | May mitigate brand risk |
| **0** | No impact on ESQR | No impact on customer service | No brand impact |

**Table 18. Operational Effectiveness**

| Score | Safety (Customer & Employee) i.e., this project mitigates exposure that could cause: | Environmental Impact/Risk i.e., this project mitigates exposure that could cause: | System Reliability i.e., this project maintains or improves system reliability: | System Expansion i.e., this project increases system capacity: | System Renewal i.e., this project is for replacement of distribution assets where: |
|---|---|---|---|---|---|
| **10** | Potential loss of life | Environmental disaster | Prevent 100,000 customer minutes of outage | New infrastructure to avert major system constraint/risk | ACA health index "Very Poor" |

| Score | Safety (Customer & Employee) i.e., this project mitigates exposure that could cause: | Environmental Impact/Risk i.e., this project mitigates exposure that could cause: | System Reliability i.e., this project maintains or improves system reliability: | System Expansion i.e., this project increases system capacity: | System Renewal i.e., this project is for replacement of distribution assets where: |
|---|---|---|---|---|---|
| 8 | Non-reversible injury | High environmental impact | Prevent 80,000 customer minutes of outage | New infrastructure required to support service capacity | ACA health index "Poor" |
| 5 | Medical aid injury | Medium environmental impact | Prevent 50,000 customer minutes of outage | Upgrade existing infrastructure to support existing service capacity | ACA health index "Fair" |
| 3 | First aid injury | Low environmental impact | Prevent 30,000 customer minutes of outage | Provide system capacity without compromising service to existing customers | ACA health index "Good" |
| 0 | No safety risk | None | No impact on customer minutes of outage | No Impact on system capacity | ACA health index "Very Good" or N/A |

**Table 19. Financial Performance**

| Score | Cost Efficiencies i.e., this project will save/avoid operational costs or create revenue of: | Ongoing Costs i.e., this project will incur/create ongoing cost of: |
|---|---|---|
| 10 | > $100,000 | < $30,000 |
| 8 | > $80,000 | < $50,000 |
| 5 | > $50,000 | < $80,000 |
| 3 | > $30,000 | < $100,000 |
| 0 | No significant amount | No significant amount |

## 2.2 Overview of Assets Managed (OEB Chapter 5.3.2)

This section provides a summary of Enersource's distribution service area, demographics, and condition of the assets managed. It also summarizes the current state of the system loading as it relates to station and feeder capacity.

### 2.2.1 Description and Explanation of Distribution System Features

Enersource owns and operates the electricity distribution system in the City of Mississauga (City or Mississauga) and serves over 203,000 customers, including homes and businesses. Enersource is governed by the *Electricity Act, 1998,* and regulated by the OEB under the *Ontario Energy Board Act, 1998*.

The current City, incorporated in 1974, was formed through the amalgamation of the Town of Mississauga and the villages of Port Credit and Streetsville, together with portions of the Townships of Toronto Gore and Trafalgar.

In 2000, the name Enersource emerged, associated with the commercial restructuring of the Company, a process that resulted in several affiliates including Enersource Hydro Mississauga Inc.

Enersource and its founding utilities achieved many innovations over the years. From the early 1900's as the first township to contract for electricity with Ontario Hydro, to the 1950's as it began to innovate with underground distribution through residential neighborhoods, Enersource set a record as a municipal utility by supporting the development of 1,000 electrically-heated homes.

Enersource's territory covers 288 square km which includes 1,797 km of overhead line circuits, 3,383 km of underground line circuits and over 25,000 distribution transformers. A map of Enersource's service territory is shown in **Figure 13**.

DRAFT

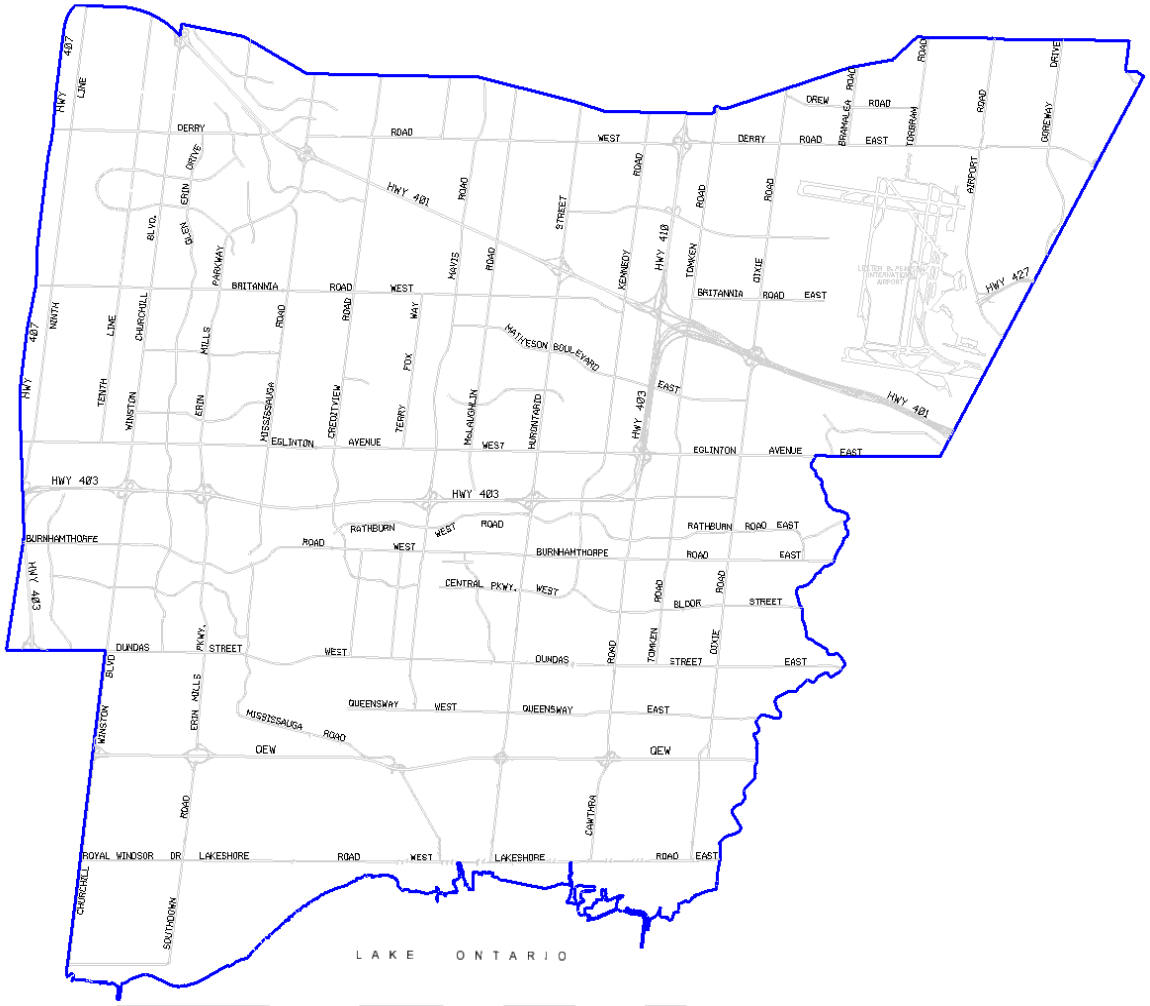



**Figure 13. Map of Enersource Territory**

### Climate Normals Comparison

For comparisons to other major Ontario cities, climate normals for Toronto, as recorded by the Government of Canada, are used.

Compared to other major cities, Mississauga is characterized by having generally average wind speeds and winters with lower snowfall.

Although Enersource strives to complete capital work throughout the year, work must be scheduled to accommodate the winter months during which time there are greater hazards to field crews and added challenges such as snow removal, before work can even begin.

The data presented in **Figures 14-18** represents the climate normals from 1981-2010 as recorded by the Government of Canada.

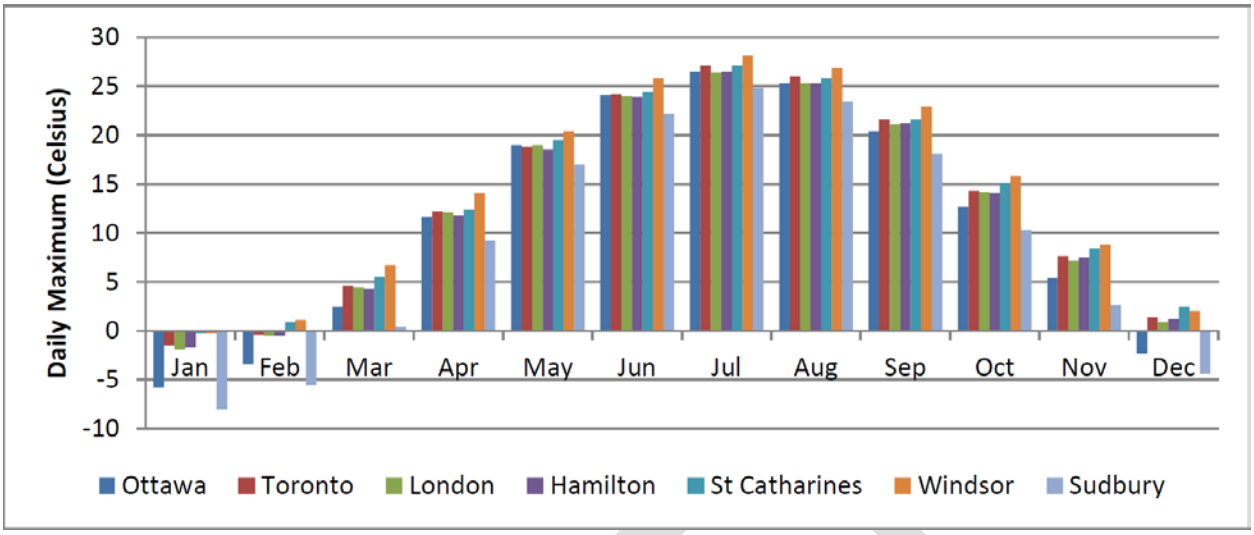



**Figure 14. Daily Maximum Temperature**

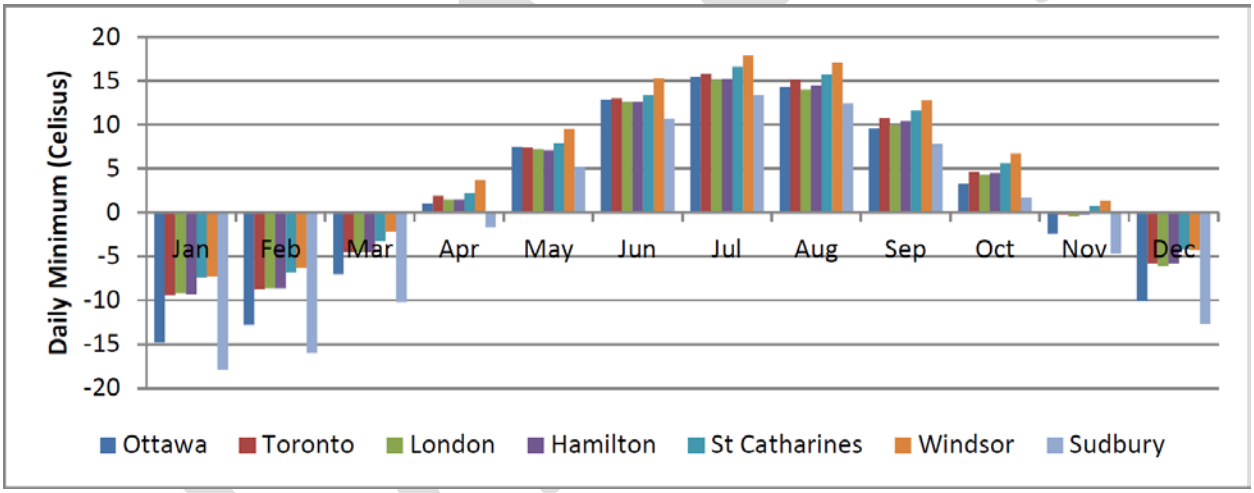



**Figure 15. Daily Minimum Temperature**

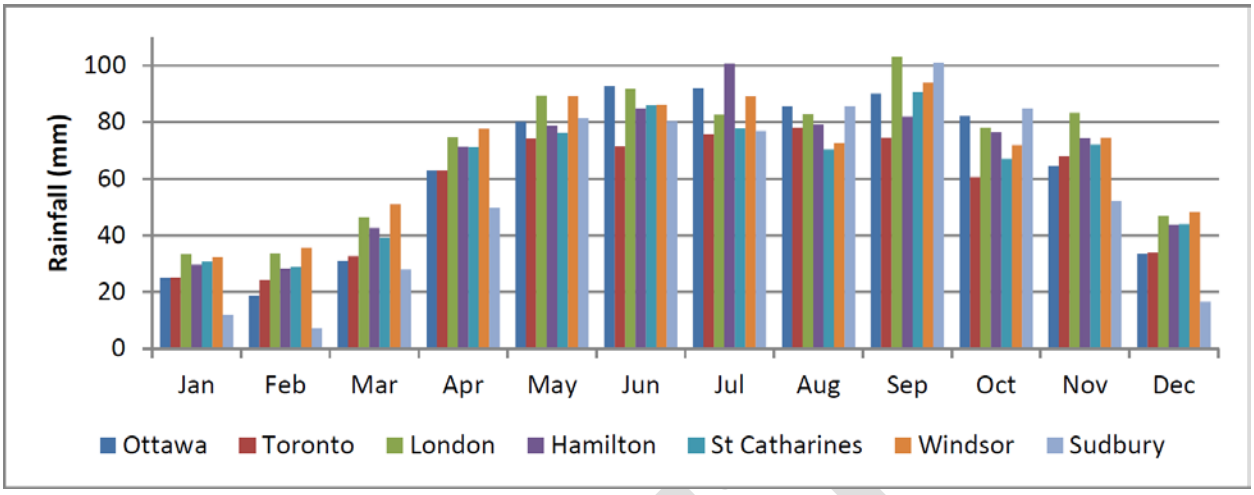



**Figure 16. Rainfall**

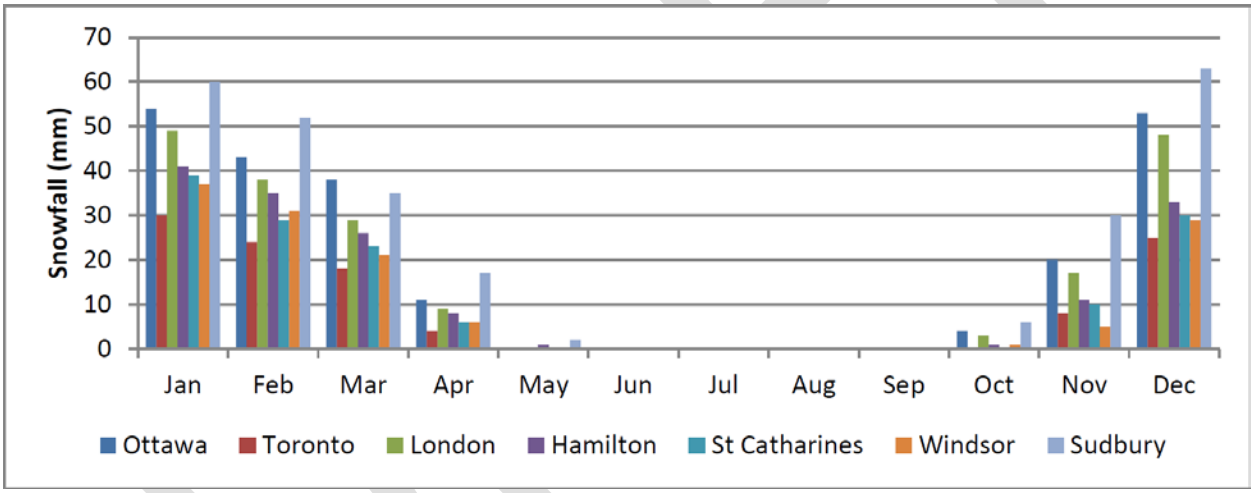



**Figure 17. Snowfall**

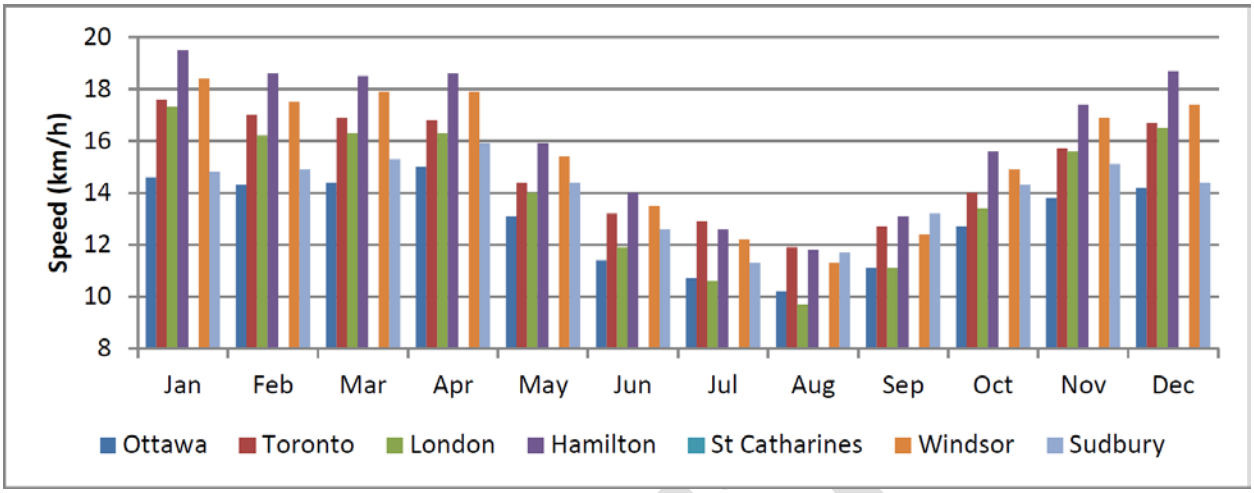



**Figure 18. Wind speed**

**Temperature Profile**

The Mississauga region temperature profile requires that Enersource equipment be able to operate under a temperature range of -40 to +40 degrees Celsius. Various pieces of equipment that contain inert gasses may not operate reliably at the lower end of this range and thus require extra heaters to ensure reliable operation. Extra heaters on equipment causes design changes and non-standard equipment procurement. The need for additional heaters may require a larger initial capital investment than that of a similar equipment model in areas with a warmer temperature range.

**Ice Accumulation & Snow Loading**

According to CSA Standard CAN/CSA C22.3 No.1 'Overhead Systems', Mississauga is located in an area of Ontario designated as "Heavy Loading", and as such requires designs to account for a radial thickness of 0.5" of ice covering overhead lines. Due to this possible ice accumulation, civil structures (concrete and wood poles) must be able to withstand ~~a~~ significant ice build-up without impacting structural integrity. This requires that larger class sizes and/or an increase in the number of poles be used when designing overhead systems.

Harsh winters also result in an increased use of road salts which can lead to premature rusting of pad mounted and pole mounted equipment located along the road. The salt spray from roadways also impacts operating and maintenance costs by increasing the need to wash porcelain insulators to prevent tracking and flash overs which lead to asset failures. The presence of road salt causes an increased need to repaint and repair rusted pad mounted and pole mounted equipment.

## 2.2.2 System Configuration

### System Description

Enersource owns and operates the electrical power system in Mississauga. The system can be divided into two main categories: subtransmission and distribution.

### Subtransmission System

Enersource's subtransmission system operates at a voltage of 44kV. The system receives electricity from HONI's Transformer Stations (TS) where voltage is transformed from 230kV to 44kV.

The HONI TS sites are: Meadowvale TS, Churchill Meadows TS, Erindale TS, Tomken TS, Bramalea TS, and Woodbridge TS. Enersource's subtransmission system is comprised of two areas: West 44kV and East 44kV, as illustrated in **Figure 19** below.

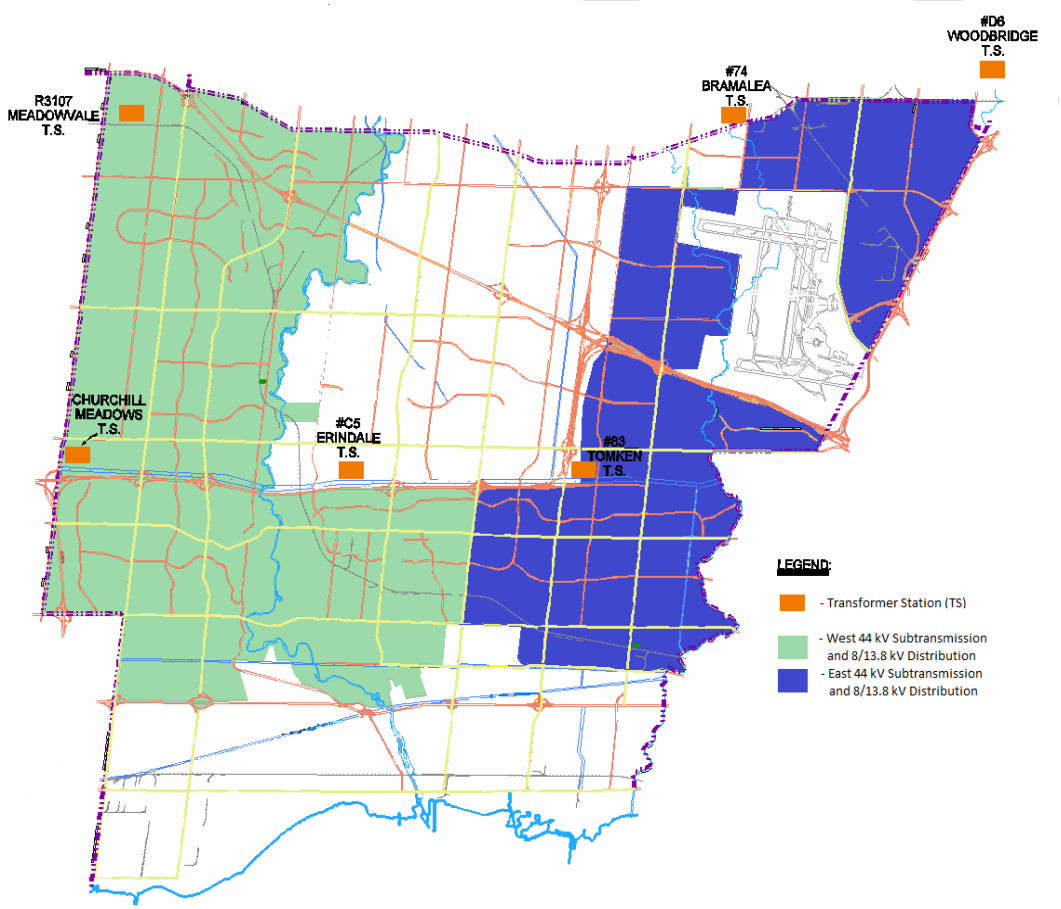



**Figure 19. Map of Enersource 44kV subtransmission system**

## Distribution System

Enersource's distribution system operates at the voltages of 16/27.6kV, 8/13.8kV, and 2.4/4.16kV.

The system receives electricity from two sources: HONI's TS's where voltage is transformed from 230kV to 16/27.6kV, or Enersource's substations sites where the voltage is transformed from 44kV to 8/13.8kV or from 16/27.6kV to 2.4/4.16kV

The HONI TS sites are: Oakville TS, Lorne Park TS, Cooksville TS, Richview TS, Erindale TS, Cardiff TS, and Bramalea TS.

Enersource supply points consist of 66 substations utilizing 108 power transformers that vary in capacity from 3 MVA to 20 MVA. In addition, 58 distribution feeders are supplied directly from HONI's TS's.

Enersource has divided its distribution system into four areas: North 16/27.6kV, South 16/27.6kV and 2.4/4.16kV, West 8/13.8kV and East 8/13.8kV as illustrated in **Figure 20** below.

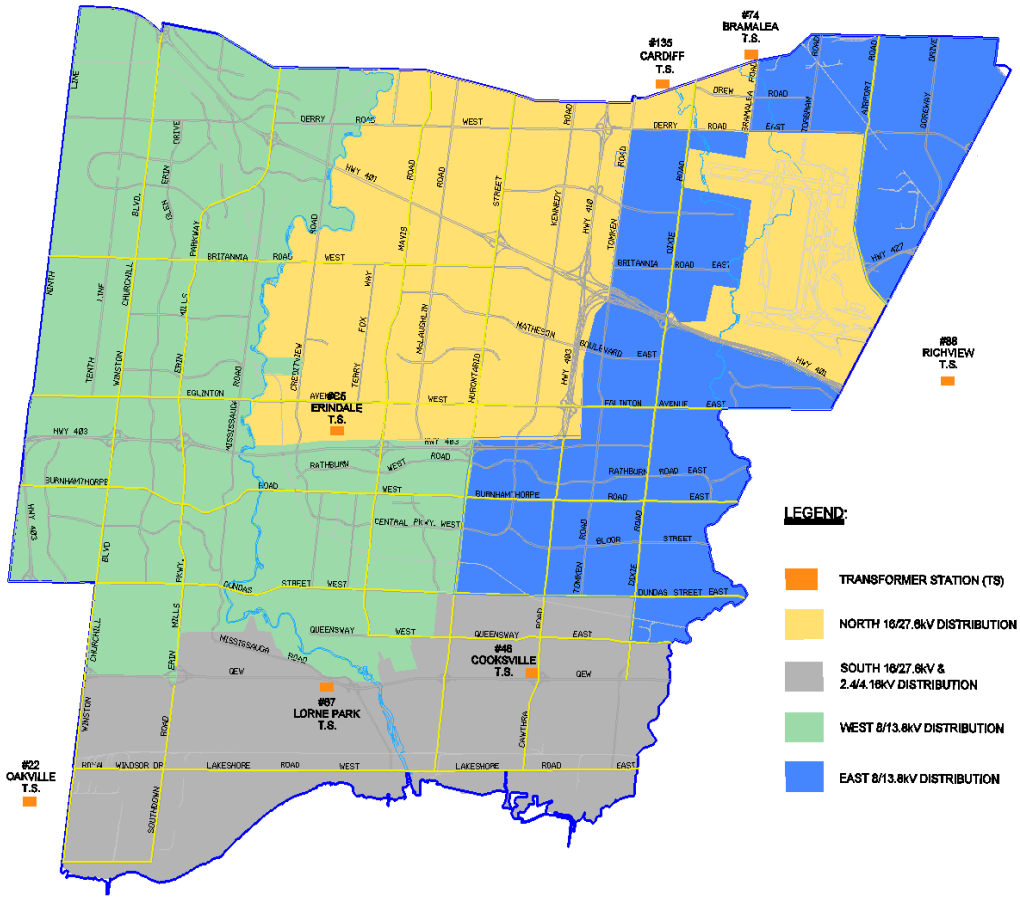



**Figure 20. Map of Enersource distribution system**

## North 16/27.6kV Distribution System

The North 16/27.6kV System consists mainly of distribution equipment which is connected directly to HONI TS feeders.

HONI TS sites are: Erindale TS, Bramalea TS, Cardiff TS, and Richview TS.

This area contains one Enersource substation site (Mini Derry) comprised of two step-down transformers rated 44/27.6kV. The overall North 16/27.6kV distribution system utilizes 36 distribution feeders, four of which are supplied by the Mini-Derry substation and 32 are supplied by HONI TS sites.

The area serviced by this system is illustrated in **Figure 21** below.

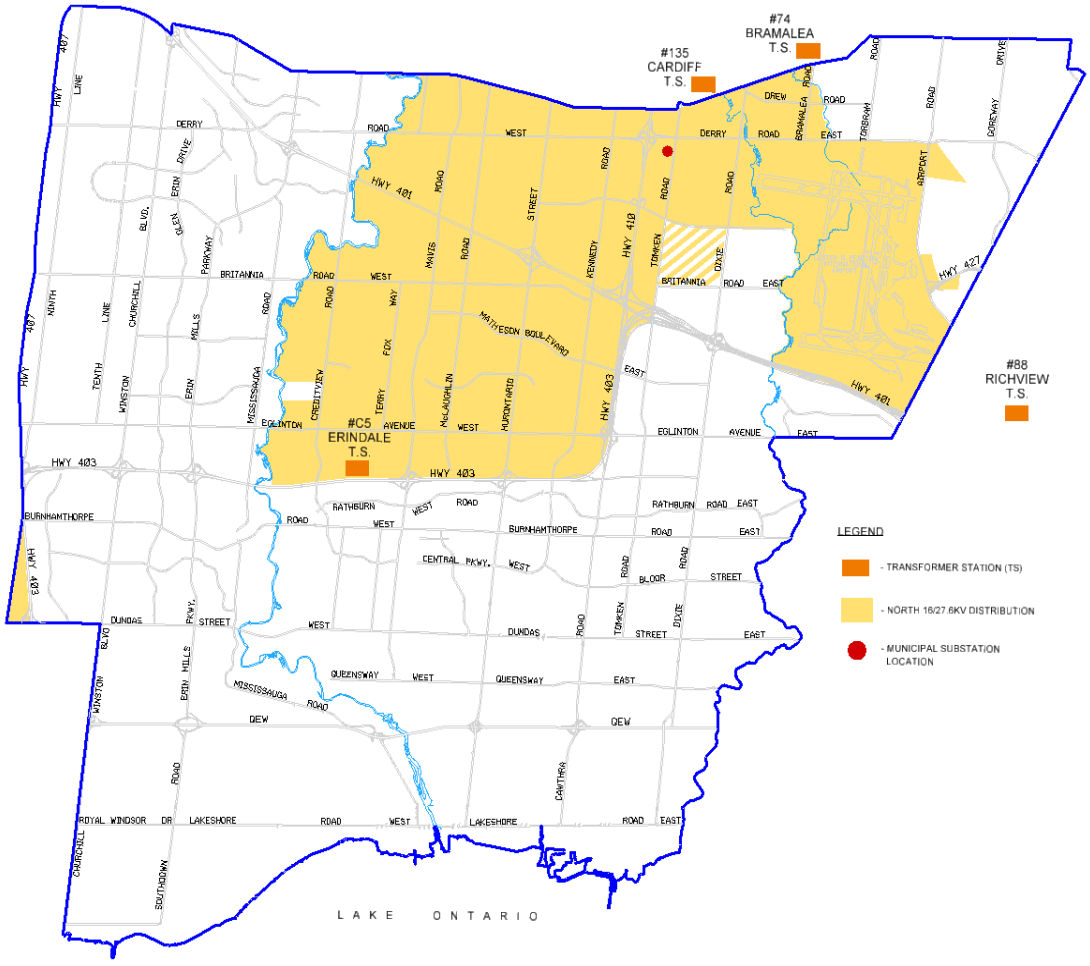



**Figure 21. Map of Enersource North 16/27.6kV distribution system**

## South 16/27.6kV and 2.4/4.16kV Distribution System

The South 16/27.6kV System is composed of several large and small customers connected directly to HONI TS supply. Enersource's MS's further step down the voltage to the 2.4/4.16kV distribution system.

HONI TS sites are: Oakville TS, Lorne Park TS, and Cooksville TS.

This area contains 25 substations comprised of 42 step-down transformers rated 27.6/4.16kV. The 2.4/4.16kV distribution system consists of 100 feeders.

The area serviced by this system is illustrated in **Figure 22** below.

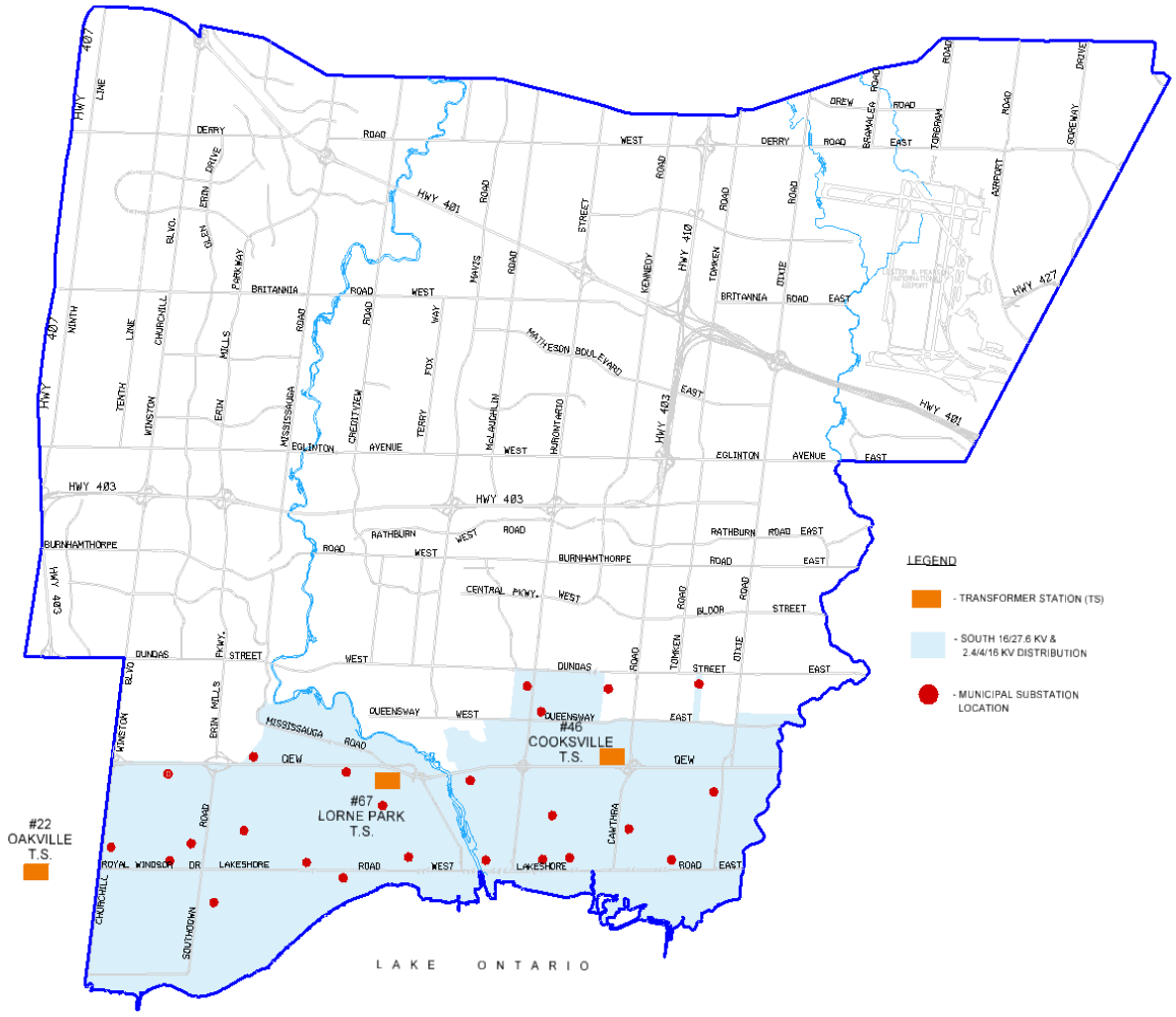



**Figure 22. Map of Enersource South 16/27.6 and 2.4/4.16kV distribution systems**

## West 8/13.8kV Distribution System

The West 8/13.8kV Distribution System covers the same geographical area as the 44kV sub transmission system, as shown in **Figure 19**. However, due to the large area and number of customers, the 8/13.8kV distribution system has been divided into west and east distribution systems, which is consistent with the division between the west and east 44kV subtransmission systems. All customers on this West 8/13.8kV system are connected directly to the distribution feeders supplied by Enersource MS's.

This area contains 23 substation sites comprised of 37 step-down transformers rated 44/13.8kV. This distribution system utilizes 137 distribution feeders.

The area serviced by this system is illustrated in **Figure 23** below:

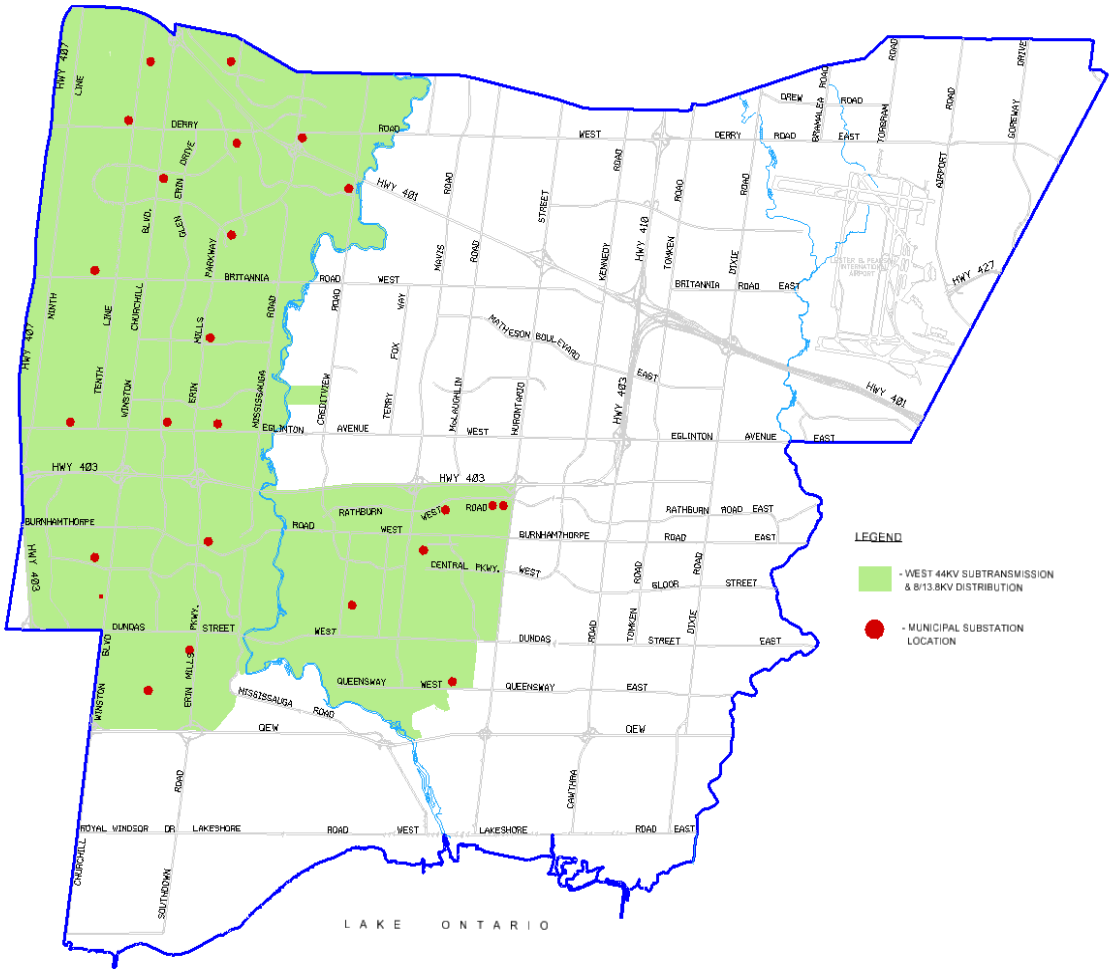



**Figure 23. Map of Enersource West 8/13.8kV distribution system**

## East 8/13.8kV Distribution System

All customers on this system are connected directly to the distribution feeders supplied by Enersource MS's.

This area contains 17 substation sites comprised of 29 step-down transformers rated 44/13.8kV. This distribution system utilizes 88 distribution feeders.

The area serviced by this system is illustrated in **Figure 24** below:

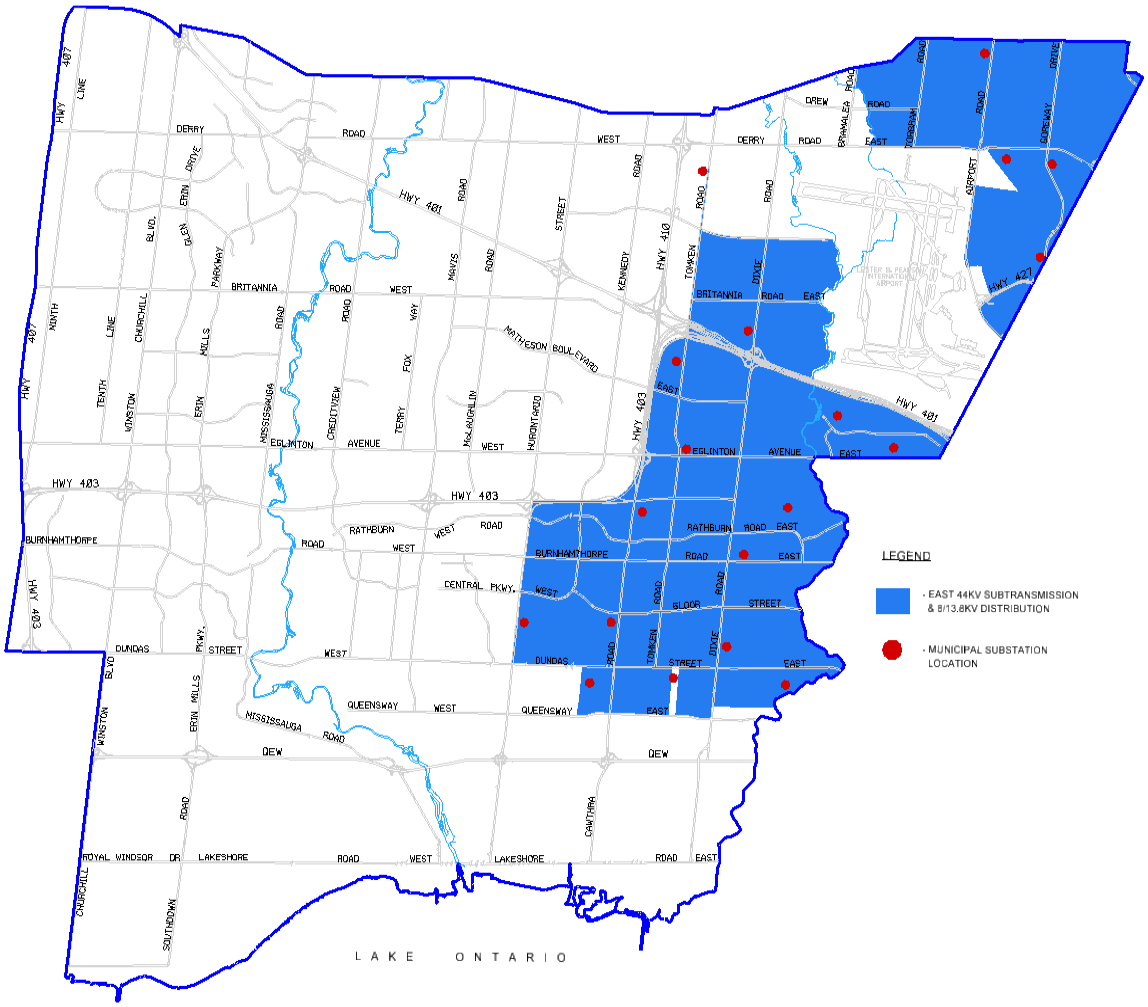



**Figure 24. Map of Enersource east 8/13.8kV distribution system**

**Tables 20-22** present a summary of the system configurations.

**Table 20. Length of underground and overhead systems**

| Location | Total Circuit Length (km) | Total Conductor Length (km) |
|---|---|---|
| Underground | 3,383 | 6,271 |
| Overhead | 1,797 | 5,139 |
| **Total** | **5,180** | **11,410** |

**Table 21. Number and length of circuits and conductors by voltage level**

| Voltage Level (kV) | Number of Circuits | Underground Circuits Length (km) | Underground Conductors Length (km) | Overhead Circuits Length (km) | Overhead Conductor Length (km) |
|---|---|---|---|---|---|
| 4.16 | 130 | 280 | 421 | 276 | 676 |
| 8.32 | 3 | 0 | 0 | 2 | 3 |
| 13.8 | 291 | 2,140 | 3,942 | 543 | 1,537 |
| 27.6 | 139 | 931 | 1,814 | 494 | 1,478 |
| 44 | 79 | 31 | 94 | 482 | 1,446 |
| **Total** | **642** | **3,383** | **6,271** | **1,797** | **5,139** |

**Table 22. Number and capacity of municipal stations**

| Secondary Voltage Level (kV) | Number of Stations | Number of Transformers | Total Transformation (MVA) |
|---|---|---|---|
| 4.16 | 25 | 42 | 181 |
| 13.8 | 40 | 64 | 1,260 |
| 27.6 | 1 | 2 | 40 |
| **Total** | **66** | **108** | **1,481** |

### 2.2.3 Asset Demographics and Condition

The following section summarizes the demographics and condition assessment for the major asset classes within Enersource's distribution system. Asset condition is based upon a health index computation which is unique for each asset class. In instances where detailed asset information is lacking, the asset condition is computed based on the age of the asset (i.e. age-based condition).

Shown in **Table 23** and **24** below is the asset demographics with associated health index contribution and the asset management strategy (i.e., replacement) for each asset category.

**Table 23. Asset Health Index Summary**

| Asset Category | | Population | Average Health Index | Health Index Distribution | | | | | Average Age |
|---|---|---|---|---|---|---|---|---|---|
| | | | | Very Poor (< 25%) | Poor (25 - <50%) | Fair (50 - <70%) | Good (70 - <85%) | Very Good (>= 85%) | |
| Substation Transformers | In Service | 108 | 82% | < 1% | 2% | 14% | 36% | 47% | 22 |
| | Spares | 12 | 80% | 8% | 0% | 17% | 8% | 67% | 33 |
| Circuit Breakers | | 510 | 94% | 2% | < 1% | 2% | 4% | 93% | 20 |
| Pole Mounted Transformers | | 5346 | 92% | 2% | < 1% | 6% | 11% | 80% | 21 |
| Pad Mounted Transformers | 1 Phase | 14242 | 87% | < 1% | 4% | 7% | 29% | 59% | 21 |
| | 3 Phase | 1821 | 94% | < 1% | 2% | 4% | 9% | 84% | 16 |
| Vault Transformers | | 3861 | 87% | 2% | 7% | 7% | 13% | 71% | 27 |
| Pad Mounted Switchgear | | 862 | 84% | 6% | 3% | 7% | 19% | 65% | 19 |
| Overhead Switches | 44 kV | 338 | 95% | 0% | 5% | < 1% | 6% | 88% | 20 |
| | 27.6 kV | 213 | 97% | 0% | 1% | 3% | 2% | 93% | 18 |
| | Inline | 2002 | 93% | 1% | 3% | 4% | 5% | 86% | 18 |
| | Motorized | 104 | 85% | 8% | 7% | 2% | 6% | 78% | 16 |
| Underground Cables *Note that results are given in terms of conductor-km | Main Feeder | 2233 | 78% | 12% | 9% | 0% | 7% | 73% | 18 |
| | Distribution | 4038 | 70% | 21% | 13% | 0% | 6% | 60% | 21 |
| Poles | Wood | 12917 | 79% | 9% | 9% | 7% | 15% | 60% | 27 |
| | Concrete | 8966 | 97% | 0% | < 1% | 1% | 4% | 95% | 20 |

**Table 24. Asset Management Strategy**

| Type | Analysis | Strategy | Frequency |
|---|---|---|---|
| Substation | Switchgear Inspections | Preventative | 1 Year |
| | Breaker & Recloser | Preventative | 4-6 Years |
| | Station Switches | Preventative | 1 Year |
| | SCADA Inspections | Preventative/Predictive | 1 Year |
| | Relay | Preventative | 4-6 Years |
| | Station Inspections | Predictive/Corrective | 1 Month |
| | Battery Maintenance | Predictive | 1 Year |
| | Transformer Maintenance | Preventative | 3-5 Years |
| | Transformer Doble Test | Predictive | 3-5 Years |
| | Transformer Oil Analysis | Predictive | 1 Year |
| | Transformer Tapchanger Maintenance | Preventative/Predictive | 3-5 Years |
| | Padmounted Switchgear IR and Visual Inspection | Predictive/Corrective | 5 Years |
| Distribution | Switchgear Dry Ice Cleaning | Preventative | 3-5 Years |
| | All Transformers Visual Inspection | Predictive/Corrective | 3 Years |
| | Graffiti Abatement | Corrective | 1 Year |
| | Vault Dry Ice Cleaning | Preventative | 5 Years |
| | Vegetation Management | Preventative/Corrective | 3 Years |
| | O/H Visual & Pole Inspection | Predictive/Corrective | 3 Years |
| | Critical Switch Operation | Preventative | 1 Year |
| | O/H Insulator Washing | Preventative | 2 Years |
| | O/H IR Inspection | Predictive | 1 Year |

### *2.2.3.1 Station Transformers*

In Enersource's distribution system, substation transformers are critical pieces of equipment, whose function is to provide transformation from high voltage transmission and subtransmission lines to a lower voltage to distribute throughout the City. Enersource has 108 station transformers with varying secondary voltages: 42 units at 4.16kV, 65 units at 13.8kV, and two units at 27.6kV. **Figure 25** shows age demographics of stations transformers.

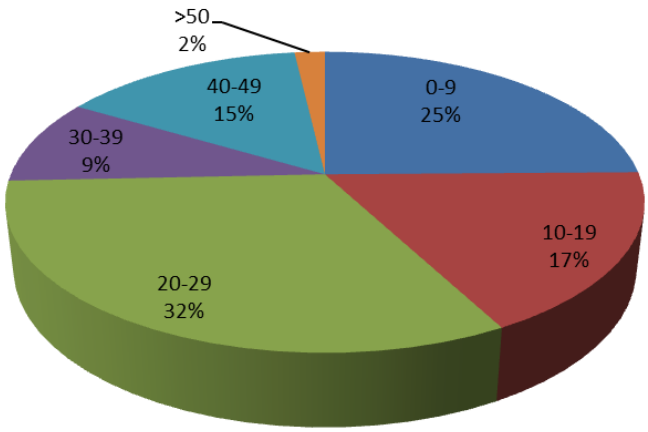



**Figure 25. Station Transformer Age Demographics**

Enersource acquires various test data to assist in tracking the transformer asset condition. This includes the results of Doble testing, oil analysis (including dissolved gas analysis or DGA), in addition to any findings acquired through routine transformer and transformer tapchanger maintenance. Through various tests and inspections, the concentration and rate of concentration change of dissolved gasses, and quality of the overall mineral oil can be monitored. Once these key indicators reach unacceptable levels, the transformer will be scheduled for off-line inspection and possibly require refurbishment or replacement. **Figure 26** outlines the condition of station transformers using health index computation methodology.

DRAFT

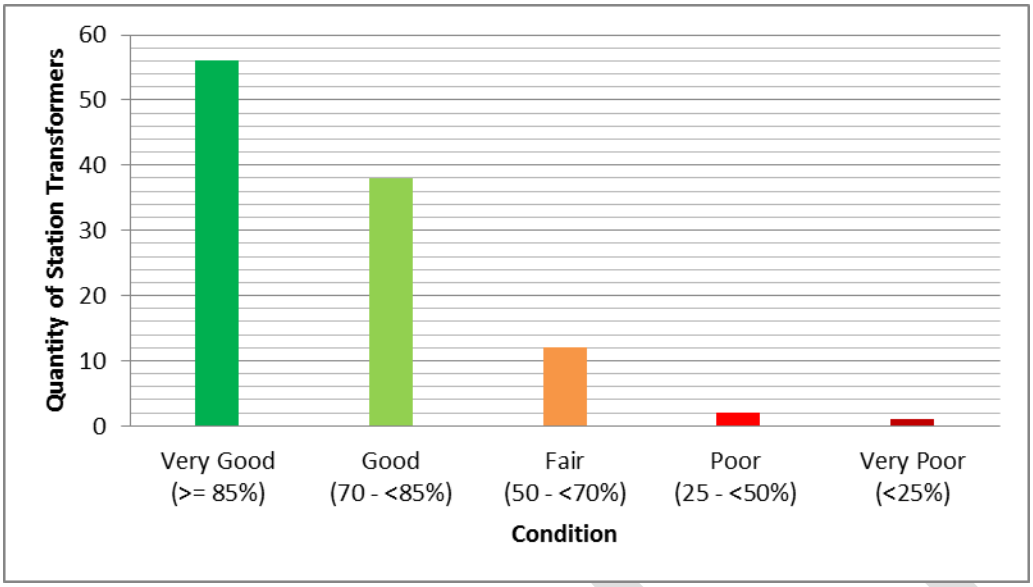



**Figure 26. Station Transformer Condition**

### *2.2.3.2 Circuit Breakers*

Enersource owns and maintains 510 circuit breakers and assemblies in 66 substations. The station circuit breaker assets consist of breakers, switches, bus insulation, support structures, protection and control systems, arrestors, control wiring, ventilation, and fuses.

**Figure 27** shows the average age of station circuit breakers is 20 years with approximately 15% of the population being 40 years or older with age distribution.

DRAFT

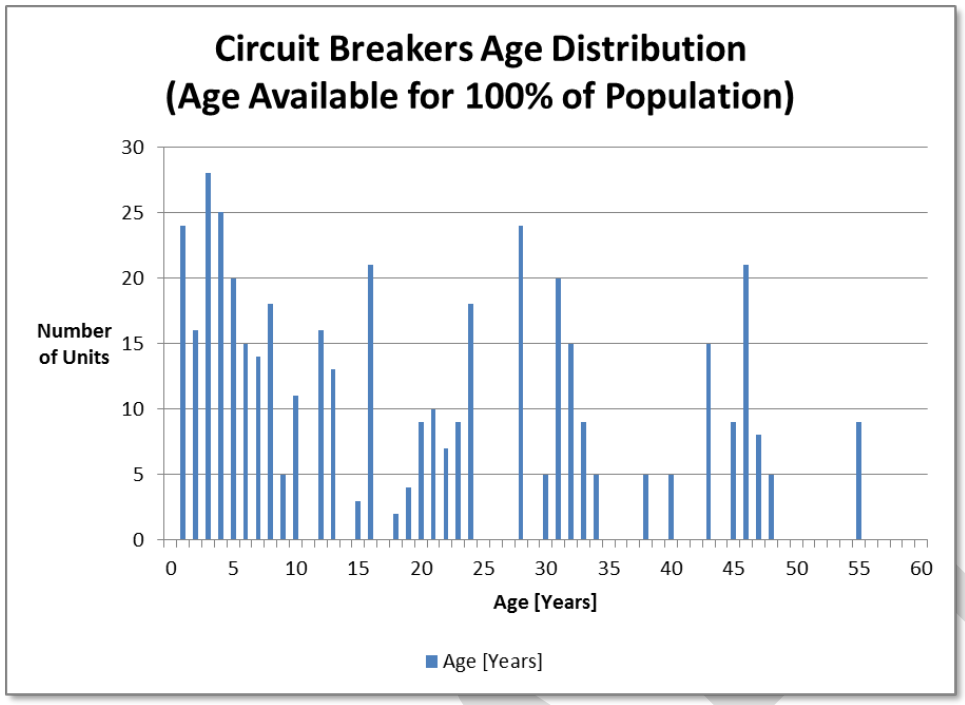



**Figure 27. Circuit Breakers Age Distribution**

The health index for circuit breakers takes into account many functional and supporting parts. A qualitative assessment of the equipment condition, based on subject matter experience, is done on the switches, breakers, bus, insulation and supporting structures. Analysis includes condition parameters such as operating mechanism, contact performance, arc extinction, insulation level, lubrication, contact resistance, tank condition, arc chute life, service record, and the interrupting medium (oil, SF6, Vacuum, Air-Magnetic). The equipment is then reviewed for functional obsolescence and the availability of spare parts. The health index is calculated using this information and the age of the equipment.

With a population of 510 circuit breakers, the average health index for the group was 94% with approximately 2% of the population found to be in 'poor' or 'very poor' condition, as shown in **Figure 28**.

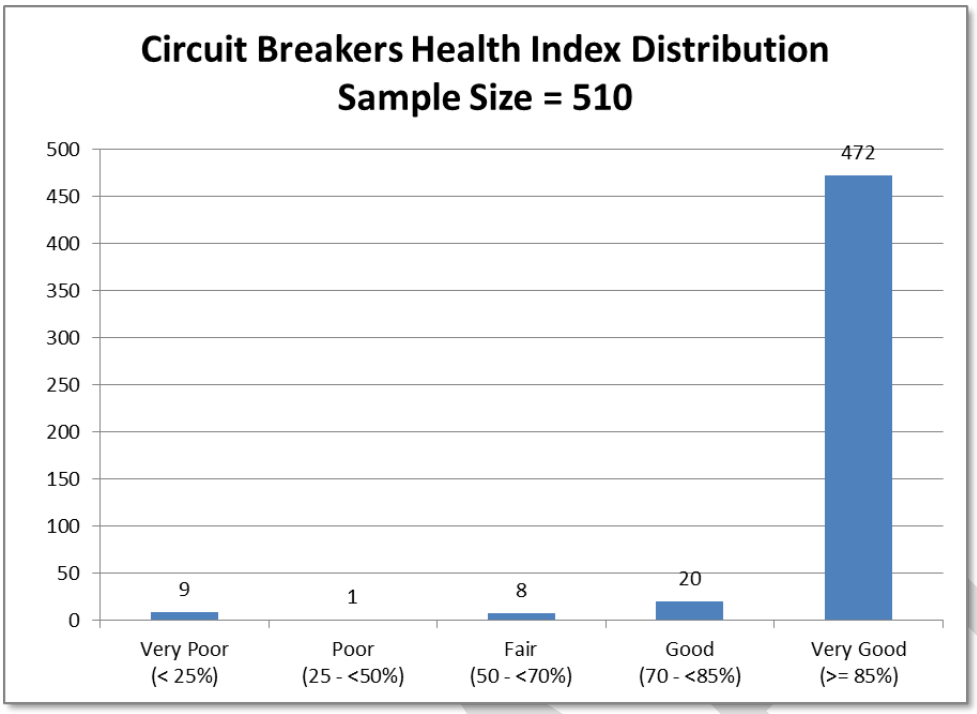



**Figure 28. Circuit breakers health index distribution (unit)**

### *2.2.3.3 Pad Mounted Switchgears*

Enersource owns and operates a distribution pad mounted switchgear population of over 860 units. These switchgear units provide connectivity, feeder protection, switching and isolation capability, and in some cases remote operation capability and load breaking capability. There are many different types of pad mounted switchgears used to service various applications and that are installed in various projects as a result of a constant need to find more reliable equipment. Like many other electricity utilities in Ontario, Enersource has had reliability issues (including premature failures) with air insulated switchgear as they face day-to-day contaminants. Within the last five years, as vacuum (solid dielectric) switchgear units gained in popularity, Enersource conducted pilot project and cost benefit analysis and moved to replacing air insulated gear with this newer technology that improves reliability and reduces ongoing maintenance costs (e.g., dry ice cleaning).

Demographic information for pad mounted switchgear assets, such as purchase date, installation date, serial number, ratings, etc., are stored in the GIS system. Currently, Enersource is in the process of improving accuracy of data by conducting comprehensive annual inspections and collecting asset data via ruggedized tablets.

The average age of all units was 19 years with approximately 37% of the population being 25 years or older, as shown in **Figure 29**.

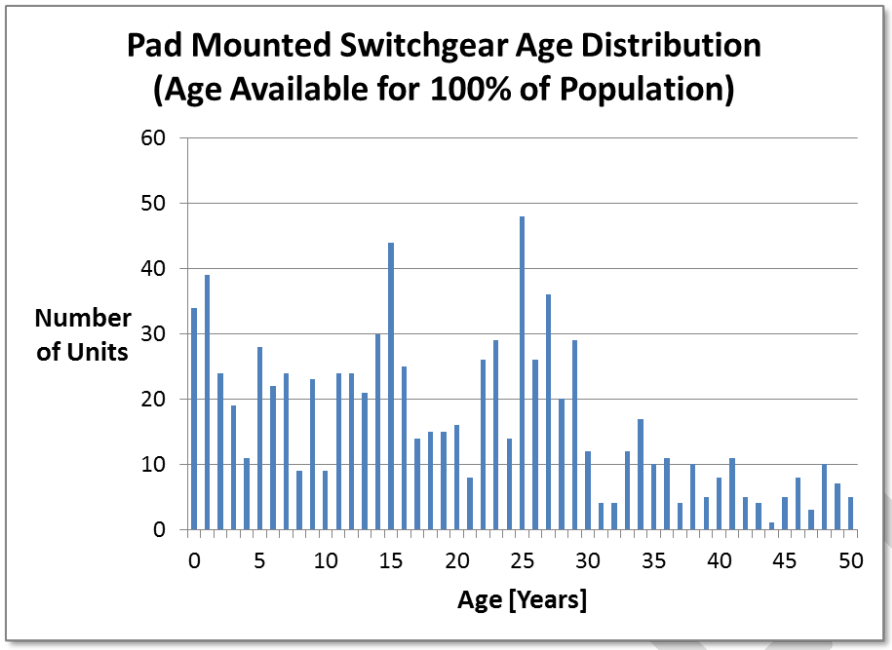



**Figure 29. Pad Mounted Switchgear Age Distribution**

The health index for pad mounted switchgears takes into account many attributes obtained through switchgear inspections. These include physical condition (such as corrosion, quality of the paint finish, contaminants, i.e., dirt and salt due to road traffic), switch/fuse condition (including remaining life of the arc suppressor), insulation (including cypoxy insulators and fiber flash barriers), and existing service records. The health index is calculated using this information and the age of the equipment.

With a population of 862 pad mounted switchgears, the average health index for the group was 84% with approximately 8% of the population found to be in 'poor' or 'very poor' condition, as shown in **Figure 30**.

DRAFT

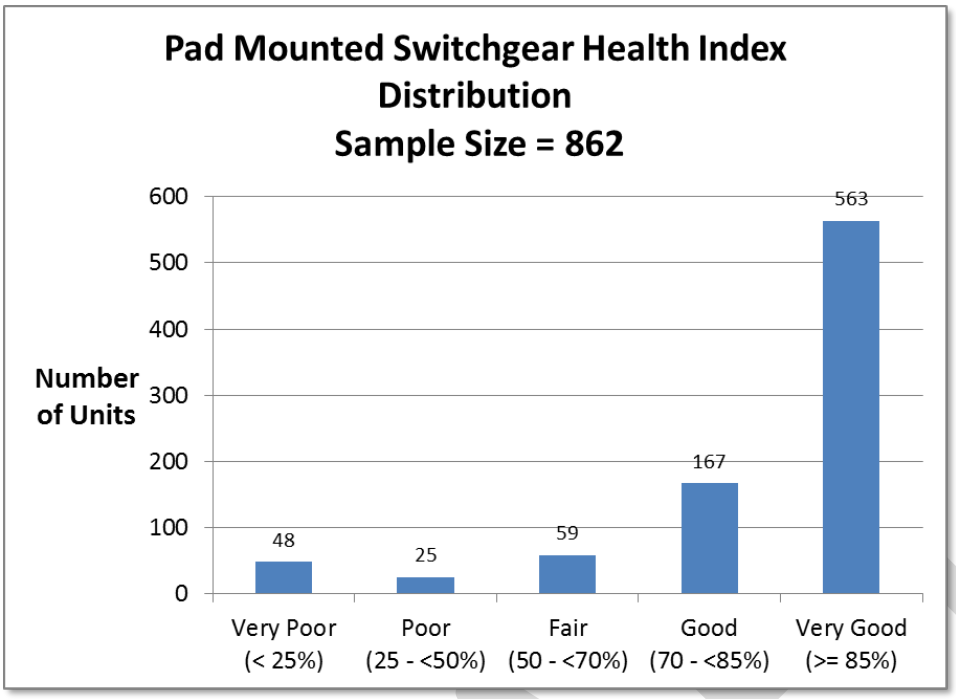



**Figure 30. Pad Mounted Switchgear Health Index Distribution (unit)**

### *2.2.3.4 Overhead Line Switches*

Enersource owns and operates various types of overhead switches. These switches are typically classified based on their voltage level and function. This includes load break switches on the 44kV and 27.6kV system, both manual operation and motorized and gang operated, and a large population of single phase in-line switches, both single and double insulator. These switches provide connectivity, switching, and isolation capability. This enables a dynamic distribution system that can react to planned isolation and emergency situations while keeping the majority of customers with power. Enersource has a population of 338 load break switches at the 44kV level, 213 load break switches at the 27.6 kV level, 104 motorized load break switches and 2,002 inline switches.

The average age of all 44kV load break switches was 20 years with approximately 9% of the population being 40 years or older, as shown in **Figure 31**.

DRAFT

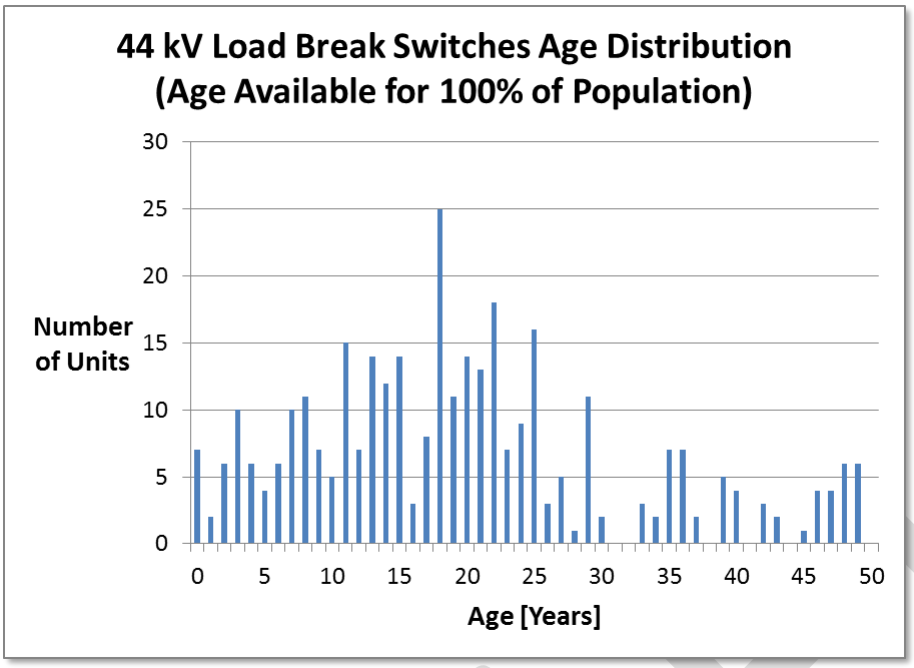



**Figure 31. Age Distribution of 44 kV Load Break Switches**

The average age of all 27.6kV load break switches was 18 years with approximately 6% of the population being 40 years or older, as shown in **Figure 32**.

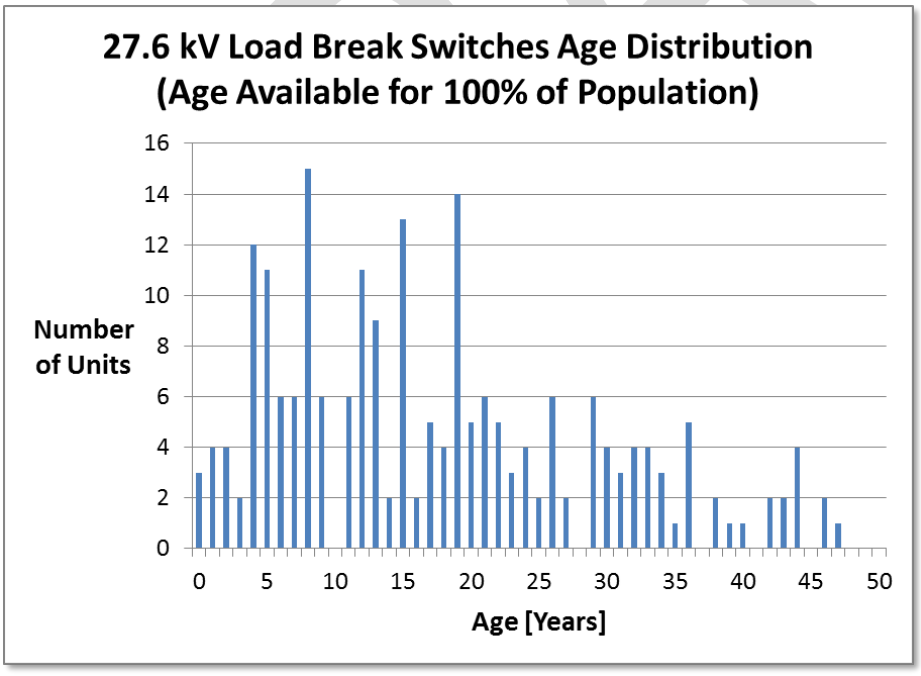



**Figure 32. Age Distribution 27.6 kV Load Break Switches**

The average age of all motorized switches was 16 years with approximately 27% of the population being 25 years or older, as shown in **Figure 33**.

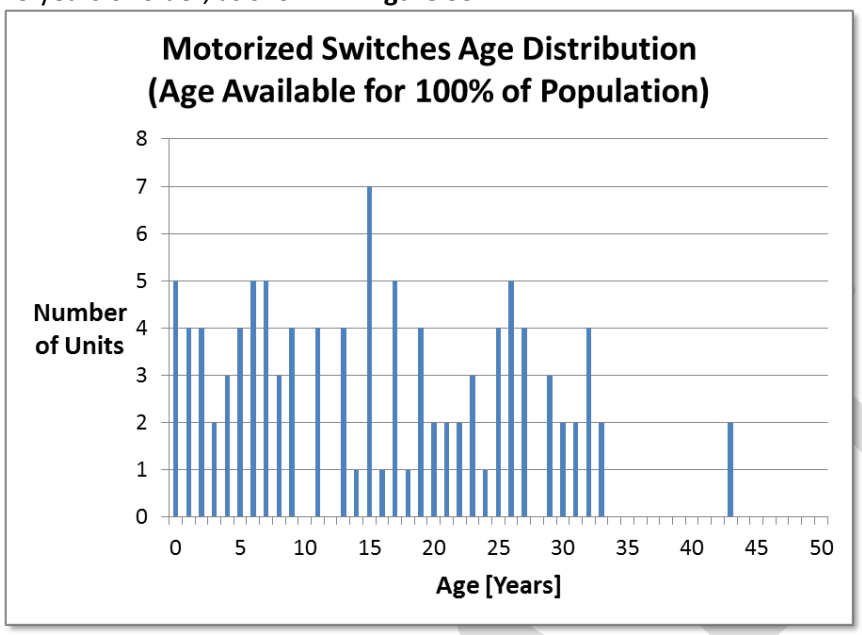



**Figure 33. Motorized Switches Age Distribution**

The average age of all in-line switches was 18 years with approximately 12% of the population being 40 years or older, as shown in **Figure 34**.

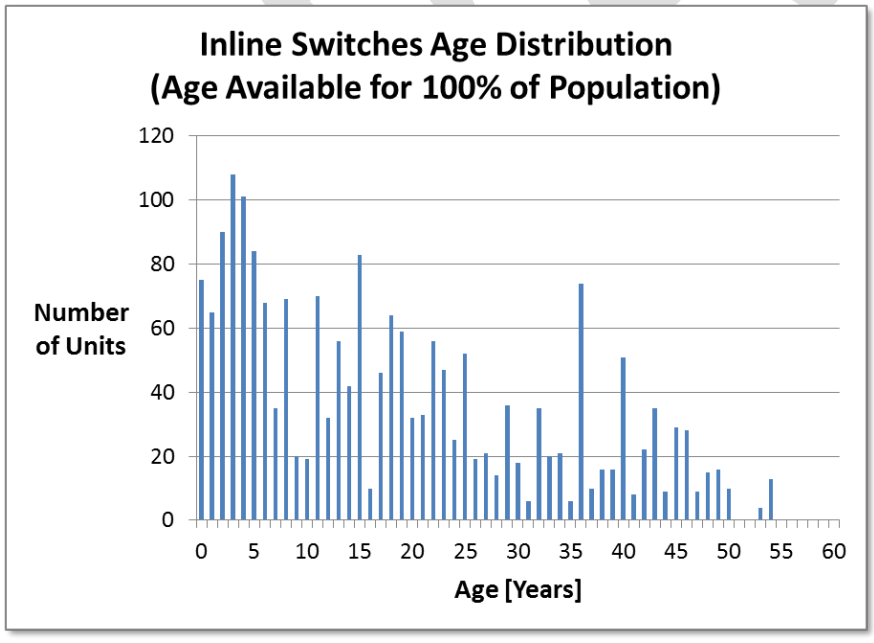



**Figure 34. In-Line Switch Age Distribution**

Overhead switches are typically run-to-failure unless a technical or health and safety issue has been identified. The heath index of these overhead switches is comprised of an age related component and results of Infra-red thermal scans, including a further de-rating based on switch type history.

The average health index for the group of 44kV load break switches, with a population of 338, was 95% with approximately 5% of the population found to be in 'poor' or 'very poor' condition, as shown in **Figure 35**.

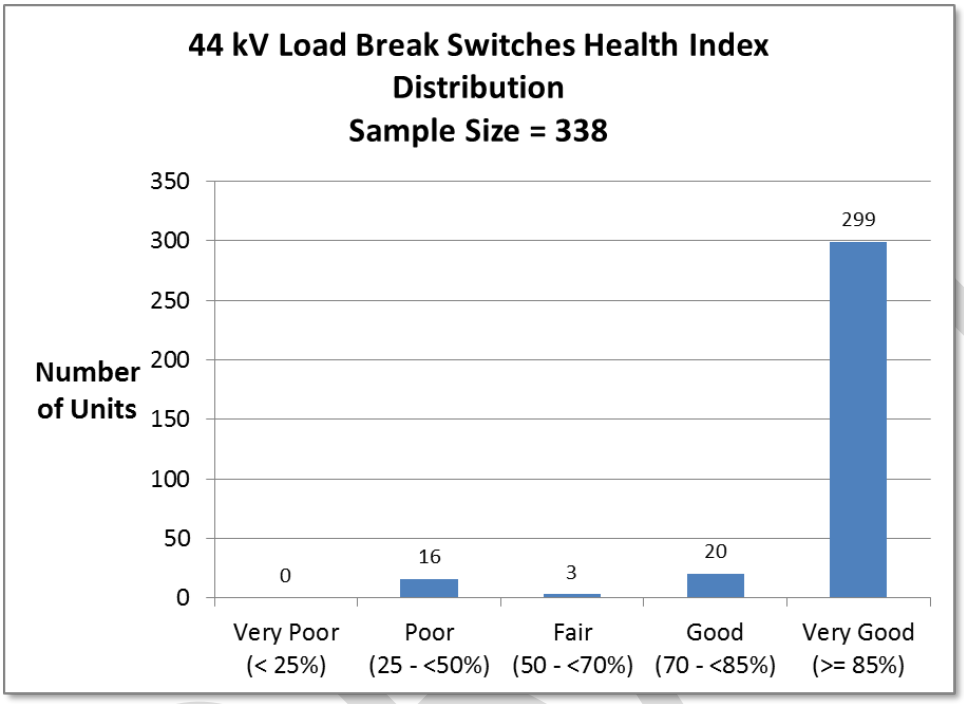



**Figure 35. Health Index Distribution of 44 kV Load Break Switches (Unit)**

The average health index for the group of 27.6kV load break switches, with a population of 213, was 97% with approximately 1% of the population found to be in 'poor' or 'very poor' condition, as shown in **Figure 36**.

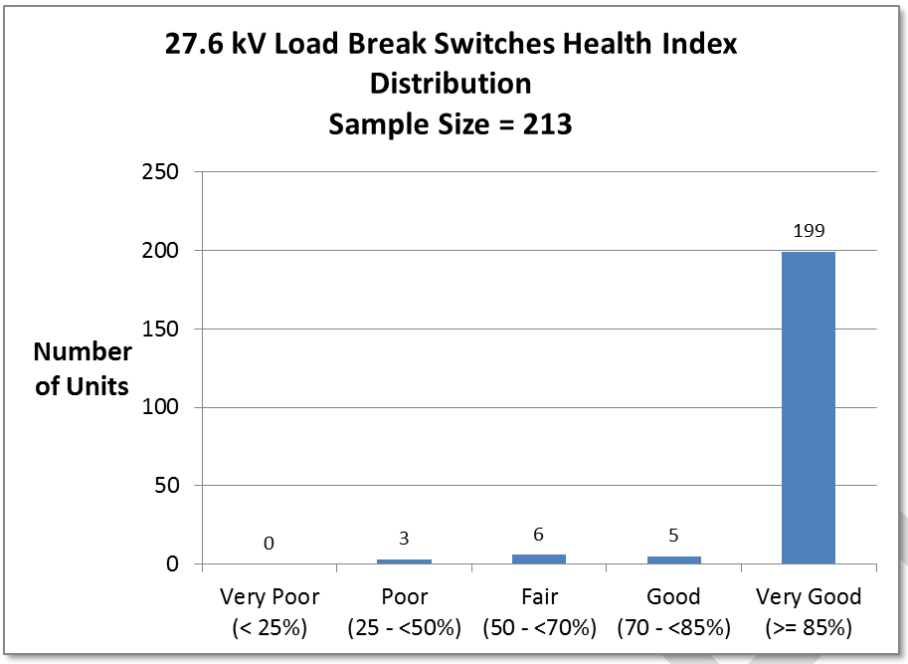



**Figure 36. Health Index Distribution of 27.6kV Load Break Switches (Unit)**

The average health index for the group of motorized load break switches, with a population of 104, was 85% with approximately 14% of the population found to be in 'poor' or 'very poor' condition, as shown in **Figure 37**.

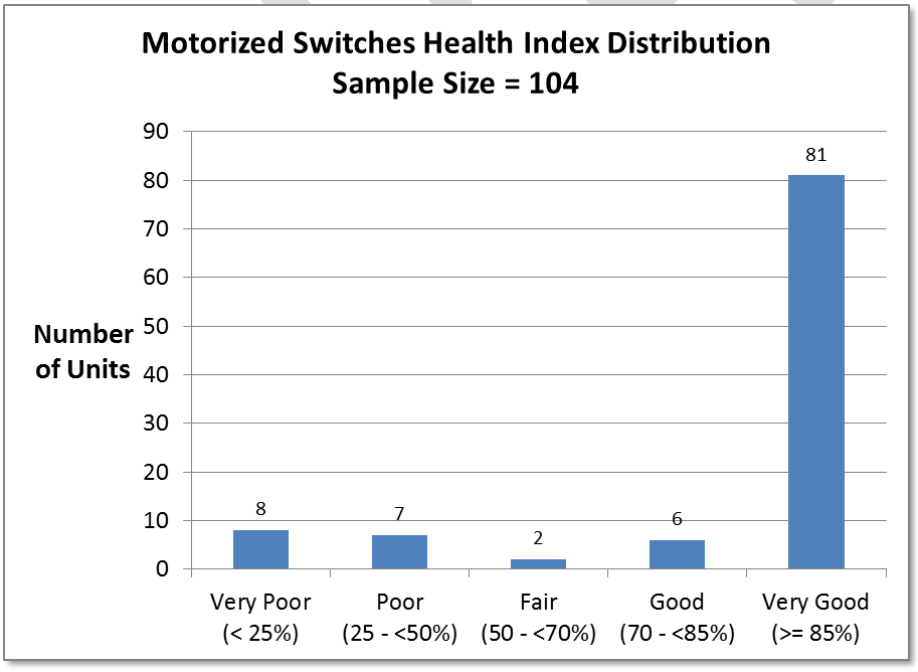



**Figure 37. Motorized Switches Health Index Distribution (Unit)**

The average health index for the group of in-line switches, with a population of 2,002, was 93% with approximately 5% of the population found to be in 'poor' or 'very poor' condition, as shown in **Figure 38**.

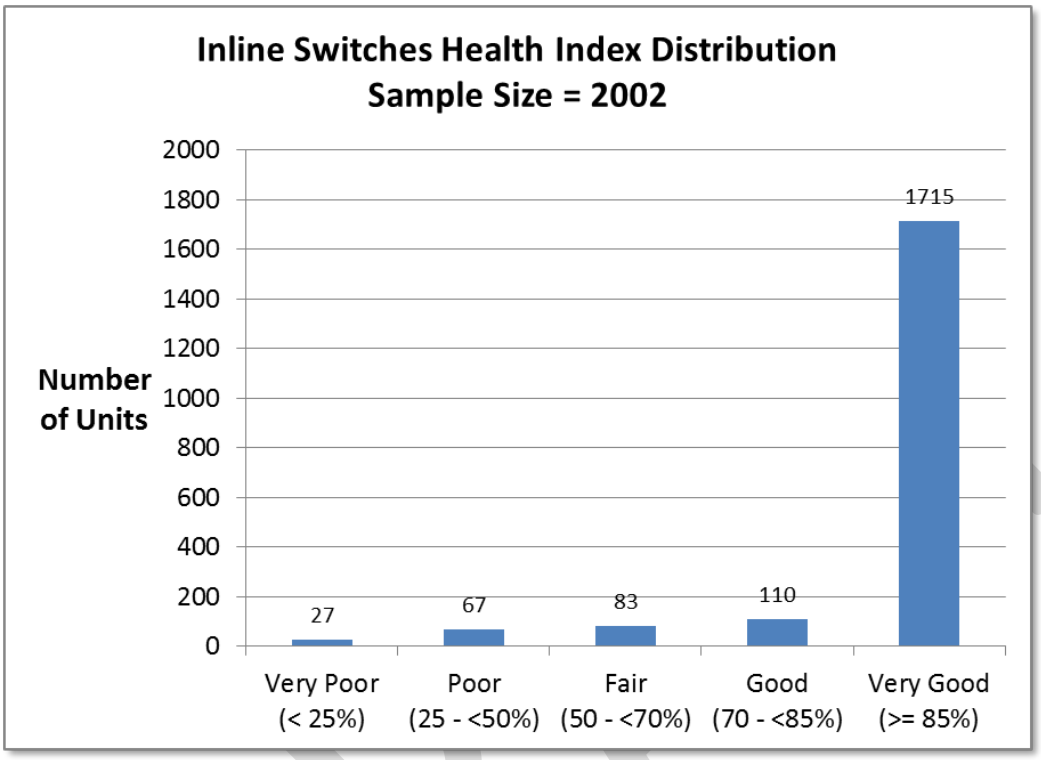



**Figure 38. In Line Switches Health Index Distribution (Unit)**

### *2.2.3.5 Overhead Conductor*

Enersource owns and operates over 1,800 km in overhead circuit length (over 5,100 km in overhead conductor length). Due to the rarity of overhead conductor failures, Enersource only performs infrared inspections on its overhead assets (e.g., switches, insulators). The conductors are replaced during pole top equipment work or pole replacement projects (such as rebuilds or road widenings).

### *2.2.3.6 Distribution Poles*

Enersource owns over 12,900 wood poles and over 8,900 concrete poles. The average age of wood poles was 27 years with approximately 14% of the population 45 years or older. The average age of concrete poles is 20 years with approximately 13% of the population 45 years or older, as shown in **Figures 39** and **40**.

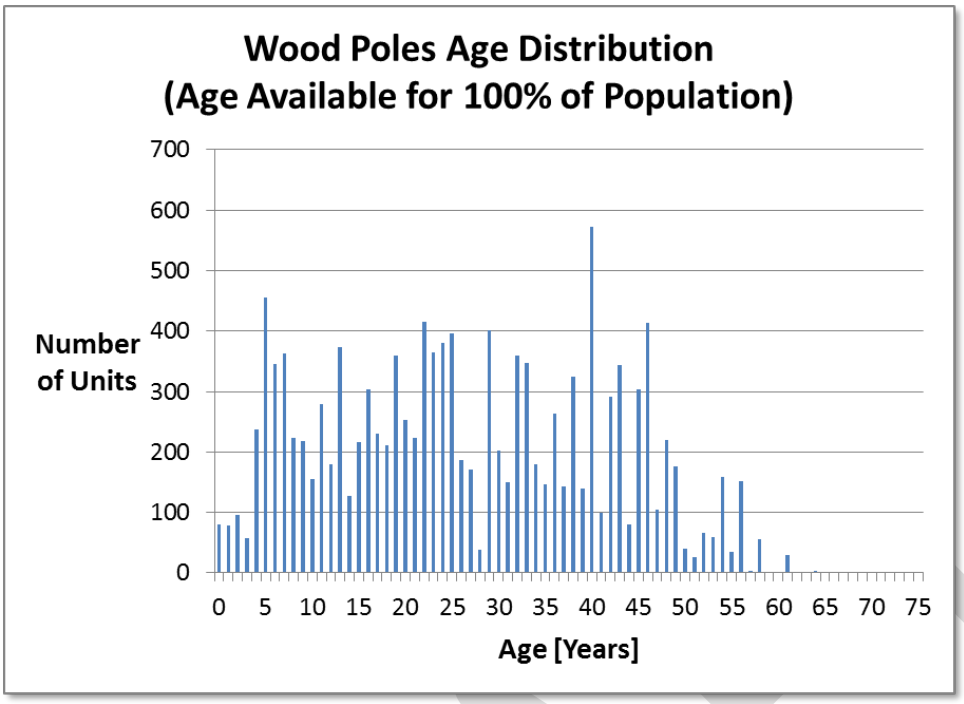



**Figure 39. Wood Pole Age Distribution**

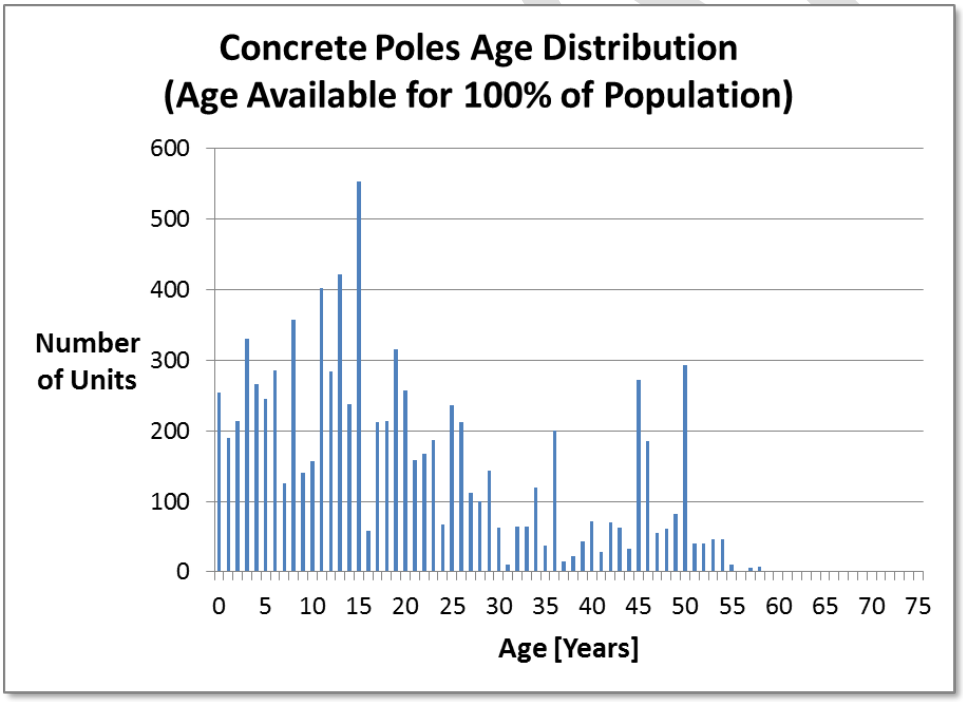



**Figure 40. Concrete Pole Age Distribution**

In recent years Enersource has increased its inspection program and has now inspected 100% of the poles in Mississauga. The overall health index for wood and concrete poles is based on data provided to

Kinectrics as part of Enersource's asset condition assessment report. Based on the Kinectrics report, the average health index for wood poles was determined to be 88% with approximately 3% of the population in 'poor' or 'very poor' condition, as shown in **Figure 41**.

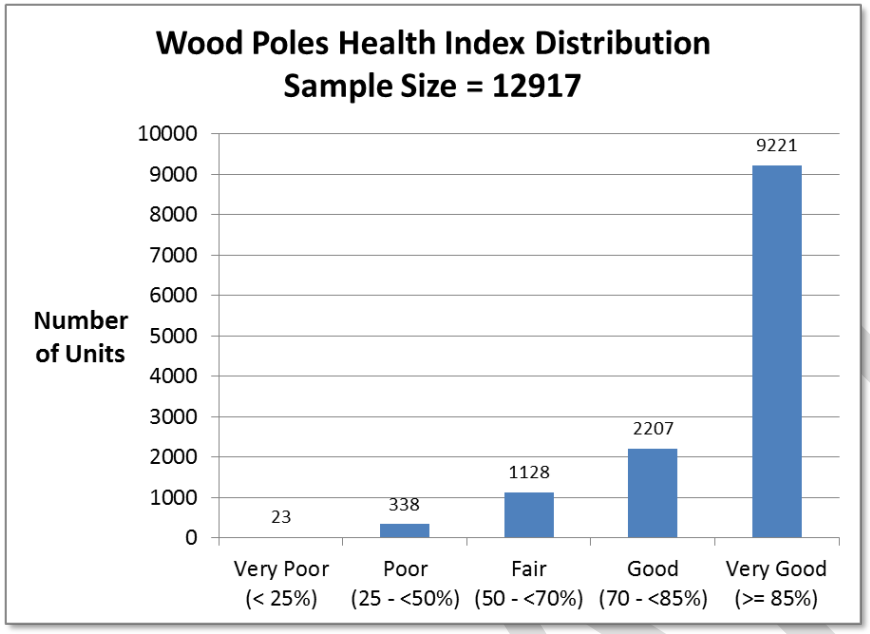



**Figure 41. Wood pole Health Index Distribution (Unit)**

The average health index for concrete poles was determined to be 97%. Less than 1% of the samples were in 'poor' or 'very poor' condition, as shown in **Figure 42**.

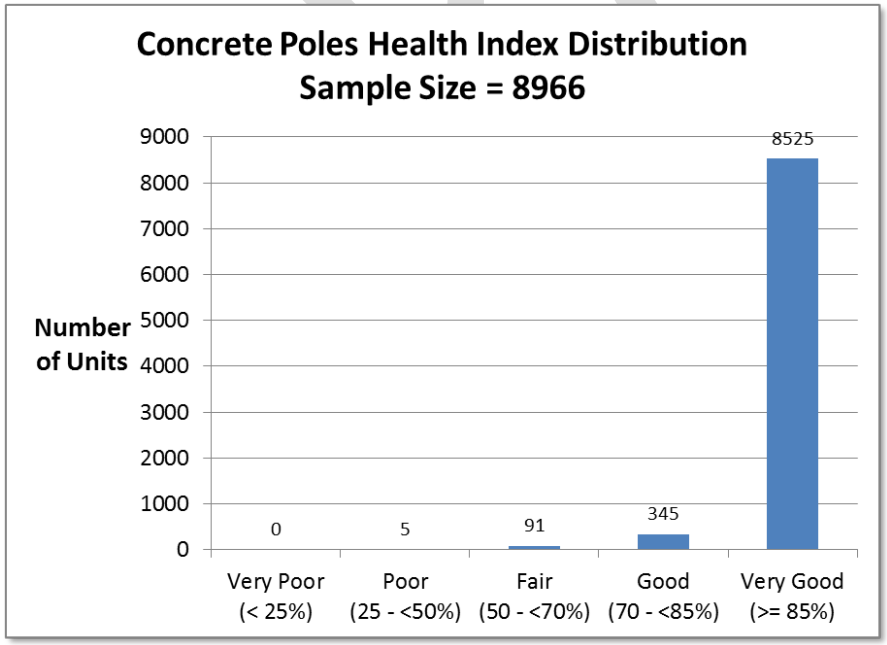



**Figure 42. Concrete Pole Health Index Distribution (Unit)**

### *2.2.3.7 Underground Distribution Cables (XLPE)*

Enersource owns and operates 3,383 km in underground circuit length (6,271 km in underground conductor length) of polymer conductor. Typically this conductor will be of type XLPE (Cross-Linked Polyethylene). These cables are installed throughout Mississauga as main feeders and distribution feeders. Cables are installed in either concrete encased duct, direct buried duct, or are direct buried. New installations of underground cable are installed in duct to assist in future replacement due to failure or end of life. Existing direct buried cables cannot be easily replaced, adding to cost and labour requirements, and typically require extensive excavation to install new duct structure to more easily install new cable both now and in the future.

The average age of main feeder cables was 18 years/conductor-km with approximately 4% being 40 years or older, as shown in **Figure 43**.

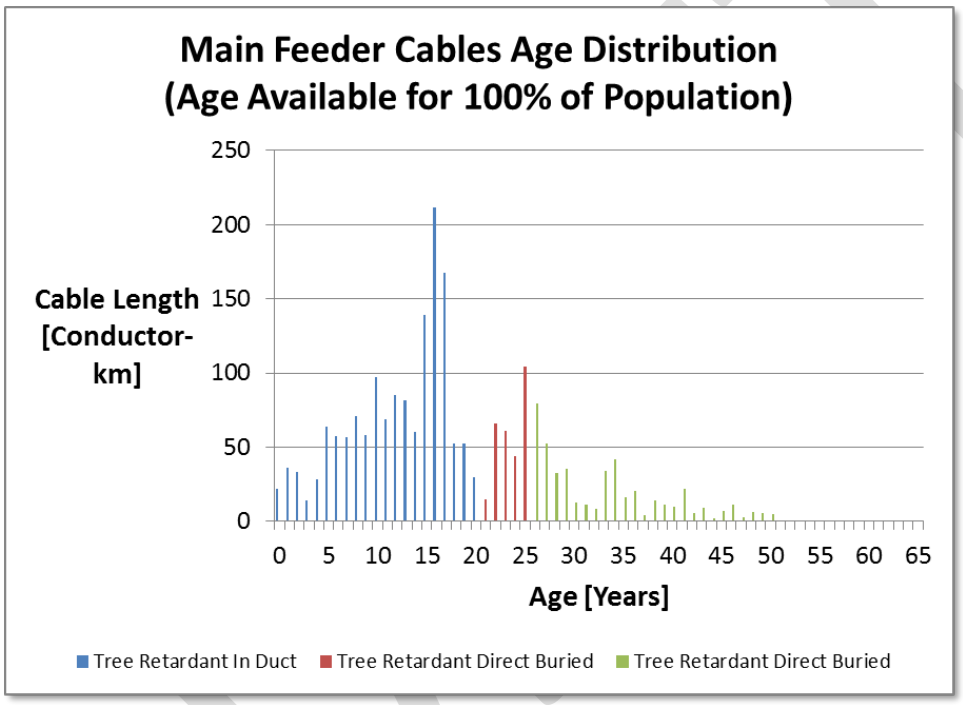



**Figure 43. Main Feeder Cables Age Distribution**

The average age of distribution cables is 21 years/conductor-km with approximately 7% being 40 years or older, as shown in **Figure 44**.

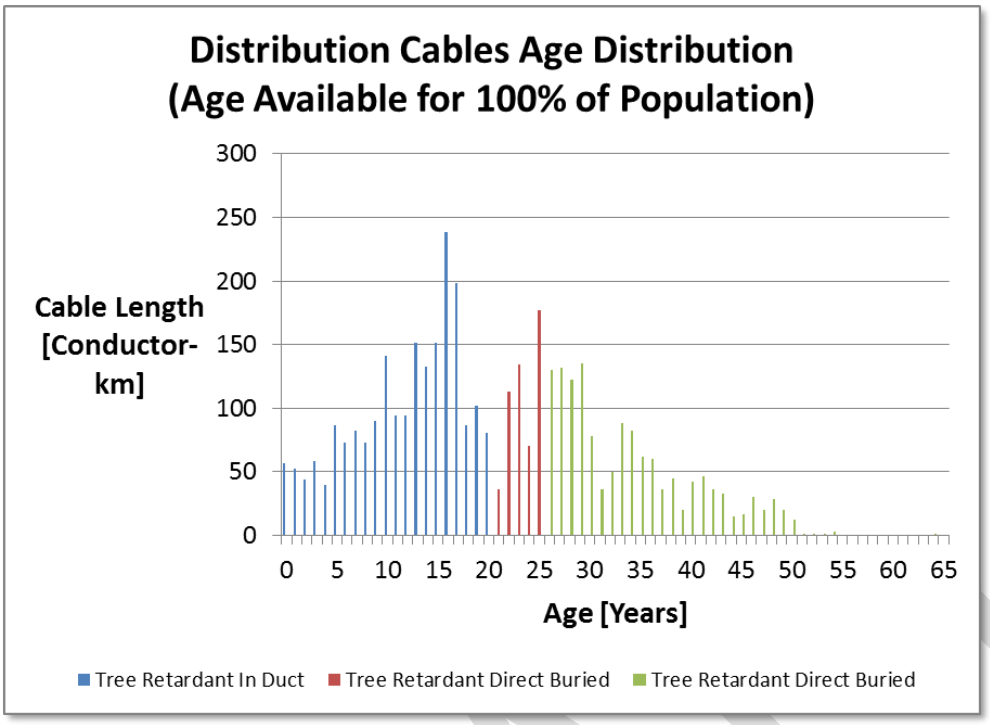



**Figure 44. Distribution Cables Age Distribution**

Health index ratings for underground distribution cables are based primarily on age, failure history, and type of installation as outlined above. In addition, the occurrence of failures over a five-year span is used to de-rate the health of cables. Enersource has also evaluated several cable testing methodologies, such as tan-delta, polarization-depolarization, and partial discharge, aimed at finding a method to more accurately determine cable health. However, these alternate methodologies are currently not used to determine cable health index.

A total of 2,233 conductor-km of main feeder cables was assessed at an average health index of 78% with approximately 20% of the population in 'poor' or 'very poor' condition, as shown in **Figure 45**.

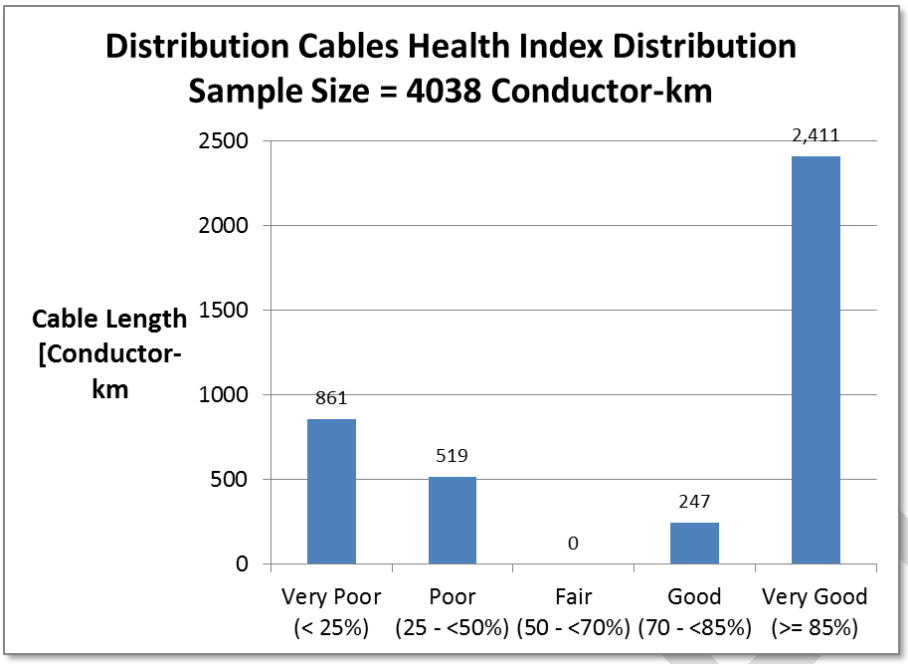



**Figure 45. Main Feeder Cables Health Index Distribution (Unit)**

A total of 4,038 conductor-km of distribution cables were assessed at an average health index of 70% with approximately 34% of the population in 'poor' or 'very poor' condition, as shown in **Figure 46**.

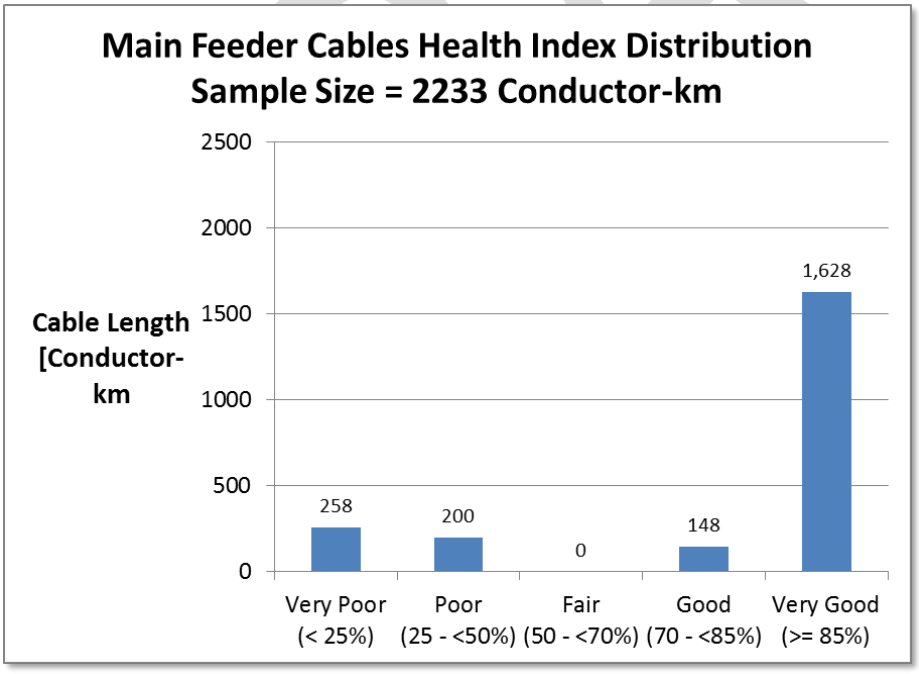



**Figure 46. Distribution Cables Health Index Distribution (Unit)**

### *2.2.3.8 Pole Mounted Transformers*

Enersource owns and operates 5,346 pole mounted transformers. Demographic information for pole mounted transformer assets, such as date of purchase, installation date, serial number, percentage impedance, ratings, etc. are stored in the GIS system.

The average age of population was 21 years with approximately 9% of the population being 45 years or older, as shown in **Figure 47**.

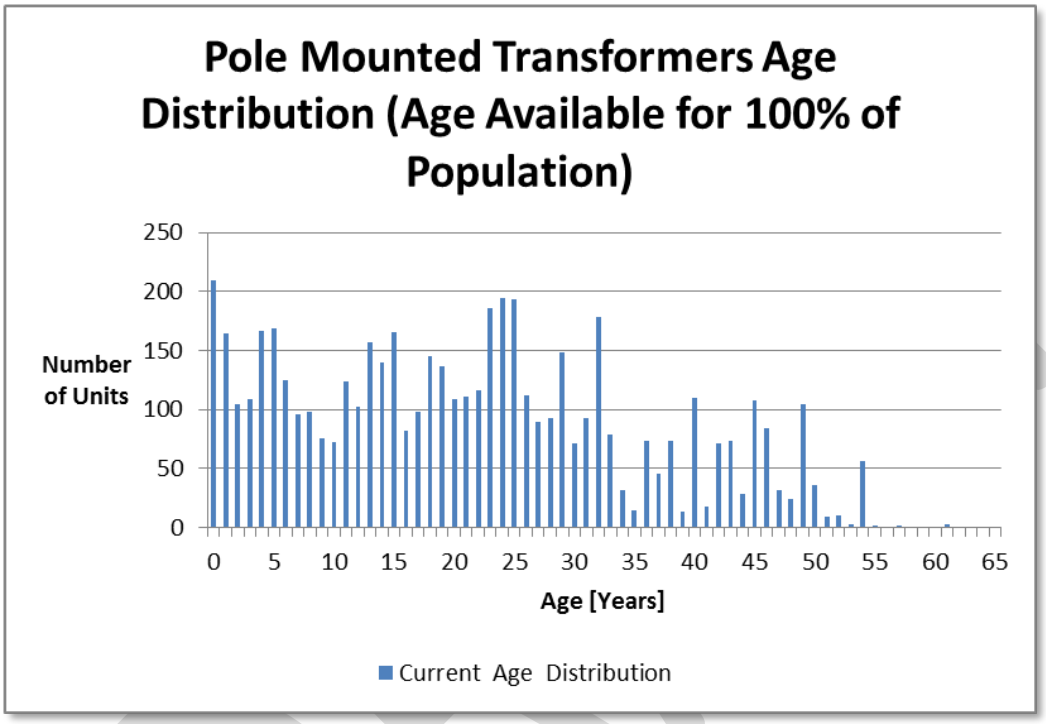



**Figure 47. Pole Mounted Transformers Age Distribution**

In addition to age, the health index of a pole mounted transformer will be reflective of PCB content (if greater than the industry accepted value of 2 ppm), results from infrared scanning, and prior history with a specific manufacturer.

The average health index for the group was 92% with approximately 2% of the population found to be in 'poor' or 'very poor' condition, as shown in **Figure 48**.

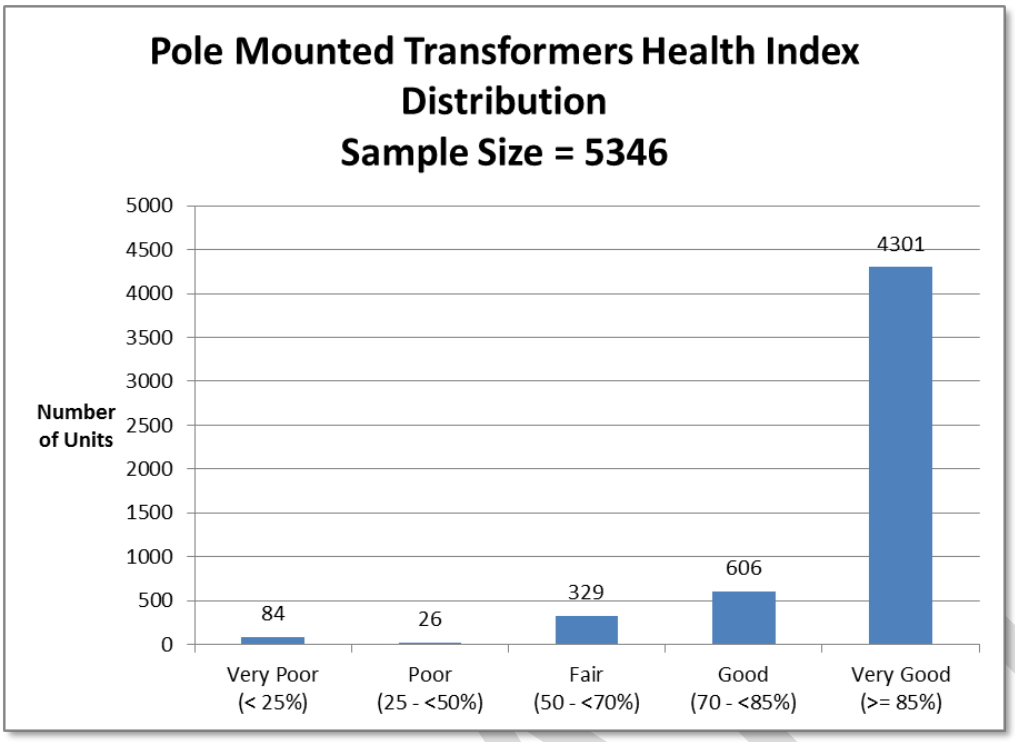



**Figure 48. Pole Mounted Transformers Health Index Distribution (Unit)**

### *2.2.3.9 Single Phase Pad Mounted Transformers*

Enersource owns and operates 14,242 single phase pad mounted transformers. These units are primarily located in residential neighbourhoods with each unit providing power for up to 14 typical homes. Demographic information for single phase pad mounted assets, such as date of purchase, installation date, serial number, percent impedance, ratings, etc., are stored in the GIS system.

The average age of all single-phase units was 21 years with approximately 10% of the population being 35 years or older, as shown in **Figure 49**.

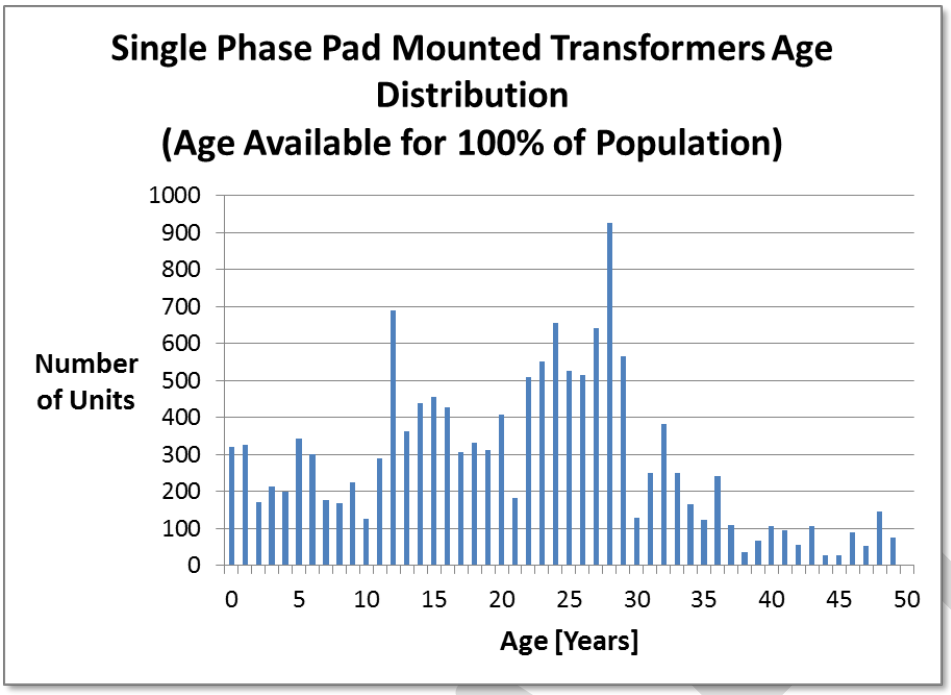



**Figure 49. Single-Phase Pad Mounted Transformers Age Distribution**

In addition to age, the health index of a single phase pad mounted transformers will be reflective of PCB content (if greater than the industry accepted value of 2 ppm), its service record, physical condition (including signs of corrosion, oil level / leaks, evidence of overheating i.e., boiling over), and prior history with specific manufacturers.

The average health index for the group was 87% with approximately 5% of the population found to be in 'poor' or 'very poor' condition, as shown in **Figure 50**.

DRAFT

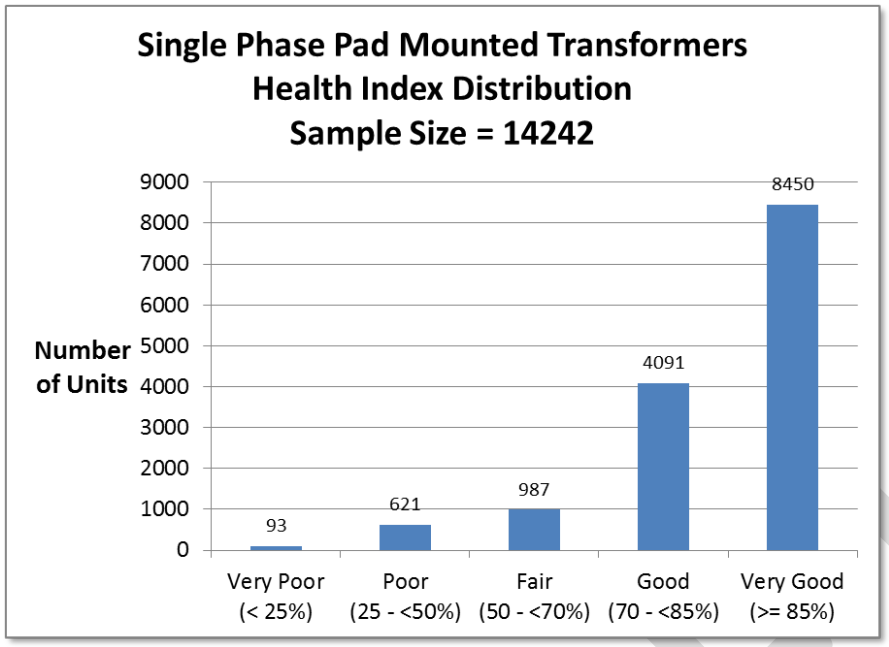



**Figure 50. Single-Phase Pad Mounted Transformers Health Index Distribution (Unit)**

### *2.2.3.10 Three Phase Pad Mounted Transformers*

Enersource owns and operates 1,821 three phase pad mounted transformers. These units are primarily located in industrial and commercial areas and vary greatly in size depending on customer requirements. Demographic information for three phase pad mounted assets, such as date of purchase, installation date, serial number, percentage impedance, ratings, etc., are stored in the GIS system.

The average age of all three phase units is 16 years with approximately 5% of the population being 35 years or older, as shown in **Figure 51**.

DRAFT

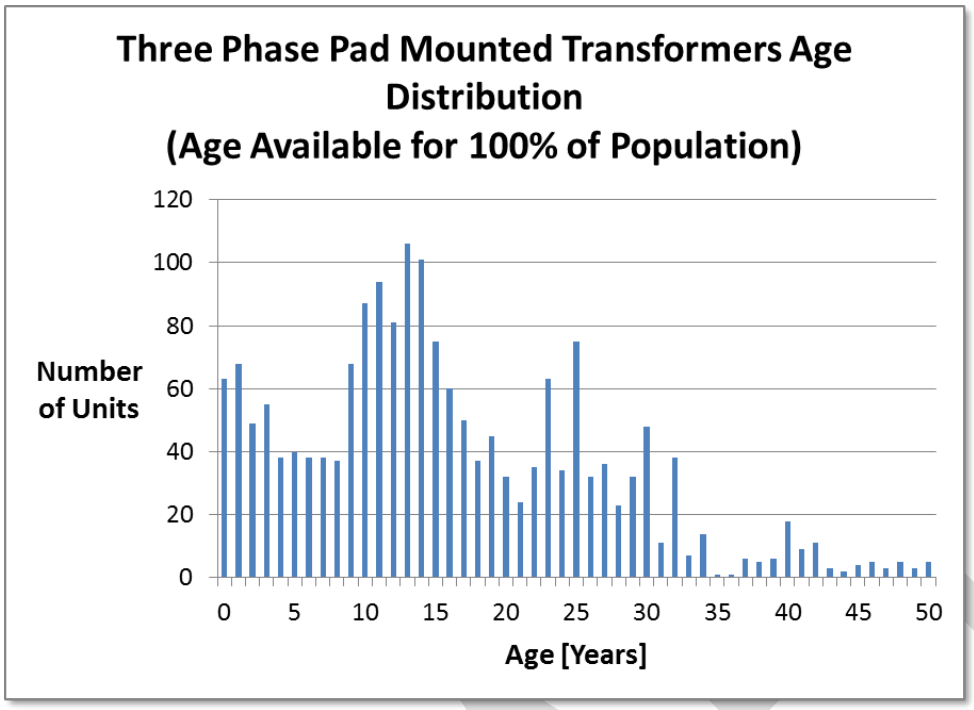



**Figure 51. Three-Phase Pad Mounted Transformers Age Distribution**

In addition to age, the health index of a three phase pad mounted transformer will be reflective of PCB content (if greater than the industry accepted value of two ppm), its service record, physical condition (including signs of corrosion, oil level / leaks, evidence of overheating i.e., boiling over), and prior history with specific manufacturers.

The average health index for the group was 94% with approximately 3% of the population found to be in 'poor' or 'very poor' condition, as shown in **Figure 52**.

DRAFT

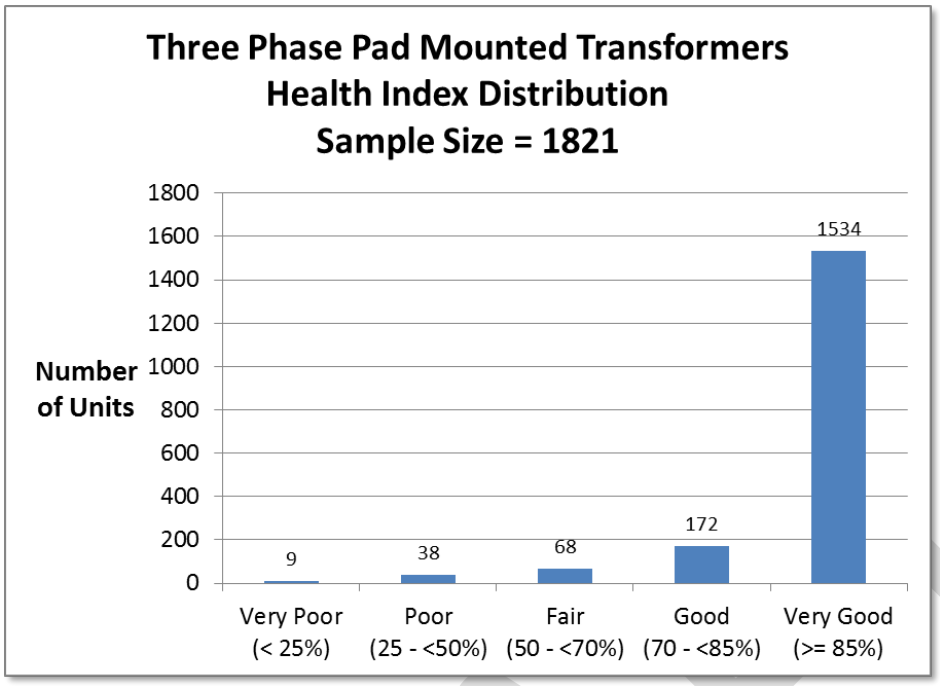



**Figure 52. Three-Phase Pad Mounted Transformers Health Index Distribution (Unit)**

### *2.2.3.11 Vault Transformers*

Enersource owns and operates 3,861 vault transformers, which are typically located in approximately 1,300 building vaults servicing large customers. Vault transformers have had a resurgence in recent years as new developments in the Mississauga's downtown core are designed, combined with city restrictions on pad mounted transformers being placed in city boulevards in the city's downtown area. The population of vault transformers is projected to increase in the next decade. Demographic information for transformer vault assets, such as date of purchase, installation date, serial number, percent impedance, ratings, etc. are stored in the GIS system.

The average age of all single phase vault transformers was 27 years with approximately 23% of the population being 35 years or older, as shown in **Figure 53**.

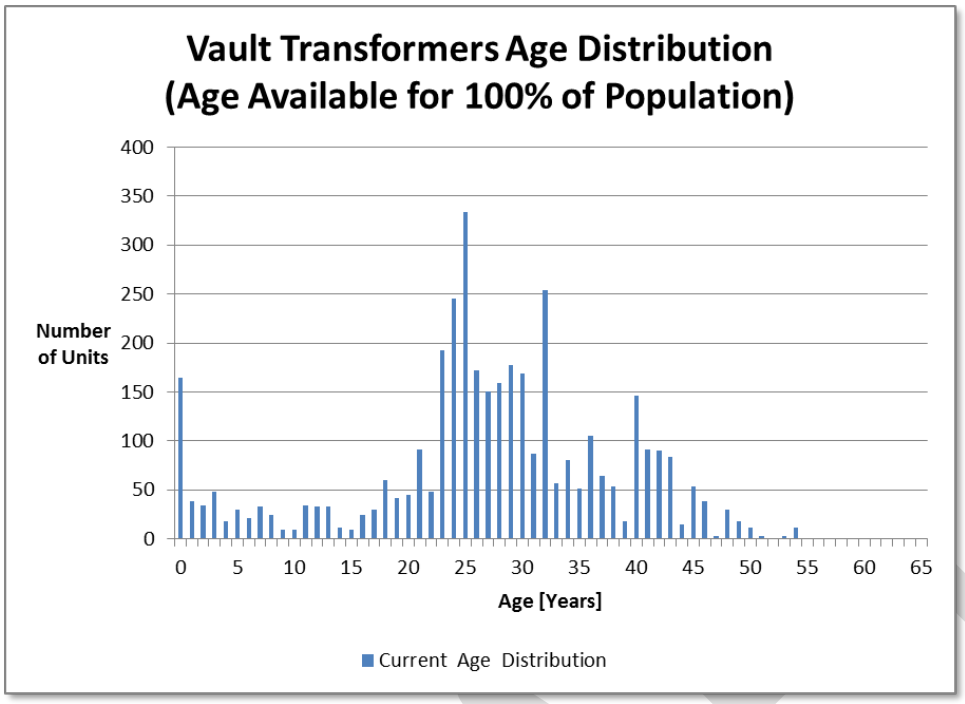



**Figure 53. Vault Transformer Age Distribution**

In addition to age, the health index of a vault transformer will be reflective of PCB content (if greater than the industry accepted value of two ppm), its service record, and physical condition (including signs of corrosion, oil level / leaks, evidence of overheating i.e., boiling over).

The average health index for the group was 87% with approximately 9% of the population found to be in 'poor' or 'very poor' condition, as shown in **Figure 54**.

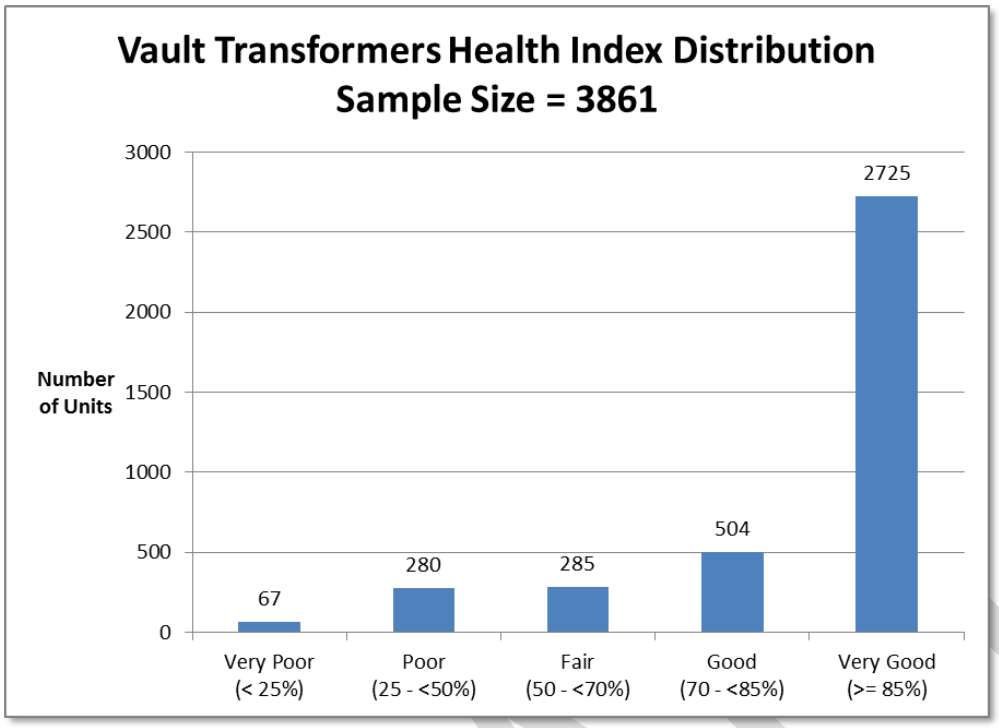



**Figure 54. Vault Transformer Health Index Distribution (Unit)**

## ACA Condition Based Health Index Summary

**Figure 55** below summarizes an overall condition based health index distribution for all major asset class types in graphical format.

DRAFT

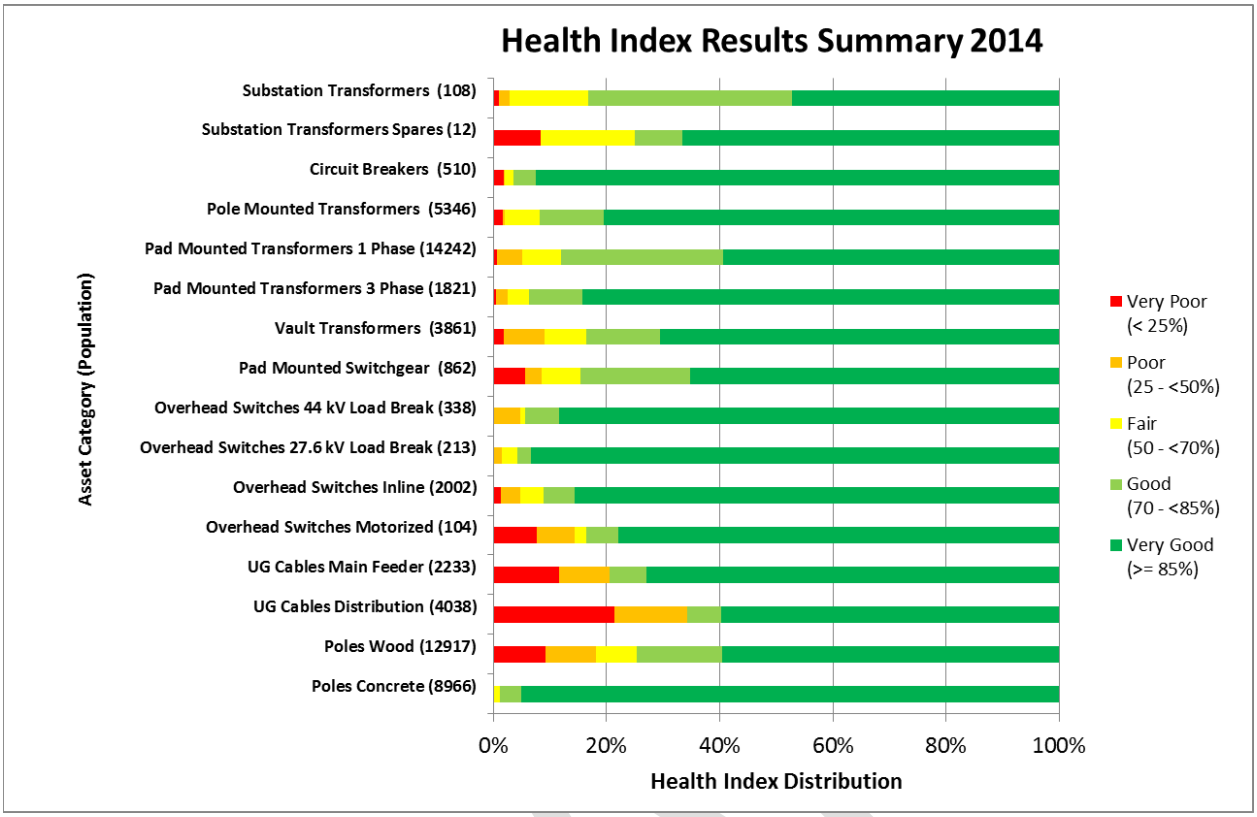



**Figure 55. Health Index Results Summary – Condition Based**

## Municipal Substation Transformer

As stated earlier, substation transformers constitute one of the largest investments in a distribution utility's system and a significant asset to Enersource. In accordance with accepted engineering and utility practices, Enersource conducts monthly and yearly inspections in order to detect developing weaknesses or impending failures. The Company also conducts preventive maintenance based on elapsed time (typically every five years).

At the end of 2014 there were 108 transformers installed in Enersource's substations. The average age of the population is 22 years with a health index of 83%. Approximately 17% of all units are 40 years or older.

Based on the ACA report (which takes into account health index or condition assessment only), Enersource should replace seven transformers over the next 10 years.

## Substation Circuit Breakers

Substation circuit breakers are used to interrupt short circuits that may occur in the system. They are inspected on a monthly basis and tested every five years in accordance with Enersource's practices.

At the end of 2014 there were 510 circuit breakers installed in Enersource's substations. The average age of the population is 20 years with a health index of 94%. Approximately 15% of all units are 40 years or older.

Based on the ACA report (which takes into account health index or condition assessment only), Enersource should replace 15 circuit breakers in the next ten years.

### Pole Mounted Transformers

Pole mounted transformers are overhead transformers that can supply up to 25 customers, and if they fail, the environmental, reliability, and customer impact is minimal. Utility practice is to run pole mounted transformers to failure. If the entire area is scheduled for a rebuild, then the transformers are replaced along with the poles, conductors, insulators, and other pole line hardware. The majority of the pole mounted transformers were inspected in 2014.

At the end of 2014 there were 5,346 pole mounted transformers installed. The average age of the population is 21 years with a health index of 92%. Approximately 9% of all units are 45 years or older.

Based on the ACA report, Enersource should replace 449 pole mounted transformers in the next 10 years.

### Pad Mounted Transformers

Pad mounted transformers share similar functions as the pole mounted transformers, but are located in a secure steel cabinet and mounted on a concrete pad. They also are run to failure or are replaced during a rebuild of an area. The majority of the pad mounted transformers were inspected in 2012 and 2013, and 2014 with inspections continuing throughout 2015.

### Single-Phase Pad Mounted Transformer

At the end of 2014 there were 14,242 single phase pad mounted transformers installed. The average age of the population is 21 years with a health index of 87%. Approximately 10% of all units are 35 years or older.

Based on the ACA report, Enersource should replace 1,591 single phase pad mounted transformers in the next 10 years.

### Three-Phase Pad Mounted Transformer

At the end of 2014 there were 1,821 three phase pad mounted transformers installed. The average age of the population is 16 years with a health index of 94%. Approximately 5% of all units are 35 years or older.

Based on the ACA report (which takes into account condition assessment only), Enersource should replace 78 three phase pad mounted transformers in the next 10 years.



DRAFT

### Vault Transformers

Vault transformers are predominantly used to supply power to industrial or commercial customers. Sometimes the transformers are also used to supply apartment buildings or townhouse complexes. About 88% of the vault transformers were inspected by the end of 2014.

At the end of 2014 there were 3,861 vault transformers installed. The average age of the population is 27 years with a health index of 87%. Approximately 23% of all units are 35 years or older.

Based on the ACA report, Enersource should replace 603 vault transformers in the next 10 years.

### Pad Mounted Switchgear

The switchgear unit consists of a low profile pad mounted enclosure with various internal compartments housing cable terminations, switches, and protection equipment. Its main purpose is to control the flow of the current and protect cables, transformers and other components from excessive current under fault conditions.

At the end of 2014 there were 862 pad mounted switchgears installed. The average age of the population is 19 years with a health index of 84%. Approximately 37% of all units are 25 years or older.

Based on the ACA report, Enersource should replace 128 pad mounted switchgears in the next 10 years.

### Overhead Switches

The primary function of overhead switches is to allow for the isolation of line sections or equipment for maintenance, safety or other operating requirements. While most switches are manually operated, a project is currently in place to install additional remotely controlled switches at key locations, in order to aid prompt power restoration in the event of an outage.

### 44 kV Load Break Switches:

At the end of 2014 there were 338 of 44 kV load break switches installed. The average age of the population is 20 years with a health index of 95%. Approximately 9% of all units are 40 years or older.

Based on the ACA report, Enersource should replace 20 of the 44 kV load break switches in the next 10 years.

### 27.6 kV Load Break Switches:

At the end of 2014 there were 213 of 27.6 kV load break switches installed. The average age of the population is 18 years with a health index of 97%. Approximately 6% of all units are 40 years or older.

Based on the ACA report, Enersource should replace seven of the 27.6 kV load break switches over the next 10 years.



DRAFT

### In Line Switches:

At the end of 2014 there were 2,002 in line switches installed. The average age of the population is 18 years with a health index of 93%. Approximately 12% of all units are 40 years or older.

Based on the ACA report, Enersource should replace 303 in line switches over the next 10 years.

### Motorized Switches:

At the end of 2014 there were 104 motorized switches installed. The average age of the population is 16 years with a health index of 85%. Approximately 27% of all units are 25 years or older.

Based on the ACA report, Enersource should replace 25 motorized switches in the next 10 years.

### Underground Primary Cables

Distribution underground feeder cables are one of the more challenging assets for electricity systems, from a condition assessment and asset management viewpoint. They are generally considered to be the most expensive components, due to the high cost of materials and very high cost of installation and maintenance.

It is extremely difficult, and therefore quite expensive, to obtain meaningful condition information for buried cables. Underground cable systems, unlike overhead lines, do not suffer from weather induced faults and can have better reliability records.

According to the ACA report, underground primary cables are the worst assets as per the health index compared to the other assets groups.

### Main Feeder Cables:

At the end of 2014 there was a total of 2,233 conductor-km of main feeder cables installed. The average age of the population is 18 years per conductor-km with a health index of 78%. Approximately 4% of all segments are 40 years or older.

Based on the ACA report, Enersource should replace 678 conductor-km in the next 10 years.

### Distribution Cables:

At the end of 2014 there was a total of 4,038 conductor-km of distribution cables installed. The average age of the population is 21 years per conductor-km with a health index of 70%. Approximately 7% of all segments are 40 years or older.

Based on the ACA report, Enersource should replace 1,775 conductor-km in the next 10 years.

DRAFT

### Poles

Poles serve as support structures for overhead conductors, switches, transformers and other devices. In addition to Enersource`s equipment, the poles often support streetlights and third party attachments such as telephone, cable TV, and fiber communication cables. Poles are made of wood, concrete and steel. The vast majority of Enersource's poles are wood or concrete.

### Wood Poles:

At the end of 2014 there were a total of 12,917 wood poles installed. The average age of the population is 27 years with a health index of 88%. Approximately 14% of all units are 45 years or older.

Based on the ACA report, Enersource should replace 2,394 wood poles in the next 10 years.

### Concrete Poles:

At the end of 2014 there were a total of 8,966 concrete poles installed. The average age of the population is 20 with a health index of 97%. Approximately 13% of all units are 45 years or older.

Based on the ACA report, Enersource should replace 116 concrete poles in the next 10 years.

## 2.2.4 Information on General Plant Assets

General Plant assets include Enersource's assets that are not part of its distribution system, including land and buildings, tools and equipment, fleet and IT hardware and software used to support daily business and operations.

The General Plant assets are broken down into following sections:

- Rolling Stock
- Grounds and Buildings
- Information Technology
- Engineering and Asset Systems
- JDE / ERP System
- Meter to Cash
- Major Tools.

### *2.2.4.1 Rolling Stock*

Enersource requires a fleet of specialized vehicles to complete daily activities, including the construction and maintenance of the electricity distribution system, and to allow for quick restoration of power due to electricity distribution system disturbances.

To effectively manage fleet assets, Enersource has adopted a strategy with the following goals:

- Provide safe, reliable and efficient vehicles and equipment to meet operational needs in consultation with the end user;



DRAFT

- Compliance with legislation and regulations;
- Compliance with accepted industry norms and practices;
- Cost effectiveness;
- Optimization of fleet size kept to minimum levels to ensure equipment is being fully used;
- Standardization of equipment specifications;
- Environmental considerations such as fuel economy and exhaust emissions;
- Disposal through reputable commercial vehicle resellers; and
- Implement computerized maintenance program to improve cost and maintenance tracking.

To achieve these goals , Enersource maintains a multiple year capital plan which is essential for both short and long term budgeting and planning. The plan lists all current vehicles and proposes future replacement dates and costs, based on past experience and accepted industry standard vehicle lifecycles. Another long term goal of the fleet plan is to evenly distribute annual capital expenditures in order to minimize the rate impact to customers.

The proposed replacement ages for each vehicle class are outlined below and is based on manufacturers' recommendations and repair history:

- Light vehicles are replaced after three - five years, or 170,000 km
- Service trucks are replaced after five - eight years or 200,000 km
- Heavy equipment trucks are replaced after eight - 12 years, or after 230,000 km
- Work equipment is replaced on a condition based assessment.

Additional capital may also be required to meet equipment requirements resulting from succession planning and work program increases.

Maintaining appropriate levels of capital fleet spending will lead to:

- Reduced repair and maintenance costs
- Decreased down time and increased fleet utilization
- Safer equipment for personnel to operate
- Reduced environmental impacts (alternative fuel considerations, compliance with new diesel standards)
- Increased service equipment diagnostics.

### *2.2.4.2 Grounds and Buildings*

Enersource has three main buildings used for business operations: a corporate office, operations centre and a business continuity recovery building. These buildings were constructed between 1963 and 2012. **Table 25** outlines Enersource's buildings and supporting information.

**Table 25. Summary of Enersource Buildings**

| Location | Type | Year built | Square footage | # of Employees |
|---|---|---|---|---|
| 2185 Derry Road | Corporate Office | 1994, renovated in 2012 | 79,400 | 146 |
| 3240 Mavis Road | Operations Centre | 1963, 1979, 1991 | Office - 50,000<br>Warehouse/<br>Garage - 75,000 | 291 |
| 5045 Glen Erin Drive | Business Continuity Management (BCM) Operations Centre | 2012 | 2,500 | None |

### *2.2.4.3 Information Technology (IT)*

Enersource has embraced the use of technology to aid efficiency enhancements in several areas. The IT infrastructure provides the foundation on which Enersource's business operates. The following systems/applications are part of the IT infrastructure:

- Corporate network (which includes data, email, voice services, and web environments);
- IT infrastructure security system (e.g., resources access, assets and data protection and availability);
- Servers supporting many critical applications used throughout the Company; and
- Corporate telecommunications infrastructure including telephone system, wireless devices platform and the call centre voice queuing system.

### *2.2.4.4 Engineering and Asset Systems*

The Engineering and Asset Systems (E&AS) department provides IT tools required to assist in the management of field assets. These include software and hardware used by employees, including both office and field personnel.

The largest two software systems utilized by Asset Management and Asset Operations, include the IOM and AM/FM.

SmartPlant Foundation (SPF) is the document management system for engineering records, providing document security based on the user, the access type requested and the document class. The system houses revisions, approved and as-constructed drawings, easements and permits. It also issues location

numbers for switches and transformers. There are dozens of workflows used to manage business processes and the system is integrated to both AM/FM and JDE.

Specialized equipment, including wide-format plotters, engineering workstations, and field lap-tops, are used on a daily basis by employees.

### 2.2.4.5 JDE / ERP System

Enersource uses JDE as its Enterprise Resource Planning (ERP) tool. It is a modular, scalable and integrated information management software system that facilitates the flow of information across the Enersource's various departments.

JDE and its supporting applications automate business processes:

- Finance – General Ledger, Accounts Payable, Accounts Receivable, Fixed Assets
- Operations – Service Orders (program/project cost)
- Supply Chain – Inventory/Warehouse Management, Procurement
- Human Resources – Employee Management.

JDE also interfaces with other major applications such as AM/FM and CC&B system to ensure data integrity and simplification of business processes.

### 2.2.4.6 Meter to Cash

Meter to Cash systems are comprised of all IT systems involved in the meter to cash process including Meter Reading, Advanced Metering Infrastructure (AMI) systems, Meter Data Management, Wholesale and Retail Settlement, EBT transactions, MDM/R transactions, Billing, Cash, Collections, Business Intelligence and related field activity systems, including interfaces among these systems. Interfaces to JDE, CRM and AM/FM applications are also supported.

CC&B and the surrounding suite of applications address:

- Customer account management/premise management
- Cash and collections
- Customer contact tracking and management
- Metering/meter management
- Meter reading/estimating;
- Rates engine
- Billing/bill creation
- Analysis and reporting.

### 2.2.4.7 Major Tools

In order to maintain and operate an electricity system and a fleet of approximately 200 vehicles, investment in quality tools is paramount. Each truck is furnished with basic hand tools and equipment



DRAFT

while specialized items are limited to specific trucks, (e.g., chainsaws on forestry vehicles, cable cutters and crimpers on underground vehicles). Tool expenditures of $7,500 or more per item is classified as a major tool and requires additional internal approvals. This category covers the purchase of such items as:

- Mud tracks – to allow vehicles to traverse over wet ground and/or buried pipelines;
- Temporary grounds – to create a safe work area for employees working within a de-energized area;
- Battery operated devices – provide better ergonomics tools for staff to reduce the risk of injury when repairing underground cables in splice pits and sleeving overhead conductors;
- Cable locating equipment – to locate buried electrical cables for internal work and to identify cables for other utilities so they can perform their work without causing cable damage; and
- Fault finding equipment – to aid in locating underground cable faults requiring repair.

DRAFT

## 2.3 Asset Lifecycle Optimization Policies and Practice (OEB Chapter 5.3.3)

This section of the DSP outlines Enersource's asset lifecycle optimization policies and practices.

Enersource's approach is to maximize the lifecycle of an asset while providing reliable service in a cost effective manner. In order to optimize the lifecycle of its assets, Enersource has numerous remediation programs for maintaining the distribution system and general plant integrity, and assesses whether an aged asset is suited for refurbishment or replacement based on criteria that are pertinent to a given asset class.

A determining factor for Enersource's asset lifecycle optimization policies and practices is an understanding of the condition of assets in the field. This is accomplished through a regular and effective inspection program. Effective testing, inspections, and maintenance programs ensure that adequate information is gathered in order to properly prioritize asset replacement and refurbishment while balancing operation and maintenance costs. Enersource uses health indexing on all major asset groups to prioritize asset refurbishment and replacement and ensure an effective proactive replacement strategy.

Using asset health indexes when developing a proactive replacement strategy ensures that dedicated resources are acquired and costs and customer outage impact is minimized.

### 2.3.1 Inspection and Maintenance Programs

#### *2.3.1.1 Underground and Overhead Assets*

Enersource has an extensive inspection program for its overhead and underground distribution assets. All overhead and underground plant is visually inspected and electronically recorded in the GIS system through the use of hand held computer tablets. Substation assets are inspected on a monthly basis to ensure compliance with the OEB's minimum inspection requirements.

Annual overhead inspections include transformers, poles, insulators, switches, arrestors, and hardware attachments, such as guy wires, cross arms, and ground wires. Underground system inspections include transformers, bushings, elbows vaults, and pad mounted switchgear. The inspection program also includes detailed inspection of high voltage electrical rooms (i.e., vaults) with components such as transformers, switches, cabling, doors, ceilings, drains, and internal lights.

Computer tablets powered with Intergraph's MobileLink software allow Enersource to carry out detailed inspections on each asset group. Gathered data is then validated against the GIS asset records using an automated Quality Assurance and Quality Control process and any validation exceptions are corrected prior to being imported into the GIS. This ensures that Enersource is using the most accurate asset data when planning its asset lifecycle optimization work.

Once all inspection data is imported into the GIS, detailed maps are generated using Intergraph's GeoMedia software. This allows Enersource to identify critical areas that require System Renewal for both underground and overhead asset components, as well as future maintenance initiatives.



DRAFT

#### 2.3.1.1.1 Vault Maintenance

Enersource has approximately 1,300 vaults in its distribution system and deploys a detailed maintenance program that includes $CO_2$ washing followed by infrared (IR) inspection of the main components within the vault. $CO_2$ washing has proven to be effective in removing contamination such as salt and dirt that contributes to tracking and flashover. All vault equipment components are washed prior to performing the IR scan. $CO_2$ washing consists of mixing carbon dioxide with clean compressed air at the spraying nozzle and safely removing surface contamination from the energized equipment. During the cleaning process the dry-ice particles are propelled at high velocities to impact and clean the surface. The particles are accelerated by compressed air, just as with other blasting type systems. This process allows Enersource to clean vaults without disrupting power to customers and is proven to be environmentally friendly and safe for the field crews.

#### 2.3.1.1.2 Poles

Enersource carries out detailed inspections of both wood and concrete poles, and the results are used as inputs to develop the asset health indexing for poles. Visual inspections identify potential risk of pole failures and interruptions of service to customers. All inspection records are collected using computer tablets with automated QA/QC process to ensure correct data is being recorded by field inspectors and imported into the GIS system in a timely manner. Any immediate concerns are appropriately dealt with and follow-up work is scheduled for resolution.

#### 2.3.1.1.3 Porcelain Insulator Washing

Porcelain insulator washing is required annually to prevent failures in the overhead distribution system. Insulators are prone to contamination especially due to road salt or other airborne contaminants which can result in pole fires, flashovers, and power interruption. Insulator washing is carried out without the need for isolation of the overhead circuits and the resulting customer interruptions. During washing, a visual inspection and identification of any damaged equipment in the overhead infrastructure is also noted.

This program is very cost effective and proactive since it reduces the chance of pole fires and, consequently, lessens the threat to system reliability.

#### 2.3.1.1.4 Critical Switch Program

Enersource's critical switch program is designed to maintain and inspect switches identified as having a high consequence of failure (e.g., motorized switches). These switches are selected based on the requirements to interrupt higher loads, supply many customers or critical customers such as hospitals, large customers, etc. The regular inspection program ensures all areas are visited and problems detected before they lead to:

- Impairing the safety of Enersource employees or the public;
- Negatively impacting system reliability and reducing the quality of service to customers; and/or



DRAFT

- Seriously reducing the life expectancy of the equipment and thereby increasing costs via equipment replacement.

#### 2.3.1.1.5 Overhead Load break Switch Maintenance Inspection and Testing

The distribution system has different types of switches to facilitate distribution of electrical energy. A load interrupter is one form of switch used in the overhead electricity power system. These three phase switches are among the most important components of the distribution system; they are infrared inspected annually and maintained when issues are found.

The objective of this program is to perform preventive maintenance to ensure the proper performance of the switch over its expected life. During the maintenance of 44kV and 27.6kV loadbreak switches, the following tasks are performed:

- Inspect the switch blade
- Check grounding
- Check the minimum clearance between shut contact and interrupting unit
- Check all contacts and clean if necessary
- Check handle location
- Check pipe for couplings and make adjustments if necessary
- Check location and connection of ground strap
- Check SCADA operation
- Record maintenance information.

#### 2.3.1.1.6 Pad mounted Switchgear Dry Ice Cleaning

Air-insulated switchgears are $CO_2$ washed to remove contamination such as road salt or dirt that contributes to tracking and flashover, as shown in **Figure 56**. To ensure effective IR scanning, the switches are washed prior to performing an IR scan. The carbon dioxide is mixed with clean compressed air at the spraying nozzle and safely removes surface contamination from both energized and de-energized internal equipment. $CO_2$ washing allows switchgear to be cleaned while energized, is environmentally friendly, safe, and increases system reliability by removing surface contamination that can lead to flashover.

DRAFT



**Figure 56. 27.6 kV Switchgear Dry Ice Cleaning**

### 2.3.1.1.7 Infrared Inspection Program

On an annual basis, the entire overhead primary system is IR scanned at which time hot spots on the system that need immediate repairs or replacement are identified. Any other significant problems on the overhead system that may require immediate attention (such as broken insulators) are also reported to the Control Room Operator who creates an IOM follow-up report to overhead maintenance crews for resolution. A sample infrared inspection report is shown in **Figure 57** below.

DRAFT

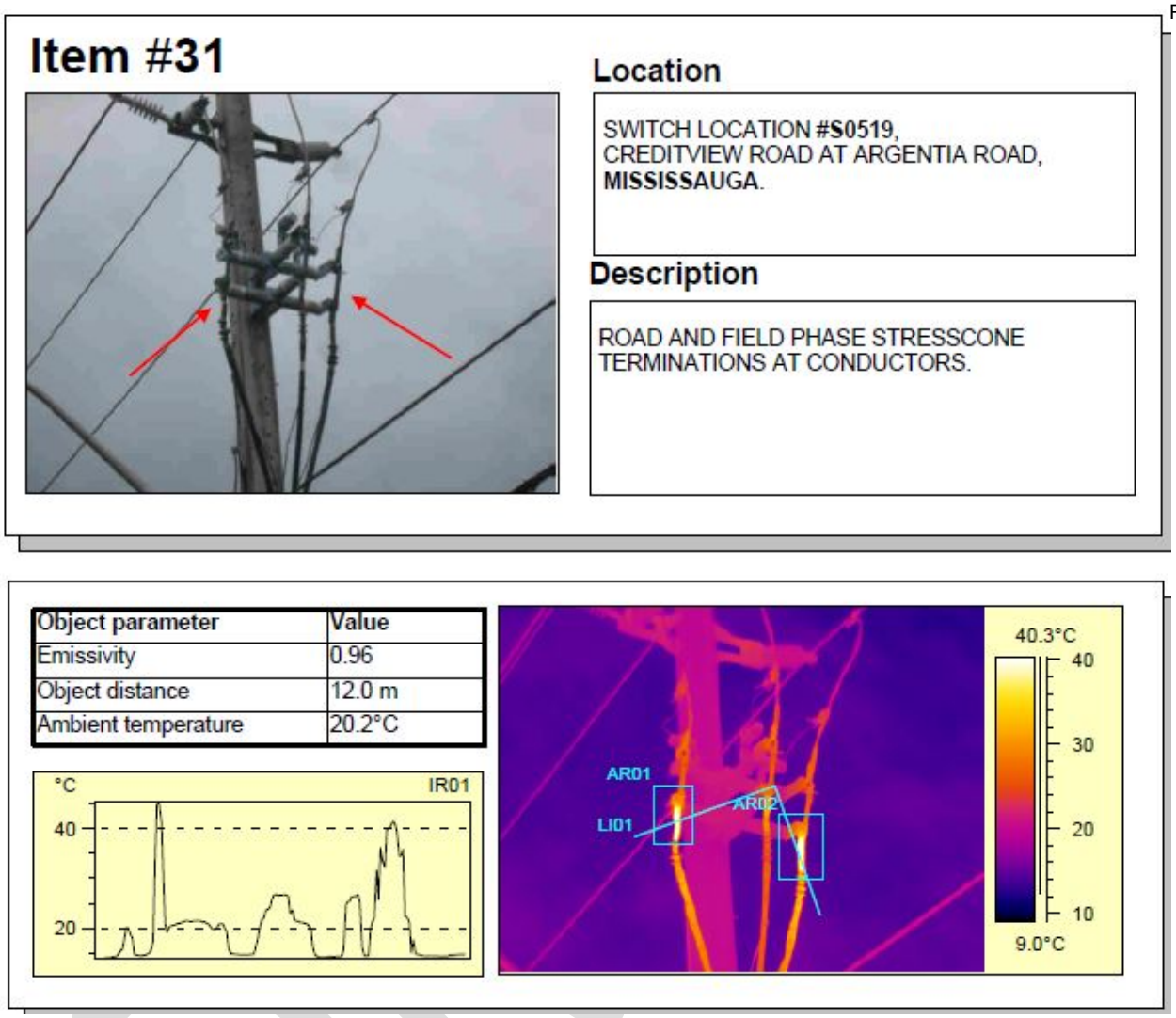



**Figure 57. Infrared Inspection Report**

### 2.3.1.1.8 Vegetation Management

Enersource's distribution system has approximately 1,800 km (circuit length) of overhead lines. Tree contacts with overhead lines account for approximately 5% of the power outages that occur in Mississauga on an annual basis, and can also be a danger to persons and property. The importance of tree trimming is to:

- Reduce power interruption due to short circuit to ground or between phases
- Reduce animal contacts by reducing animal accessibility to power lines via trees
- Prevent damage to conductors, hardware, and poles
- Mitigate danger to persons and property within the vicinity due to fire and falling conductors hardware, poles, and trees
- Mitigate danger of electric shock potential from electricity energizing vegetation.

The Forestry program is an integral part of maintaining a safe and reliable distribution system and is part of the overall maintenance plan for conductor assets. The Forestry team handles numerous tree trimming activities such as planned line clearing, following up on Control Room calls, responding to customer calls, system emergencies, and trimming trees for the installation of new power lines. There has been an increase in demand and a heightened awareness of the need for tree trimming in Mississauga due to recent events such as the 2013 ice storm as well as the infestation of the Emerald Ash Borer.

Routine tree-trimming occurs on a four-year cycle and requires that the City be divided into four north-south blocks in order to provide equal division of the heavier tree covered south areas and less dense north areas. A map of the maintenance areas is shown in **Figure 58** below.

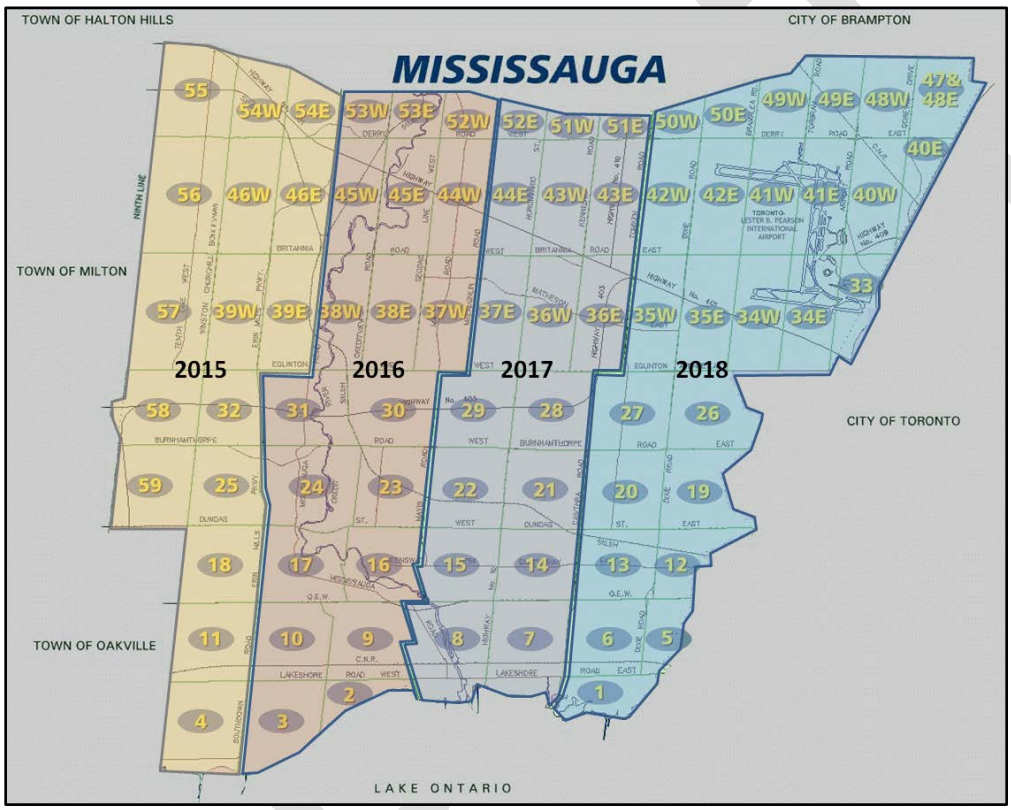



**Figure 58. Map of 2015-2018 Vegetation Cut Plan**

### *2.3.2.1 Substation(s)*

Enersource's substations are used to transform subtransmission voltages to distribution voltages in order to ensure safe and reliable delivery of power. Within a substation, power transformers play a critical role in making the power usable to Enersource's customers. When a subtransmission line comes into the substation, it goes through a transformer that steps down voltages from 44kV to 13.8kV or 27.6kV to 4.16kV. The typical transformer sizes are 3, 5, 10 or 20 MVA. The life expectancy of a substation power transformer is approximately 40 years and with proper maintenance, this target can be achieved.

After transformation to lower voltages, a substation distributes electricity through many feeders which are dispersed geographically and can be used to back up one another in the event of a feeder outage or failure. Feeder outages and reconfigurations are necessary to isolate faulty equipment or to make safe work zones for construction or repair work.

Enersource currently has 66 active municipal substations (MS) throughout Mississauga. Enersource's substations have protection and control systems to protect the transformers and switchgears as well as any load centres within the vicinity. The protection and control components include protective relays along with programming and wiring. The protection and control system is used, via the circuit breakers, to isolate faults on equipment inside the substation or downstream in the distribution network.

The relays also monitor and record equipment status and telemetry. With battery backup, the relays continue to function in the event of a power outage. This information is transmitted to the SCADA system which collects data from substations as well as switchgears and switches fitted with remote terminal units (RTU's). This information is displayed in the Control Room for system monitoring. System Control Operators monitor the status of these devices and respond to abnormal events. The operators can then control these devices remotely via the SCADA to reconfigure and reroute power in the event of an outage.

Enersource's substations represent a major component of Enersource's distribution system and are considered its most significant assets. A substation contains very expensive equipment and a component failure can adversely affect a critical customer or large number of customers. Therefore, Enersource treats its substation equipment with high importance and inspects, maintains, and replaces components proactively in order to ensure safe and reliable power delivery.

The inspection and testing programs consist of the following:

- Monthly inspections
- Power transformer insulating oil testing
- Doble testing
- Tap changer maintenance
- Preventive maintenance.

#### 2.3.2.1.1 Inspection Programs

The inspections consist of visual assessments of the building and grounds as well as the electrical equipment inside the substations. The building and grounds are checked for fence and gate/door integrity, vandalism, vegetation and environmental hazards such as transformer oil or $SF_6$ (sulphur hexaflouride) gas leaks. The electrical equipment checks include inspection of the power transformer fans, battery and battery charger readings and protection relay flags.

All monthly inspection findings are recorded and corrective actions are undertaken as required.

#### 2.3.2.1.2 Power Transformer Insulating Oil Testing

Power transformers undergo annual dissolved gas analysis (DGA) and oil quality analysis. Both are important diagnostic tools that are used to monitor the condition of the transformer. Emphasis is placed on these tests for detecting insulation breakdown, water in the oil, stressing of the coils, and localized overheating and arcing that can lead to failure of the transformer. Currently, Enersource uses a third-party laboratory to carry out testing of oil samples, including comparison of results of previous transformer oil samples, and providing detailed recommendations for the transformer.

DGA analysis is performed using portable equipment as well as DGA online monitoring. Online DGA equipment is used for continuous monitoring of transformer gas concentrations and can be used to set alarms at specific gas concentration thresholds. DGA online monitoring systems are part of Enersource's standard installations and can send DGA data to SCADA when an alarm threshold is reached.

DGA and oil quality tests identify abnormalities within the transformer and provide detailed information to allow for sound decision making for future operation and maintenance of the transformer.

#### Doble Testing

Doble testing equipment is used to assess the overall power factor, winding turns ratio, leakage reactance and exciting current of the transformer. These tests detect moisture in the oil or insulation, detect contamination in the transformer bushing, determine the electrical insulation quality, and locate bad connections and winding movement. The Doble equipment provides test results and expected values and thresholds to effectively translate the results. Doble testing, DGA testing and oil quality analysis complement each other to provide clear indication of the overall health of the transformer.

DRAFT

### 2.3.2.1.4 Preventive Maintenance Programs

Substation electrical equipment is maintained on a regular schedule. The objective is to perform preventive maintenance approximately once every five years on each substation. This time interval can be reduced or increased based on operating conditions, equipment type, and operating experience with the equipment.

Types of substation maintenance activities include:

- Transformer maintenance
- Tap changer maintenance
- Switchgear maintenance
- Protection relay maintenance
- Batteries and battery charger maintenance.

#### *2.3.2.1.4.1 Transformer Maintenance*

Transformer maintenance activities are based on the following documents and standards:

- Manufacturer's instruction book
- IEEE 62-1995 IEEE Guide for Diagnostic Field Testing of Electric Power Apparatus Part 1: Oil Filled Power Transformers, Regulators, and Reactors
- Doble transformer maintenance and test guide.

The following maintenance tasks are performed on every oil-filled power transformer:

- Inspect and test all controls, wiring, fans, alarms and gauges
- In-depth inspection of transformer cooling system (check for leaks and proper operation)
- In-depth inspection of transformer bushings, cleaning, waxing if needed
- Doble test transformer and bushings
- Inspect pressure controls
- Inspect and test the tap changer.

#### *2.3.2.1.4.2 Tap Changer Maintenance*

Oil filled tap changer maintenance activities include:

- Recording the position of the tap changer
- Inspecting the physical and mechanical condition
- Verifying correct auxiliary device operation
- Verifying the correct liquid level in all tanks
- Performing tests as recommended by the manufacturer
- Verifying operation of heaters and grounding

DRAFT

- An internal inspection which includes removing the oil and cleaning carbon residue and debris from compartment
- Inspecting the contacts for wear and alignment
- Tightening electrical and mechanical connections to calibrated specifications
- Inspecting the tap changer components for signs of moisture, cracks, electrical tracking or excessive wear and then refilling the tank with filtered oil.

#### *2.3.2.1.4.3 Switchgear Maintenance*

Substation switchgear maintenance is based on the manufacturer's recommendation and consists of the following work:

- Busbar, enclosure and insulator maintenance
- External visual inspection
- Check and tighten connections
- Check and clean enclosure.

Circuit breaker maintenance includes the following work:

- Lubricate, clean, adjust, and align control mechanism
- Contact resistance measurement
- Test tripping and closing circuits.

#### *2.3.2.1.4.4 Protection Relay Maintenance*

Three types of relays are used to clear faults that occur in the distribution grid. The maintenance performed on each type of relay is as follows:

##### Electromechanical (GE IAC type) relays

- Visual inspection
- Mechanical adjustment and inspection
- Electrical tests and adjustments.

##### Electronic Relays (MCGG and UR types)

Since there are no moving parts in these electronic relays, there is no physical wear due to usage. Maintenance consists of secondary injection tests to verify the tripping time accuracy of the relays.

#### *2.3.2.1.4.5 Battery & Battery Charger Maintenance*

The battery and battery charger maintenance consists of the following activities:

- Record the room temperature
- Measure and record each battery voltage
- Record the charging current.



DRAFT

## 2.3.2 Renewal Programs

### *2.3.2.1 Underground Assets*

Remediation programs for maintaining the underground assets consist of the following:

- Pad Mounted Switchgear Renewal
- Primary Distribution Equipment Renewal
- Pad Mounted Transformer Replacement Program
- Underground Cable and Splice Renewal
- Secondary Cable Renewal.

#### 2.3.2.1.1 Pad Mounted Switchgear Renewal

Pad mounted switchgear units are used in distribution loops; they supply residential subdivisions and commercial/industrial customers. Switchgear units are used to isolate and control other distribution equipment and provide operational flexibility to reconfigure the loops for maintenance, restoration or other operating requirements. Because each unit can have up to 500 customers connected to it, a failure can have a significant impact on the customers. As a result, a proactive yearly plan targets poor switchgears for replacement or cleaning.

As outlined in Appendix C of the DSC, the minimum inspection requirements for the distribution system within an urban environment are to be scheduled and inspected on a three-year cycle. As such, Enersource inspects its 862 pad mounted switchgears in adherence with the DSC requirement and all inspection information is recorded into the GIS via field computer tablets.

Pad mounted switchgear are critical components of the underground distribution system and have significant reliability and safety risk due to condition, age, and design/installation practices. Switchgear degradation has shown a strong correlation with a number of factors, such as condition of mechanical components, contamination due to dirt, moisture and corrosion. The population targeted for replacement consists of 27.6kV air insulated switchgears, based on safety and reliability concerns since the 27.6kV units have shown a tendency to fail or flash over. Poor condition of 15kV switchgear units are also being targeted for replacement with a new type of solid-dielectric switchgear to reduce safety concerns and maintenance costs. These units use a magnetic actuator for fault interruption which is proven to be safer for field operation compared to its air-insulated counterparts.

Based on the yearly inspection results and the health index calculation, several switchgear are recommended for replacement, as shown in **Figure 59** below. This ensures funding and effort are directed to the correct switchgear locations for replacement in the most efficient manner.

DRAFT

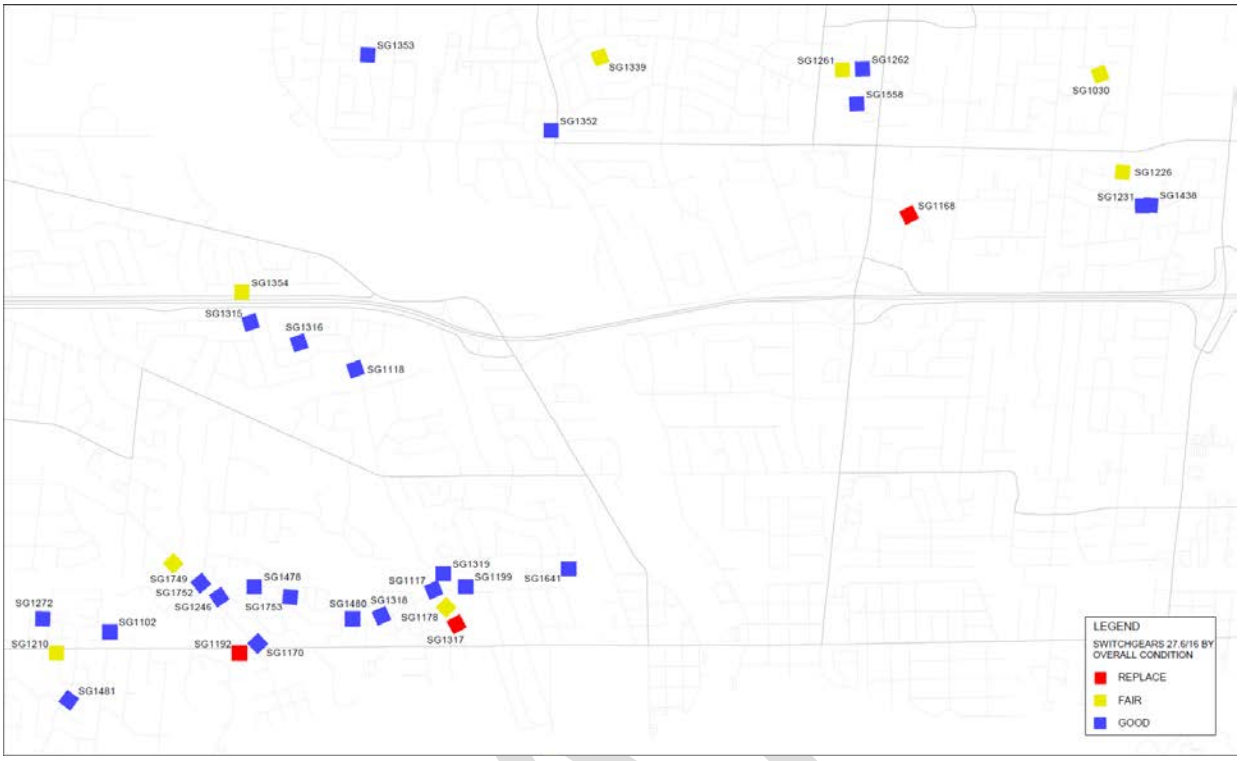



**Figure 59. Switchgear Overall Condition**

### 2.3.2.1.2 Primary Distribution Equipment Renewal Program

In addition to the main system components such as transformers, switchgears, cables, etc., the underground distribution system also consists of smaller, auxiliary components such as elbows, inserts, lightning arresters, fault indicators, etc. Without these auxiliary accessories, the main components of the system become inoperable, making replacement of this equipment before failure necessary.

Some of the auxiliary system components installed in transformers, such as elbows and inserts, are used in order to perform switching operations, isolations, and restoration. Therefore, their condition directly influences system reliability as well as the safe operation of the equipment.

Other auxiliary devices, such as fault indicators, are used to troubleshoot system outages. Their proper operation influences restoration time and in turn, overall reliability of the system. After significant research, Enersource has begun to use a new type of fault indicator which is much easier to install at transformer and switchgear locations. The new fault indicators allow Enersource to find cable faults more rapidly which helps reduce power outage times.

In addition, equipment condition is routinely assessed by operations personnel when performing work on a transformer, switchgear, or other asset replacements. If a defective component is found, the crew notifies the Control Room, a report is created, and a maintenance crew is dispatched to perform necessary repairs.

#### 2.3.2.1.3 Pad Mounted Transformer Replacement Program

Enersource uses a two-tiered approach to transformer remediation. It first collects and analyzes critical asset data on each transformer, including inspection, physical location (e.g., rear lot), asset condition and reliability data. This information is used to help identify future underground subdivision rebuild areas.

The following asset data are collected:

- Transformer age
- Inspection reported condition (e.g., poor, fair)
- Leaking transformer (both PCB and non-PCB)
- Physical location of transformer (e.g., rear or front lot)
- Reliability data from IOM
- Cable faults.

As shown in **Figure 60** below, a detailed map is generated and reviewed by both the Asset Operations and Asset Management teams to determine areas that qualify for underground renewal projects. This allows Enersource to replace transformers that have reached end-of-life or are found to be leaking and thus pose a safety and environmental risk, and/or have exhibited reliability issues. This information is used to determine areas that require an extensive underground renewal and is a major component within the overall System Renewal investment category.

DRAFT

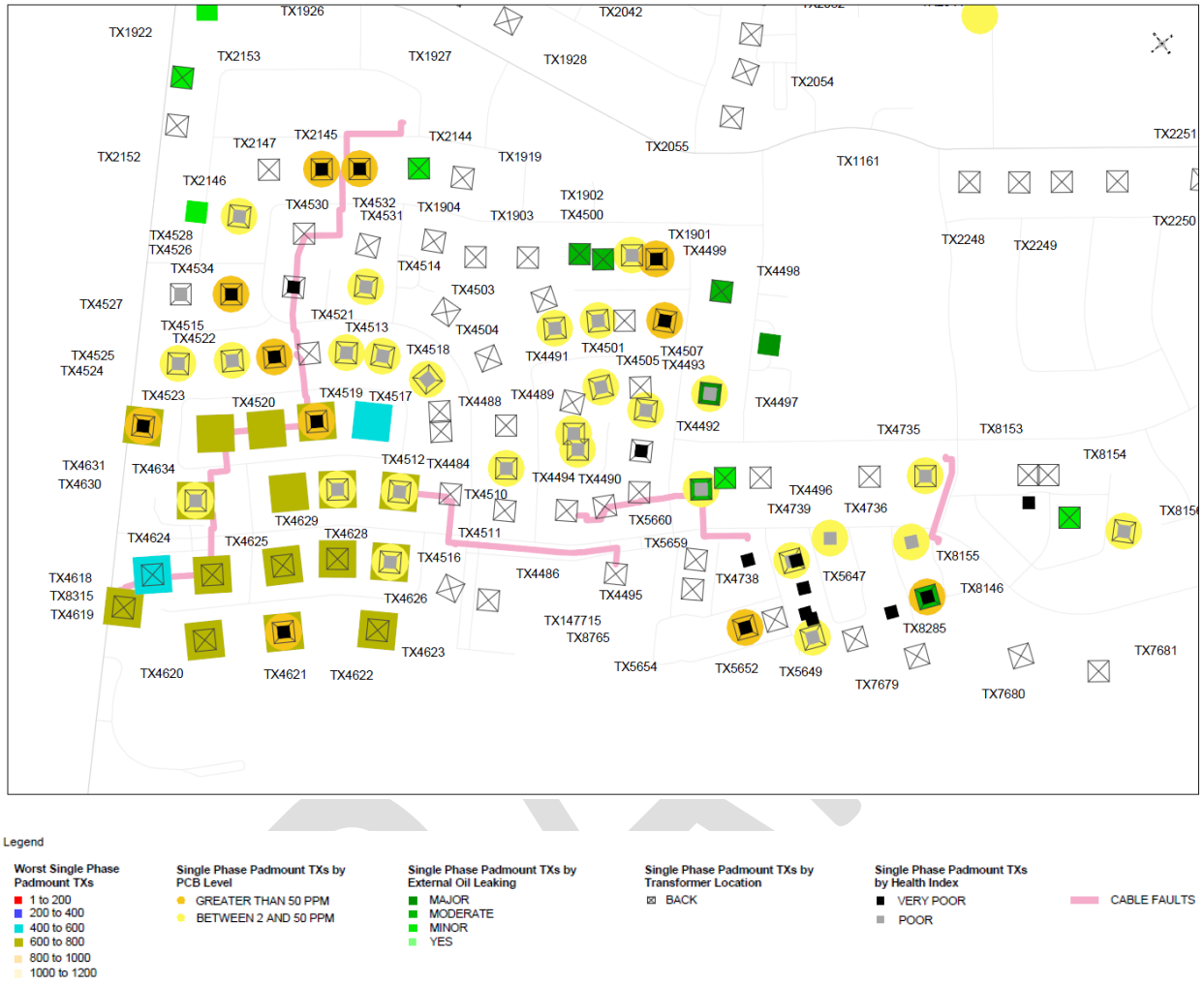



**Figure 60. Analysis of Underground Areas with Aging Assets and Poor Reliability**

In addition, Enersource identifies and replaces individual pad mounted transformers that have reached end-of-life, have shown to be in poor condition, or have shown signs of leakage.

### 2.3.2.1.4 Underground Cable and Splice Renewal Program

Primary underground cables and overhead conductors are used to transport power from HONI's transformer station either directly to Enersource's distribution system or to an Enersource substation. At a substation, the 44kV or 27.6kV voltage is then converted through a substation transformer to either 13.8kV or 4.16kV. From there, customers are either directly connected to the system or the voltage is converted further by the distribution transformers at 8kV or 2.4kV down to secondary voltages such as 120/240, 120/208 or 346/600V, depending on the location within the City. The older primary cables are either direct buried or installed in a separate direct buried PVC duct if installed along the City boulevards. Underground cable failures are the leading cause, accounting for 50% of equipment failures in the distribution system.

Typically, underground cable failures are caused by degradation of the insulation, which is the dielectric medium that insulates the central conductor from the grounded concentric neutral wires. Insulation failure can be caused by several factors, for example:

- Contaminated materials during the manufacturing stage
- Poor adhesion of the extruded insulation shield
- Imperfections at the conductor shield-insulation interface
- Water inside the conductor strands, or at the concentric neutral wires
- Fault currents
- Voltage surges from lightning and switching.

To address this risk, Enersource has an extensive cable replacement program. On an annual basis, the worst performing areas of the underground cable system are identified and cables are either replaced individually or form part of a larger underground renewal project.

The impact of a single cable failure on reliability varies greatly depending on the cable size, voltage level, type of customer supplied and location of the cable. The subtransmission main feeder cables typically supply a substation so the failure of a cable supplying a single substation may result in a disruption of power affecting up to 5,000 customers.

Main feeder cables typically supply several pad mounted switchgear units and can deliver power to up to 1,000 customers. The local distribution cables that are connected to the pad mounted switchgear units or overhead distribution system will typically supply up to 500 customers. Distribution cable failures will result in a power outage to all nearby customers connected and will momentarily trip the substation breaker as the fuse isolates, thus affecting even more customers.

Main feeder cable failures will result in a significant increase in number of customers affected and increase the length of time of the outage. In 2014, Enersource experienced 135 feeder cable failures that affected reliability significantly, which resulted in over 2,650,000 customer outage minutes. Of those 135 cable failures, 28 were main feeder failures that resulted in over 770,000 customer outage minutes, and impacted close to 18,000 customers.

#### 2.3.2.1.5 Secondary Cable Renewal Program

The distribution system has over 203,000 customers, the majority of which are connected to a distribution transformer via an underground secondary service cable. Based on past experience, secondary cables are less prone to failure compared to primary cables of the same age. This is mainly due to less electrical stress and fewer fault current spikes. However when secondary cables fail, they must be immediately repaired. Every year, many underground residential and industrial/commercial services fail beyond reasonable repair and require complete replacement. These failures typically result in outages to single residential or industrial/commercial businesses.

The secondary cable renewal program targets replacements based on their condition and number of failures, rather than their age or size. This program entails the spot replacement of secondary services, over various parts of the city that are at end-of-life and are beyond reasonable repair.

### *2.3.2.2 Overhead Assets*

The projects and programs under this section encompass the replacement of poles, attachments, and overhead pole lines that have reached their end-of-life or have been determined to be a potential public or employee safety concern.

This section is divided into two main types:

- Overhead distribution pole line renewal projects
- Poles, accessories, and pole mounted transformers renewal programs.

#### 2.3.2.2.1 Overhead Distribution Pole Line Renewal Program

Overhead distribution pole line renewal projects are required to replace overhead distribution infrastructure to ensure it is kept at a safe and acceptable performance level.

The main components of the overhead system are poles, pole mounted transformers, switches, conductors and associated overhead hardware such as insulators, fuses and lightning arresters. Pole lines deteriorate over time and their strength may be reduced, resulting in a risk of failure, especially under adverse weather conditions.

Overhead assessments including safety, environmental, regulatory, reliability, reputational, and financial risks are made to determine which investments have the greatest impact on the business values. Assuming there were no constraints, all overhead investments with a positive impact on the business values would be approved. Due to resource constraints such as appropriate funding, internal and external labour availability, projects are selected and prioritized based on the assessments.

Enersource completed a full inspection of its overhead system during the 2014-2015 period. The inspection data is then used to identify the overhead assets that need to be addressed as well as their relative priority in relation to the business values. The hierarchy of criteria that was used to prioritize the projects is as follows:

1) **Poles in 'poor' condition** – Clusters of poles in poor condition represent the greatest safety risk to the public and to Enersource personnel who may need to work on the poles (i.e., switching, service work, etc.), as shown in **Figure 61**. In addition, they also pose significant reliability risk. If any of these clusters also include another priority criterion, that cluster will be ranked as having higher priority. For example, a cluster of poles in 'poor' condition and having PCB transformers (priority 2) will be ranked higher than a similar cluster that does not have PCB transformers.

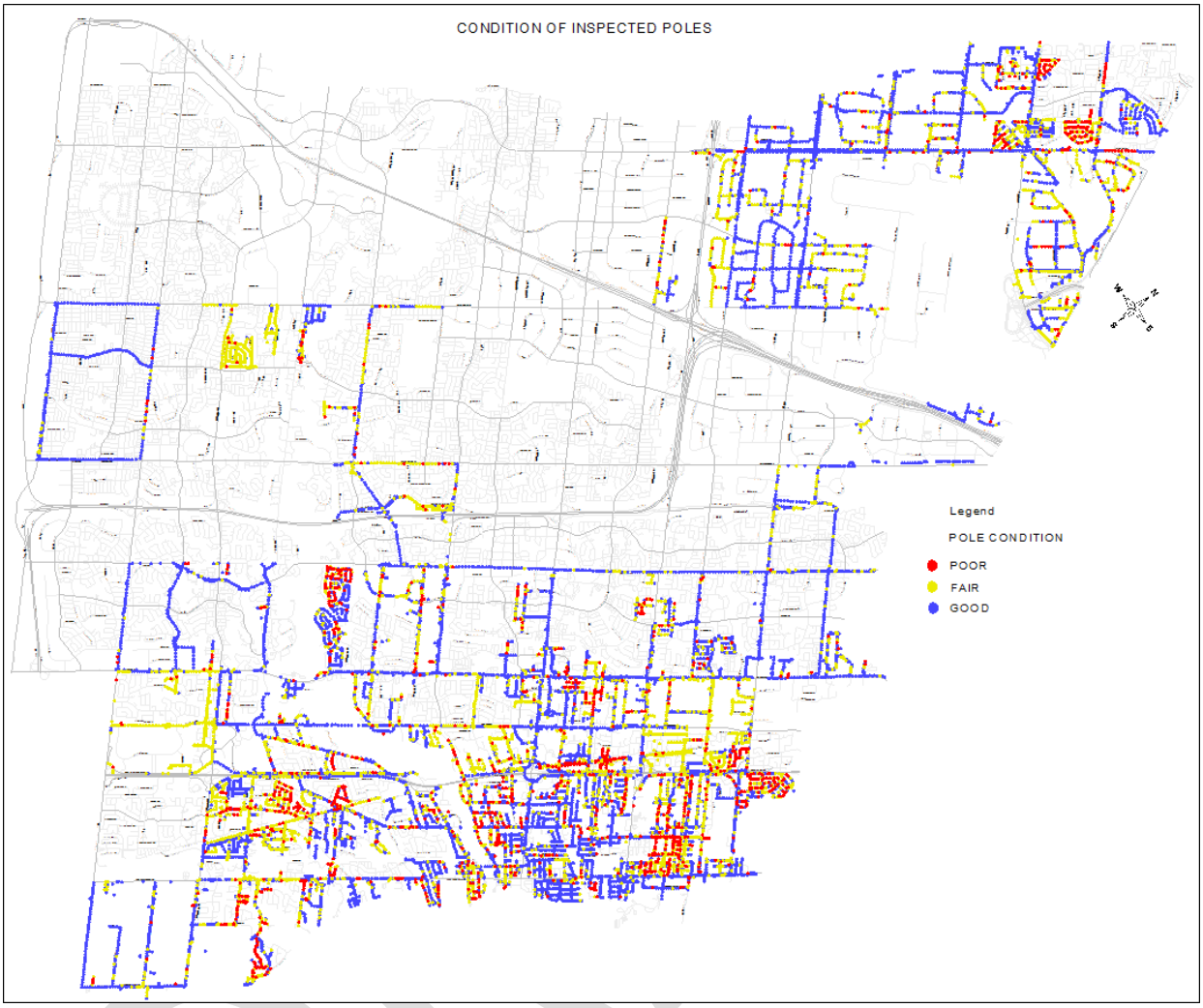



**Figure 61. Pole Condition from Field Inspections**

2) **PCB transformers < 50 PPM PCBs, > 2 PPM PCBs** – Transformers containing PCB oil can pose a major safety, environmental, regulatory, financial, and reputational risk. The category of transformers with PCB content greater than 50 ppm are not being considered in the renewal program as Enersource is on track to have all such transformers removed by the end of 2015, as shown in **Figure 62**.

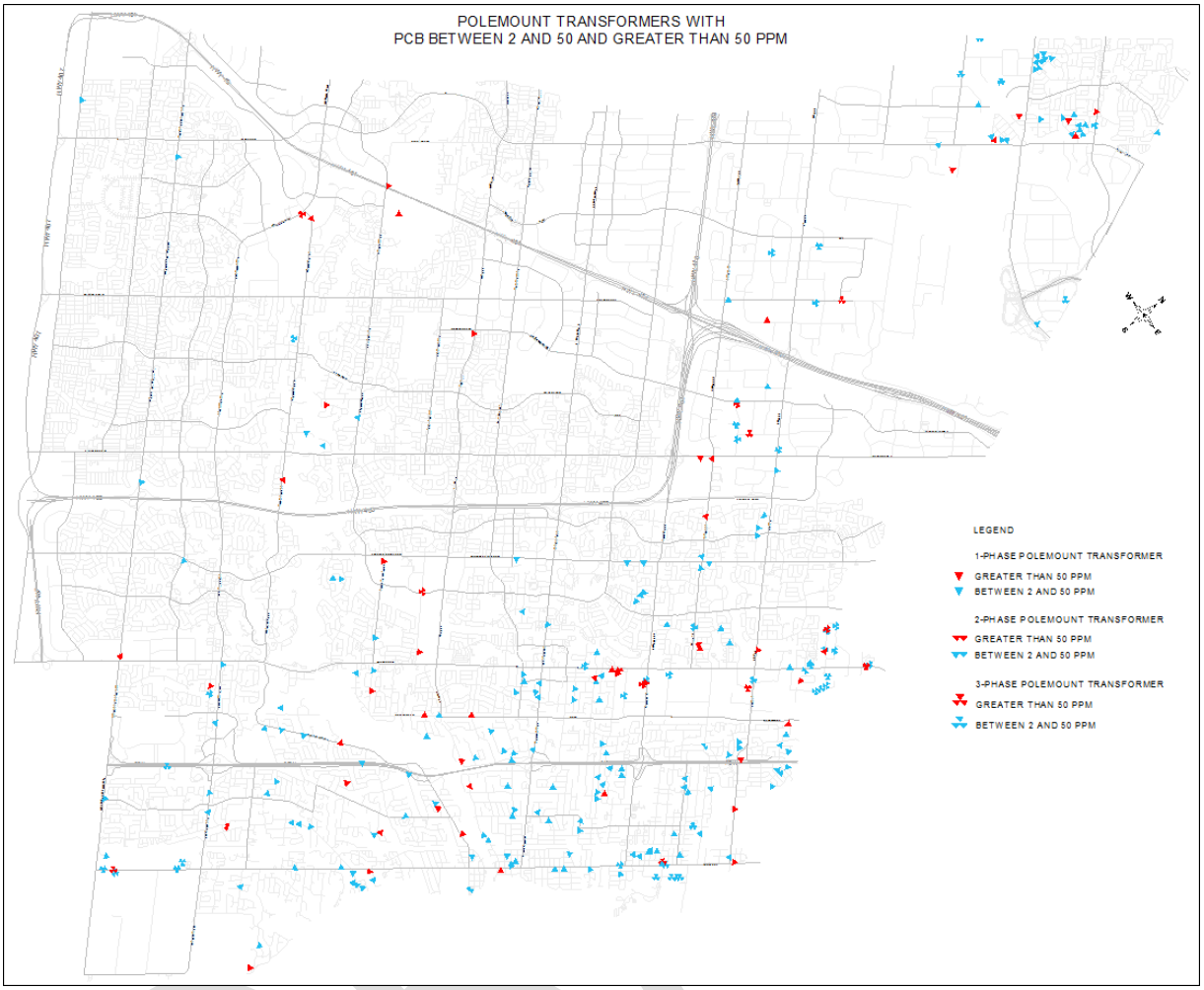



**Figure 62. List of Pole Mounted Transformers with PCB Content**

3) **'Major Leak' transformers** – Non-PCB transformers that have been identified as having a major oil leak pose an environmental, financial, and reputational risk. The list of non-PCB leaking transformers is shown in **Figure 63**.

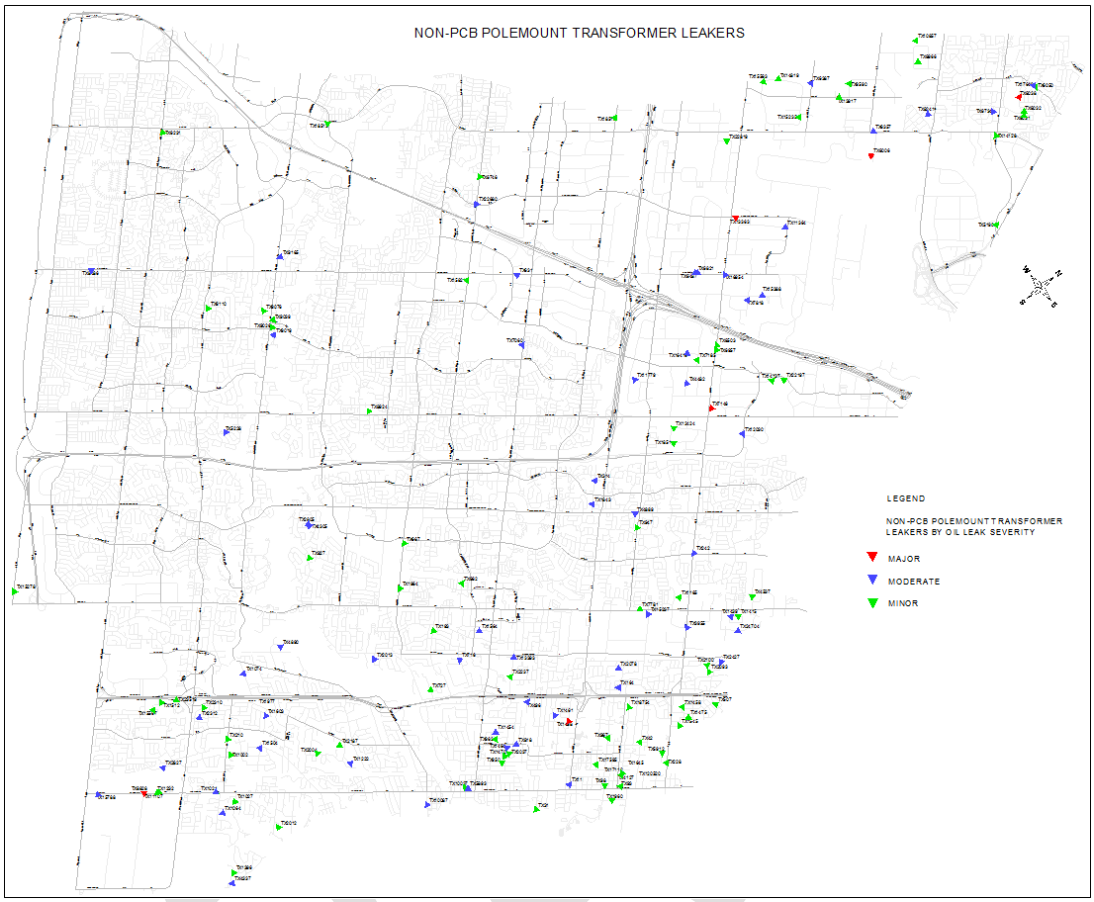



**Figure 63. Leaking Pole Mounted Leaking Transformers (Non-PCB)**

4) **Top Nine Large Customers** – Large customers (with demand of 5 MW or greater) and hospitals pose increased reliability risk as outages can adversely impact their businesses and operations and can cause major reputational damage to Enersource. An example of distribution feeders supplying large customers and hospitals is shown in **Figure 64**.

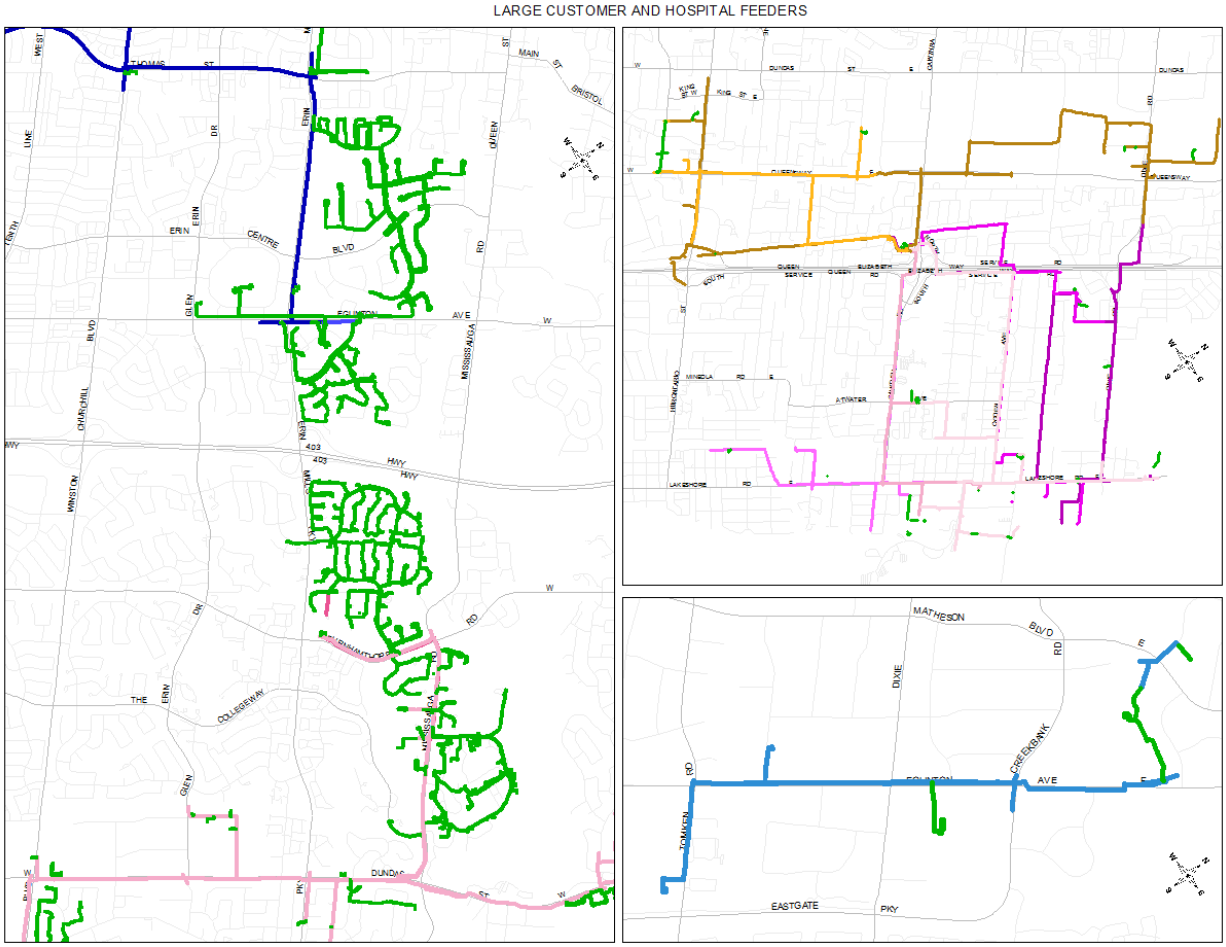



**Figure 64. Feeders Supplying Large Customers and Hospitals**

5) **Poles 35 years or older** - As shown in **Figure 65**, areas where the majority of poles are older than 35 years old are given higher priority as they have passed or are nearing the end of their useful lives. The financial impact (i.e., asset write-down) would be minimized as these assets would be fully or almost fully depreciated.

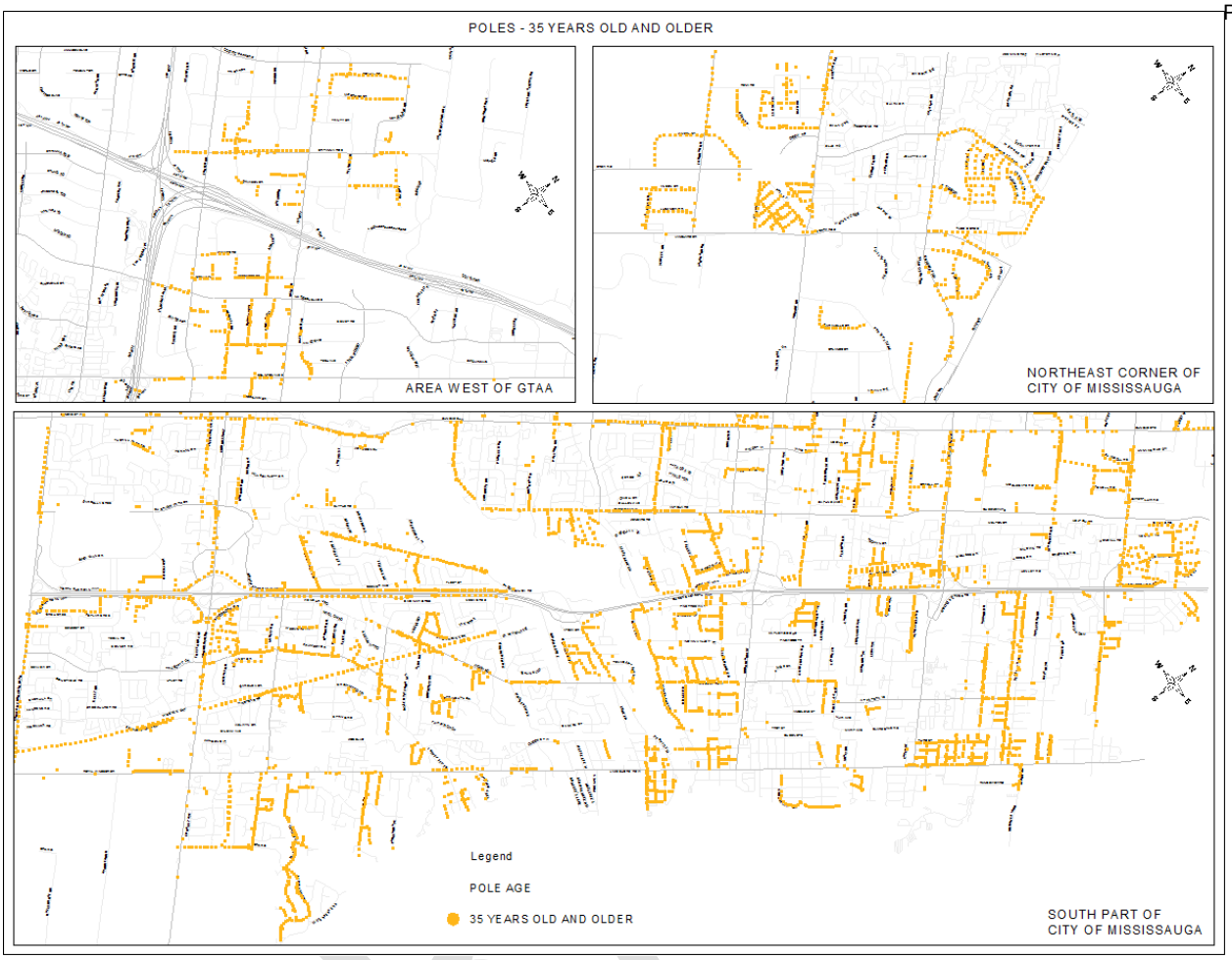



**Figure 65. Location of Poles 35 Years or Older**

The list of projects for overhead distribution renewal is determined based on the evaluation process of using pole inspection data and assessing need against Enersource's business values. The selected overhead System Renewal projects are then designed and constructed to meet all relevant safety and regulatory requirements.

### 2.3.2.2.2 Poles, Accessories & Transformers Renewal Programs

As stated earlier, the main components of the overhead system are poles, pole mounted transformers, switches, conductors, and associated overhead hardware such as insulators, fuses and lightning arresters. This program deals with the replacement of overhead components, switches, and associated equipment that have reached their expected end-of-life, namely:

- Concrete poles
- Wood poles
- Overhead wwitches

- Insulators
- Polemounted transformers.

Failure of overhead equipment can result from exposure to various adverse conditions and causes, including:

- Mechanical stress on operating linkages, operating rods and springs
- Contacts due to wear and tear during fault interrupting conditions
- Exposure to contaminants such as salt and pollutants and extreme environmental weather conditions
- Chemical contamination such as dust and powder produced by arc erosion during switching and fault interruptions
- Thermal stress resulting from localized heating and varying load currents.

The condition of overhead equipment is identified via:

- Inspections program
- Additional field assessments carried by staff doing work in the area
- Known reliability performance issues/customer outages
- Non-compliance with current standards
- Infrared and radio frequency testing results.

#### 2.3.2.2.3 Wood and Concrete Pole Renewal Program

Poles in 'poor' condition not identified as a part of a distribution System Renewal project are replaced under this program. This is required to ensure that substandard wood poles, cross arms, and concrete poles that have reached their end-of-life are replaced on an annual basis. This program also ensures the replacement of poles deemed to be in 'poor' condition and considered an emergency. By way of example, this would include rotten poles or those affected by a failure or event such as a pole fire, damage from vehicle contact, weather storm, or tree falling on the power line.

A major component of Enersource's overhead distribution system is wood and concrete poles. Enersource has over 12,900 wood poles and over 8,900 concrete poles which support approximately 1,800 km of overhead primary and over 1,200 km of overhead secondary circuits. Under this program, poles are replaced based on their condition rather than their age, location, or system improvements.

Poles deteriorate over time and when their strength is reduced to the point there is a risk of failure under adverse weather conditions, they are deemed to be at end-of-life. The safe, reliable operation of the distribution system depends on the condition of pole assets. Pole condition is routinely assessed by operational personnel performing work such as switching or other asset replacement (such as transformers, insulators, and lightning arrestors). Furthermore, during the pole numbering project undertaken in 2014, Enersource flagged numerous poles that are in poor condition and in need of replacement under the Overhead Renewal Program.

Because wood is a naturally grown material all such poles differ in internal structure and consequently in mechanical strength. Degradation of strength can result from naturally occurring fungi that attack the wood, which results in decay. The severity of the degradation depends on several factors such as location, treatment, type of wood, and installation practices. Wood poles can also be damaged by woodpeckers, termites, or pole fires, which are caused by current leakage during insulator tracking. In addition, in the past, some wood poles were painted grey with the goal of improving visual appeal; however, the paint trapped moisture inside the pole which has accelerated decay.

Failures of concrete poles may be caused by deterioration of the steel re-bars inside the pole due to exposure to corrosive chemicals in the soil or winter road salt. The severity of the degradation depends on several factors such as location, rusting of the exposed re-bars, and whether a protective coating was used on the ground section of the pole.

Since distribution and subtransmission poles support bare overhead wires and other equipment, pole failure is very serious, especially since the public may come in contact with live conductors. In addition, depending on the number of circuits supported by the pole and the voltage, failure may disrupt power to thousands of customers.

Enersource carries out detailed field inspection of wood and concrete poles and associated distribution equipment (e.g., transformers and overheard switches). The condition of the poles is recorded through computer field tablets and imported into the GIS. Subsequent geo-spatial maps are generated to identify areas that require pole replacement, as shown in **Figure 66** below.

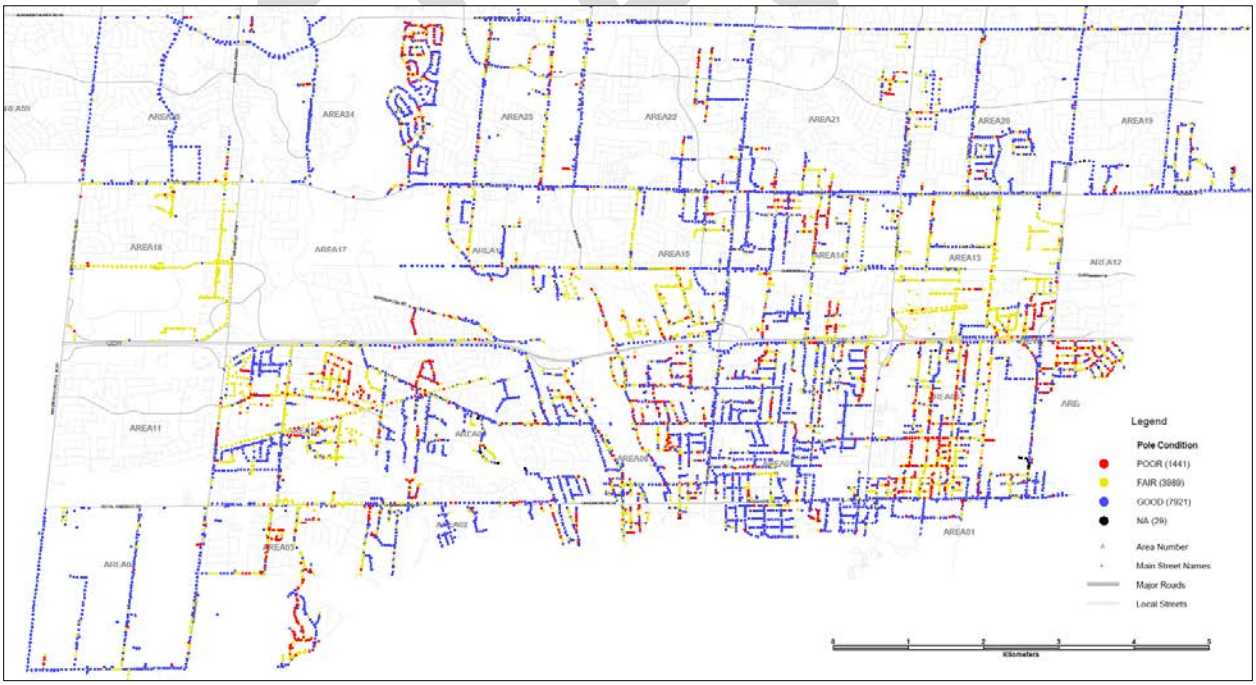



**Figure 66. Pole Condition**

### 2.3.2.2.4 Overhead Switch Renewal Program

Switches are one of the key components of the power system. They are used to reconfigure an electrical circuit by interrupting the current flow, or to isolate conductors. In addition, fused cutouts are used to protect transformers and underground conductors under fault conditions.

Enersource utilizes four types of overhead switches:

- Loadbreak switches (load interrupter)
- Remotely-controlled switches
- In-line switches
- Fused cutouts.

The overhead distribution system has approximately 570 gang-operated, three-phase load break switches and over 2,000 in-line solid blade switches, cutouts, and other components.

In most cases when an overhead switch failure occurs, it is caused by contamination of the insulator, which can lead to a flashover and further degradation of the insulating medium. Sometimes contamination will cause leakage current to develop across the insulator, or other parts of the switch that are not meant to carry current. As a result, these parts may overheat and cause the switch to fail. Also, the loadbreak switch mechanism that suppress the arc when the switch contacts are opening can sometimes fail, causing arcing and damage to the switch contacts.

In addition, when overhead switches are not operated over a long period of time, the switch contacts seize, preventing the crew from operating the switch.

System impact from an overhead switch failure can be very significant because they are typically installed on overhead main feeders that may supply multiple substations or subtransmission feeders. Failure of an overhead switch installed near HONI's transformer station may interrupt power to several thousand customers, including large commercial and industrial customers.

To ensure that switches on the system are in proper working condition, all switching equipment is inspected each year with an infrared camera for arcing and overheating. During switching operation or as a follow-up to trouble calls, a number of overhead switches have been found to be beyond repair and require replacement. In addition, Enersource continues to replace equipment with porcelain insulating components such as cutouts, standoff insulators, and mid-span openers that have proven to be susceptible to failure, with new equipment that contains polymer insulators.

The inspection and maintenance performed annually in the loadbreak switch maintenance program identifies a number of switches beyond economic repair that require replacement.

Enersource carries out both proactive and reactive replacement programs of overhead switches in its distribution system.

A type of polymer switch was identified as an area of concern due to its likelihood of premature failure, confirmed through field failures and testing analysis completed by the manufacturer. As a result, Enersource has created a program to replace these faulty switches to mitigate the risk of extended customer outages associated with the reactive replacement of defective switches. This tactic also reduces the safety risk to employees and the public. A sample area with these switches identified through the overhead inspection program is shown in **Figure 67** below.




**Figure 67. Sample Area Identifying the Location of SMD-20 Switch**

### 2.3.2.2.5 Insulator Renewal Program

The system impact from the failure of an overhead insulator is also very significant, as it could support an overhead main feeder conductor that may supply multiple substations or subtransmission feeders. The failure of an overhead insulator installed near a TS may directly interrupt power to several thousand customers, including large commercial and industrial customers.

In the past few years, a number of outages on the overhead system was caused by porcelain or EPAC insulator tracking or breaking. These outages ranged from intermittent power interruptions to a few hundred customers, to sustained outages that affected several thousands of customers. In some cases, porcelain insulator tracking caused pole fires which resulted in prolonged outages and caused damage

to other distribution equipment. During a freezing rain storm in March, 2015, there were 25 pole fires in one night, caused by insulator tracking from road salt.

In addition, when porcelain insulators track, they may heat up to a point where they may shear, posing a safety hazard to the public or to Enersource personnel working near the defective insulator.

Through the pole and infrared inspection programs, the locations of porcelain and EPAC insulators are being identified (an example is shown in **Figure 68** below). The key locations will be prioritized and these insulators will be replaced with more reliable and safer silicone insulators. Approximately 1,000-2,000 insulators will be replaced each year for the next 10 years.

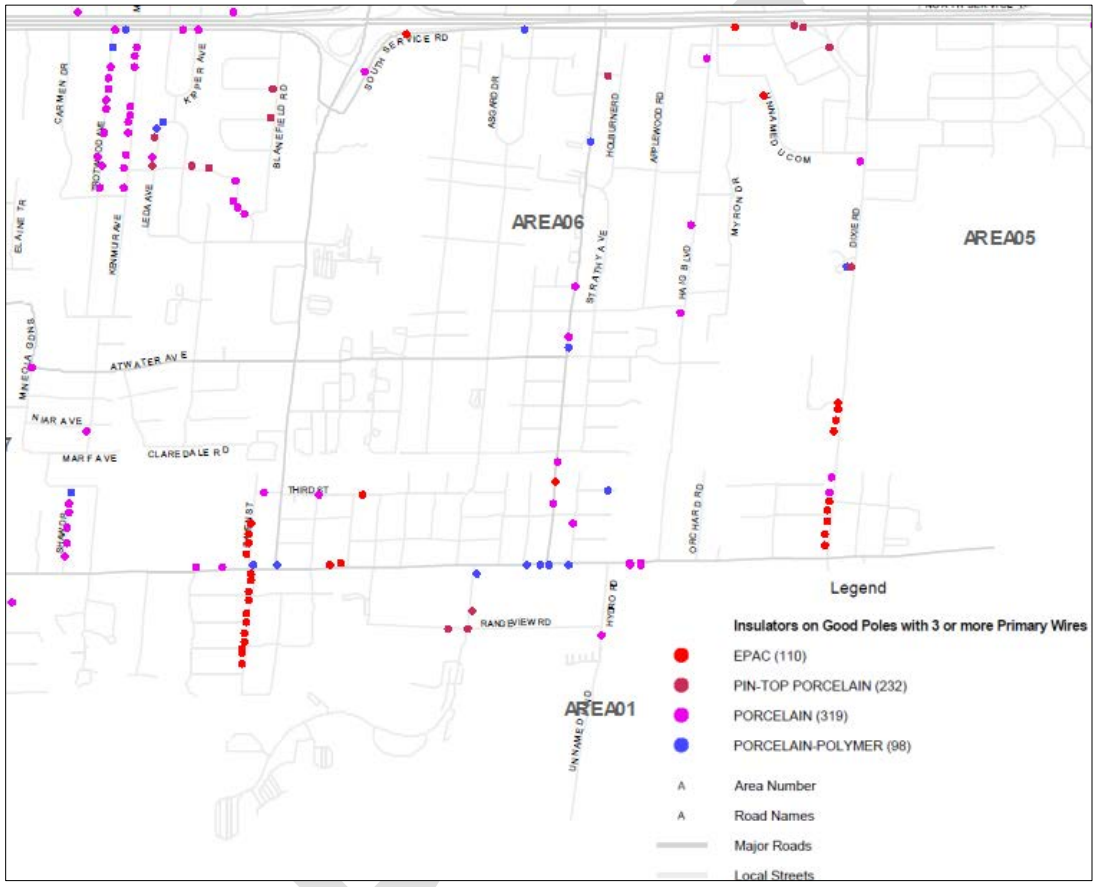



**Figure 68. Porcelain and EPAC Insulator Locations**

### 2.3.2.2.6 Pole-Mounted Transformer Renewal Program

Similar to the pad mounted transformers, the main purpose of the pole mounted transformers is to lower the primary voltage to secondary voltage levels acceptable to residential, industrial or commercial customers. Pole mounted transformers are not as affected by rust or vehicle accidents since they are not installed as close to traffic as pad mounted transformers.

The pole mounted transformers are similar in construction to single phase pad mounted transformers and therefore mostly fail due to insulation breakdown at which time they must be immediately replaced. Because a transformer failure in a residential area may only affect 10 to 20 customers, outage customer minutes and time is minimal. However, a transformer failure for an industrial/commercial customer could prove costly to their business.

Transformer condition is routinely assessed by Enersource personnel performing work such as switching, responding to trouble calls, or outages. The outside crews advise the Control Room of transformers that are in poor condition at which time the Control Room would generate an IOM report and send it to the Overhead Maintenance Department for follow-up. In addition to replacements of failed transformers, this program also provides for replacements of rusted, leaking, or overloaded transformers.

The program is needed to allow for the planned and unplanned replacement of overhead transformers that are in poor condition in various parts of the City.

#### 2.3.2.2.7 Fault Indicator Replacement

Enersource has deployed numerous fault indicators of varying types throughout its distribution system. The replacement program is aimed at adding fault indication to areas where it is absent, as well as replacing older fault indicators that are technologically obsolete or prone to malfunction.

Fault Indicators are significant to the distribution system because they reduce fault locating times, improving outage response and, consequently, outage restoration times. They also help determine the root cause of transient faults (i.e., auto reclosures). The deployment of functional fault indicators are crucial to maintaining high levels of reliability and customer service and to achieving gains in operational efficiency.

### *2.3.2.3 Substation and Automation Assets*

#### 2.3.2.3.1 Substation Renewal Program

Enersource has 66 municipal substations in service. They are as follows:

- 52 bungalow building style substations
- 14 outdoor substations.

Based on Enersource's significant asset class ranking, substation equipment has the highest significance to the Company's sustainability as an organization and to its business values. Therefore, Enersource proactively replaces substation equipment before a major failure occurs which could negatively impact customers, system reliability, and the Company's reputation. Among the list of critical equipment in the ACA, substation equipment was identified as the second most significant to the sustainability of the organization. Therefore, it is imperative that such equipment is replaced before a failure occurs.

Enersource's proactive replacement strategy considers the health index, location, number of customers served, transformer protection enhancement opportunity (implementing transformer differential protection) and the condition of other substation assets, including buildings and grounds. The

component replacement program addresses assets such as switchgears, circuit breakers, protection relays, transformers, enclosures, tap changers, batteries, and battery chargers that have reached end-of-life and can no longer fulfill their intended function.

A smaller but essential program that Enersource carries out each year is to replace the battery chargers and batteries which are critical for substation operations. In the event of a substation power failure batteries continue to supply power to the protection relays, the Remote Terminal Units (RTU's) and to the control mechanism for circuit breaker operation. These batteries are continually charged by battery chargers that use AC voltage, rectifies them to a useable DC voltage. The substation battery chargers and DC systems have an approximate life cycle of 10 years. The substation batteries have an approximate life cycle up to 15 years inside a climate-controlled substation.

#### 2.3.2.3.2 Automation/SCADA Renewal Program

The SCADA and protection system are considered critical assets for proper operation of Enersource's distribution system. To ensure that there is an appropriate level of automation to satisfy operational requirements, Enersource identifies the system automation and SCADA needs in two ways:

- Tracking the age of remotely controlled switches and substation auxiliary components from the result of inspection programs; and
- Identifying the worst performing supply points on the electrical grid from the result of system planning studies; new remotely controlled switch locations are selected to increase system performance.

The electricity power grid is designed to automatically react to external events to ensure public safety. This could be to instantly shut off power for sustained events (such as a contractor digging into underground cables) or could cause sub-second momentary outages for events such as tree contacts. This ensures homes, businesses, and safety services such as traffic lights are not unnecessarily exposed to long outages.

The SCADA system provides Enersource with the ability to monitor and control its distribution system and is connected to 66 substations and 240 field automated switches with a total of 15,500 digital, analog, and control points. Communication from the SCADA to the substations have traditionally been via S4T4 serial communication lines.

The S4T4 serial leased line communication links between the substation RTU's is a legacy system that is slow and approaching obsolescence. To improve this communication infrastructure, Enersource plans to upgrade the S4T4 communication infrastructure to a more robust IP-based Multiprotocol Label Switching (MPLS) technology.

MPLS technology provides multiple advantages over the legacy S4T4 technology such as:

- The ability to remotely connect to the protection devices at the substation
- Remote monitoring of the communication circuit health



DRAFT

- Advanced cyber security and ability to connect multiple services such as phone, internet and security cameras, on the same MPLS network.

Once a substation is selected to undergo this communication technology upgrade, the protection relays and the RTU will also be upgraded.

#### 2.3.2.3.3 Automated Switches Renewal Program

To ensure the continued safe and efficient operation of the electricity system, remotely controlled overhead and underground load break switches allows Enersource to restore power to a large number of customers in the event of a power outage.

A major trend in the electricity utility industry is a move towards increased system automation and remote operation. In recent years, Enersource has been steadily increasing the amount of automated switchgears in its distribution system, resulting in improved system reliability and decreased outage durations. It is imperative that this move towards increased automation continues in order to ensure continued improvement of the system.

The majority of Enersource's automated switchgears are on the 27.6/16kV distribution system. Many of the first generation switchgears were installed over 20 years ago, and have been gradually losing their effectiveness in recent years. In particular, remote operations are not as reliable and many older switchgears must resort to manual operation which, during a power failure, leads to an increase in outage duration.

It is imperative that Enersource upgrade these aging units in order to avoid diminishing system reliability in the future. New switchgears use the latest solid dielectric technology and have proven to be reliable in the high voltage as well as the automation components. A comprehensive automation study was completed to identify high priority areas and considered factors including historical reliability (momentary and sustained outages), number of affected customers, and existing automation in the vacinity.

Scada-Mate switches are deployed on the 27.6kV system while Alduti-Rupter switches are deployed on the 44kV system. Enersource has strong in-house expertise in working with these switches and the associated automation, and with this knowledge can maximize switch functionality and continue to improve it, even after the initial installation.

A typical overhead automation project involves the installation of one or two automated switches in close proximity to a substation. Such an arrangement allows for a substation's incoming subtransmission feed to be transferred quickly to an alternative feed in the case of an upstream fault. This will result in greatly reducing outage durations, thereby improving system reliability performance.

## 2.3.3 Expansion Programs

### *2.3.3.1 Downtown Core*

The Downtown Core began its development in 1973 with the construction of the newly built Square One Shopping Centre. At that time, the Downtown Core consisted of little more than Square One and large amounts of vacant farmland. Square One has undergone many expansions over the past four decades, during which time the Downtown Core has seen an increase in high-rise residential and office development.



**Figure 69. Square One Shopping Centre After and Before Construction**

Today, the Downtown Core is the focus of the Urban Growth Centre for Mississauga and houses the City's cultural and institutional centres, as well as being a regional centre and major transportation hub for the Greater Toronto Area. The Core also contains the Civic Centre, the Living Arts Centre, the Central Library, the YMCA and Kariya Park. Additionally, this area is comprised of a mix of office buildings and high-rise residential apartments focused around the retail commercial development within and around Square One. Recently the Downtown Core has seen the emergence of Celebration Square, the completion of the new Sheridan College Campus, new commercial development along Rathburn Road and improvements to the LRT and BRT transit terminal.

The Mississauga Official Plan was adopted by City Council in September, 2010 where the Downtown Core, shown in **Figure 70**, was identified as part of a new urban structure. This new urban centre focuses growth in areas with existing service, proposed service, and infrastructure capacity, particularly transit and community infrastructure. The Downtown Core is intended to be a vibrant regional centre where residents are able to live, work, and play.



**Figure 70. Today's Mississauga Downtown Core**

### Downtown Planning Districts and Projected Loads

The City of Mississauga's Official Plan outlines basic goals and objectives, and provides direction for long term growth and development within the City. The Official Plan is divided into nine planning districts. Specific policies and land use maps define a long term plan for the road system, land use development, and other details regarding the Downtown Core. The districts, along with the corresponding potential development summary, are shown below in **Figure 71**.

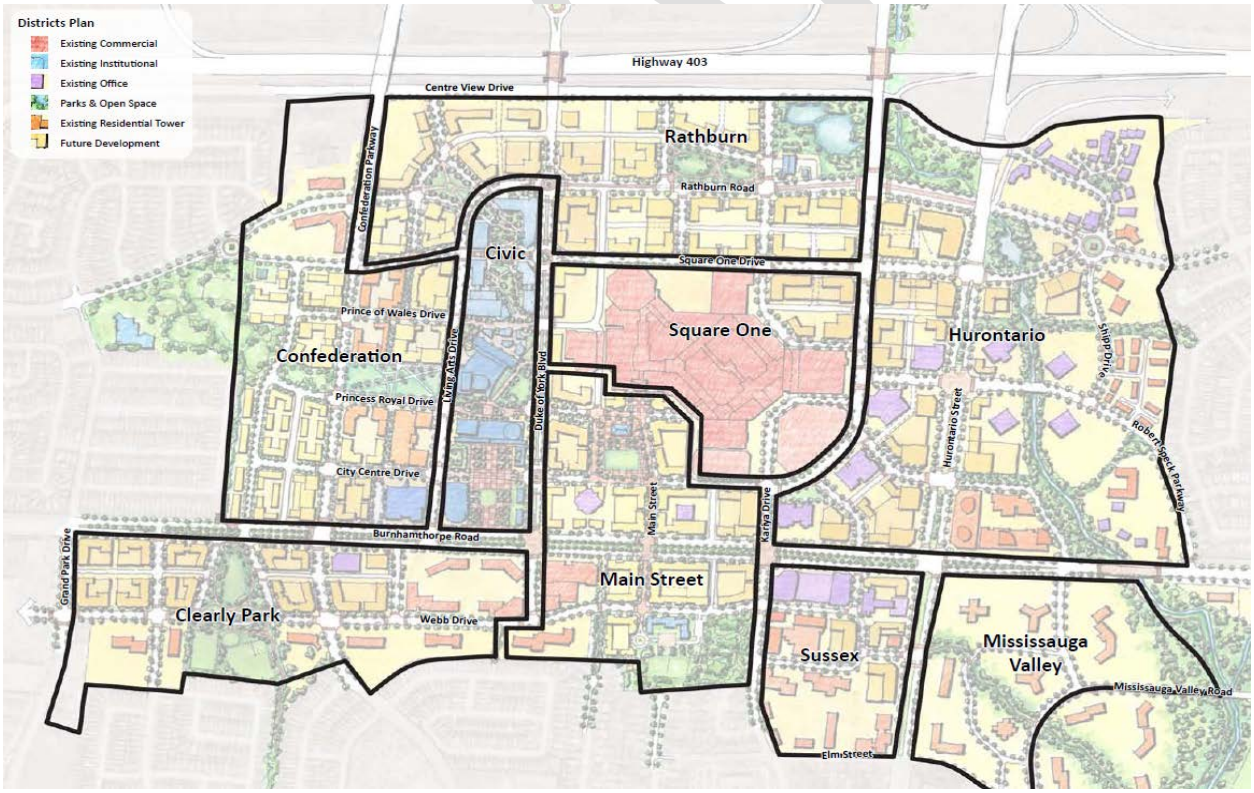



**Figure 71. Downtown 21 Planning Districts**

Enersource has forecasted electricity demand in each of the City planning districts. The loads projected are for the complete Downtown Core and are based on the Downtown 21 build out potential. Where available, the loads have been projected based on applications that specify the number of units or commercial space that will be available. The loads for other buildings, where such information is not available, have been estimated based on the type of building, approximate building footprint, and number of floors. In cases where no information regarding future buildings are available, the load for the area is based on the load of a similar area that was completed in the past. The projected load for each district is shown in **Figure 72**.

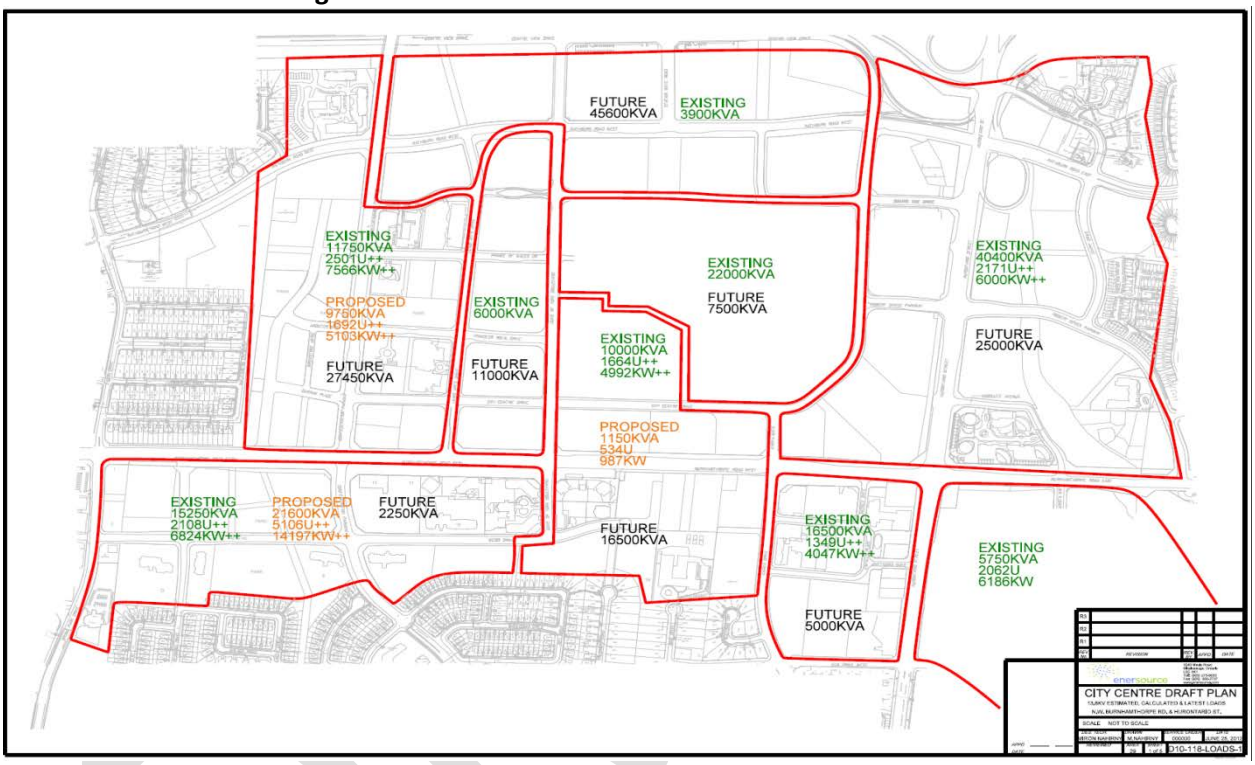



**Figure 72. Present and future loads in Downtown 21 Planning Districts**

**Table 26. Planning Districts, Potential Population, and Estimated Load**

| Planning District | Category | DT21 Potential | Existing Load (MVA) | Estimated Load (MVA) |
|---|---|---|---|---|
| Main Street | Population | 12,316 | 10 | 27.65 |
| | Employment | 4,221 | | |
| Civic | Population | 5,500 Students | 6 | 17 |
| | Employment | 2,650 | | |
| Confederation | Population | 22,246 | 11.75 | 48.95 |
| | Employment | 20 | | |
| Cleary Park | Population | 16,004 | 15.25 | 39.1 |
| | Employment | 603 | | |
| Rathburn | Population | 0 | 3.9 | 49.5 |
| | Employment | 28,636 | | |
| Hurontario | Population | 6,057 | 40.4 | 65.4 |
| | Employment | 25,423 | | |
| Square One | Population | 0 | 22 | 29.5 |
| | Employment | 4,087 | | |
| Sussex | Population | 6,402 | 16.5 | 21.5 |
| | Employment | 5,574 | | |
| Mississauga Valley | Population | 6,070 | 5.75 | 5.75 |
| | Employment | 199 | | |

**Existing Load and Supply Points in the Downtown Core**

Currently, there are approximately 65 buildings in the Downtown Core and three substations: Woods MS, Confederation MS, and City Centre MS. These substations are equipped with either two or three power transformers and most of their capacity is dedicated to supply the existing load in the Downtown Core. In addition, John MS, located on Hurontario Street near John Street, also provides power to the Downtown 21 area, especially to Mississauga Valley and Sussex districts. The total connected transformation in the Downtown Core is approximately 130 MVA. The current capacity available for all districts of the Downtown 21 area is approximately 140 MVA. The small over-capacity allows for short term growth and N-1 contingency in the Downtown Core. A detailed breakdown of the existing loads, based on the planning districts and existing substation sites, is shown below, in **Figure 73**.

DRAFT

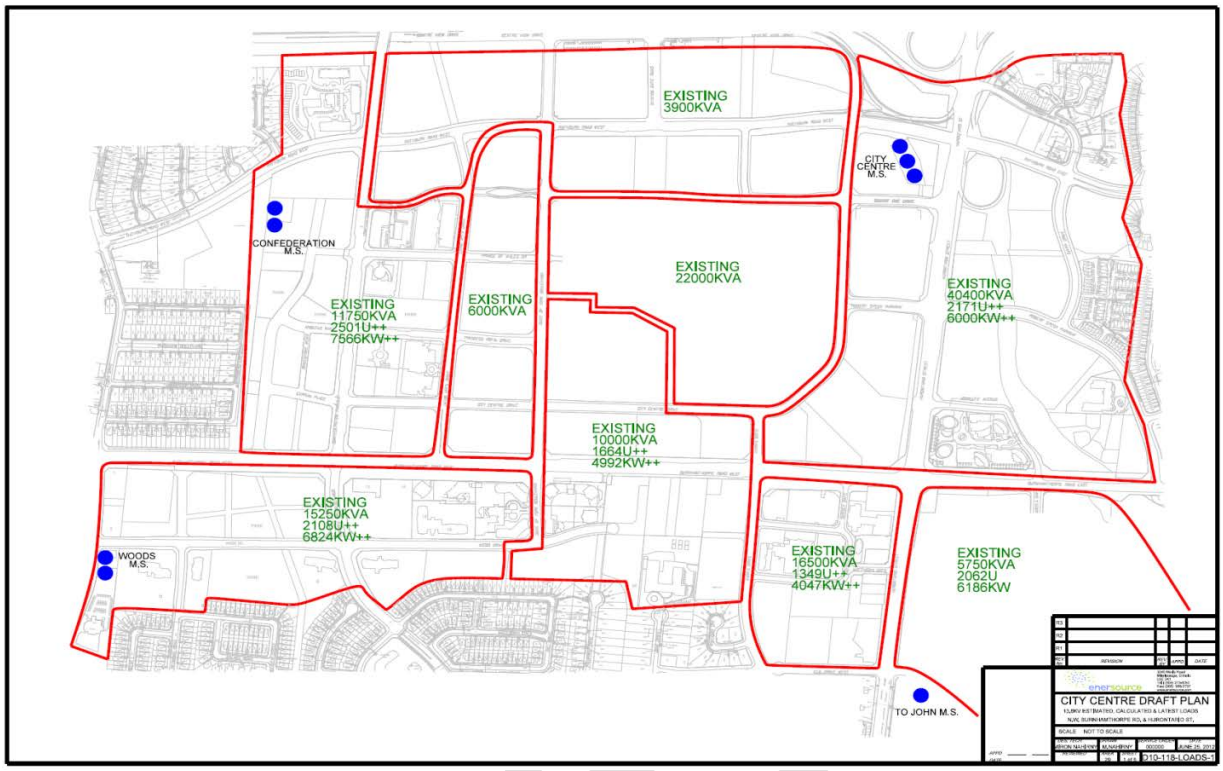



**Figure 73. Existing Loads and Substations**

Based on the proposed model and Master Plan provided by the City, it is estimated that upon completion of Downtown 21, the combined transformation load will increase to approximately 300 MVA. Enersource will have to expand its infrastructure in the Downtown Core and increase the number of substations in order to reliably supply power to all the buildings. At least 10 substation transformers will need to be dedicated to meet the future demand in the Downtown Core, in order to allow for contingency. Future transformers will have to be installed at Woods MS site and possibly Confederation MS, depending on land availability. In addition, two new substation sites will need to be purchased and new substations will have to be constructed. The new substation sites are required because City Centre MS site cannot be further expanded and John MS, due to its distance from the City Centre, cannot be further utilized for new load in the Downtown Core.

### *2.3.3.2 CDM Initiatives in Downtown Core*

Enersource plans to run a Conservation and Demand Management (CDM) program in the Downtown Core to reduce the expected load growth. The CDM program projects a reduction of 1,887 kW off the projected incremental system demand in the Downtown Core as shown in **Table 27** below. This is equivalent to the annual reduction of 1% on incremental load and is consistent with the CDM 2011-2014 targets (90% of 92 MW of summer peak demand). Also, the new 2015 -2020 Conservation energy reduction targets of 483 GWH should result in approximately 1% peak demand load reduction per annum over the six year period to 2020.

**Table 27. Downtown Core Conservation Estimates**

| District | Existing Load (kW) | Proposed Future Load (kW) | Incremental Load (kW) | Annual Conservation Target (kW): 1% of Incremental Load |
|---|---|---|---|---|
| Confederation District | 17,500 | 61,700 | 44,200 | 442 |
| Civic District | 10,250 | 15,000 | 4,750 | 48 |
| Cleary Park District | 15,250 | 41,400 | 26,150 | 262 |
| Rathburn District | 5,850 | 46,700 | 40,850 | 409 |
| Square One District | 13,000 | 22,000 | 9,000 | 90 |
| Main Street District | 11,300 | 29,500 | 18,200 | 182 |
| Sussex District | 15,000 | 21,500 | 6,500 | 65 |
| Hurontario District | 21,250 | 55,500 | 34,250 | 343 |
| Mississauga Valley District | 7,750 | 12,500 | 4,750 | 48 |
| **Total** | **117,150** | **305,800** | **188,650** | **1,887** |

After considering the CDM program, a substantial amount of additional capacity is still required to meet future demand. The added system capacity is required to supply the remaining projected load growth after the CDM program has been considered.

### *2.3.3.2 Proposed Supply Points in the Downtown Core*

Enersource will ultimately need an additional four to five substation transformers dedicated to supply load in the Downtown Core in order to meet the future load growth and peak demand when Downtown 21 is completed. The following options were reviewed and considered, in regards to the location of the new transformers.

### *2.3.3.3 Confederation MS Expansion and Duke MS*

In 2012, after careful review was undertaken of the existing distribution feeders and supply from Confederation MS, which currently has two transformers and an anticipated demand from the northern part of the Downtown Core. This process determined that additional feeders and capacity will be required to supply future buildings between Rathburn Road and Centre View Drive. The current property allows for the installation of a transformer and breaker lineup to increase the capacity at Confederation MS. However, the City has proposed an extension of Square One Drive to Rathburn Road, which will require a portion of the land to be used for the new road. The remaining substation property will then be too small to accommodate an additional transformer and the high voltage equipment associated with it.

Originally, Enersource asked the City to swap the land to the west of the substation to allow for the relocation of the pad mounted switchgears, which are in conflict with the proposed Square One Drive

extension. Additionally, at the time, only a limited number of feeders were available in the area and the relocation of the switchgear required the relocation of all pad mounted equipment in front of the substation to a new location. This meant that the substation had to be completely de-energized for an extended period of time.

Due to the already limited capacity in the Downtown Core, the risk associated with taking a double substation out of service, with no backup available in case of an emergency, was too great. Therefore, the only option was to construct another substation along Centre View Drive prior to switchgear relocation and Square One Drive construction.

In recent conversations with the City, Enersource was advised that a developer owns the land in the Downtown Core that is adjacent to Confederation MS. The Developer is willing to sell the land to the City, which in turn could be swapped for the land taken up by the Square One Drive expansion. Below is a sketch showing the existing Confederation MS land, as well as the lands owned by the developer.

Detailed sketches showing the existing substation location and the lands owned by the developer are shown below, in **Figures 74** and **75**. Additionally, **Figure 76** shows an overlay of the proposed road and the existing substation.




**Figure 74. Existing Station Location and Developer's Property**

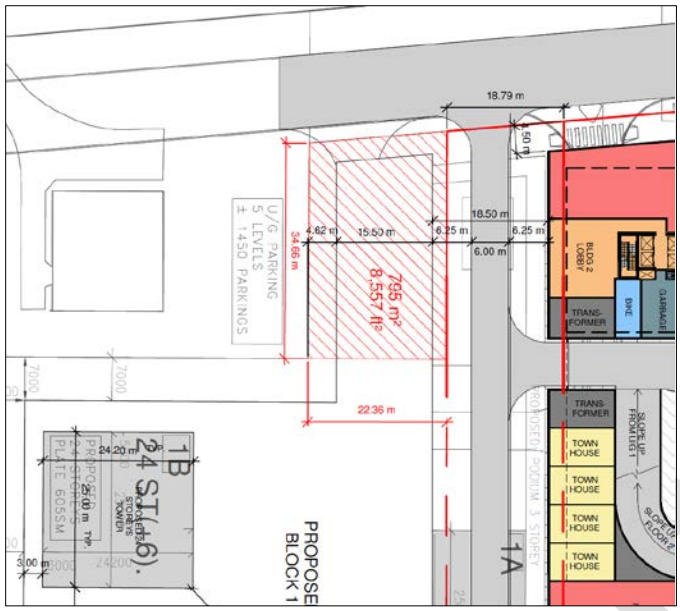



**Figure 75. Existing Substation and Switchgear Locations**

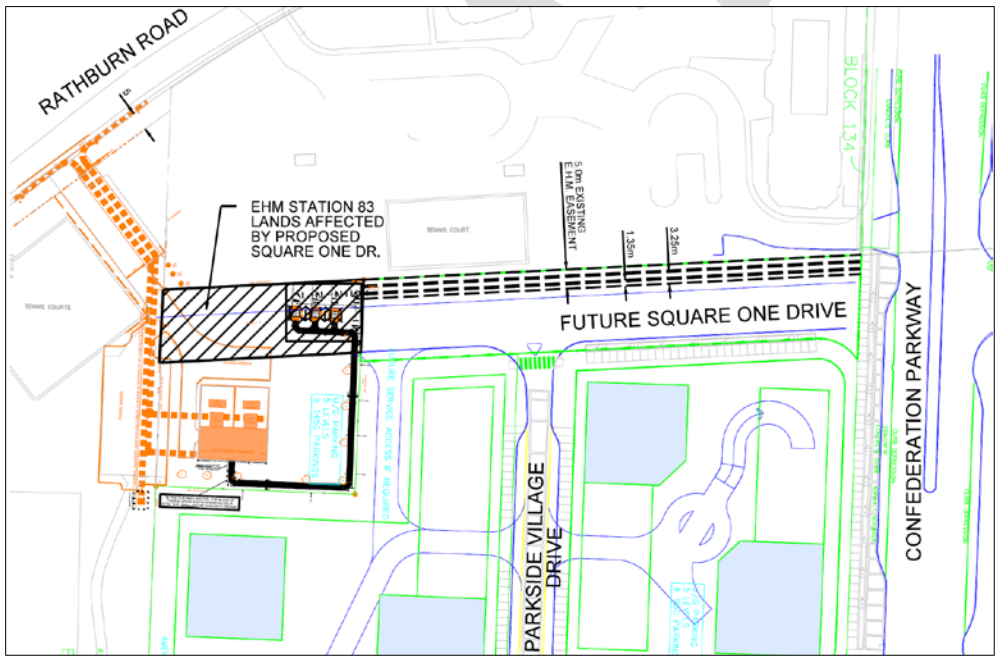



**Figure 76. Existing Substation Location and the Proposed Square One Drive**

Since 2012, several feeder upgrades and extension projects in the northern and central part of the Downtown Core were under way. In 2016, Enersource plans on installing a new pole line along Centre View Drive, from Mavis Road to Station Gate Road. All of these upgrades will allow for a partial transfer of capacity from City Centre MS and Woods MS.

After careful review of all factors, including the latest option which involves a land purchase and trade, as well as feeder upgrades in the area, Enersource has concluded that relocation of the existing switching units can be done with the de-energization of half of the substation during the time of construction. This option presents more risks when compared with the construction of a new substation along Centre View Drive, but for a short period of time, the level of risk is tolerable as it would meet the N-1 contingency level. Because of the new anticipated load in the north area of the Downtown Core, additional capacity is required and will have to be addressed by the construction of a new substation along Centre View Drive, between Confederation MS and City Centre MS.

Due to uncertainty regarding land availability for the new substation and the unpredictable timing of future developments and load growth in the north section of the Downtown Core, Enersource will need to secure the required substation land prior to the relocation of the switches in front of Confederation MS. At the same time, because of the possibility of a land transfer at Confederation MS, the actual construction of the new substation, Duke MS, can be postponed and the substation does not have to be energized prior to the commencement of the Square One Drive expansion.

After reviewing the current sites along Centre View Drive, it was determined that the best remaining site for the new substation is west of Duke of York Blvd., the area to the north east of the existing movie theatre as shown in **Figure 77** below. The majority of the area required for the substation is currently owned by the City and the additional area that may be required below is owned by a developer. Alternately, the new substation could be located east of the proposed location, along Centre View Drive.

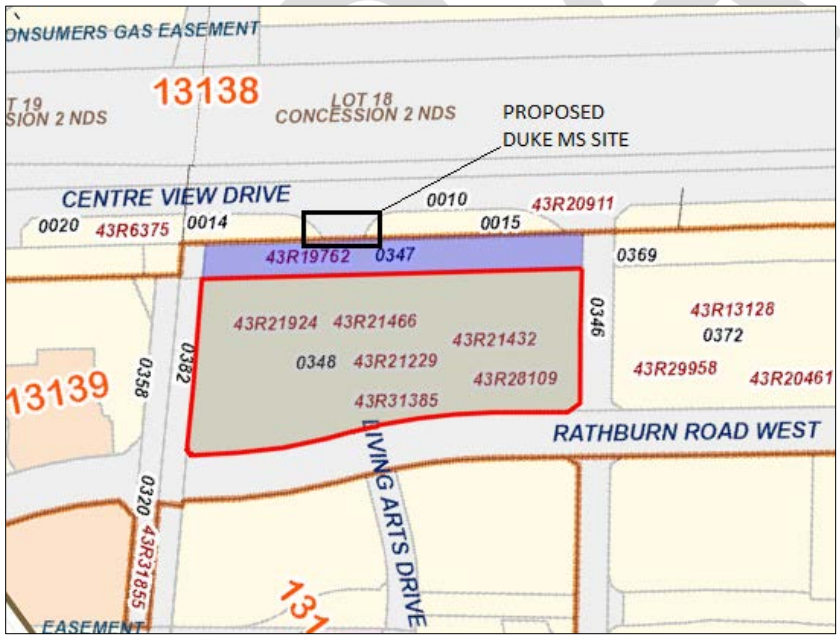



**Figure 77. Proposed Duke MS Location**

There are several other issues associated with the extension of Square One Drive, such as vehicle traffic control (due to close proximity of the road to the station), easement requirements, building access and

other issues that must be addressed prior to land transfer and agreement acceptance between Enersource and the City.

**City Centre MS Expansion Alternative**

There are three 20 MVA transformers installed at the City Centre MS site where the existing infrastructure, including duct banks and switchgears, is fully utilized. The installation of any additional transformers and feeders will require a major reconstruction of the substation and the associated civil infrastructure. In addition, new feeders coming out of the substation will have de-rated capacity due to main feeder cable congestion and restricted duct bank configuration. As a result, the installation of an additional transformer is not economical and does not meet the technical requirements needed to supply load in the Downtown Core efficiently.

**John MS Expansion Alternative**

The John MS site has sufficient space for the installation of an additional transformer. However, the new feeders coming out of the substation cannot be extended north to the Downtown Core unless a new, second pole line is constructed along the west side of Hurontario Street from John MS to Burnhamthorpe Road. Considering future projects, including the LRT along Hurontario Street, it is unlikely that Enersource will be granted permission to install a new pole line on the west side of Hurontario Street, in addition to the existing pole line on the east side.

### *2.3.3.5 Future Substation Needs*

With the exception of the above mentioned locations, the only substation site that can be expanded without a need to purchase or transfer land is Woods MS. This substation is currently equipped with two transformers and seven feeders, where the additional transformer will increase the number of feeders to 10. Any further expansions, as in the case of City Centre MS, will not be economical or efficient, due to substation cable congestion and the major reconstruction of civil structures at the substation.

Consequently, an additional three to four transformers will need to be installed in new locations. Due to existing infrastructure in the Downtown Core and predicted location of the new load, it is recommended to install the new transformers at two separate locations: one in the northern part and one in the southern part of the Downtown Core. After careful review and consideration of the existing feeder locations, future development and locations of the existing substations, the optimal location for the northern substation is near the intersection of Centre View Drive and Duke of York Blvd. (Duke MS). The optimal location of the second substation is near the intersection of Webb Drive and Kariya Drive (Webb MS). **Figure 78** shows the existing and proposed substation locations in the Downtown Core.

DRAFT

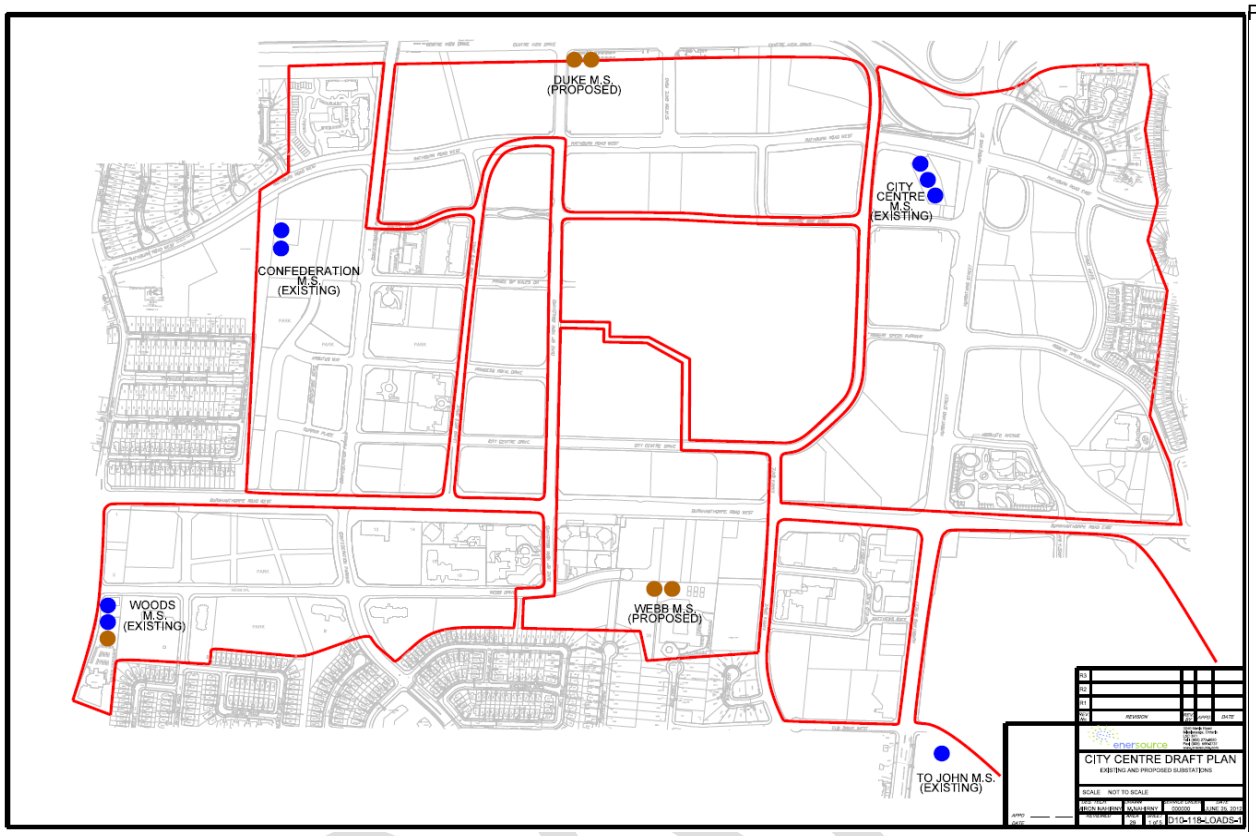



**Figure 78. Existing and Proposed Substation Locations in the Downtown Core**

### *2.3.3.6 Webb MS Substation*

Originally, the Webb MS substation was proposed at the edge of Kariya Park, to service some of the load on the south side of the Downtown Core. However, after several meetings with the City, it was decided that the location had to be changed. Several developers in the area were approached in regards to the available land.

After two years of negotiations with the City and the developer, it was determined that the new substation will be constructed at the northeast corner of Webb Drive and B-Street as shown in **Figure 79** below.

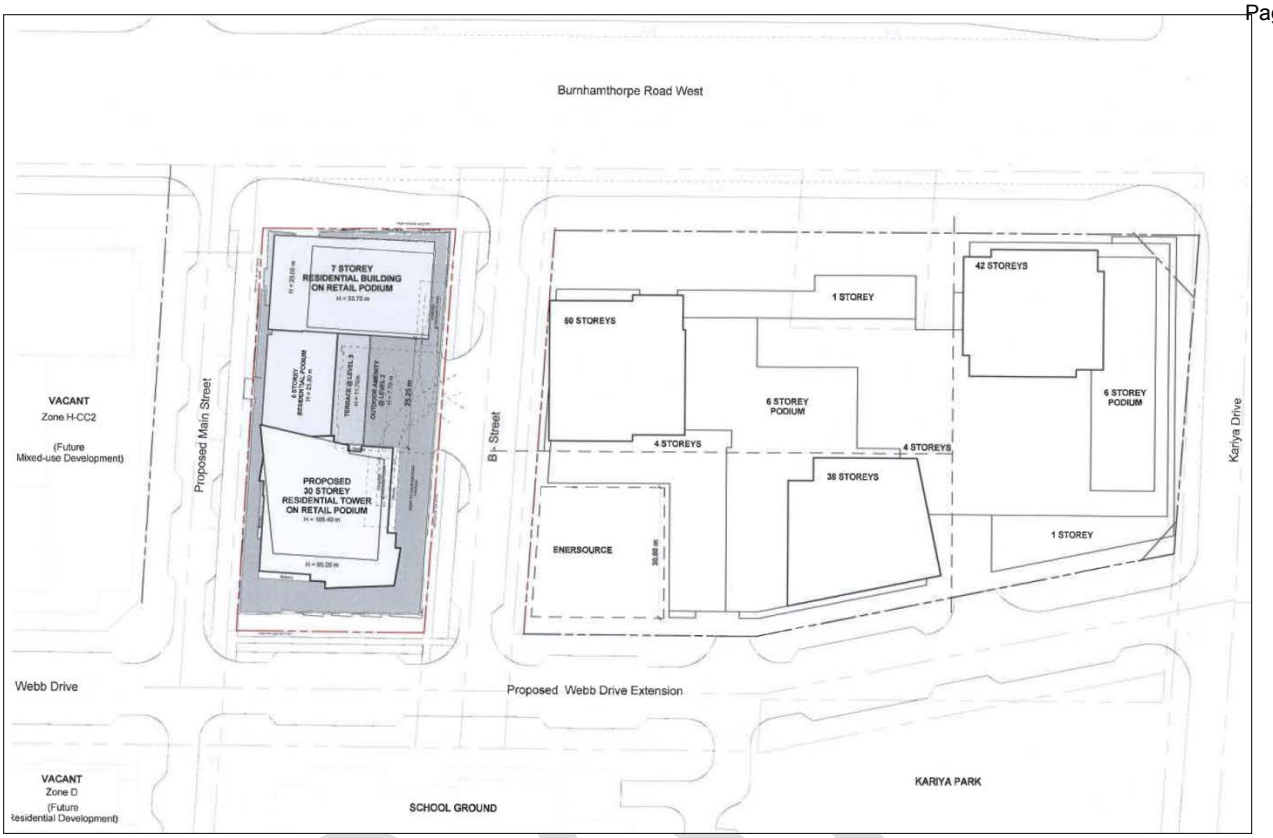



**Figure 79. Proposed Location of Webb MS**

Enersource's typical substation footprint is 50 square meters, but considering the challenges with the property in the Downtown Core, Enersource will utilize a different layout and reduce the site to approximately 30 square meters. In addition, to meet maintenance and construction requirements, the City will allow Enersource to block a portion of B-Street or Webb Drive to allow for setup of heavy lifting equipment for replacement of the substation transformers.

While the Webb MS substation will be designed and constructed for dual transformer setup, the substation will initially be equipped with only one high voltage transformer. The second transformer will be added at a later date, as the load from the new buildings in the southern part of the Downtown Core materializes.

To reduce the pad mounted equipment outside of the substation building, a different approach is being reviewed. Instead of using seven outgoing breakers inside the substation and three to four switchgears outside, a different configuration of using 10 smaller footprint outgoing breakers inside the substation and no switchgears immediately outside the building is being reviewed. This approach will reduce a need for pad mounted equipment and will maintain the same level of switching flexibility and reliability.

The building facade will match the surrounding buildings and the substation will be constructed as part of a four storey townhouse development. It is likely that the substation building will be constructed

initially and the facade finish will be constructed later, at the same time as the rest of the townhouse development.

Additionally, to ensure that the proposed substation blends in with the high rise towers, the developer and the City have requested Enersource to construct a roof over the transformer. To address that requirement, Enersource is reviewing an option of installing a removable louver roof, which will provide adequate ventilation to the substation and to allow for replacement of the transformers.

The substation will be supplied with two 44kV circuits, connected to the overhead lines on Hurontario Street. **Figure 80** below shows the proposed location of the underground cables and overhead pole line. The outgoing feeder egress will be underground and installed along Webb Drive, B-Street and Main Street as shown in **Figure 82**.

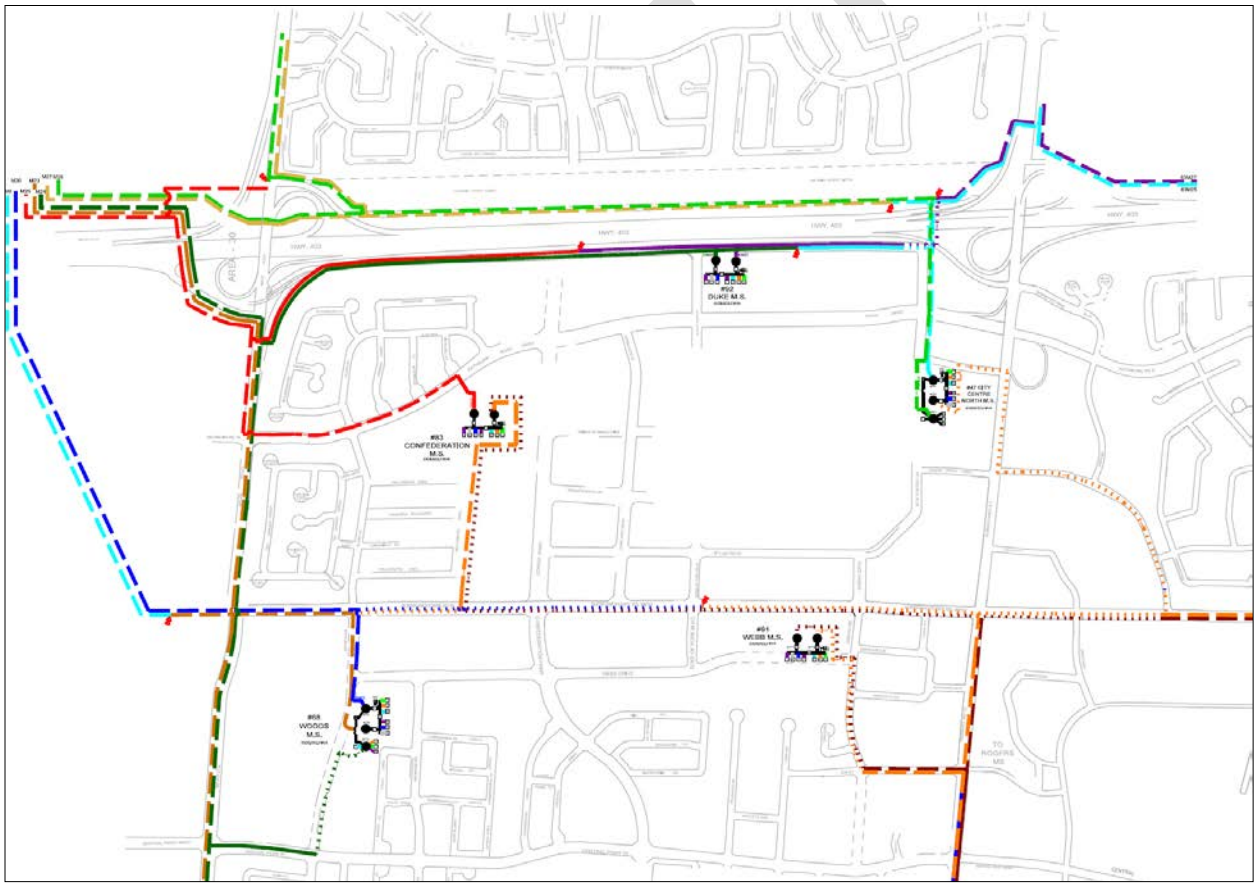


**Figure 80. Proposed Supply Points to the Downtown Substations**

### *2.3.3.7 Underground Distribution Infrastructure*

Substations convert voltage from subtransmission levels to distribution levels. Then, through a series of feeder breakers and switches, the power is directed to loads in the area. In addition to the equipment installed at the substations, a network of underground cables, ducts and cable chambers is necessary to

deliver power to customers. **Figure 81** shows the existing duct and manhole system in the Downtown Core.

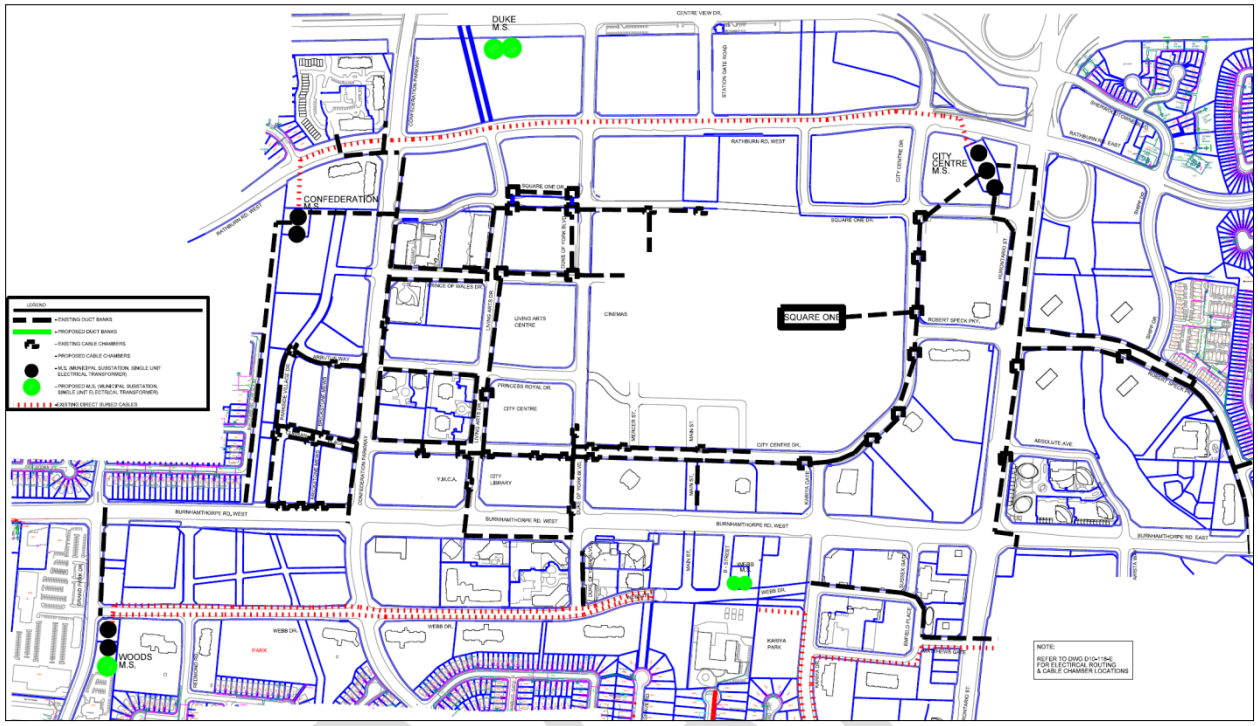



**Figure 81. Existing Underground Distribution Infrastructure**

The existing underground infrastructure is sufficient to supply the current demand in the Downtown Core. However, in order to meet future demand, old cables in the existing ducts must be replaced and new duct banks with new cables and manholes must be added. Since all distribution infrastructure is located in a common trench below grade, it is much more efficient and economical to install concrete encased ducts and manholes before construction of the permanent buildings. This avoids issues with space in the common trench, and prevents expensive repairs and restoration to new road surfaces, sidewalks and landscaping. In addition, power disruption to buildings and the expensive rental of generators can be avoided if duct banks and manholes are installed prior to building construction. **Figure 82** shows the duct bank and manhole system proposed for the Downtown Core. The figure includes existing and proposed installations.

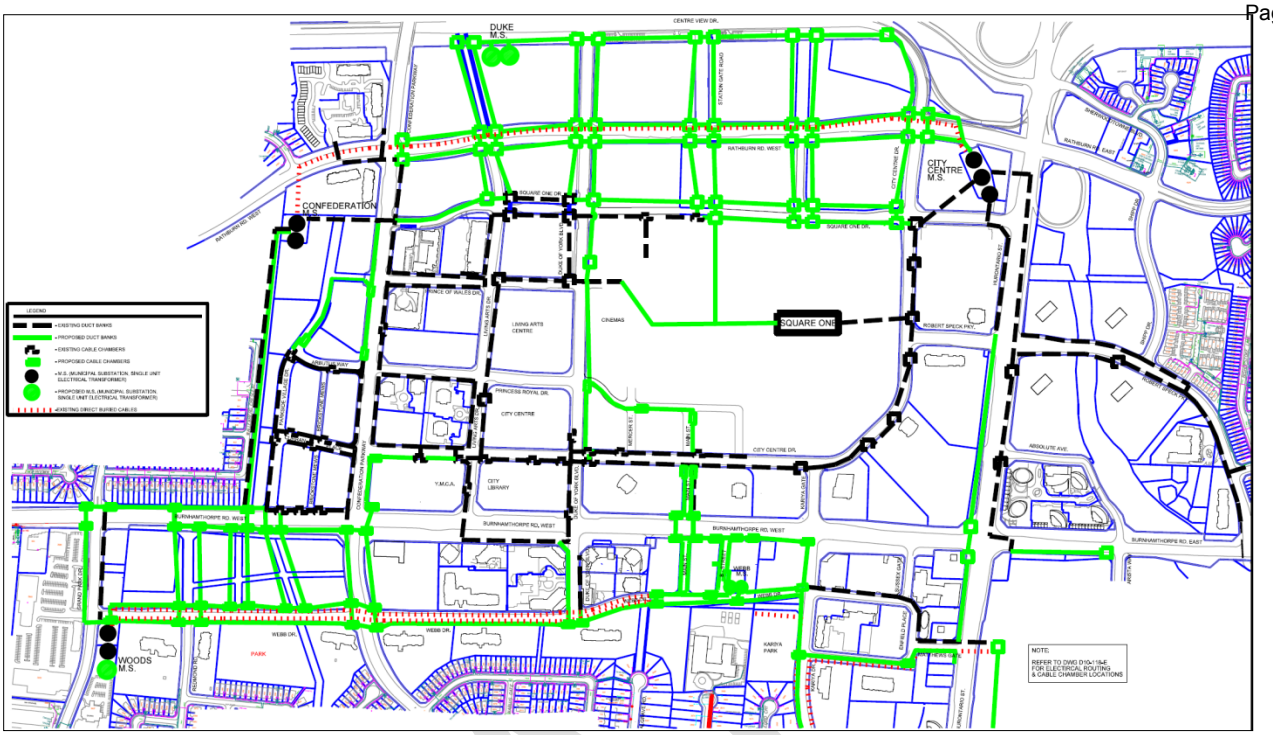



**Figure 82. Existing and proposed underground distribution infrastructure in the Downtown Core.**

## 2.3.4 Information Technology Assets

### *2.3.4.1 Sustain Existing System Program*

#### 2.3.4.1.1 Hardware

Enersource employees utilize IT systems on a daily basis. This is achieved through the following categories:

- Endpoint hardware i.e., desktop computers, laptops, tablets, plotters, printers, phones, and mobile devices
- Back-end hardware i.e., servers, storage, computing, network, databases, etc.

For hardware assets Enersource utilizes the hardware refresh program as shown in Table 28.

**Table 28. Hardware Category**

| Hardware Category | Lifecycle |
|---|---|
| Desktop (single-task users and task-oriented users) | 4 years |
| Desktop (specialized users), laptops, tablets, GPS units, etc. | 3 years |
| Printers, plotters, etc. | 5 – 6 years (dependent on vendor support expiry) |
| Monitors, projectors | 6 years |
| Servers, data storage, switches, voice and telecommunications, etc. | 4 – 8 years (dependent on vendor support expiry) |

This hardware refresh program is needed in order to maintain the reliability of IT assets. Dependable IT assets enable Enersource employees to effectively complete their daily tasks by reducing downtime and lost productivity. Where applicable, Enersource utilizes the approach of replacing all of its assets in a category at the same time rather than spreading the replacement cycle over multiple years. For example, all desktops are replaced at the same time in order to ensure asset standardization across the organization. A standardized desktop infrastructure forms the foundation for desktop optimization. It is by standardizing desktop hardware and software that organizations can ultimately advance toward a more flexible, agile, and optimized infrastructure.

Ad-hoc desktop purchases often driven by price or by departmental and end-user preferences can ultimately prove much more costly when a comprehensive view of desktop lifecycle costs is taken into account. While the cost of equipment and software remains relatively constant whether a company uses a staggered replacement cycle or a single enterprise-wide deployment, the maintenance costs associated with a staggered cycle can be considerably higher than a single-cycle approach. This is attributed to maintaining and supporting multiple inconsistent computing platforms, operating systems, applications and one-off configurations. For other hardware types (i.e., servers, data storage) the replacement cycle is determined based on the asset type, vendor support coverage, and acceptable performance of the hardware.

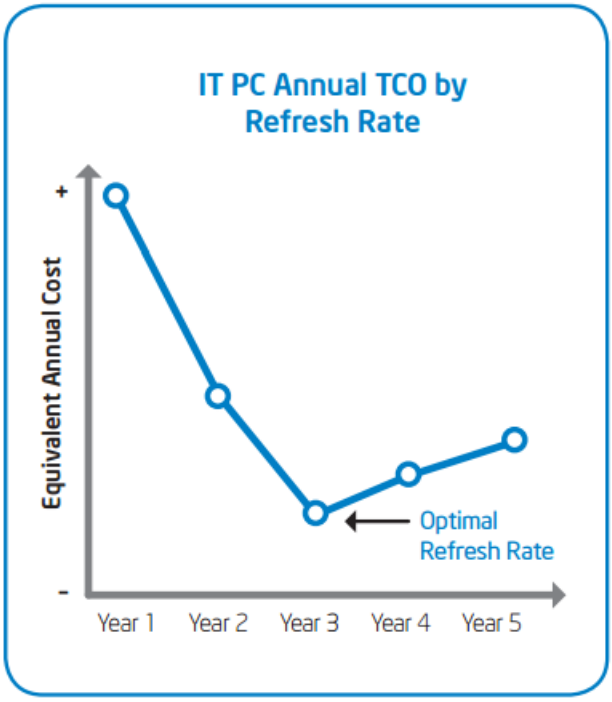



**Figure 83. Intel White Paper - PC Total Cost of Ownership by Refresh Rate**

#### 2.3.4.1.2 Software

Software renewal includes planned software upgrades and maintenance required to maintain vendors' support and reliable system operation. These upgrade projects are considered technical upgrades.

Projects in this software roadmap program typically include the following activities:

- Engage vendor(s) to provide upgrade assistance
- Upgrade underlying infrastructure
- Configure the application to ensure compatibility with underlying components
- Configure the application to meet existing business requirements
- Integrate with other utility IT systems, as needed
- Complete regression testing to ensure the upgrade is successful
- Train business users of the new features
- Deploy the new systems and release them to the business users.

Enersource's practice is to ensure that it has continuous vendor support during the asset life-cycle, particularly with back-end hardware (i.e., servers, switches) as well as all core corporate applications, such as engineering, finance, customer care and billing applications. Maintaining vendor support is a critical component of the asset plan for the following reasons:

- **Availability of replacement parts**: most hardware vendors commit to four to eight years of parts availability.
- **Security risks**: security fixes and vulnerability patches are often not available for older systems.
- **Cost Avoidance**: having an out-of-support asset could prove more costly since Enersource may have to procure specialized technical resources to maintain the outdated asset.

### *2.3.4.2 Mandatory-Regulation*

These are known future planned system changes related to regulatory initiatives. For example, on January 16, 2014, the OEB issued a Notice of Proposal to Amend a Code in which it proposed to require a distributor to install an interval meter (i.e., a 'MIST meter') on any installation that is forecast by the distributor to have a monthly average peak demand during a calendar year of over 50 kW. These accounts must bill as MIST by August 2020. This initiative requires system changes and implementation in order to accomplish the required results of billing customers with over 50 kW as MIST.

These mandatory initiatives are captured under the 'sustain existing systems' program because they are mandatory in order for Enersource to meet its regulatory obligations to the OEB.

### *2.3.4.3 Enhancement Initiatives Program*

The second component of Enersource's IT AMP is the 'Enhancement Initiatives' program which addresses future system enhancements that are driven to fulfill the benefits shown in Table 29.

**Table 29. Benefits of Enhancement Initiatives program**

| Category | Benefits |
|---|---|
| Customer Value | • Software enhancements provide process optimization and automation which allows Enersource to utilize its resources more efficiently, in turn, benefits customers/ratepayers<br>• Software enhancements allow Enersource to provide more positive customer-centric service because new enhancements often provide greater flexibility in providing customers with up-to-date data, among other things. |
| Operational Reliability | • Software issues could pose risks to the business, or cause inefficient use of resources due to the need for manual controls or workarounds<br>• Software enhancements help meet growing business needs while ensuring appropriate controls are in place<br>• Software enhancement provides necessary data to help Enersource make informed decisions using factual data analytics. |

Projects in this program utilize Enersource's standard investment prioritization and evaluation process.

**Table 30. Prioritization Drivers**

| Investment Drivers | Objective |
|---|---|
| Regulatory/Public Policy Responsiveness | Services are provided to address a regulatory requirement or mandate. This category includes IT roadmap projects as they are mandated in order to maintain vendor support. |
| Customer Focus | Services are provided in a manner that responds to an identified customer need or preference. |
| Operational Effectiveness | Continuous improvement in productivity and cost performance is achieved and delivers system reliability and quality objectives. |
| Financial Performance | Financial viability is maintained and savings from operational effectiveness are sustainable. |

Project prioritization process is followed to ensure that resources are utilized according to consistent investment drivers as outlined above. Projects in this program normally involve the following activities:

- Evaluation of business needs
- Assessment of available solution(s)
- Determine acceptable solution both from the business perspective and IT support perspective
- Engage vendor(s) to provide necessary assistance e.g., code development
- Configure the application to ensure compatibility with underlying components
- Configure the application to meet business requirements
- Integrate with other utility IT systems, as needed
- Complete testing of new functionality
- Complete regression testing of existing functionality
- Train business users of the new features and functionality
- Deploy the new systems and release them to business users.

When business applications are initially deployed, functionality is typically limited to the scope of the original business requirement. Subsequent application changes may result from:

- Change in business needs whether to address new requirement(s) or optimize an existing process
- Vendor release of service pack(s) to address open issues/defects
- Utilize new application functionality to maximize productivity, eliminate manual workarounds, or enhance user experience.

### 2.3.5 Facilities Remediation

Enersource has three main buildings used for business operations: the Corporate Office on Derry Road, Operations Centre on Mavis Road and a Disaster Recovery building on Glen Erin Drive. These buildings were constructed between 1963 and 2012.

The Derry Road building received substantial renovations in 2012 to ensure a healthy and productive work environment for the administration staff that was transferred to the facilility. Based on Building Conditions Assessments, the 23 year-old HVAC system will need to be replaced in the near future.

The BCM Operations Centre was constructed in 2012 and will not need any significant improvements over the DSP period.

The Mavis Road Operations Centre was constructed in three phases between 1963 to 1991. Generally, up to 2013, the Mavis facility received only minimal capital improvements during a period of busy growth years whereby Enersource was adding staff, to the point that a congested and unsafe work environment was created. With the move of the administration staff to the Derry Road facility in 2012, Enersource was able to start renovation projects to support the 'Mavis Facilities Plan' and to address issues raised in the Building Condition Assessment. Since then, a number of projects such as the men's locker/shower room, metering department work area, and the north tower office space have been completed. Additional projects over the next six years will address remaining projects from the Mavis Facilities Plan and the Building Condition Assessment.

Enersource building facilities must be reasonably current and in good working order. Based on regular assessments, all buildings require various investments to maintain them in a good state of repair, improve productivity, accommodate growth and change in the workforce, and address identified health and safety risks. As described above, the three facilities are of various ages.

The areas of concern for Enersource facilities that require expenditures are:

- HVAC (heating, ventilation and air conditioning)
- Structural (building envelope, walls and windows)
- Equipment (furniture, elevators)
- Mechanical and Electrical (i.e., plumbing, electrical components)
- Security (access control, CCTV, building automation system)
- Life Safety (fire suppression, sprinklers, fire alarm panels)
- Exterior (i.e., pavement, fencing, landscaping).

### 2.3.6 Fleet Replacement

Enersource requires a fleet of specialized vehicles to complete many daily activities, including the construction and maintenance of the electricity distribution system, and to allow for quick restoration of power due to electricity distribution system disturbances. Degradation of fleet assets could jeopardize worker safety and negatively affect electricity distribution system performance and response to outages.

To effectively manage fleet assets, Enersource has adopted a fleet strategy with the following goals:

- To provide safe, reliable, and efficient vehicles and equipment to meet the operational needs in consultation with the end user;
- Compliance with legislation and regulations;
- Compliance with accepted industry norms and practices;
- Cost effectiveness;
- Optimization of size of fleet - kept to minimum levels to ensure equipment is being fully used;
- Standardization of equipment specifications;
- Environmental considerations such as fuel economy, exhaust emissions;
- Disposal through reputable commercial vehicle and equipment resellers; and
- Implement computerized maintenance program to improve cost analysis and maintenance tracking.

To achieve the goals outlined above, Enersource maintains a multiple year capital plan. This plan is an essential tool for both short and long term budgeting and planning. This plan lists all the current vehicles and proposes the future replacement dates and costs, based on past experience and accepted industry standard vehicle lifecycles. Another long term goal of the fleet plan is to smoothly pace the annual capital expenditures to ensure the rate impact to customers is minimized.

Contributing to the proposed replacement date of individual vehicles are factors such as vehicle age, mileage, engine hours, operation costs, maintenance costs, and general mechanical condition of the vehicle. As vehicles approach their expected replacement date, individual assessments of each vehicle are performed to determine if vehicles may be retained longer, since they are in better than average condition, or need to be replaced earlier due to being in poorer condition.

Vehicles are not always replaced "like for like". Prior to replacement of a vehicle, an assessment of the current fleet needs is made with the applicable Enersource personnel to determine if an alternate vehicle type or size would be more beneficial.

The proposed replacement ages for each vehicle class are outlined below. Present replacement criteria are based on manufacturers' recommendations and repair history.

- Light vehicles are replaced after 3 - 5 years, or 170,000 km;
- Service trucks are replaced after 5 - 8 years or 200,000 km;
- Heavy equipment trucks are replaced after 8 – 12 years, or after 230,000 km; and
- Work equipment is replaced based on condition assessment.

As of June, 2015, Enersource has 190 vehicles and the distribution is as seen in **Figure 84** below.

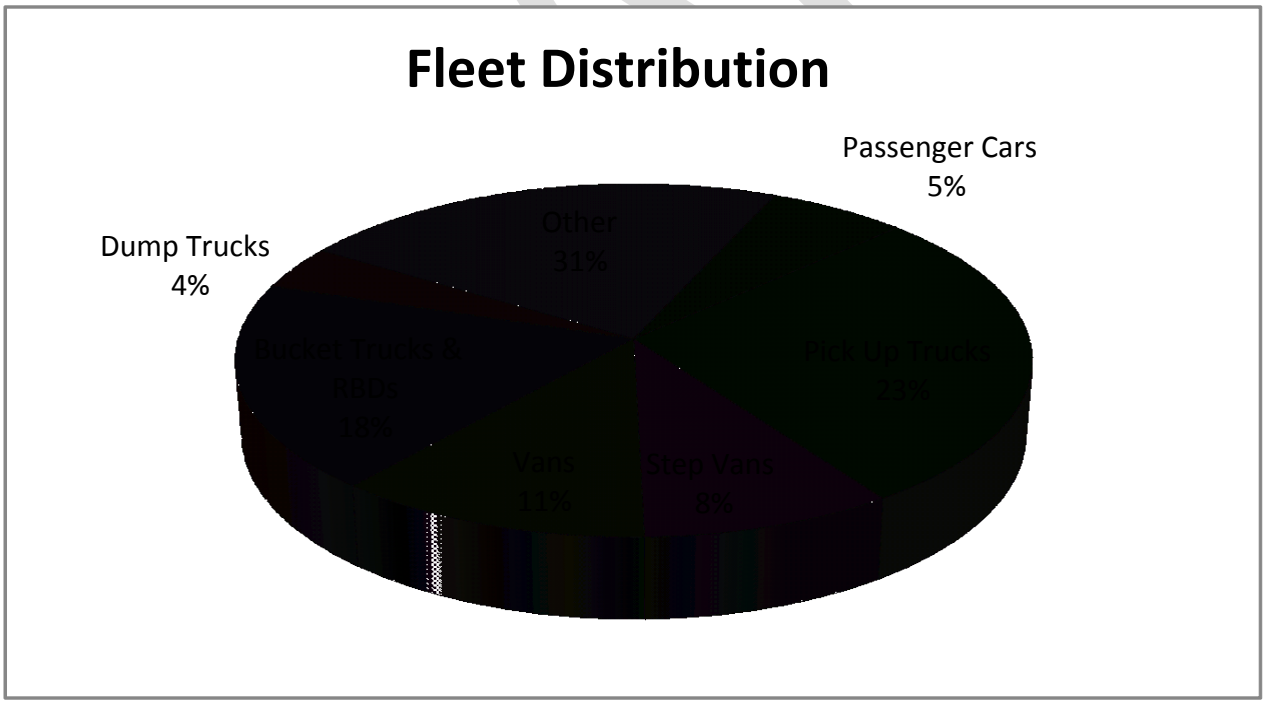



**Figure 84. Fleet distribution by type**

Additional capital may also be required to meet equipment requirements for staff growth, resulting from succession planning and work program increases.

Maintaining appropriate levels of capital spending on fleet will lead to:

- Reduced repair and maintenance costs;
- Decreased down time and increased fleet utilization;
- Safer equipment for personnel to operate;
- Reduced environmental impacts (alternative fuel considerations, compliance with new diesel standards); and
- Increased service equipment diagnostics.

DRAFT

## 2.4 Asset Lifecycle Risk Management

Enersource currently evaluates its business plan and investment projects and programs against the following significant business values:

- Regulatory/Public Policy Responsiveness
- Operational Effectiveness/Safety
- Customer Focus
- Financial Performance.

The risks associated with the business values are assessed as follows:

**Regulatory/Public Policy Responsiveness** - Does Enersource remain fully compliant in all legal and regulatory aspects of its operations? Will increased activity in embedded generation, future micro grids and electric cars have an impact on the service offering to customers?

**Operational Effectiveness/Safety** - Is Enersource's distribution system designed, constructed and maintained with safety in mind, for both Enersource employees and the public? Are critical assets maintained properly and replaced prior to their expected end-of-useful life? Is there sufficient staff that are trained and developed to have sustainabe operations?

**Customer Focus** – What is the impact of asset failure to customers? Do the projects and programs sustain or deliver more reliable power to customers? Will there be stranded assets? Are Enersource's information systems secured? Are all stakeholders' and customers' preferences considered when projects and programs are prioritized?

**Financial Risks** - Is the condition of the existing assets evaluated to ensure they are repaired or replaced effectively to achieve the lowest long term owning costs? Is there sufficient cash flow available when required?

Each business value was then assigned a weighting based on the significance and probability as can be seen in **Table 31**.

**Table 31. Business value weighting.**

| Investment Driver / Business Value | Significance | Probability | Risk Score | Weighting |
|---|---|---|---|---|
| Regulatory/Public Policy Responsiveness | 5 | 3 | 4 | Mandatory Yes/No |
| Operational Effectiveness/Safety | 5 | 3 | 3.5 | 50% |
| Customer Focus | 4 | 2 | 3 | 30% |

| Investment Driver / Business Value | Significance | Probability | Risk Score | Weighting |
|---|---|---|---|---|
| Financial Performance | 3 | 2 | 2.5 | 20% |

Enersource then reviewed and assessed each of its asset classes against the business values. The process to evaluate asset classes was completed through an internal multi-disciplinary working group consisting of expert representatives from several departments and was led by the Asset Management Division with the assistance of Internal Audit & Enterprise Risk Division. Each asset class was evaluated based on the significance and the effect each class potentially would have on the business values listed above. Once the group completed the ranking for each asset class from 1-5, the ranking score was multiplied by the business value weighting. The following list of asset classes has been ranked from the highest to lowest based on the significance to Enersource's sustainability as an organization and can be seen in **Table 32**.

**Table 32. Significant asset classes**

| Asset Class | Estimated Useful Lives | Regulatory/Public Policy Responsiveness | Operational Effectiveness/Safety | Customer Focus | Financial Performance | Total |
|---|---|---|---|---|---|---|
| **Municipal Distribution Station Equipment** | 40 | 17% | 44% | 11% | 6% | 78% |
| **Major Software – Corporate/ Enterprise** | 10 | 17% | 33% | 15% | 12% | 77% |
| **Computer Equipment – Corporate/ Enterprise** | 10 | 17% | 33% | 12% | 12% | 74% |
| **SCADA / Protection and DC Systems** | 15 | 15% | 39% | 11% | 5% | 69% |
| **Wholesale Meters** | 25 | 21% | 19% | 9% | 7% | 57% |
| **Rolling Stock - Single Buckets, Dump trucks & Cranes** | 8 | 13% | 31% | 8% | 5% | 56% |
| **Rolling Stock - Double Buckets and RBDs** | 12 | 13% | 31% | 8% | 5% | 56% |

DRAFT

| Asset Class | Estimated Useful Lives | Regulatory/Public Policy Responsiveness | Operational Effectiveness/Safety | Customer Focus | Financial Performance | Total |
|---|---|---|---|---|---|---|
| **Air Insulated switchgear** | 25 | 4% | 30% | 8% | 5% | 46% |
| **Building & Fixtures – Other Construction** | 20 | 15% | 23% | 6% | 2% | 46% |
| **UG Cable System** | 40 | 8% | 24% | 8% | 5% | 45% |
| **Pad mounted Transformer** | 35 | 8% | 26% | 8% | 2% | 44% |
| **OH Wood Pole System** | 45 | 6% | 27% | 8% | 2% | 43% |
| **OH Concrete Pole System** | 55 | 4% | 28% | 8% | 2% | 43% |
| **Major Tools** | 10 | 11% | 28% | 3% | 1% | 43% |
| **Rolling Stock - Pick-up Trucks and Vans** | 5 | 11% | 22% | 6% | 2% | 42% |
| **Building & Fixtures – Brick, Stone, Concrete & Steel** | 60 | 6% | 23% | 6% | 5% | 40% |
| **OH Transformer System** | 45 | 8% | 23% | 5% | 1% | 38% |
| **Land** | N/A | 15% | 11% | 8% | 2% | 36% |
| **Meters** | 25 | 11% | 12% | 9% | 2% | 34% |
| **Solid Dielectric Switchgear** | 35 | 4% | 16% | 8% | 5% | 32% |
| **Rolling Stock - Trailers & Off Road Equipment** | 15 | 11% | 14% | 6% | 1% | 32% |
| **Easements** | N/A | 11% | 11% | 8% | 2% | 32% |
| **Rolling Stock - Automobiles** | 4 | 11% | 12% | 6% | 1% | 29% |
| **SCADAmate / Reclosures** | 25 | 4% | 15% | 6% | 2% | 27% |
| **Smart Meters** | 15 | 11% | 8% | 6% | 1% | 26% |
| **Overhead Switches/Fuses** | 40 | 2% | 18% | 3% | 1% | 24% |

DRAFT

| Asset Class | Estimated Useful Lives | Regulatory/Public Policy Responsiveness | Operational Effectiveness/Safety | Customer Focus | Financial Performance | Total |
|---|---|---|---|---|---|---|
| **Comp Equip – Networking and Printing** | 5 | 6% | 7% | 6% | 1% | 21% |
| **System Software - Office Automation & Collaboration** | 5 | 6% | 7% | 6% | 1% | 21% |
| **Minor Software** | 2 | 6% | 7% | 6% | 1% | 21% |
| **Underground Accessories** | 20 | 2% | 10% | 6% | 1% | 20% |
| **General Equipment** | 10 | 4% | 12% | 2% | 1% | 19% |
| **Overhead Fault Indicators** | 10 | 2% | 7% | 6% | 1% | 17% |
| **Duct, Foundations** | 50 | 2% | 7% | 2% | 4% | 14% |
| **Computer Equipment – Desktop or Laptops and Security Infrastructure** | 3 | 2% | 5% | 2% | 0% | 9% |

DRAFT

# 3. Capital Expenditure Plan (OEB Chapter 5.4)

## 3.1 Summary (OEB Chapter 5.4.1)

### 3.1.1 Load Connection Capability

Enersource services an urban territory with limited area for greenfield development. The growth in its service area is largely driven by the redevelopment and re-intensification of existing and previously developed areas. In 2014, Enersource prepared a long term load forecast report as part of its Regional Planning collaborative effort with HONI, IESO, and neighbouring utilities. Enersource's capacity and ability to connect new customers is summarized by the operating areas listed below.

To better understand asset capacity utilization and constrained areas, Enersource has developed a long term peak demand projection for each of the four areas of the distribution power system outlined in subsequent sections. Enersouce takes into account ongoing and future CDM programs and their effect on short and long term demand projections.

The City went through a very aggressive expansion period spanning the mid 1980's to the mid 2000's. Over the last 15 years, Mississauga has effectively transitioned from a rapidly growing suburban community to a mature urban community with an emphasis on intensification, redevelopment, and transit. Enersource's rate of expansion has slowed relative to the past peak periods, and the available green space for further development has been significantly reduced. Currently, the City is under-going a post-greenfield phase. Population growth will be accommodated through intensification and redevelopment within existing built-up areas and Mississauga will continue to focus on higher density housing forms, particularly apartment and condominium development in the Downtown Core, infill projects in major community nodes, and through redevelopment along planned intensification corridors.

#### North 16/27.6kV System

In the North 16/27.6kV system, residential, industrial, and commercial development is still occurring and this trend is expected to continue in the near term. This portion of the system is nearing transformation capacity to adequately serve its customers. Through the Needs Screening process initiated by HONI and the IESO (formerly OPA), it was identified that a peak load on Erindale TS T1/T2 has reached normal supply capacity and will require further assessment. In the near future, Enersource will require additional capacity to service the North 16/27.6kV system; these new capacity needs are being addressed under System Service investment category. Historical actual and forecasted peak demand for this area is shown below in **Figure 85** North 16/27.6kV Distribution.

DRAFT

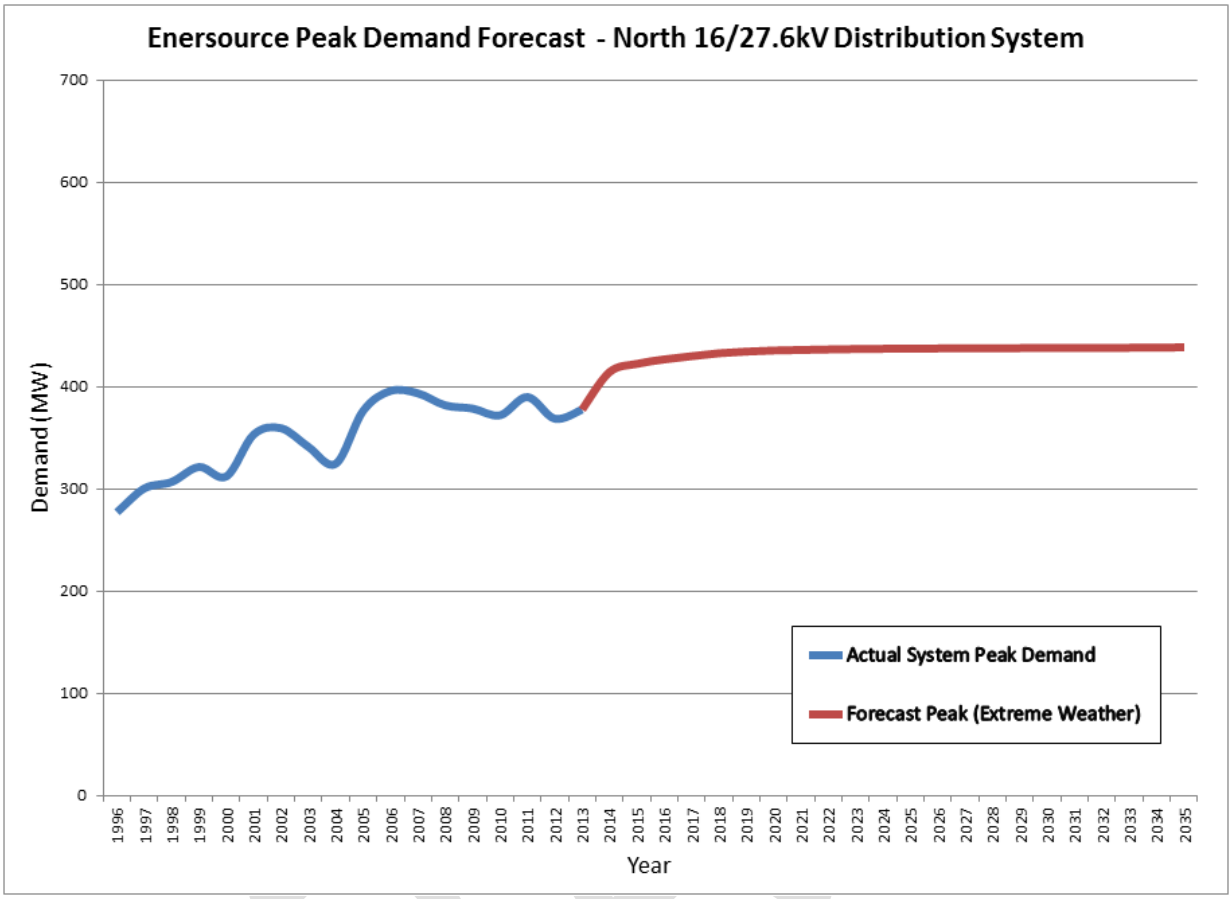



**Figure 85. Enersource Peak Demand Forecast - North 16/27.6kV Distribution System – Extreme Weather Scenario (1996-2035)**

## South 16/17.6kV and 2.4/4.16kV Distribution

In the South 16/27.6kV region, redevelopment growth is projected through a number of new condominiums, industrial/commercial developments and at the water and wastewater pumping stations. The Lakeview, Clarkson, Herridge, and Lorne Park pumping stations continue to slowly expand and increase their load as more pumps and water mains are added. Historical actual and forecasted peak demand for this area is shown below in **Figure 86** South 16/27.6kV Distribution.

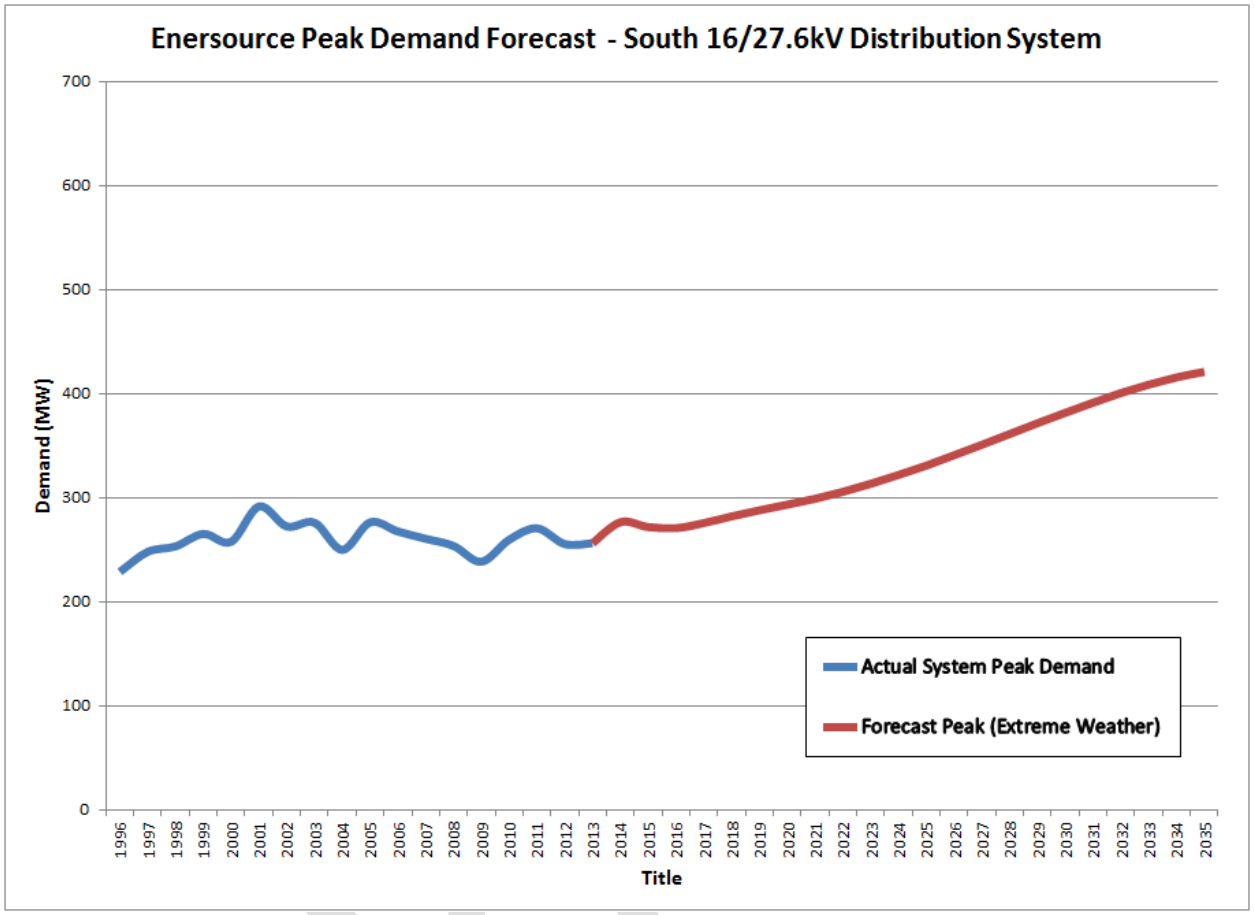



**Figure 86. Enersource Peak Demand Forecast - South 16/27.6kV Distribution System – Extreme Weather Scenario (1996-2035)**

### West 44kV Subtransmission and 8/13.8kV Distribution

The West 44kV system continues to serve predominantly condominium, residential and industrial/commercial loads. This part of the system will be further loaded by significant new condominium loads that are planned and under construction in the City Centre, along Eglinton Avenue in the west end of the city, and in new industrial/commercial loads in the Meadowvale area. Historical actual and forecasted peak demand for this area is shown below in **Figure 87** West 44kV Subtransmission and 8/13.8kV Distribution Load Growth.

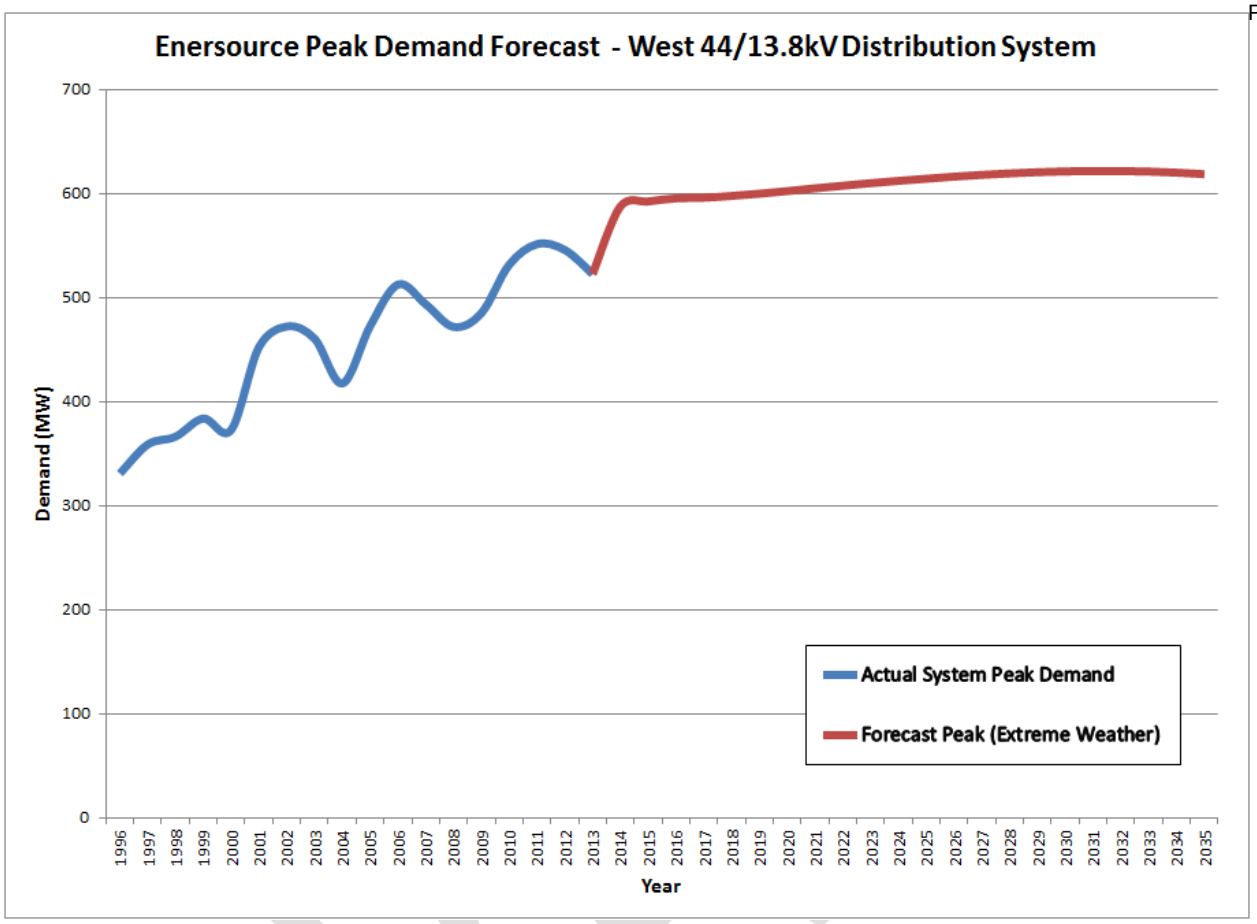



**Figure 87. Enersource Peak Demand Forecast - West 44/13.8kV Distribution System – Extreme Temperature Scenario (1996-2035)**

## East 44kV Subtransmission and 8/13.8kV Distribution

The East 44kV system continues to serve predominantly industrial/commercial loads. This part of the system is projected to experience moderate near term growth through additional new commercial and industrial loads from existing service upgrades and new customers. Historical actual and forecasted peak demand for this area is shown below in **Figure 88** East 44kV Subtransmission and 8/13.8kV Distribution Load Growth.

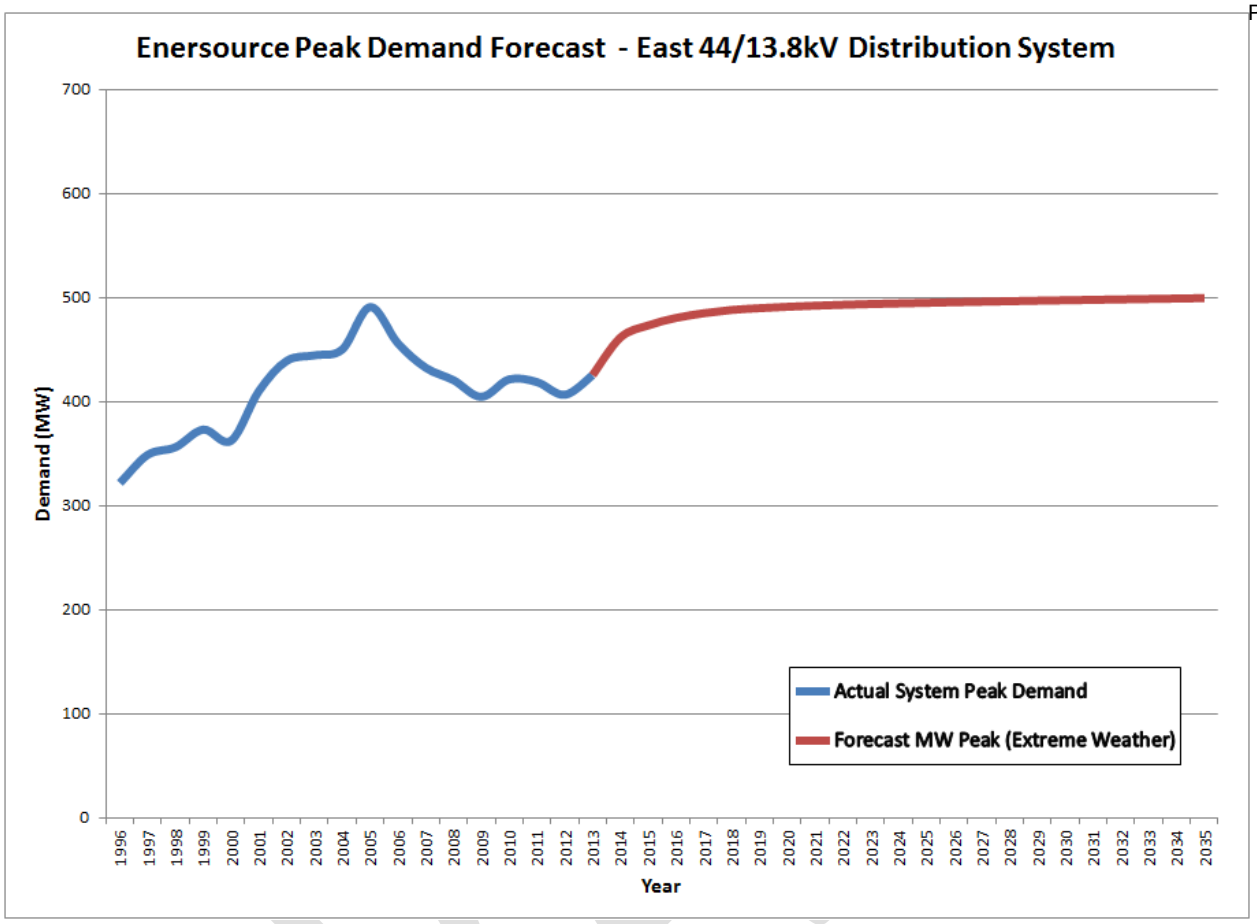



**Figure 88. Enersource Peak Demand Forecast - East 44/13.8kV Distribution System – Extreme weather scenario (1996-2035)**

## Downtown 21

Downtown 21 is the master plan for Mississauga's City Centre aimed at creating a more vibrant and transit-oriented urban centre. The City Council approved a new planning framework for the downtown that aims to transform Mississauga from suburban to an urban centre. As shown in **Figure 89**, some of the major Downtown 21 initiatives are as follows:

- Development of Main Street
- Extension of East-West Streets
- Expansion of Square One Shopping Mall
- Burnhamthorpe Road Project.

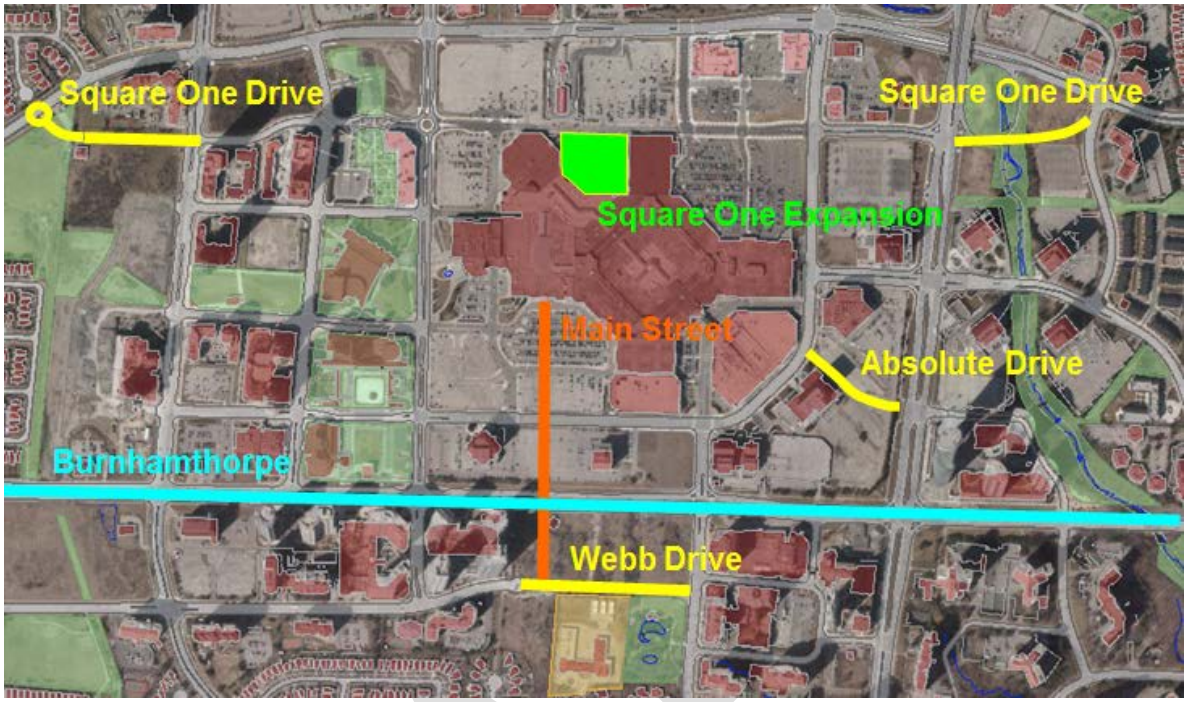



**Figure 89. Downtown 21 Initiatives**

In addition, the Downtown 21 master plan will focus on building office building infrastructure in hopes to make downtown the major urban destination for future office, employment and creative economic growth in Mississauga. Existing and future residential and commercial buildings envisioned in the Downtown 21 framework are shown in **Figure 90**.

The current electrical supply in downtown Mississauga will be inadequate to meet the future proposed infrastructure needs that are planned in the Downtown 21 master plan and thus, Enersource will need to make major investments such as:

- Installing new subtransmission circuits
- Building new substations and increasing capacity at existing substations
- Installing new distribution feeders and reconfiguring existing feeders.

To accommodate future growth in the Downtown Core, Enersource is proposing transformational capacity be added as discussed in Section 2.3.3. Expansion Programs.

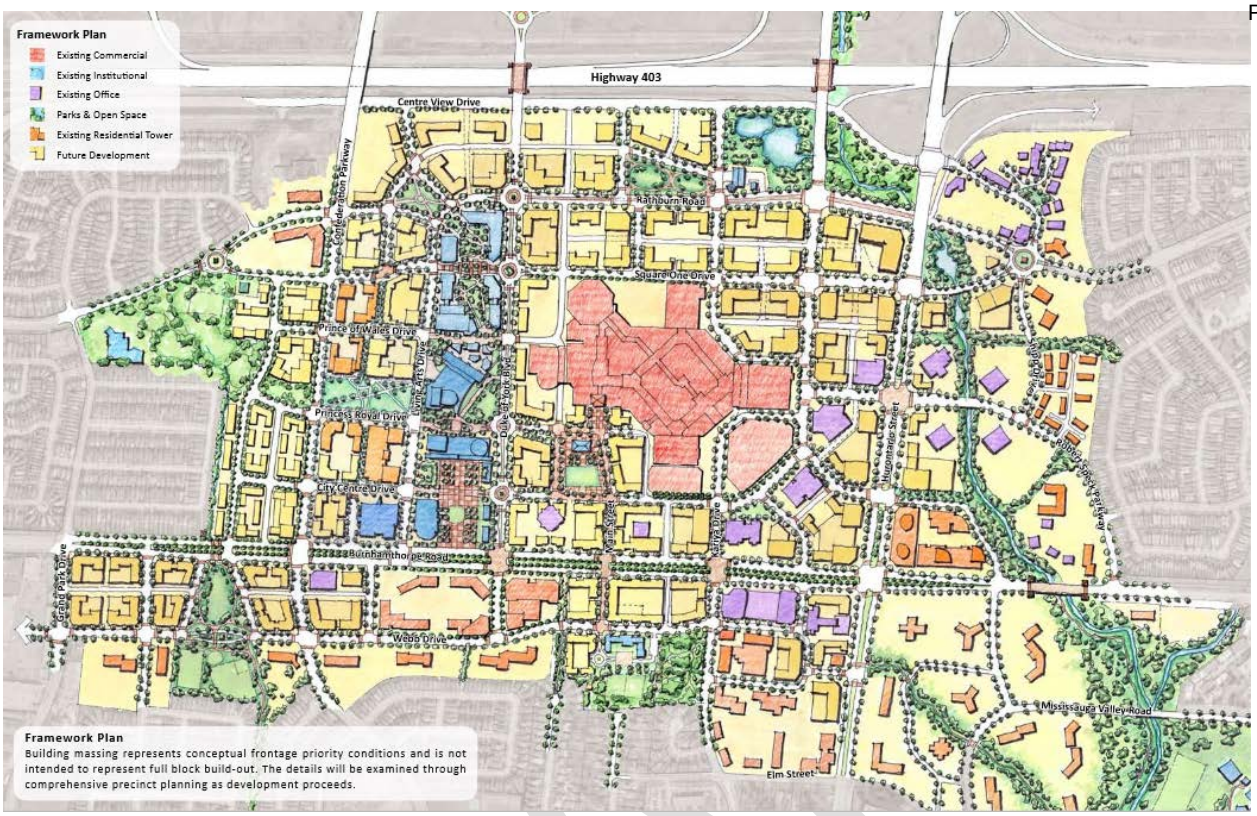



**Figure 90. Downtown 21 Framework Plan**

## Lakeview Revitalization

The Lakeview revitalization is a joint effort by the City, Province of Ontario, and Ontario Power Generation. This major initiative envisions the development of a cultural hub, housing developments and employment corridor on the grounds of the old Lakeview Generating Station in the southeast part of Mississauga. As outlined in the Lakeview Master Plan, this initiative is expected to develop 8,000 housing units, result in 15,000 to 20,000 new residents, and bring 7,000 to 9,000 new jobs to the area. The proposed land use layout is shown in **Figure 91**.




**Figure 91. Lakeview Master Site Plan.**

This DSP time period does not include significant expenditures relating to the Lakeview Master Site Plan.

### Lakeshore Road/Port Credit Re-Intensification

Both sides of Lakeshore Road between Hurontario Street and Stavebank Road are characterized by low rise apartment buildings and mixed use commercial offices and restaurants. In the coming years, this area is expected to go through a major revitalization that will see its low rise buildings turned into mid-rise apartment buildings. The current 4.16kV distribution network is inadequate to supply projected demand, and Enersource is currently considering replacing its aging 4.16kV distribution network with 27.6kV to accommodate the future growth.

The DSP does not include significant expenditures relating to the Lakeshore Road Re-Intensification at this time except for the rebuilding of an overhead line on Park Street, west of Hurontario Street.

## Hurontario Light Rail Transit (LRT)

Light Rail Transit (LRT) is a transportation system being developed by the Province of Ontario to connect Mississauga's Port Credit neighbourhood and Brampton. The LRT project supports Mississauga's vision of becoming a vibrant and modern urban centre and ensures the long-term urban intensification of downtown Mississauga. With the development of LRT infrastructure, all of the Downtown Core will be within a five-minute walk of a transit station. Accordingly, five transit stations are proposed within the Downtown Core that will require installation or relocation of electricity distribution infrastructure. The current proposed scope of the LRT system is shown in **Figure 92**. With the development of the LRT system, Enersource will have to ensure that new distribution infrastructure is built and that the reconfiguration of the existing distribution network is carried out in order to ensure adequate supply to the Downtown Core. The new transit line would serve Mississauga along the Hurontario corridor, running between Port Credit and Steeles Ave., and connecting with existing transit routes in the GTA.

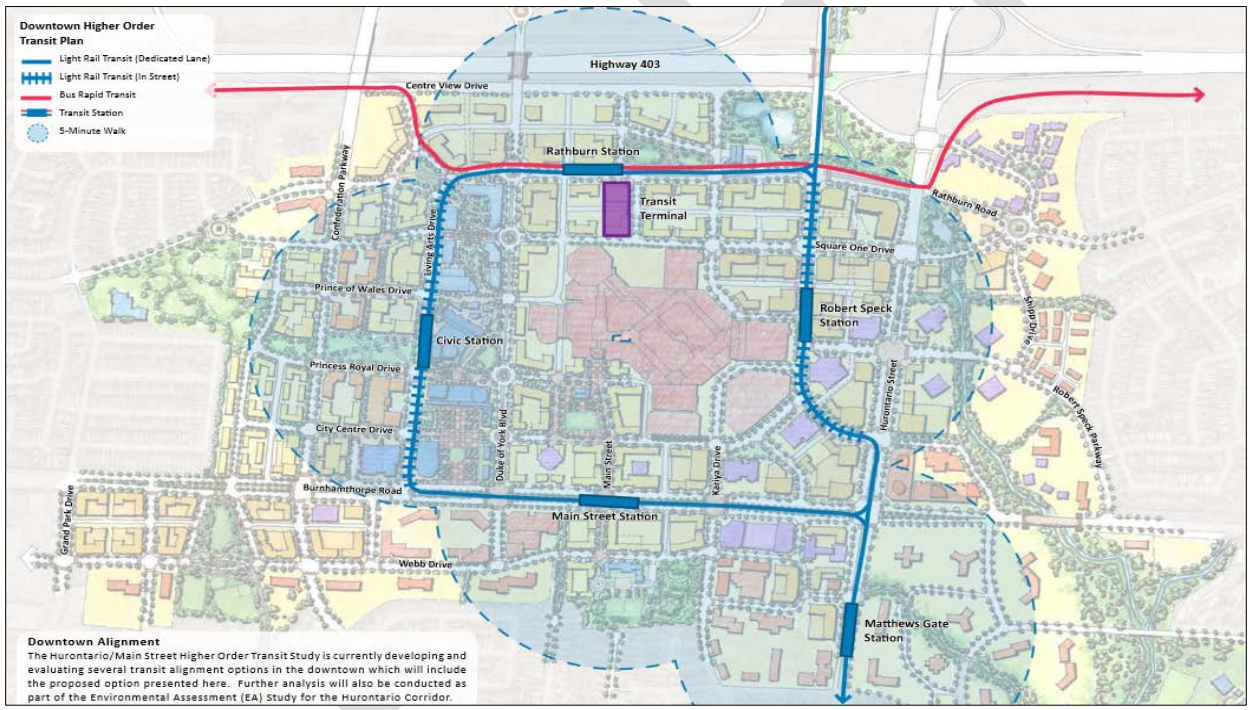



**Figure 92. LRT Plan**

In April 2015, the Province of Ontario announced that the LRT project will move ahead in support of the Moving Ontario Forward plan aimed at increasing transit ridership, reducing travel times, managing congestion, connecting people to jobs, and improving the economy. Currently, the construction of the LRT is expected to start in 2018 and the in-service date is expected in 2022. Consequently, Enersource has made provisions in its capital budgets under System Access investment category to ensure adequate

funds are available to conduct the work required to accommodate construction of the LRT (e.g., relocation of overhead assets).

### 3.1.2 Total Annual Capital Expenditures by Category

**Tables 33-34** and **Figure 93** below summarize the historical and proposed investments that were and will be required to ensure that Enersource is able to provide a safe, secure and reliable supply of electricity, meet system load growth demands, and complete all regulatory driven initiatives.

**Table 33. Historical expenditures by investment category (2011-2015) ($000's)**

| Description | 2011 | 2012 | 2013 | 2014 | 2015 |
|---|---|---|---|---|---|
| System Service | 11,858 | 9,860 | 10,712 | 11,228 | 16,497 |
| System Renewal | 11,422 | 16,224 | 20,887 | 31,257 | 36,058 |
| System Access | 14,326 | 11,493 | 10,055 | 9,474 | 16,452 |
| General Plant | 9,052 | 29,220 | 6,831 | 6,230 | 10,682 |
| Churchill Meadows CCRA payment | - | - | - | - | 40,479 |
| **Total** | **46,657** | **66,798** | **48,485** | **58,189** | **120,168** |

**Table 34. Projected Expenditures by Investment Category (2016-2021) ($000's)**

| Description | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 |
|---|---|---|---|---|---|---|
| System Service | 17,200 | 13,015 | 13,130 | 12,825 | 13,105 | 13,490 |
| System Renewal | 34,735 | 37,243 | 38,240 | 40,280 | 38,570 | 38,490 |
| System Access | 12,408 | 17,916 | 18,123 | 18,162 | 17,238 | 10,568 |
| General Plant | 12,796 | 11,337 | 10,281 | 10,794 | 10,755 | 9,984 |
| **Total** | **77,139** | **79,511** | **79,773** | **82,061** | **79,668** | **72,532** |

DRAFT

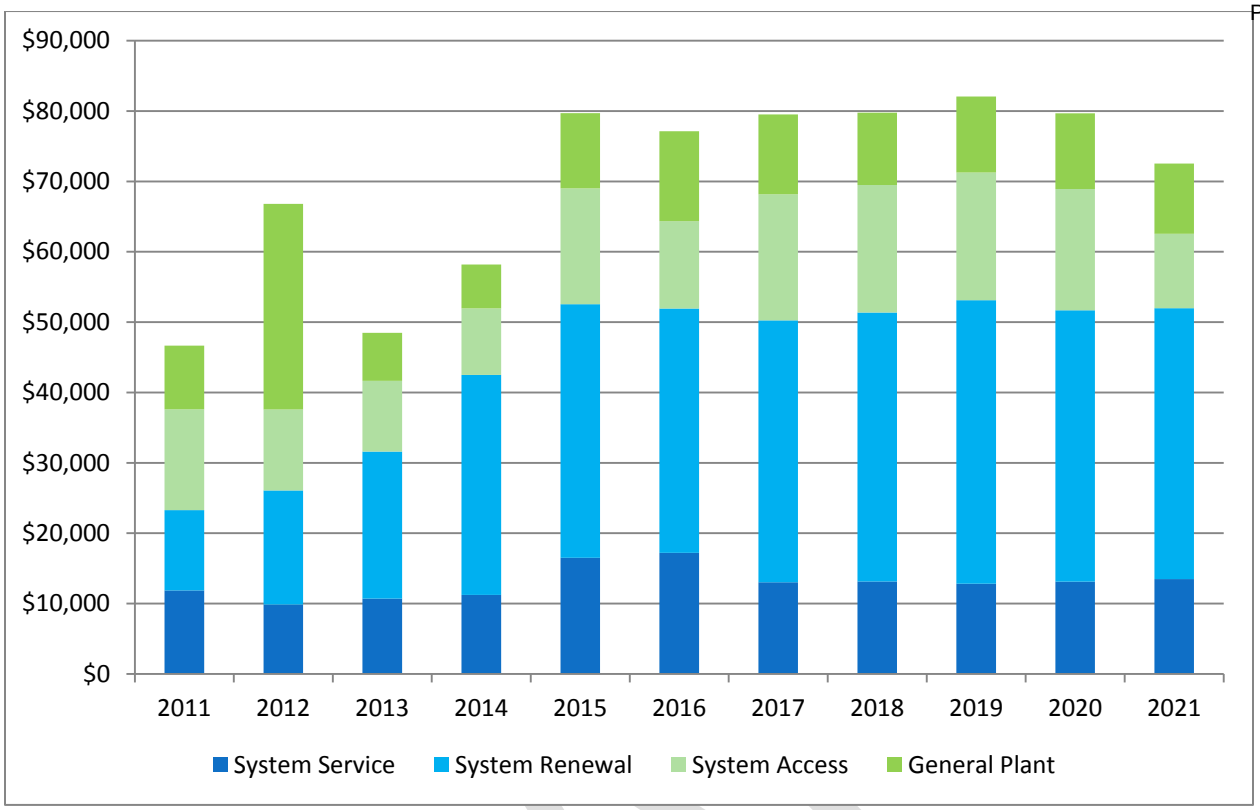



**Figure 93. Enersource's Investment Portfolio (2011-2021)**

### 3.1.3 Capital Expenditures Description by Category

This section provides a brief description of capital expenditures within each OEB prescribed category and how such investments are driven by Enersource's asset management process. The justification for the overall scope and level of investment for the capital expenditures in each of the categories listed below is provided in Section 3.5: Justification of Capital Expenditures.

#### Budgets

#### System Access

The System Access investment program proposed investments from 2016 through 2021 are shown in **Table 35**.

**Table 35. System Access Expenditures by Capital Program (2016-2021) ($000's)**

| Description | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 |
|---|---|---|---|---|---|---|
| Road Projects | 3,000 | 3,000 | 3,000 | 3,000 | 3,000 | 3,000 |
| Light Rail Transit | 400 | 8,400 | 8,650 | 8,750 | 7,800 | 1,200 |
| New Subdivisions | 800 | 800 | 800 | 800 | 800 | 800 |

| Description | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 |
|---|---|---|---|---|---|---|
| Industrial & Commercial Services | 2,600 | 2,600 | 2,600 | 2,600 | 2,600 | 2,600 |
| Residential Service Upgrades | 125 | 125 | 125 | 125 | 125 | 125 |
| Smart Metering Large Commercial | 1,506 | - | - | - | - | - |
| Wholesale Metering | 1,263 | 33 | 43 | 35 | 65 | 10 |
| Metering Equipment | 1,172 | 1,427 | 1,384 | 1,337 | 1,337 | 1,337 |
| Smart Metering | - | - | - | - | - | - |
| Smart Metering in New Condos | 1,387 | 1,407 | 1,426 | 1,446 | 1,446 | 1,446 |
| Green Energy - FIT/MicroFIT | 155 | 125 | 95 | 70 | 65 | 50 |
| **Total** | **12,408** | **17,916** | **18,123** | **18,162** | **17,238** | **10,568** |

System Access initiatives are investments required to meet customer service obligations in accordance with the OEB'S DSC and Enersource's Conditions of Service. System Access projects include the following:

- Connecting new customers
- Building new subdivisions
- Road authority projects (e.g., relocating system plant for roadway reconstruction projects).

Enersource uses an economic evaluation methodology prescribed in the DSC to determine the level of capital contributions for each project, which is to be included in the annual capital budgets. Due to the mandatory nature of System Access projects, these investments cannot be deferred and must proceed as planned to ensure Enersource's compliance with the DSC and its Conditions of Service.

### System Renewal

The System Renewal Investment program historical and proposed investments from 2016 through 2021 are shown in **Table 36**.

**Table 36. System Renewal expenditures by Capital Program (2016-2021) ($000's)**

| Description | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 |
|---|---|---|---|---|---|---|
| Subdivision Renewal Program | 13,250 | 15,750 | 16,800 | 18,000 | 18,000 | 18,000 |
| Overhead Distribution Renewal and Sustainment | 6,090 | 6,360 | 6,270 | 6,810 | 6,450 | 7,620 |
| Subtransmission Renewal | 4,200 | 3,000 | 2,850 | 3,150 | 3,300 | 4,050 |
| Transformer Replacement | 7,125 | 7,313 | 7,500 | 7,500 | 6,000 | 4,000 |

| Description | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 |
|---|---|---|---|---|---|---|
| Underground Distribution Renewal and Sustainment | 3,750 | 4,500 | 4,500 | 4,500 | 4,500 | 4,500 |
| Emergency Replacement Program | 320 | 320 | 320 | 320 | 320 | 320 |
| **Total** | **34,735** | **37,243** | **38,240** | **40,280** | **38,570** | **38,490** |

System Renewal investments are driven by long term plans to replace assets that are near or at the end of their useful lives. The Asset Management Planning Process is the main driver for determining proposed projects and expenditures within the System Renewal category. System Renewal strategies are prioritized based on condition of assets, age, as well as the impact on system reliability. In particular, the Kinectrics' Asset Condition Assessment (ACA) and replacement recommendations were used as the basis for determining the investment requirements for System Renewal. The level of spending within System Renewal is driven by the assessment of project criticality, asset condition, reliability, and safety.

### Asset Condition Assessment Investment Requirements

**Table 37** below illustrates the forecasted number of assets flagged for replacement. This forecast and the asset health index distribution were the key outputs of the ACA process carried out by Kinectrics. The timing of replacements, as identified by Kinectrics, represents the optimum timing for asset renewal. As such, the year one values are substantially higher than subsequent years due to the high percentage of Enersource's distribution system with a health index of either 'very poor' or 'poor' and recommended for immediate replacement.

**Table 37. Condition-based replacement schedule by asset category**

| Years from Now | Asset Category | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Substation Transformers | | Circuit Breakers | Pole Mounted Transformers | Pad Mounted Transformers | | Vault Transformers | Pad Mounted Switchgear | Overhead Switches | | | | Underground Cables *Note that results are given in terms of conductor-km | | Poles | |
| | In Service | Spares | | | 1 Phase | 3 Phase | | | 44 kV | 27.6 kV | Inline | Motorized | Main Feeder | Distribution | Wood | Concrete |
| 0 | 3 | N/A | 10 | 58 | 177 | 6 | 89 | 31 | 1 | 0 | 32 | 5 | 254 | 799 | 1021 | 3 |
| 1 | 0 | N/A | 0 | 49 | 161 | 7 | 67 | 16 | 2 | 0 | 29 | 3 | 91 | 259 | 709 | 5 |
| 2 | 0 | N/A | 0 | 40 | 148 | 7 | 62 | 11 | 2 | 0 | 26 | 3 | 59 | 159 | 499 | 5 |
| 3 | 0 | N/A | 0 | 35 | 139 | 7 | 58 | 9 | 2 | 0 | 26 | 2 | 51 | 126 | 372 | 8 |
| 4 | 1 | N/A | 0 | 33 | 126 | 7 | 55 | 6 | 2 | 0 | 29 | 2 | 46 | 101 | 297 | 10 |
| 5 | 0 | N/A | 0 | 34 | 124 | 8 | 53 | 8 | 1 | 1 | 27 | 3 | 41 | 82 | 256 | 13 |
| 6 | 1 | N/A | 0 | 36 | 126 | 8 | 50 | 7 | 1 | 0 | 28 | 1 | 37 | 70 | 235 | 15 |
| 7 | 1 | N/A | 0 | 39 | 136 | 6 | 46 | 6 | 2 | 2 | 27 | 2 | 34 | 62 | 234 | 14 |
| 8 | 0 | N/A | 0 | 40 | 141 | 6 | 43 | 10 | 1 | 0 | 26 | 1 | 33 | 59 | 238 | 19 |
| 9 | 0 | N/A | 0 | 42 | 151 | 9 | 40 | 12 | 3 | 2 | 26 | 2 | 32 | 58 | 240 | 24 |

### System Service

System Service investments are required to support the expansion, operation, and reliability of the distribution system. These types of investments are primarily identified through Enersource's planning process. For example, although overall load growth in Enersource's service territory is expected to stay fairly low during the forecasted period, there are specific areas within the service territory that require capacity investments to accommodate growth.

The reliability driven investment program proposed investments from 2016 through 2021 are shown in **Table 38**.

**Table 38. System Service expenditures by Capital Program (2016-2021) ($000's)**

| Description | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 |
|---|---|---|---|---|---|---|
| Municipal Substation Construction & Upgrades | 11,600 | 8,200 | 8,000 | 7,800 | 7,650 | 7,900 |
| Subtransmission Expansion | 2,400 | 2,650 | 2,400 | 2,400 | 2,400 | 2,400 |
| Automation / SCADA Replacement and Enhancement Program | 3,200 | 2,165 | 2,730 | 2,625 | 3,055 | 3,190 |
| **Total** | **17,200** | **13,015** | **13,130** | **12,825** | **13,105** | **13,490** |

### General Plant

The General Plant investment program proposed investments from 2016 through 2021 are shown in **Table 39**.

**Table 39. General Plant Expenditures by Capital Program (2016-2021) ($000's)**

| Description | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 |
|---|---|---|---|---|---|---|
| Engineering & Asset Systems | 1,510 | 1,187 | 1,391 | 1,228 | 1,345 | 1,293 |
| Rolling Stock | 2,775 | 2,244 | 2,033 | 3,011 | 2,298 | 1,946 |
| Information Technology | 671 | 456 | 572 | 1,040 | 870 | 560 |
| JDE/ERP System | 2,185 | 2,000 | 1,180 | 1,320 | 1,637 | 1,410 |
| Meter to Cash | 2,470 | 2,055 | 2,180 | 1,420 | 1,830 | 2,000 |
| Grounds & Buildings | 2,985 | 3,195 | 2,725 | 2,575 | 2,575 | 2,575 |
| Major Tools | 200 | 200 | 200 | 200 | 200 | 200 |
| **Total** | **12,796** | **11,337** | **10,281** | **10,794** | **10,755** | **9,984** |

DRAFT

### 3.1.4 Regional Planning Process or Regional Infrastructure Plan Impact

The Regional Planning carried out with HONI has confirmed the capacity overloading at Erindale TS T1/T2 during summer peak. Thus, Enersource has made a provision in its capital plan to build a 40 MVA substation that will be fed from Churchill Meadows TS (44kV system) and provide transformational capacity to feed 27.6kV load currently supplied by Erindale TS T1/T2.

### 3.1.5 Customer Engagement Activities

Enersource has endeavoured to maintain a customer-centric approach to the DSP and capital planning pursuant to the RRFE and the OEB's filing requirements.

Enersource's day-to-day customer engagement opportunities have guided decision-making in the DSP and capital expenditure programs. Through the asset management process, Enersource addresses customer needs on a case-by-case basis and is responsive to customer preferences. This type of engagement, which has included key account meetings and discussions with customers following events such as storms and other unplanned outages, has historically allowed for efficient planning at both the macro and micro levels of the distribution system.

To ensure Enersource's DSP formally considers customer preferences, pursuant to the OEB's RRFE, Enersource engaged Decision Partners Inc., a third party consultant, to conduct broad, professional, and scientific research on customers' behaviour regarding the DSP. This work is now underway. The consultant is responsible for the following:

- Designing the customer consultation process in consultation with Enersource
- The collection of customer feedback
- The documentation of customer engagement results.

Enersource has worked with Decision Partners to design a multi-faceted customer engagement program that combines traditional consultation elements and qualitative and quantitative research elements. Consultation with customers is continuing, currently via a 'video dialogue', accompanied by an online survey at www.enersource.com/survey. Enersource will use the information gathered to ensure customer preferences are documented and included in proposed capital plans and the overall DSP.

### 3.1.6 System Development Expectations

This section describes how Enersource expects the distribution system to develop over the next six years, including in relation to load and customer growth, smart grid development, and the accommodation of future renewable energy generation projects.

## 3.2 Capital Expenditures Planning Process Overview (OEB Chapter 5.4.2)

### 3.2.1 Objectives

Enersource's capital expenditure planning objectives are as follows:

- To align with Enersource's corporate strategic objectives of Customer Focus, Operational Effectiveness, Public Policy Responsiveness, and Financial Performance;
- To optimize projects by ranking investment criteria and comparing project benefits;
- To ensure that investments are financially sound using the approved budget and required resources;
- To provide optimal customer service by assessing value and maintaining reliability at levels preferred by customers;
- To provide cost efficiency by considering timing of projects, resources, and contingency scenarios;
- To improve future investment decisions by analyzing historical investment trends; and
- To pace investment expenditures to minimize rate impact.

The capital planning process is undertaken annually as a component of Enersource's annual financial and business planning process which includes the development of detailed departmental business plans. Investment requirements and implementation plans to achieve identified objectives are included in the business plans. Objectives requiring significant (greater than $150,000) investment or requiring cross departmental resources are specifically identified and supported by a business case.

The capital and operational expenditure requests identified in the business plans are compiled and assessed against Enersource's capital planning objectives identified above. The quantity and timing of resources required to execute the prioritized list of projects are assessed for resource availability.

Enersource's asset management objectives focus on identifying asset needs and enhancing the distribution system, as well as capital planning objectives identified to maximize the outcome of the invested capital, based on the available budget.

Enersource also ensures that focus is placed on assessing and implementing customer distributed generation, including solar generation projects under the Feed-In-Tariff (FIT) or microFIT programs. Enersource works closely with generation customers regarding their connection proposals, ensuring that the equipment and design meets all required standards and regulations. Enersource will complete a connection impact assessment to verify that connection at the proposed location is viable and that the proposed generation will not negatively impact the grid.

### 3.2.2 Policies, Regional Planning and Non-Distribution System Alternatives

Enersource is currently involved in an Integrated Regional Resource Planning process (IRRP) as developed by the IESO and updated by the OEB. The IRRP process develops and analyzes forecasts of demand growth for a 20-year time frame, determines supply adequacy in accordance with the Ontario Resource and Transmission Assessment Criteria (ORTAC), and develops regionally integrated solutions to address identified needs. These include: conservation, demand management, distributed generation, large-scale generation, transmission, and distribution. Enersource continues to work with HONI and the IESO to develop optimal solutions to the transmission and bulk system needs within the Mississauga area.

### 3.2.3 Prioritization and Pacing of Investments

Enersource's forecasted investment plan is realistic and takes into consideration customer expectations and preferences, public policy responsiveness, and stakeholder requirements. Enersource prioritizes projects and programs based on a set of business values, and assessments are made regarding investment proposals which have the greatest impact on the business values. Due to resource constraints (e.g., funding, labour availability, information technology support) and other considerations such as the rate impact to customers, other stakeholders and environmental requirements, projects and programs are selected and prioritized based on supplemental quantitative and qualitative analysis.

One of Enersource's primary goals is to pace and prioritize capital investments in a manner that considers resource needs and rate impacts. To facilitate this goal, Enersource reviews and analyses programs and projects both qualitatively and quantitatively.

In the initial phase of the capital investment process, Enersource compiles developer/site plan submissions from the City and developers, and then assesses how the distribution system must be developed in order to meet the anticipated electrical demand. Enersource also seeks to determine from the City, the Region of Peel, and the Ministry of Transportation - Ontario (MTO) their respective road, water main, and wastewater projects anticipated for the next five to 10 years. These projects are considered mandatory and are included in System Service or System Access investment categories within this DSP.

In addition to including development plans, Enersource receives input from internal Subject Matter Experts (SMEs) in order to identify other risk areas and projects required to maintain the reliability and safety of the distribution system. Condition assessments are also used to assess future project requirements. Asset condition and environmental concerns are assessed, at which time urgent issues are noted. In some cases, simple maintenance tasks are not sufficient, prompting the need for a capital renewal project. In these situations a project is initiated, designed, planned and estimated to fix the problem(s).

Enersource systematically plans and evaluates its multi-year project portfolio and creates a prioritized list of projects that are used as the basis for the capital investment plan included in this DSP. The optimization of future programs and projects allows Enersource to invest in the appropriate areas of the distribution system and General Plant assets in order to mitigate risk and improve overall value.

As stated above, Enersource considers System Service and System Access investments mandatory. The programs and projects that fall under System Renewal involve replacing and/or refurbishing system assets to extend the original service life of the assets. Modifications fall under General Plant: for example, replacements or additions to Enersource's assets that are not part of its distribution system, including land and buildings, tools and equipment, rolling stock and electronics devices and software used to support day to day business and operations activities.

The pace of investment during the 2016-2021 period is driven mainly by System Renewal needs. The rationale and decision-making framework that ultimately yielded this proposed pacing are described in Section 2.1.1. At a high level, the long-term objective of Enersource's CAMP is to achieve an investment plan that is:

- **Risk based**: Incorporate risk management appropriately into decision-making strategy;
- **Sustainable**: Optimize asset life cycle value;
- **Multi-disciplinary**: Asset management accountability framework crosses departmental and discipline boundaries;
- **Integration Oriented**: View assets in their total relative value context;
- **Optimal**: Strike the right balance among competing objectives, such as short-term performance and reliability versus long-term planning and sustainability; and
- **Systematic:** Rigorously applied in a structured management system complete with a monitoring framework and evidentiary structures and tools.

An asset reaches its economic end-of-life when the annualized capital cost of replacing the asset becomes less than the annualized risk cost of continuing to operate the asset. Replacing the asset sooner than the optimal intervention time risks wasting its remaining useful life. Conversely, replacing the asset after the optimal intervention time risks incurring unnecessary and avoidable costs associated with asset failure. The objective of this risk-based approach is to minimize the total lifecycle or operational cost of the equipment in order to maximize the value derived from the assets. Enersource believes that by efficient and effective planning, it can renew a portion of its distribution system annually in order to help reduce customer outages, weather related failures, mitigate environmental concerns, while ensuring distribution rates that are just and reasonable and predicable.

The Company plans to significantly increase its System Renewal projects over this DSP timeframe. Enersource has met with potential third-party contractors that are committed to increasing their workforce over the next few years in order to meet the forecasted renewal project increases. To ensure Enersource's distribution system continues to remain safe and reliable, increased investments are required due to the age and condition of a significant portion of Enersource's overhead and underground system. Enersource has also seen a significant increase in operating and maintenance costs over the last few years, due to the condition of aged assets, and is committed to reversing this trend.

After considering the System Renewal investment increases and what is required for System Service (Substations – two for the Downtown Core and one to meet the 27.6kV load forecast) and System Access (LRT), Enersource reviewed its General Plant investment proposals submitted by the SMEs and re-prioritized many of the planned activities over the entire DSP period. By distributing the General Plant investments over the DSP time frame, Enersource was able to maintain a relatively stable year-to-year investment plan that ensured sufficient cash flows would be available, labour resources would not be overly committed, and customer rate changes would be predictable.

### 3.2.4 Details of the Mechanisms Used by the Distributor to Engage Customers

Please see sections 1.2.5 Customer Consultation and 3.1.6 Customer Engagement Activities.

### 3.2.5 Method and Criteria Used to Prioritize REG Investments

Enersource prioritizes Renewable Energy Generation (REG) investments based on customer requests and follows regulated timelines outlined in the OEB's DSC. Enersource works closely with customers, HONI, the IESO, and the ESA to integrate all proposed residential and commercial customer generation projects into the grid. As outlined in Section 3.3, numerous projects of varying generation capacity are proposed and connected to the distribution system every year.

The connection process for integrating the generation projects into the distribution system involves the following:

- Analyzing the generation capacity of the connecting feeder and interface transformer;
- Verifying that the relevant substation transformer can accept reverse flow;
- Ensuring that the short circuit changes and voltage fluctuations will cause no material impacts on either the distribution or transmission grid;
- Reviewing the proposed single line diagram, electrical protection scheme and site plan for adherence to all Enersource, ESA and IESO standards and requirements.

In instances where proposed generation connection is not possible, Enersource will work with the customer to provide an alternative solution. This solution may involve expanding the distribution system to meet customer needs or relocating the project to a property that meets all applicable connection requirements. Where work on the distribution system is required for the connection, the project is coordinated to ensure regulatory timelines are met while optimizing crew time.

DRAFT

## 3.3 System Capability Assessment for Renewable Energy Generation (OEB Chapter 5.4.3)

This section describes distributed energy generation (DEG) facilities (including renewable generation) in Enersource's distribution system.

Enersource currently has a number of DEG facilities connected to the grid. These facilities are mostly a part of the IESO-administered programs (FIT, microFIT, RESOP), net metering and load displacement. The Company has conducted numerous feasibility assessments for other kinds of projects that may be characterized as DEG facilities – battery energy storage, for example. **Figure 94** illustrates currently existing DEG facilities within Enersource service territory.

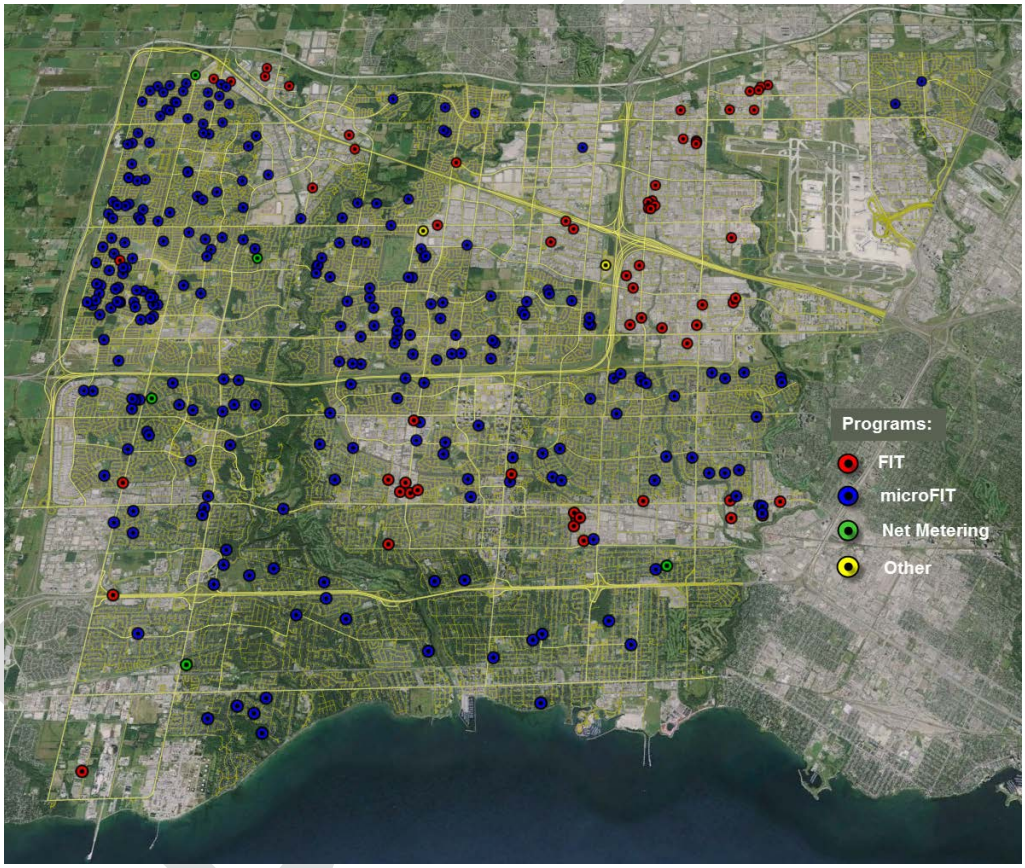



**Figure 94. Currently Connected DEG Facilities**

### 3.3.1 Applications from Renewable Generators

As of the end of June, 2015, Enersource has connected 67 small-sized projects with the cumulative capacity of 11.5 MW. Additionally, 47 projects with the cumulative capacity of over 8.6 MW have been approved and are currently in the process of being connected to the distribution system. A summary of DEG facility connections for the historical period 2008 to 2015 is outlined in **Table 40**.

**Table 40. Number of DEG Connections (as of the end of June, 2015)**

| | 2005 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 to date | Total |
|---|---|---|---|---|---|---|---|---|---|---|
| # of Micro connections | - | - | 4 | 28 | 35 | 57 | 64 | 41 | 49 | 278 |
| Micro connections (kW) | - | - | 4 | 149 | 226 | 346 | 420 | 326 | 472 | 1,943 |
| # of Small connections | - | 1 | 1 | - | 10 | 6 | 10 | 28 | 11 | 67 |
| Small connections (kW) | - | 25 | 50 | - | 1,725 | 1,185 | 2,350 | 5,027 | 1,130 | 11,492 |
| # of Medium connections | 1 | - | - | - | - | - | - | - | - | 1 |
| Medium connections (kW) | 5,625 | - | - | - | - | - | - | - | - | 5,625 |

*Note: DEG connections based on meter installation dates*

Of the 345 connected DEG facilities, only two are not powered by solar panels. **Figure 95** illustrates the generation capacity of DEG facilities broken down by fuel type.

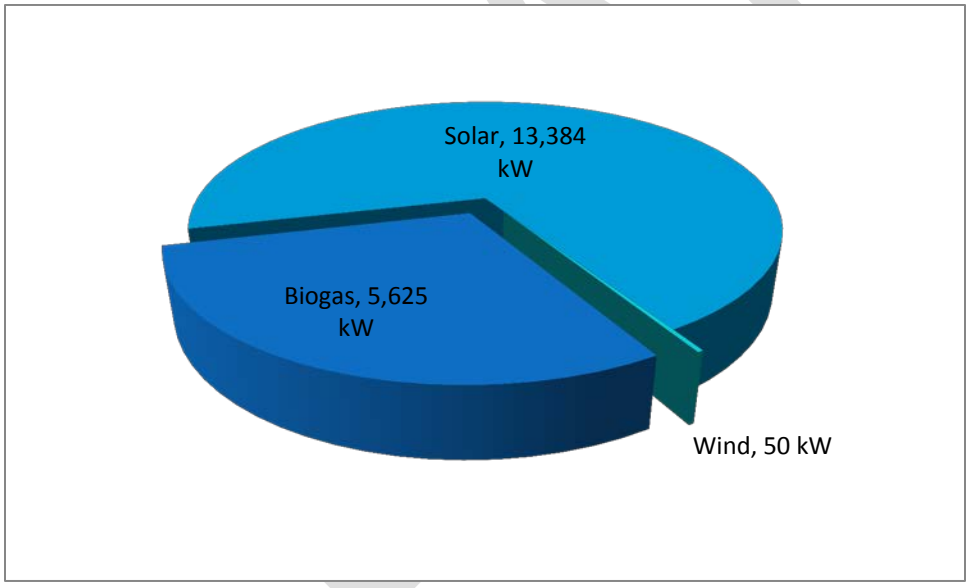



**Figure 95. DEG Facility Generation Capacity by Fuel Type**

### 3.3.2 The Number and the Capacity of Renewable Generation Connections Anticipated

Customers have been steadily interested in DEG projects as evidenced by Enersource's historical connection figures above in **Table 40**. The majority of applications received are for FIT initiatives, with little interest in net metering at this point.

In 2014, the Peel District School Board (PDSB) was awarded 70 FIT 3.0 contracts within Enersource's service area and the Company is currently processing connection impact assessments (CIAs) for these projects. Additionally, 14 projects with cumulative capacity of almost 2.2 MW have been deemed feasible and are currently in progress.

A DEG connection forecast shown in **Table 41** has been compiled based on historical trends, completed assessments, and anticipated projects. The forecast assumes that the microFIT program will transition to a net metering program in 2017, and that no major changes wil be introduced to the FIT program.

**Table 41. Forecasted Number of DEG Connections**

| | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 |
|---|---|---|---|---|---|---|---|
| Number of micro generation facilities | 80 | 65 | 65 | 20 | 30 | 30 | 30 |
| micro generation capacity (kW) | 570 | 570 | 570 | 180 | 270 | 270 | 270 |
| Number of small generation facilities | 20 | 30 | 20 | 20 | 15 | 10 | 5 |
| small generation capacity (kW) | 3,500 | 5,250 | 3,500 | 3,500 | 2,625 | 1,750 | 875 |
| Number of medium generation facilities | 1 | 1 | - | - | - | - | - |
| medium generation capacity (kW) | 1,400 | 2,000 | - | - | - | - | - |

Generation categories were adopted from the OEB's DSC in the following manner:

- Micro-embedded generation facility: name-plate rated capacity of 10 kW or less;
- Small embedded generation facility: not a micro-embedded generation facility with name-plate rated capacity of 500 kW or less if connected to a less than 15 kV line, and 1 MW or less if connected to a 15 kV or greater line;
- Mid-sized (medium) embedded generation facility: not a small embedded generation facility with name-plate rated capacity of 10 MW or less;
- Large embedded generation facility: name-plate rated capacity of more than 10 MW.

### 3.3.3 The Capacity of Enersource's Distribution System to Connect Renewable Energy Generation

**Table 42** illustrates both the distribution capacity of Enersource's system to accommodate DEG facilities and transmission capacity allocated by HONI. 'Connected and In Progress' column represents all DEG facilities that are connected to the distribution system, are in the process of getting connected, or have completed their CIA, resulting in capacity allocation.

**Table 43. DEG Station Capacity**

| HONI Transformer Station | DESN | Bus | Connected and In Progress (kW) | Distribution Capacity available (kW) | Transmission Capacity allocated (kW) |
|---|---|---|---|---|---|
| Bramalea TS | DESN 1 | B | 1,560 | 880 | 2,500 |
| | DESN 1 | Y | 710 | 790 | 1,800 |
| Churchill Meadows TS | DESN | BY | 1,150 | 9,440 | 5,000 |
| Erindale TS | DESN 1 | E | 966 | 7,930 | 5,000 |
| | DESN 1 | Q | 8,113 | 5,450 | 5,000 |
| | DESN 2 | YZ | 1,417 | 15,780 | 5,000 |
| | DESN 3 | BJ | 1,331 | 14,460 | 5,000 |
| Lorne Park TS | DESN | B | 1,269 | 3,530 | 5,000 |
| | DESN | J | 29 | 4,770 | N/A |
| Meadowvale TS | DESN | EZ | 1,788 | 11,880 | 5,000 |
| Oakville TS | DESN | E | 0 | 1,900 | N/A |
| | DESN | Z | 601 | 590 | 1,000 |
| Tomken TS | DESN 1 | BY | 5,807 | 8,790 | 7,000 |
| | DESN 2 | EZ | 2,019 | 14,180 | 5,000 |
| Woodbridge TS | DESN 1 | Q | 10 | 1,900 | N/A |
| **TOTAL** | | | **26,770** | **102,270** | **52,300** |

Enersource anticipates almost 25 MW of DEG facilities to be connected by the end of 2021 as shown above in **Table 41**. As shown above in

DRAFT

Table 43, Enersource has an additional 102 MW of distribution capacity for connection of DEG facilities. Future connections have to be coordinated with HONI to ensure there is adequate capacity at the transformer stations beyond what is currently allocated, as shown in

DRAFT

Table 43.

### 3.3.4 Constraints Related to the Connection of Renewable Generation

Connection constraints for DEG facilities can come from (i) the rating of the supplying distribution transformers; (ii) load in the supplying distribution feeder; or (iii) restriction in the supplying transformer station (e.g., short circuit or thermal capacity).

The difference between the proposed DEG facility size and the minimum load must not exceed the supplying transformer rating. If the proposed DEG facility size exceeds the transformer rating, Enersource will work with the customer to upgrade the distribution transformer.

The cumulative DEG capacity on a single feeder must not exceed the minimum load. **Table 44** indicates the feeders that have reached their maximum DEG capacity. Enersource uses industry accepted safety factors in the feeder capacity calculations.

**Table 44. Feeders with No capacity to Accommodate DEG Facilities**

| Feeder | Capacity Consumed (kW) |
|---|---|
| 74M7 | 745 |
| C5M37 | 6144.7 |
| C5M41 | 918 |
| 24F2 | 350 |
| 14F4 | 184 |
| 90F6 | 250 |
| 24F4 | 700 |
| 38F4 | 1005 |
| 17F1 | 750 |
| 17F3 | 500 |
| 17F4 | 325 |
| 15F5 | 250 |

*Note that M-class denotes sub transmission feeders, F-class – distribution feeders.*

There are several HONI transformer stations within Enersource's service territory with restricted or constrained connection capacity for DEG facilities. This information is summarized in **Table 45**. Enersource is currently unaware of any plans to eliminate the listed restrictions.

**Table 45. HONI Station Restrictions for DEG Facilities**

| HONI station | Restriction |
|---|---|
| Bramalea TS DESN 2 | Thermal capacity |
| Bramalea TS DESN 3 | Thermal and short circuit capacity |
| Cardiff TS DESN | Short circuit capacity |
| Cooksville TS DESN 1 | Short circuit capacity |

| | |
|---|---|
| Cooksville TS DESN 2 | Short circuit capacity |
| Richview TS DESN3 | Short circuit capacity |

While Enersource has enough capacity to accommodate the anticipated DEG connections, the generation proponents might face geographical constraints due to HONI transformer station capacity restrictions.

### 3.3.5 Constraints for an Embedded Distributor that may Result from the Connections

Enersource does not have any embedded distributors within the service territory.

DRAFT

## 3.4 Capital Expenditure Summary (OEB Chapter 5.4.4)

System Service

Expenditures on System Service projects are expected to increase slightly in 2016 and flatten out over the remaining term of the DSP. Because development of new infrastructure in Mississauga is almost at capacity, subtransmission expansion is expected to decrease, with focus shifting to subtransmission renewal at a balanced rate over the remaining test years.

- 2012 actuals of $9,860,395 were $1,997,475 lower than 2011 actuals of $11,857,869 due to decreases in substation upgrades and subtransmission expansion and renewal;
- 2013 actuals of $10,711,823 were $851,429 higher than 2012 due to an increase in substation upgrades;
- 2014 actuals of $11,227,758 were $515,935 higher than 2013 due to an increase in subtransmission expansion and renewal;
- 2015 forecast of $16,267,139 is $5,039,381 higher than 2014 due to significant increases in scheduled substation upgrades, higher subtransmission expansion, and major upgrades of the SCADA system;
- 2016 forecast of $17,200,000 is $932,861 higher than 2015 due to scheduled substation upgrades offset by a shift in focus of subtransmission activities from expansion to renewal;
- 2017 forecast of $13,015,000 is $4,189,000 lower than 2016 due to lower substation upgrade requirements;
- 2018 forecast of $13,130,000 is $115,000 higher than 2017 due to an increase in SCADA switch replacements;
- 2019 forecast of $12,825,000 is $305,000 lower than 2018 due to lower substation upgrade requirements;
- 2020 forecast of $13,105,000 is $280,000 higher than 2019 due to an increase in SCADA switch replacements; and
- 2021 forecast of $13,490,000 is $385,000 higher than 2020 due to an increase in substation upgrades.

System Renewal

Expenditures for System Renewal are expected to increase by about 20% over the next five years. Increasing costs in this area are mainly due to a significant portion of the distribution equipment installed in the 1970's, 1980's, and early 1990's having aged and reached the end of its expected useful life.

- 2012 actuals of $16,224,485 were $4,802,564 higher than 2011 actuals of $11,421,921 due to increases in transformer replacements, overhead, underground, and subdivision rebuilds;
- 2013 actuals of $20,887,175 were $4,662,691 higher than 2012 due to increases in transformer replacements, overhead and subdivision rebuilds;



DRAFT

- 2014 actuals of $31,256,743 were $10,369,568 higher than 2013 due to significant efforts to remove and replace leaking and PCB transformers. In addition, an accounting policy change regarding the capitalization of major spares resulted in a $5,000,000 increase to capital;
- 2015 forecast of $35,203,614 is $3,946,870 higher than 2014 due to more planned subdivision renewals and overhead rebuilds;
- 2016 forecast of $34,735,000 is $468,614 lower than 2015 due to lower transformer replacement spend offset by higher subtransmission renewal projects;
- 2017 forecast of $37,242,500 is $2,507,500 higher than 2016 due to an increase in major subdivision rebuild projects and underground rebuilds;
- 2018 forecast of $38,240,000 is $997,500 higher than 2017 due to a continued focus on renewing deteriorating subdivision infrastructure;
- 2019 forecast of $40,280,000 is $2,040,000 than 2018 due to a continued focus on renewing deteriorating subdivision infrastructure;
- 2020 forecast of $38,570,000 is $1,710,000 lower than 2019 due to fewer planned transformer replacements; and
- 2021 forecast of $38,490,000 is $80,000 lower than 2020 due to fewer transformer replacements offset by higher subtransmission renewal projects.

System Access

Expenditures on System Access projects are primarily dependent on customer requirements and are mandatory per Enersource's Conditions of Services and the Distribution System Code. The primary driver for spending over the test period is the LRT project that will run from the south end of Mississauga into Brampton.

- 2012 actuals of $11,493,425 were $2,832,559 lower than 2011 actuals of $14,325,984 due to fewer Offer to Connect (OTC) projects;
- 2013 actuals of $10,054,863 were $1,438,562 lower than 2012 due to fewer mandated road projects and fewer wholesale metering projects;
- 2014 actuals of $9,474,167 were $580,696 lower than 2013 due to decreases in mandated road and OTC projects, partially offset by higher industrial/commercial services;
- 2015 forecast of $14,632,780 is $5,158,613 higher than 2014 due to higher OTC and industrial/commercial services;
- 2016 forecast of $12,407,831 is $2,224,949 lower than 2015 due to fewer OTC projects offsetting increased road projects;
- 2017 forecast of $17,916,237 is $5,508,406 higher than 2016 due to significant activities for the LRT project;
- 2018 forecast of $18,122,967 is $206,731 higher than 2017 due to a slight increase in LRT spend;
- 2019 forecast of $18,162,212 is $39,245 higher than 2018 due to a slight increase in LRT spend;
- 2020 forecast of $17,237,700 is $924,512 lower than 2019 due to lower activity in the LRT project; and

- 2021 forecast of $10,567,700 is $6,670,000 lower than 2020 due to completion of the LRT project.

General Plant

Overall, expenditures in General Plant are expected to be flat over the test period. Facilities, rolling stock, and IT expenditures have been planned to maintain and renew existing assets with minimal year over year impact.

- 2012 actuals of $29,220,053 were $20,168,463 higher than 2011 actuals of $9,051,590 due to acquisition of the administration building partially offset by lower spend on the JD Edwards system;
- 2013 actuals of $6,830,748 were $22,389,305 lower than 2012 due to the administration building acquisition in the prior year, with lower IT spend offset by higher facilities spend;
- 2014 actuals of $6,230,459 were $600,289 lower than 2013 due to lower rolling stock spend;
- 2015 forecast of $10,585,191 is $4,354,732 higher than 2014 due to minor JDE upgrades and higher rolling stock spend;
- 2016 forecast of $12,796,000 is $2,210,809 higher than 2015 due to improvements to the Meter to Cash system;
- 2017 forecast of $11,337,000 is $1,459,000 lower than 2016 due to lower rolling stock replacements and Engineering & Asset Systems (E&AS) spend;
- 2018 forecast of $10,280,500 is $1,056,500 lower than 2017 due to lower JDE and facilities spend;
- 2019 forecast of $10,794,000 is $513,500 higher than 2018 due to higher rolling stock and IT hardware spend offset by lower Meter to Cash spend;
- 2020 forecast of $10,754,862 is $39,138 lower than 2019 due to higher Meter to Cash spend offset by lower rolling stock spend; and
- 2021 forecast of $9,984,236 is $770,626 lower than 2020 due to lower spends in fleet, IT hardware, and JDE upgrades.

DRAFT

## 3.5 Justification of Capital Expenditures (OEB Chapter 5.4.5)

This section provides the justification and supporting information for investments that have been included in the DSP. The underlying data, information, and analysis are included to support the forecasted capital expenditures as proposed by Enersource.

### 3.5.1 Overall Plan

The Overall Plan section provides comparative data from the historic period of 2011-2015 and the forecast period of 2016-2021 by investment category and by primary drivers.

#### *3.5.1.1 Comparative Expenditures by Category*

**Tables 46-47** and **Figure 96** depict the expenditures by investment category over the historic period of 2011-2015 and the projected expenditures for the forecast period of 2016-2021.

**Table 46. Historical Expenditures by Investment Category (2011-2015) ($000's)**

| Description | 2011 | 2012 | 2013 | 2014 | 2015 |
|---|---|---|---|---|---|
| System Service | 11,858 | 9,860 | 10,712 | 11,228 | 16,267 |
| System Renewal | 11,422 | 16,224 | 20,887 | 31,257 | 35,204 |
| System Access | 14,326 | 11,493 | 10,055 | 9,474 | 14,633 |
| General Plant | 9,052 | 29,220 | 6,831 | 6,230 | 10,585 |
| **Total** | **46,657** | **66,798** | **48,485** | **58,189** | **76,689** |

**Table 47. Projected Expenditures by Investment Category (2016-2021) ($000's)**

| Description | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 |
|---|---|---|---|---|---|---|
| System Service | 17,200 | 13,015 | 13,130 | 12,825 | 13,105 | 13,490 |
| System Renewal | 34,735 | 37,243 | 38,240 | 40,280 | 38,570 | 38,490 |
| System Access | 12,408 | 17,916 | 18,123 | 18,162 | 17,238 | 10,568 |
| General Plant | 12,796 | 11,337 | 10,281 | 10,794 | 10,755 | 9,984 |
| **Total** | **77,139** | **79,511** | **79,773** | **82,061** | **79,668** | **72,532** |

DRAFT

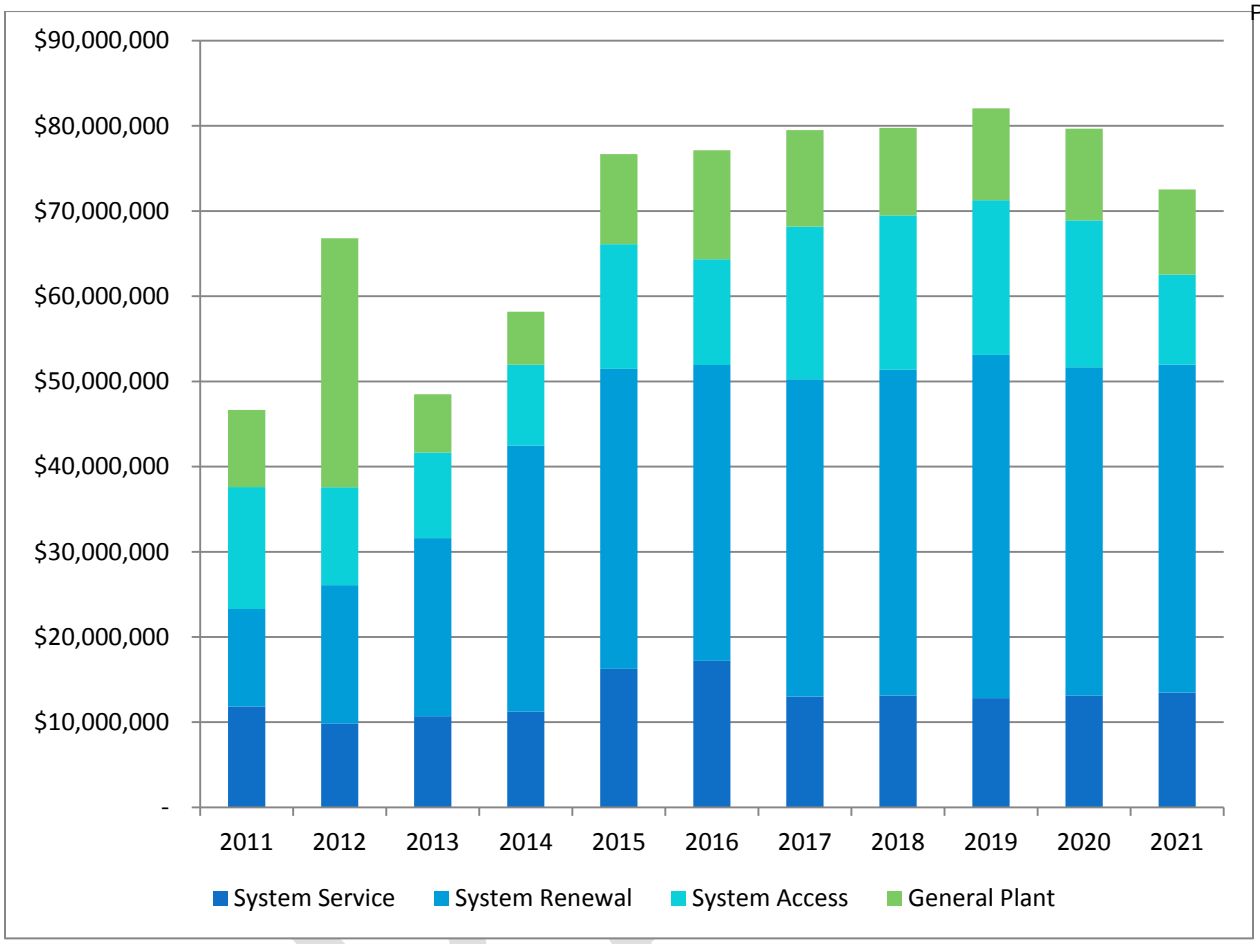



**Figure 96. Enersource's Investment Portfolio (2011-2021)**

### *3.5.1.2 Forecast Impact to System Operating and Maintenance Costs*

Forecast impact to operation and maintenance costs vary by each of the investment categories, as described below.

**System Access**

System Access investments are mandatory, non-discretionary projects initiated by customers or third parties (e.g., City of Mississauga, Region of Peel, Ministry of Transportation, etc.). The projects include the following:

- New connections and subdivisions (including industrial/commercial) connections
- Road authority projects that require the relocation of distribution system assets
- Metering
- Other customer initiated work
- Renewable Generation projects, FIT/microFIT.

System Access projects can introduce new distribution assets to the system, which results in an increase of equipment requiring regular maintenance which in turn creates additional points of potential failure within the distribution grid. In addition, these projects may include the expansion of the communication infrastructure and would result in ongoing licencing fees.

**System Service**

System Service investments represent the costs associated with growing the distribution system and addressing capacity, reliability and safety initiatives. An increased number of assets installed in the distribution grid, will result in increased maintenance and potential failure points within the system. In addition, these projects may include the expansion of the communication infrastructure and may result in incurring ongoing licencing fees.

**System Renewal**

System Renewal investments are projects and programs directed toward replacing or rehabiliting aging infrastructure. As an asset ages, the costs associated with operating the asset increases as inspection and maintenance activities become more frequent and onerous. However, when an asset is replaced, while maintenance is still required, it may involve less time and resources, thus resulting in lower operating and maintenance costs. In addition, as an asset ages and its condition deteriorates there is a higher likelihood of failure which may result in higher operating costs associated with emergency work required to replace faulty equipment and restore power to customers. Thus, through risk-based approached planning and pro-active replacement projects and programs, Enersource chooses to renew certain portions of its distribution system, thereby reducing customer outages, weather related failures, and avoiding additional operating costs.

**General Plant**

General plant investments are focused on Information Technology and Information Systems, buildings, facilities, fleet, and major tools.

### *3.5.1.3 Justification and Investment Drivers*

The drivers by investment category from the historic period moving through the forecast period have been summarized in **Table 48** below.

**Table 48. Investment Drivers by Category**

| Investment Category | Investment Drivers |
|---|---|
| **System Access** | • **Third Party Requirements**<br>o Plant relocation or upgrade to an existing service<br>• **Customer Connection Requests**<br>o Request for new load or generation connection<br>• **Mandated Service Obligations**<br>o Regulatory requirement typically fromthe OEB's DSC |

DRAFT

| Investment Category | Investment Drivers |
|---|---|
| **System Renewal** | • **Assets at end of Service Life**<br>o Risk of failure<br>▪ Asset at risk of failure<br>o Failure<br>▪ Asset no longer meets functional and operational requirements<br>o Substandard Performance<br>▪ Asset performs below technical and operational requirements |
| **System Service** | • **Capacity Constraints**<br>o Need for additional system capacity at substations or distribution circuits to accommodate planned or realized load<br>• **Reliability**<br>o Need for system upgrade to mitigate/improve reliability performance in areas with high frequency and duration of power interruptions<br>• **System Efficiency**<br>o Need for improved system operability and efficiency |
| **General Plant** | • **System Support**<br>o Requirement for fleet/vehicles to meet business needs<br>• **Major Tools**<br>o Requirement for major tools and equipment for business needs<br>• **Information Technology**<br>o Requirement for IT software, hardware and systems<br>• **Grounds & Building**<br>o Requirement for building infrastructure investments |

### *3.5.1.4 Distributor's System Capability Assessment*

Over the period 2016-2021, Enersource will be addressing several system constraints that were identified during the Regional Planning initiative and internal system planning work. Mississauga's Downtown Core is expected to expand substantially as part of an overall vision outlined by the City in the Downtown 21 Plan. As part of this plan, the Downtown Core will be the centre of new urban structure focused on growth to areas with existing service, proposed service and infrastructure capacity, particularly transit and community infrastructure. Detailed planning determined that the transformational capacity in the Downtown Core is expected to increase to approximately 300 MVA, which is beyond the current transformation capacity of 140 MVA. Enersource has been working closely with the City of Mississauga and developers proposing new commercial and residential towers in the Downtown Core to determine the timing and load requirement. As a result, Enersource is proposing to construct two new substations in the Downtown Core, as shown in **Figure 97**.

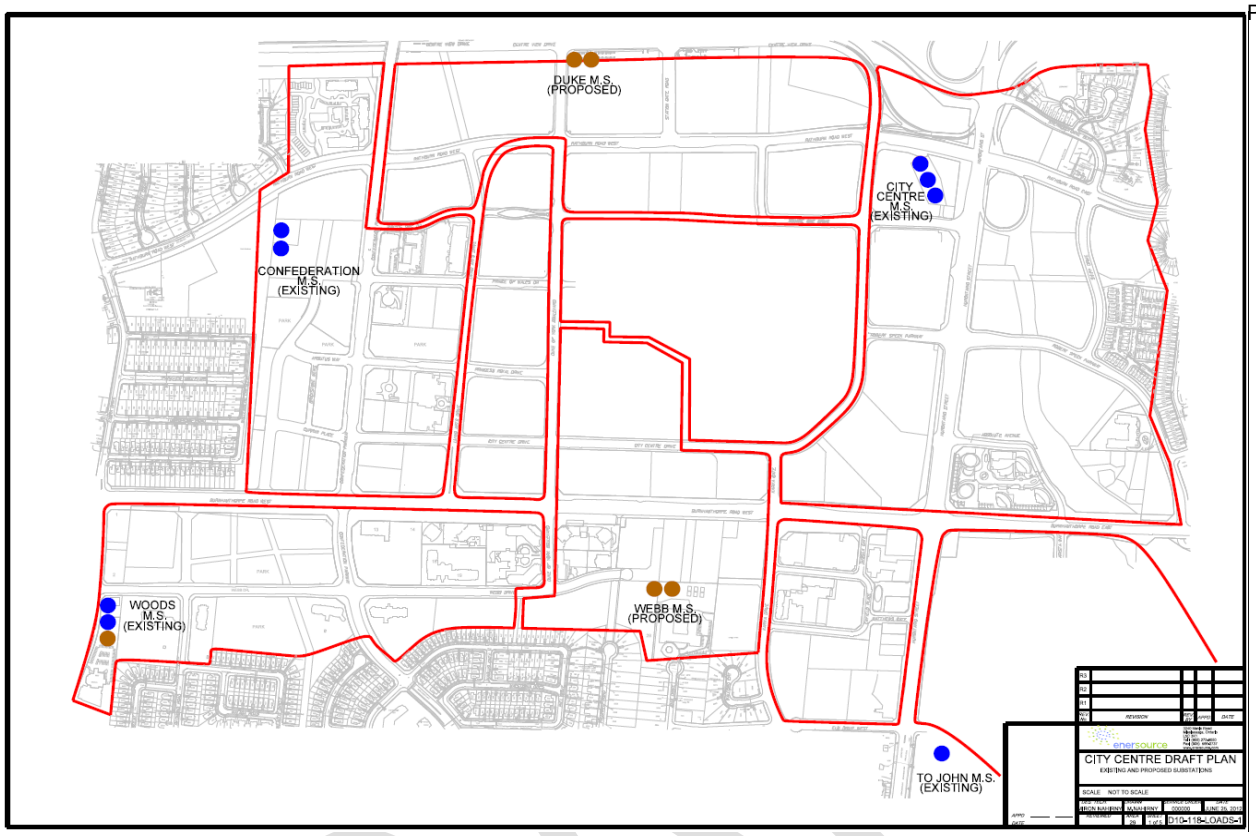



**Figure 97. Proposed Locations for New Substations**

The first substation, Webb MS, is planned for 2016-2017 period and will provide additional transformation capacity to meet the load requirements of new residential high-rise buildings planned in the Downtown Core. While the Webb MS substation will be designed and constructed for dual transformer setup, the substation will initially be equipped with only one high voltage transformer. The second transformer will be added at a later date, as the load from the new buildings in the southern part of the Downtown Core materializes.

The second substation, Duke MS, is planned for 2020-2021 and will provide additional transformation capacity to meet load requirements for new commercial buildings planned in the Square One area, north of Rathburn Road. Similar to Webb MS, Duke MS will be designed and constructed for dual transformer setup.

In addition, based on the system planning load forecast, the installation of a new substation is required in the area of Mavis, south of Highway 401 in order to provide additional capacity for the planned commercial/industrial development in the area. Moreover, during the Regional Planning effort with HONI and participating utilities, including Enersource, it was determined that Erindale TS T1/T2 is expected to be overloaded above the 10-day LTR during summer peak, and that over-capacity should be addressed through available transformation capacity existing adjacent to the limiting assets. Proposed Mini-Britannia MS is planned to be fed from the 44kV subtransmission system and will provide

transformational capacity to feed 27.6kV load currently supplied by Erindale TS T1/T2. This configuration will reduce over-capacity loading at Erindale TS T1/T2 while balancing the loading capability on the 44kV system via Churchill Meadows TS.

### 3.5.2 Material Investments

This section describes Enersource's capital programs and projects that meet the materiality threshold of $750,000 in each of the four investment categories (System Access, System Renewal, System Service and General Plant) for the forecast years of 2016 through 2021.

#### *3.5.2.1 System Access*

System Access investments include modifications to Enersource's distribution system in order to provide a customer, both load and generation, with access to electricity services, as outlined in the OEB's DSC. **Table 49** details Enersource's expenditures by capital program within System Access from 2016 through 2021.

**Table 49. System Access Expenditures by Capital Program (2016-2021) ($000's)**

| Description | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 |
|---|---|---|---|---|---|---|
| Road Projects | 3,000 | 3,000 | 3,000 | 3,000 | 3,000 | 3,000 |
| Light Rail Transit | 400 | 8,400 | 8,650 | 8,750 | 7,800 | 1,200 |
| New Subdivisions | 800 | 800 | 800 | 800 | 800 | 800 |
| Industrial & Commercial Services | 2,600 | 2,600 | 2,600 | 2,600 | 2,600 | 2,600 |
| Residential Service Upgrades | 125 | 125 | 125 | 125 | 125 | 125 |
| Smart Metering Large Commercial | 1,506 | - | - | - | - | - |
| Wholesale Metering | 1,263 | 33 | 43 | 35 | 65 | 10 |
| Metering Equipment | 1,172 | 1,427 | 1,384 | 1,337 | 1,337 | 1,337 |
| Smart Metering | - | - | - | - | - | - |
| Smart Metering in New Condos | 1,387 | 1,407 | 1,426 | 1,446 | 1,446 | 1,446 |
| Green Energy - FIT/MicroFIT | 155 | 125 | 95 | 70 | 65 | 50 |
| **Total** | **12,408** | **17,916** | **18,123** | **18,162** | **17,238** | **10,568** |

##### 3.5.2.1.1 Road Projects

The road projects initiative is in response to the OEB's DSC, Section 3.4. – Relocation of Plant that requires Enersource to address relocation of its assets upon certain third party requests.

Projects in this category involve the relocation of Enersource's distribution system assets to support road relocation and road reconstruction projects at the request of the Region of Peel, City of Mississauga, or the Ministry of Transportation. The initiation and timing for the execution of these projects is outside of Enersource's control and therefore the timing and value of this required investment is subject to change.

Enersource adheres to the *Public Service Works on Highways Act* and associated regulations governing the recovery of costs related to road reconstruction work by collecting contributed capital for 50% of labour and labour saving devices.

To the fullest extent possible, Enersource coordinates its proposed distribution system projects with these stakeholders in order to maximize efficiencies and minimize disruptions to the public. Enersource holds regular planning discussions with these stakeholders and actively participates in Public Utilities Coordination Committee meetings in order to better identify the scope and number of road authority projects forecast in future years.

#### 3.5.2.1.2 Light Rail Transit

In April 2015, the Province of Ontario made an announcement that the Hurontario LRT project is proceeding in support of the Moving Ontario Forward plan aimed at increasing transit ridership, reducing travel times, managing congestion, connecting people to jobs and improving the economy. Based on preliminary timelines provided by the Province, Enersource expects that construction work and thus, relocation of overhead assets, will be carried out from 2017 through 2020 period and anticipated completion in 2021. This aligns with the Province's proposed in-service date for the LRT in 2022.

#### 3.5.2.1.3 New Subdivisions

This is an ongoing capital expenditure comprised of non-discretionary projects initiated by developers where investment is required to enable customers to connect to Enersource's distribution system. Enersource uses the economic evaluation methodology as prescribed by the DSC to determine the amount, if any, of capital contributions for each subdivision project. These investments are driven by subdivision developers and cannot be deferred. Expenditures related to new subdivision project costs are forecasted using a number of factors which include the following:

- Historical levels of activity and investment
- Known developments in the planning stages using the City's zoning information and permit applications
- City of Mississauga plans
- Review of economic factors.

Although these factors are used as a basis for capital expenditure forecasts, there is a high likelihood that actual expenditures will vary significantly because each of the above driving factors may vary considerably from underlying assumptions made during the capital planning phase. Enersource tracks proposed developments from information provided by the City's Planning and Building department and

uses this information to estimate future loading requirements. The number of concept draft plans and rezoning applications are a good indication of capital expenditures required in future years. Subdivision development is primarily dependent on the local economy. Growth has been steady in this sector over the past few years with townhouses and high-rise condominium towers dominating the new construction, as the City transitions into a mature urban community through its emphasis on intensification and redevelopment, evident from the large number of high-rise building construction projects in the Downtown Core and northwest part of Mississauga.

The 2016 to 2021 investment requirements for new subdivisions, as provided above in **Table 49**, are aligned with the decreasing trend in availability of green space for building new subdivisions.

#### 3.5.2.1.4 Industrial & Commercial Services

This is an ongoing capital expenditure comprised of non-discretionary projects initiated by customers or developers where investment is required to enable customers to connect to Enersource's distribution system. This program includes requests for new connection and upgrade of services for commercial and industrial customers. New condominium, industrial, commercial, and residential subdivision projects are initiated by developers and property owners.

Commercial development is largely influenced by the state of the local economy and commercial vacancy rates. The majority of commercial development work is occurring in the northwest corner of the City. Commercial growth has been slow but steady over the past few years.

Industrial and Commercial Services proposed investments from 2016 through 2021 are shown above in **Table 49**.

#### 3.5.2.1.5 Smart Metering Large Commercial

The remaining class of customers with a significant number of mechanical meters is the large commercial/industrial greater than 50 kW. In May 2014, the OEB mandated utilities to replace mechanical meters with meters capable of providing hourly interval data for billing purposes using the existing Advanced Metering Infrastructure (AMI) communication capability to backhaul the usage data to their billing systems. The OEB directed that all replacements be completed by 2020.

Enersource created a separate business unit to track the costs of this project in a deferral account which will be disposed or cleared through a future rate hearing. Enersource intends on completing the replacement of the remaining 1,800 large mechanical meters by the end of 2016.

Smart Metering Large Commercial proposed investments from 2016 through 2021 are shown above in **Table 49**.

#### 3.5.2.1.6 Wholesale Metering

All wholesale metering installations used for settlement in the Ontario electricity wholesale market must be registered with the IESO and conform to the specifications outlined in the IESO Market Rules.



DRAFT

Furthermore, each wholesale metering installation must also comply in accordance with Measurement Canada's (MC) rules and regulations. Specifically, all instrument transformers and meters must be approved by MC for use. If any of the instrument transformers are not approved by MC, the non-compliant units must be replaced or approved at the earliest seal expiry date.

All market participants are required to assume ownership of their wholesale meters from HONI per the Market Rules and ensure these meters are compliant with current IESO and MC standards. Enersource is responsible for the costs of installing and maintaining the metering installations. However, the Company must contract the services of an IESO-registered Metering Service Provider (MSP) who is authorized to register the wholesale meter installation for operation in the IESO wholesale electricity market. Furthermore, Enersource is required to contract HONI to perform certain aspects of the upgrade (i.e., construction, installation, and commissioning) since the transformer stations are HONI's property and related work must only be completed by HONI.

Failure to comply with the IESO Market Rules exposes Enersource to market sanctions, potential fines, and increased electrical losses applied against Enersource. As such, in 2015 Enersource plans to undertake wholesale metering upgrades at Tomken TS. While this transformer station has market compliant wholesale metering equipment, it is not in a closed enclosure and therefore, the station is not fully compliant with the wholesale market rules. Due to HONI's plan to replace the protection and control building at Tomken TS, Enersource has only one viable option which is to move to bus metering with a full upgrade on the 44kV bus. Enersource has previously completed such upgrades at other transformer stations.

As a part of the compliance requirements, Enersource is required to provide access to the metering equipment to the IESO auditor on an as-requested basis. The IESO-registered MSP and Enersource staff are required to be onsite in order to ensure compliance of installation and equipment to the IESO Market Rules.

As part of the wholesale metering maintenance program and the MC regulation, Enersource must ensure wholesale meters are changed prior to their seal expiry date. Over the next two years, the Company will be required to change up to 36 meters and will upgrade communication at these sites to an internet networking protocol (i.e. TCP/IP), greatly reducing communication issues encountered with wired telephone lines and ensure consistent and full data retrieval.

Wholesale Metering proposed investments from 2016 through 2021 are shown above in **Table 49**.

#### 3.5.2.1.7 Metering Equipment

Metering involves measuring various aspects of power usage in order for utilities to understand usage trends and bill customers for electricity usage. New metering installations are required in order to support the growth of Enersource's customer base. Operation and maintenance of existing metering equipment is necessary in order to collect and provide automated meter reading data as the first stage of Enersource's meter to cash process. The reliability and accuracy of the metering equipment is

paramount to Enersource's customer bills and directly impacts Enersource's revenue stream and financial risk.

The vast majority of the meters are now smart meters or meters that can be read remotely. Maintenance of existing metering installations and their communication components remains a critical function to ensure consistent and complete data for routine billing and to provide hourly data to the provincial Meter Data Management and Repository (MDM/R). Incorrect installation or setup and/or lack of maintenance could result in a metering failure resulting in incorrect customer billing, potential loss of revenue and damage to Enersource's reputation.

Enersource has several initiatives underway including:

- Large Commercial Mechanical meter replacements with MIST interval meters pursuant to OEB Decision EB-2013-0311 released May 21, 2014; Enersource plans to complete the conversion to smart metering for Large Commercial services by the end of 2016;
- Gatekeeper (Collector or Advanced Metering Regional Collectors (AMRC)) Replacement due to the addition of the mechanical meters; it is necessary to replace the existing gatekeepers to accommodate the additional data channels that must be collected in order to correctly bill for large commercial usage; Enersource plans to complete the replacement and removal of the existing gatekeepers by the end of 2016;
- Upgrading of existing metering equipment due to customer electrical service upgrades;
- Replacing obsolete or damaged meters;
- Replace related aging metering equipment (instrument transformers older than 45 years in 2016, older than 40 years in 2017);
- Conversion from 2.5 elements to three elements metering;
- New service installations (Residential and Commercial/Industrial);
- Primary Metering installations and upgrades;
- Installation of Individually Metered Suite (IMS) metering in condominium buildings, new build development and retrofitting of existing condominium buildings and rental apartment buildings; and
- Revenue metering reverification under MC guidelines for residential, small commercial and IMS metering.

Revenue metering is federally regulated under the *Electricity and Gas Inspection Act* (E&GIA), governed by MC. Under MC regulations, all revenue meters must be approved, routinely inspected and maintained. At periods specified by MC, the revenue meters must be removed from service and verified as performing accurately and within MC prescribed tolerances. Verification of the meter performance is completed by an MC-accredited meter verifier using certified equipment as required by the E&GIA.

Under MC regulations, retail customers require a revenue meter for measuring and billing electricity use. Enersource owns and operates approximately 197,000 retail revenue meters in the residential and small commercial classes, 4,500 in the large commercial/industrial classes and nine Large Users.

Historically, approximately 500 of these revenue meters are removed or replaced each year due to random failures, damage or functional obsolescence.

Included in this category is the replacement of mechanical meters for GS>50 kW customers, as described above.

In order to provide the hourly interval data mandated under the OEB initiative, as mentioned above, Enersource must replace all currently deployed gatekeeper meters with newer technology capable of collecting additional hourly interval information. The existing gatekeepers use older technology, that is not only incapable of supporting this requirement but is also extremely slow and causes communication issues. The proposed replacement gatekeepers will greatly improve communications and allow for the AMI application to utilize the outage notification (Call-in on Failure) functionality thereby improving outage management as a by-product of the replacement of the collectors. The upgraded gatekeepers are also capable of managing data from a larger number of smart meters. The total number of collectors to be deployed can be reduced while still maintaining the same backhaul coverage for the AMI systems. The new collectors are required for the daily collection of hourly interval data required to bill the large commercial customers as directed by the OEB.

Metering Equipment proposed investments from 2016 through 2021 are shown above in **Table 49**.

#### 3.5.2.1.8 Smart Metering in New Condos

Smart metering in condominiums is part of the Government's plan to create a conservation culture in Ontario. The legislation provides condominium boards with the authority to have smart meters installed within their building.

In compliance with the DSC, Enersource provides individual metered suites (IMS) as an option for both new and existing condominium buildings. When requested by a master consumer, a distributor shall install unit smart meters that meet the specifications prescribed by Ontario Regulation 389/10. Smart metering also allows the building owner to individually meter suites within the building.

Historically, condominium buildings were bulk metered and received one bill for the entire building. This electricity bill was paid by the condominium corporation and included suites and common area electricity usage. Under this scenario, there was little incentive to reduce electricity use within the suites because usage costs were included uniformly in the condominium fee. Suite owners were not directly responsible for their own electricity bill which may have resulted in higher overall electricity usage. With the implementation of suite meters, suite owners are now given the opportunity to manage their own electricity use. Benefits of this program include, but are not limited to:

- Providing the most equitable way to accurately allocate electricity costs as suite owners pay only for what they use;
- Empowering suite owners with a tool to monitor and manage their own usage; and

- Promoting conservation by encouraging suite owners to participate in energy conservation programs to further reduce their electricity usage.

Similar to the residential and general service system, the smart metering system for new condominiums meets AMI functional specifications. The smart meter system for condominiums interfaces to the MDM/R and uploads daily consumption information for all the customers into the central system. The MDM/R receives the data, validates, estimates, and prepares the meter data for billing. The billing data is then sent by the MDM/R to Enersource for use in its CC&B system for customer billing.

Enersource is responsible for installing, supporting and developing, and implementing processes that are required to be put in place for a fully functional smart meter system, including:

- System procurement
- System installation
- Project management
- Deployment logistics
- Mobile workforce management
- Customer and community communications
- Process re-engineering
- Interface development to the MDM/R
- System testing
- Contract management
- Audit of system security
- Quality control.

In 2013, Enersource installed approximately 1,450 suite meters. The 2015 budget predicts a moderate increase (1,550) in the number of suite meters to be installed.

Enersource continues to expand its efforts in installing IMS, with over 11,500 units currently being metered. This technology is mainly used in condominiums, but is also applicable for use in metered rental units and apartment buildings through retrofitting. Enersource utilizes Power Line Carrier technology to allow the individual meters to communicate to a transponder which collects the usage data for the suites. This effectively allows the system to utilize the existing electrical wiring in the building as a communication medium thereby saving space and cost. Enersource uses a combination of wired phone lines, and where applicable, wireless communication protocols to contact the transponder/collector and download the data.

In January 2015, Enersource was approached by a rental apartment building to provide individual suite metering. This is Enersource's first such installation of IMS metering and it is expected to bring additional requests once the first building has been successfully converted.

Smart Metering in New Condominiums Proposed Investments from 2016 through 2021 are shown above in **Table 49**.

#### 3.5.2.1.9 Green Energy – Renewable Generation, FIT/MicroFIT

Enacted in May, 2009, the Gre*en Energy Act* (GEA) was introduced to encourage renewable generation, energy conservation, and the creation of green jobs. A key GEA element to enable renewable generation is the IESO's Feed-in-Tariff (FIT) program.

The FIT program is divided into two streams: large projects above 10 kW and up to 500 kW follow the FIT process for connection; and smaller projects of 10 kW or less follow the microFIT process for connection. Typically, it is residential customers who apply for microFIT projects whereas business and large industrial customers apply for the FIT projects. The program rules, contracts, and prices are administered by the IESO.

Enersource has the responsibility to connect renewable generators in accordance with the IESO's FIT program rules, OEB codes, ESA requirements, and Enersource standards, as outlined in the Company's Conditions of Service.

Green Energy and FIT proposed investments from 2016 through 2021 are shown above in **Table 49**.

### *3.5.2.2 System Service*

System Service investments include modifications to Enersource's distribution system in order to provide a customer, both load and generation, with access to electricity services, as outlined in the DSC.

System Service investments are modifications to Enersource's distribution system to ensure the distribution system continues to meet the Company's objectives while addressing anticipated future customer electricity service requirements.

The capital programs listed below ensure the continuation of Enersource's capability to provide a safe, secure and reliable supply of electricity to customers. Growth is predicted through the combined use of 1) growth projections; 2) historical growth patterns; and 3) load forecast models.

In 2013, approximately 13% of the power was delivered to large industrial and commercial customers, who account for less than 0.001% of the total number of Enersource customers. Individual large customers can add significant load to the system and provide unique challenges to connect and supply. Some customers may need to be connected in areas where there is insufficient capacity, necessitating construction of new feeders or substations to meet their specific needs.

**Table 50** details Enersource's expenditures by Capital Program within System Service from 2016 through 2021.

**Table 50. System Service Expenditures by Capital Program (2016-2021) ($000's)**

| Description | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 |
|---|---|---|---|---|---|---|
| Municipal Substation Construction & Upgrades | 11,600 | 8,200 | 8,000 | 7,800 | 7,650 | 7,900 |
| Subtransmission Expansion | 2,400 | 2,650 | 2,400 | 2,400 | 2,400 | 2,400 |
| Automation / SCADA Replacement and Enhancement Program | 3,200 | 2,165 | 2,730 | 2,625 | 3,055 | 3,190 |
| **Total** | **17,200** | **13,015** | **13,130** | **12,825** | **13,105** | **13,490** |

### 3.5.2.2.1 Substation Construction & Upgrades

Enersource currently owns and operates 66 substations within its service territory. A substation transforms power from 44kV to 8/13.8kV or from 16/27.6kV to 2.4/4.16kV. Substations are capital intensive and are critical components of the electricity distribution system. Impact from a failure of a substation can be very significant due to the large number of affected customers. The outage duration of a substation failure is usually relatively long due to the amount of switching required to supply customers from other nearby substations.

There has been an increase in failure rates of the magnetic air circuit breakers (two failures in the past 12 months). Furthermore, there has been scarcity of spare parts combined with the possibility of arc chutes containing asbestos. Enersource plans to replace all switchgear units housing magnetic air circuit breakers with modern circuit breakers by 2023.

Substation site enhancement consists of small projects at different sites in order to preserve or improve the substation site condition. They include roof replacements, paving, small civil construction projects and adding gravel in the transformer yards. The Station RTU and protection relay replacement projects will coincide with the substation rebuild projects in order to minimize cost and system down time. Substation RTU and protection relay replacement projects will improve system reliability, minimize communication downtime, and improve cyber security. It will also be possible to remotely connect to the protection devices and monitor any service interruptions at the substations.

There are situations when, in order to promote standardization and to better serve Enersource customers, the substation layout configuration is modified and the transformers are replaced not because they have approached the end-of-life but because they would not fit in the new configuration. The replaced transformers become spare inventory units or are used to replace other units that are in worse conditions and prone to failure.

Based on the substation renewal programs identified in Section 2.3.2.3.1, Enersource has programs to increase substation capacity in response to system load growth forecast. Substation renewal projects

on the other hand, aim to rebuild/replace substation equipment that is at the end of service life as identified through inspection, maintenance, and asset condition analysis.

Municipal substation construction and upgrades proposed investments from 2016 through 2021 are shown above in **Table 50**.

#### *3.5.2.2.1.1 New Construction*

As outlined in Section 2.3.3 Expansion Programs, the following are proposed new substations to satisfy load growth in the service territory.

#### *Mini – Orlando Substation (44kV – 27.6kV)*

Based on the system planning load forecast, a new substation is required in the area of Mavis, south of Highway 401. It is a growth driven investment in order to provide additional capacity for the planned commercial/industrial development in the area.

The new substation will add 40 MVA of capacity by the end of 2016 and the project scope includes the following work:

- 2015
  - Acquisition of one 20 MVA on-load power transformer
  - Acquisition of one high voltage 46 kV switchgear
  - Acquisition of one low voltage 35 kV solid dielectric switchgear (operated at 27.6 kV)
- 2016
  - Acquisition of one 20 MVA on-load power transformer
  - Acquisition of one high voltage 46 kV switchgear
  - Acquisition of one low voltage 35 kV solid dielectric switchgear (operated at 27.6 kV).

At completion, the substation will house two power transformers, two high voltage switchgears and two low voltage switchgears, which will deliver power via four 27.6 kV feeders.

#### *Webb MS (44kV-13.8kV)*

Based on system planning load forecast a new substation is required in Mississauga's Downtown Core. It is a growth driven investment needed in order to provide additional capacity for the planned residential, commercial, and transit infrastructure development in the area.

This project consists of adding 20 MVA of capacity by the end of 2017. The project scope includes the following work:

- Completion of the municipal substation building (2016)
- Order placed on the following major substation equipment 2016)
  - HV switchgear
  - LV switchgear



DRAFT

  - Power Transformer
- Installation and commissioning of the above equipment (2017).

At completion, the substation will house one 20 MVA power transformer, one high voltage switchgear and two low voltage switchgear units which will deliver power via eight 13.8 kV feeders. The substation will have provision to add an additional 20 MVA of future capacity at completion of load growth projection.

### Duke MS (44kV-13.8kV)

Based on system planning loading forecast and a new substation is required in Mississauga's Downtown Core. It is a growth driven investment needed in order to provide additional capacity for the planned residential/commercial and transit infrastructure development in the area.

This project consists of adding 20 MVA of capacity by the end of 2021. The project scope for 2020 includes the following:

- Completion of the municipal substation building
- Placing on order the following major substation equipment
  - HV switchgear
  - LV switchgear
  - Power transformer.

Upon completion in 2021, the substation will house one 20 MVA power transformer, one high voltage switchgear and two low voltage switchgear units which will deliver power via eight 13.8 kV feeders. The substation will have provision to add an additional 20 MVA of future capacity at completion of load growth projection.

### Mini - Britannia Substation (44kV – 27.6kV)

Based on the system planning load forecast, a new substation is required to be installed in the Britannia – Credit View area. It is a capacity driven investment. During the Regional Planning effort with HONI and participating utilities, including Enersource, it was determined that Erindale TS T1/T2 is expected to be overloaded above 10-day LTR during summer peaks. The peak load at Erindale TS T1/T2 has reached the capacity, and is expected to exceed it by as much as 40 MW by 2023. In addition, as outlined in Section 1.2., it was concluded that the capacity needs to Erindale TS T1/T2 should be addressed through available transformation capacity existing adjacent to the limiting assets.

The proposed Mini-Britannia MS is planned to be supplied from Churchill Meadows TS (44kV system) and provide additional capacity to feed the 27.6kV load currently supplied by Erindale TS T1/T2. This configuration will reduce over-capacity loading at Erindale TS T1/T2 while balancing the loading capability on the 44kV system via Churchill Meadows TS.

The new station will add 40 MVA of capacity by the end of 2019 and the project scope includes the following work:

- 2018
  - Acquisition of one 20 MVA on-load power transformer
  - Acquisition of one high voltage 46 kV switchgear
    - Place on order for a pre-engineered electrical house (E-House) which comes complete with a low voltage 38kV metal clad switchgear line-up (to be operated at 27.6 kV)
  - 2019
    - Acquisition of one 20 MVA on-load power transformer
    - Acquisition of one high voltage 46 kV switchgear
    - Delivery of the electrical house (E-House) housing the 38 kV arc resistant metal clad switchgear
    - Installation and commissioning of the substation components.

At completion, the substation will house two power transformers, two high voltage switchgears and two low voltage switchgear units that will deliver power via four 27.6kV feeders.

#### *3.5.2.2.1.2 Substation Rebuild*

Enersource proactively replaces substation equipment before a major failure occurs which could negatively impact customers, system reliability, and the Company's reputation.

Enersource's proactive replacement strategy considers the health index, location, number of customers served, transformer protection enhancement opportunity, and the condition of other substation assets, including buildings and grounds. The component replacement program addresses individual assets such as switchgears, circuit breakers, protection relays, transformers, enclosures, tap changers, batteries, and battery chargers that have reached end-of-life and can no longer fulfill their intended function.

The list of substation rebuild projects is listed below in **Table 51**. The detailed description and drivers for each rebuild investment is outlined in the LTIP.

**Table 51. Substation Equipment Replacement by Year.**

| Replacement year | Station | TX1 | TX2 | LVSG1 | LVSG2 | HVSG1 | HVSG2 |
|---|---|---|---|---|---|---|---|
| 2016 | Cawthra MS | ✓ | | | | ✓ | |
| | Orr MS | ✓ | | ✓ | | ✓ | |
| | Rifle Range MS | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ |
| 2017 | Avonhead MS | | | ✓ | | | |
| | Parkland MS | ✓ | | ✓ | | ✓ | |
| | Pinetree MS | | | ✓ | | | |
| | Stavebank MS | ✓ | | ✓ | | ✓ | |
| | Summerville MS | | | | ✓ | | |

| Replacement year | Station | TX1 | TX2 | LVSG1 | LVSG2 | HVSG1 | HVSG2 |
|---|---|---|---|---|---|---|---|
| 2018 | Bloor MS | | | ✓ | | | |
| | City Centre North MS | | | ✓ | ✓ | | |
| | Hensall MS | | ✓ | | | | ✓ |
| | Western MS | | | ✓ | | | |
| | York MS | ✓ | | ✓ | | ✓ | |
| 2019 | City Centre South MS | | | ✓ | | | |
| | Park Royal MS | | ✓ | | | | ✓ |
| | Rockwood MS | ✓ | | ✓ | ✓ | ✓ | |
| | Shawson MS | | | ✓ | | | |
| 2020 | Hamilton MS | | | ✓ | | | |
| | John MS | | | ✓ | | | |
| | Meadowvale MS | | | ✓ | | | |
| | Western MS | ✓ | | | | ✓ | |
| | Woodlands MS | | | ✓ | ✓ | | |
| 2021 | Battleford MS | | | ✓ | | | |
| | Munden MS | ✓ | | ✓ | | ✓ | |
| | Rogers MS | | | ✓ | ✓ | | |
| | Shawanaga MS | ✓ | | | | | |
| | Summerville MS | ✓ | | | | ✓ | |

Note: TX stands for transformer, LVSG – low voltage switchgear, HVSG – high voltage switchgear.

Substation rebuild program proposed investments from 2016 through 2021 are shown above in **Table 50**.

### *3.5.2.2.1.3 Automation / SCADA Replacement and Enhancement Program*

Enersource's automation enhancement program will ensure continued safe and efficient operation of the electrical grid.

As much as possible, these automation enhancement projects are planned to coincide with the substation upgrade projects which minimizes cost and system down time. The following programs are planned over the next five years:

- S4T4 replacement to MPLS (Multiprotocol Label Switching)
- Battery and battery charger replacement
- Overhead automated switches
- Underground automated switches.

### *S4T4 Replacement to MPLS*

The S4T4 conversion to MPLS program will continue for the next five years. To minimize cost and system down time, this replacement program will coincide with the substation rebuild projects. Any newly constructed substations will be equipped with MPLS communication. The station RTU and protection relay replacement projects complete with MPLS communication will improve system reliability,

minimize communication downtime, and improve cyber security. It will also be possible to remotely connect to the protection devices as well as monitor any communication interruptions to the substation.

### *Battery and battery charger replacement*

Station battery and charger replacement projects will coincide with the substation rebuild projects. The Substation rebuild provides the opportunity to replace the existing charger and batteries without requiring additional system outages. Under this program, new battery and battery chargers will be installed in the proposed new substations.

### *Overhead & Underground Automated Switches*

In 2014, a comprehensive system automation study was conducted in order to prioritize each substation in terms of its potential impact and importance to the overall system. Factors such as historical reliability (momentary and sustained outages), customers affected, and existing automation were considered in the study. As a result of the study a number of switches were targeted as ideal candidates for automation upgrade projects.

The detailed list of automation/SCADA replacement and enhancement projects included in the DSP is outlined in the LTIP. Automation/SCADA replacement and enhancement program proposed investments from 2016 through 2021 are shown above in **Table 50**.

## *3.5.2.3 System Renewal*

System renewal investments involve replacing and/or refurbishing system assets to extend the original service life of the assets and thereby maintain the ability of Enersource's distribution system to provide customers with electricity services.

Maintaining reliability is one of the key success factors of Enersource and helps reduce operational risks. To maintain reliability Enersource actively tracks outage cause and effect. Based on this information Enersource has ongoing renewal, upgrade, and replacement programs.

Enersource currently evaluates and prioritizes its renewal programs and projects against the significant business values described under Section 2.1 and again are listed below:

- Regulatory/Public Policy Responsiveness
- Operational Effectiveness/Safety
- Customer Focus
- Financial Performance

**Table 52** below details Enersource's expenditures by capital program within System Renewal from 2016 through 2021.



DRAFT

**Table 52. System Renewal Expenditures by Capital Program (2016-2021) ($000's)**

| Description | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 |
|---|---|---|---|---|---|---|
| Subdivision Renewal Program | 13,250 | 15,750 | 16,800 | 18,000 | 18,000 | 18,000 |
| Overhead Distribution Renewal and Sustainment | 6,090 | 6,360 | 6,270 | 6,810 | 6,450 | 7,620 |
| Subtransmission Renewal | 4,200 | 3,000 | 2,850 | 3,150 | 3,300 | 4,050 |
| Transformer Replacement | 7,125 | 7,313 | 7,500 | 7,500 | 6,000 | 4,000 |
| Underground Distribution Renewal and Sustainment | 3,750 | 4,500 | 4,500 | 4,500 | 4,500 | 4,500 |
| Emergency Replacement Program | 320 | 320 | 320 | 320 | 320 | 320 |
| **Total** | **34,735** | **37,243** | **38,240** | **40,280** | **38,570** | **38,490** |

### 3.5.2.3.1 Subdivision Renewal Program

Programs and projects included within this section deal with the replacement of underground cables and components that have reached their expected end-of-life and have been determined to create unacceptable operational risks.

The actual locations of the yearly rebuild projects are prioritized by using three years' worth of operational data, ranked by age and number and type of customers involved. Once the rebuild locations are selected, the projects are included in the following year's capital renewal plans, budgeted for, and designed. To optimize work efficiencies, renewal projects typically involve the replacement of the complete underground system including cables, transformers, switchgear, and other system components that are also near the end of their useful life.

Below are the factors used to determine the areas that need to be rebuilt:

- Reliability – based on the worst feeder methodology
- Transformers that are leaking oil
- Transformers that contain PCB
- Health Index of the cables and transformers
- Frequency of cable failures
- Age of the cables and transformers that are located in rear lots.

Moreover, a detailed map, as shown in **Figure 98,** allows Enersource to determine areas that qualify for underground renewal projects. This ensures replacement of transformers that have reached end-of-life or are found to be leaking and thus pose a safety and environmental risk and/or have exhibited reliability issues. The detailed list of subdivision renewal projects included in the DSP is outlined in the LTIP.

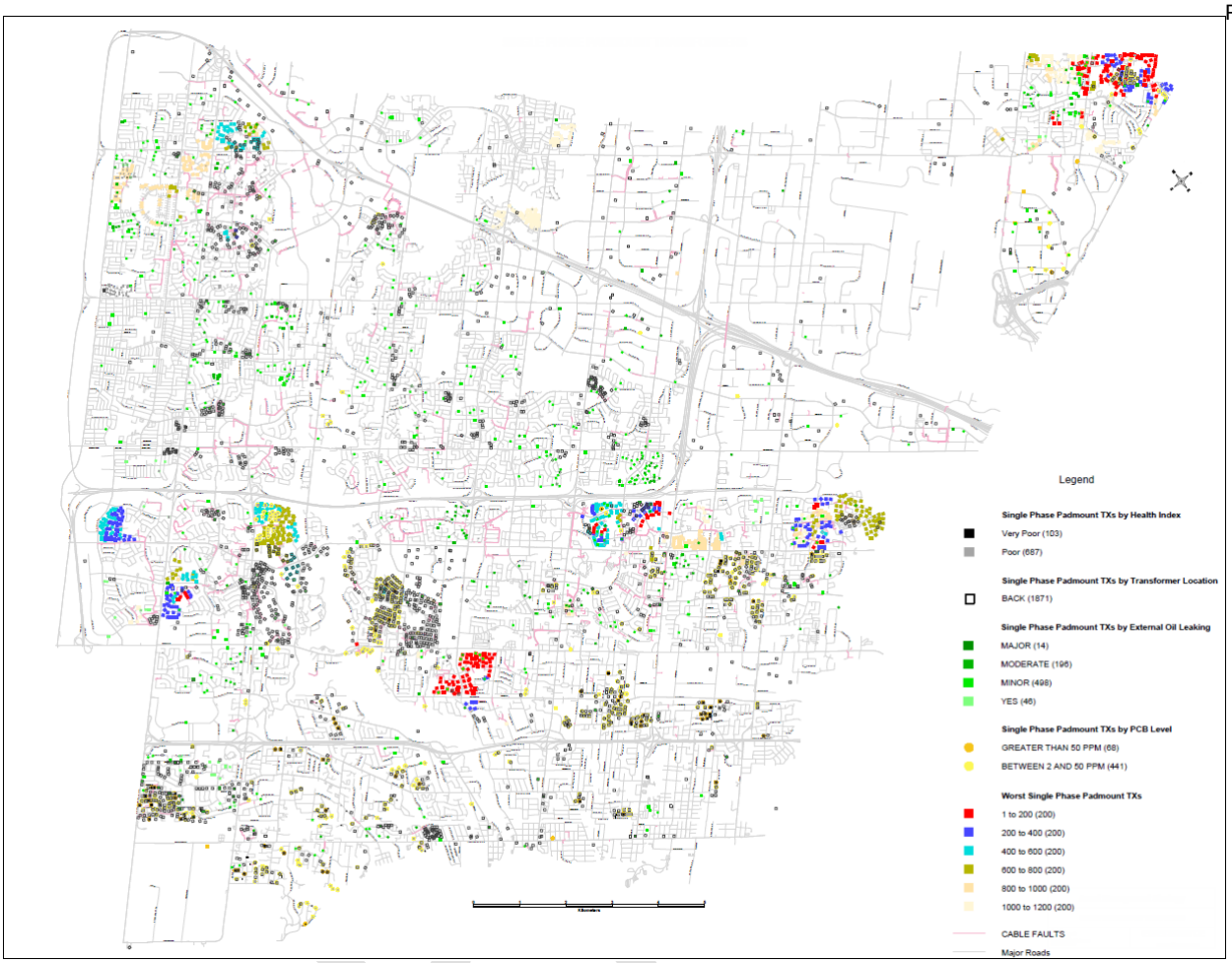



**Figure 98. Enersource Underground Reliability Performance (2012-2014)**

Subdivision renewal program proposed investments from 2016 through 2021 are shown above in **Table 52**.

### 3.5.2.3.2 Overhead Distribution Renewal and Sustainment

Program and projects under this section deal with the replacement of overhead pole lines and attachments that have reached their expected end-of-life or have been determined to be a potential employee or public safety concern.

Overhead assessments are made regarding investment proposals and which investments have the greatest impact on the business values. Assuming there were no constraints, all overhead investments with a positive impact would be approved. Due to resource constraints such as funding, internal and external labour availability, and other considerations inlcuding impact on customers, stakeholders and the environment, programs and projects are selected and prioritized based on supplemental quantitative and qualitative analysis.

Overhead recommendations are made on the timing of system asset additions, replacements and disposals, taking into consideration factors mainly around operational requirements, labour constraints, asset condition, age, criticality, reliability information, new capacity or regulatory requirements, as well as environmental and other stakeholder impacts.

Enersource's overhead System Renewal projects are then selected, designed, and constructed with employee and public safety in mind. The operational risks associated with overhead also plays an important role in determining which projects are undertaken. Since overhead distribution systems are more susceptible to the impact of weather and external forces, the impact of asset failures on Enersource's business values may be substantial.

The detailed list of overhead distribution renewal and sustainment projects included in the DSP is outlined in the LTIP. Overhead distribution renewal and sustainment proposed investments from 2016 through 2021 are shown above in **Table 52**.

#### 3.5.2.3.3 Subtransmission Renewal

Overhead subtransmission pole line renewal projects are required to replace overhead subtransmission infrastructure to ensure it is kept at a safe and acceptable performance level.

The overhead subtransmission system consists of the main feeders that run throughout the City typically on the main arterial roadways and rights-of-way. They are the main backbone of the City's electricity supply, and failure of any main feeder would likely result in a major safety risk and major reliability issue.

The main components of the overhead system are poles, pole top transformers, switches, conductors and associated overhead hardware such as insulators, fuses and lightning arresters. Pole lines deteriorate over time and their strength may be reduced which introduces a risk of failure, especially under adverse weather conditions.

Overhead assessments are made to determine which investments have the greatest impact on the business values. These include safety, environmental, regulatory, reliability, reputational, and financial. Assuming there were no constraints, all overhead investments with a positive impact on the business values would be approved. Due to resource constraints such as appropriate funding, internal and external labour availability, projects are selected and prioritized based on the assessments.

Enersource completed a full inspection of its system in 2014/2015. The inspection data is then used to identify the overhead assets that need to be addressed as well as their relative priority in relation to the business values. The hierarchy of criteria that was used to prioritize the projects is as follows:

- Poles in 'poor' or 'fair' condition: These represent the greatest safety risk to the public and Enersource workers working on or near the poles. For a subtransmission line, both 'poor' and 'fair' pole conditions are of concern due to the higher level of safety risk associated with the taller poles and more circuits located on main roadways. The fact that they consist of taller poles with more

circuits also makes them subject to higher level of forces that can cause failure would likely result in a major reliability issue. This is in contrast to distribution lines where the focus is primarily on 'poor' pole conditions;

- PCB transformers at less than 50 ppm PCBs, greater than 2 pmm PCBs: transformers containing PCBs pose a major safety risk (carcinogen), environmental risk, regulatory risk (Ministry of Environment directive), financial risk (spill remediation), and reputational risk. Note that the category of transformers greater than 50 ppm are not considered, as Enersource is on track to have all such transformers removed by the end of 2015;

- 'Major Leak' transformers: non-PCB transformers that have been identified as having a major oil leak. These pose an environmental risk (environmental damage), financial risk (spill remediation), and reputational risk;

- Top nine large customers and hospitals: large customers and hospitals pose increased reliability risk as outages can impact their businesses and operations with the potential to cause significant financial/critical losses for customers and major reputational damage to Enersource; and

- Majority of poles greater than 35 years old: areas where the majority of poles are older than 50 years are considered because the financial impact of asset write-downs is minimized.

Based on this assessment, the list of projects for overhead subtransmission renewal is determined and projects are then designed and constructed to meet all relevant safety and regulatory requirements.

The detailed list of projects included in the DSP is outlined in the LTIP. Subtransmission renewal proposed investments from 2016 through 2021 are shown above in **Table 52**.

#### 3.5.2.3.4 Transformer Replacement

Distribution transformers are one of the key components of the power system. Their purpose is to lower the primary voltage to secondary voltage levels acceptable to residential, industrial, or commercial customers.

Typically transformer failures are random events that occur for various reasons, most common being insulation breakdown. Lightning-induced failures typically result from turn-to-turn winding failures at or near the end turns of the windings. Lightning surges are random and may be decreased by the installation of lightning arrestors on the distribution system. Deterioration of insulation is also a function of time and temperature. Transformer temperature, in turn, is related to loading. The thermal stress leads to the aging and decomposition of both the oil and cellulose used as an insulating material inside the transformer. Once the insulation fails, the transformer windings are short circuited. Because it is uneconomical to try to repair or refurbish a distribution transformer, such equipment that fails in the field is automatically replaced by a new unit.

Some of the older single-phase pad mount transformers are rusted, especially those installed near roads or sidewalks due to salt application in winter time. This will negatively impact on the transformer and affect performance and operation. The transformer will either rust at the back near the tank, eventually causing the cooling oil to leak out, or rust at the cable compartment. The rusted cable compartment may pose a potential public hazard since it may leave exposed energized parts. As a result, these transformers are replaced immediately.

Every year a number of transformers fail which results in outages to customers. Sometimes transformers are found to be damaged by vehicle contact or are leaking oil and require changing before they fail. A transformer failure in a residential area may only affect 10 to 12 customers so outage effects are minimal. However a transformer failure in an industrial/commercial area could prove costly to those businesses.

In addition, as shown below in **Table 53** the overall transformer inspection program has identified the number of transformers that will need to be replaced. Moreover, field inspections have confirmed that 65 units with PCB concentrations greater than 2 ppm are currently leaking in the field and require immediate replacement. In addition, 1,892 transformer units with no PCB are found to be leaking in the field and will need replacement as well.

**Table 53. Transformers Showing Signs of Leakage and Containing PCB**

| Transformer Type | PCB Leaker | PCB Non-Leaker (>2ppm) | Non-PCB Leaker |
|---|---|---|---|
| Single-Phase Pad Mount | 3 | 474 | 682 |
| Three-Phase Pad Mount | 4 | 23 | 63 |
| Vault Transformers | 42 | 197 | 790 |
| Pole Mount Transformers | 16 | 290 | 357 |
| Total | 65 | 984 | 1,892 |

Transformers are essential elements of the electricity distribution system and when they fail or become unsafe, they must be immediately replaced, as is the equipment attached to it, such as elbows, inserts, fault indicators, or arrestors.

### *Transformer Replacement - Underground*

The program is needed to allow for the planned and unplanned replacement of underground transformers that are in poor condition or fail in various parts of the city. Transformers are replaced when a failure occurs, or are identified as damaged or rusting beyond safe limits.

There are over 15,000 underground transformers on the system. Enersource staff routinely assess transformer condition through work such as switching, and when responding to trouble calls or outages.

As a result of the ACA and the routine asset inspection program, which includes transformers on a three-year inspection frequency, a number of transformers have been identified for replacement due to the transformer condition and/or the presence of PCBs.

As shown below in **Table 53**, the underground transformer inspection program has identified number of transformers that need to be replaced.

These leaking and/or rusted transformers must be replaced since they do not meet safety standards and may result in environmental damage, remediation costs and potential regulatory penalties as a result of a future leak. These units have been included in the six year transformer replacement plan.

### *Single Phase Pad Mount Transformer Replacement*

Enersource's asset inspection program includes the inspection of single phase pad mount transformers and identified 691 which show signs of leaking, of which three units have a PCB concentration above 2 ppm. These transformers should be changed to prevent environmental damage, remediation costs, and potential regulatory penalties as a result of a current or future leak. Many of these units are in residential areas including in backyards or boulevards and are visible to the public. These units have been included in the six-year transformer replacement plan.

### *Three Phase Pad Mount Transformer Replacement*

Enersource recognizes that transformers have been identified as a concern in the ACA and that the future replacement rate should be increased.

Enersource's asset inspection program has identified 67 three-phase pad mount transformers which are leaking, of which four units have a PCB concentration above 2 ppm. These transformers should be changed to prevent environmental damage, remediation costs and potential regulatory penalties as a result of a current or future leak. These units have been included in the five-year transformer replacement plan.

### *Vault Transformer Replacement*

Enersource's asset inspection program has identified 832 vaults which show signs of leakage, of which 42 units contain oil with PCB levels above 2 ppm. These units need to be replaced to ensure reliable service and to prevent environmental damage, remediation costs, and potential regulatory penalties as a result of a future leak. These units have been included in the five-year transformer replacement plan.

### *Transformer Replacement - Overhead*

Transformer condition is routinely assessed by performing work such as switching, responding to trouble calls or outages. The outside crews advise the Control Room of transformers that are in poor condition typically leaking oil.

Enersource will be inspecting transformers on a rolling three-year basis and will be proactively changing transformers in poor condition or leaking oil.



DRAFT

Through ongoing inspection, many overhead transformers are visited up-close, with those requiring immediate attention being changed out. Some transformers were identified for future replacement based on the severity of the issues.

As a result of the routine asset inspection program, which includes transformers on a three-year inspection frequency, a number of transformers have been identified for replacement as a result of the transformer condition or based on the PCB concentration of the oil contained within. As shown above in **Table 53**, the overhead transformer inspection program has identified number of transformers that need to be replaced.

The inspection program has identified a total of 357 non-PCB leakers and 16 units leaking with PCB concentrations greater than 2 ppm. These units should be changed to prevent environmental damage, remediation costs, and potential regulatory penalties as a result of a future leak.

### *Underground Distribution Renewal and Sustainment*

This section has four program sub-components:

- Pad Mounted Switchgear Renewal
- Primary Distribution Equipment Renewal
- Underground Cable and Splice Renewal
- Secondary Cable Renewal.

### *Pad Mounted Switchgear Renewal Program*

The electricity distribution system consists of several important components to deliver electricity to customers. Enersource uses pad mounted switchgear as an integral component on the underground primary distribution system. These switchgear units serve as an electricity distribution location as well as a switching point. There are approximately 852 switchgear units in the distribution system of which 8% are motorized and monitored via SCADA.

Air insulated switchgear have increasingly been experiencing failures due to age, design configurations, and application voltage levels. This results in power quality, reliability and maintenance issues. These types of faults may expose customers to multiple power interruptions and may take days to troubleshoot and locate the problem. As Enersource's system ages, this type of failure has become even more prevalent.

Several different options were explored to mitigate the deteriorating performance of air insulated switching units. Enersource has selected solid dielectric technology for the pad mounted switchgear replacement program. These units have a projected life span of 50 years and will enhance reliability performance as compared to air insulated switchgear.

In 2009, two pilot projects were approved and implemented in order to evaluate the Solid Dielectric (SD) products. Four automated units from two different companies were installed in the 13.8kV distribution



DRAFT

system at Credit Valley MS. Following the evaluation of these units, Enersource started replacing the end-of-life air insulated pad-mounted switchgear with SD switchgear in 2011.

In March, 2013 Enersource experienced a failure on one of the SD switchgear units installed on the 16/27.6kV system. The failed unit was returned to the manufacturer for analysis and Kinectrics was hired as a third party consultant to jointly conduct the failure review. The root cause analysis included a review of the manufacturing process and in-depth examination of the failed components. After the review, Enersource determined that it would only install 35kV switchgear on the 16/27.6kV distribution system to ensure the units were capable of handling the associated electrical loads and voltage fluctuations.

### *Primary Distribution Equipment Renewal Program*

In addition to the main underground system components such as transformers, switchgears, and cables, the underground distribution system also consists of smaller, auxiliary components such as elbows, inserts, lightning arresters, fault indicators, etc. Without these auxiliary accessories, the main components of the system can become inoperable; therefore, replacement of this equipment before failure is necessary.

Some of the auxiliary system components, such as elbows and inserts, are used to perform switching operations, isolations and restoration. Therefore their condition directly influences system reliability as well as the safe operation of equipment.

The useful life for elbows and inserts, which are used in the operation of transformers, varies significantly. Based on past experience, elbows are typically found to be in poor condition after 20 to 25 years, and need changing along with their inserts.

Other auxiliary devices, such as fault indicators, are used when troubleshooting a system outage. Their proper operation influences restoration time and, in turn, overall system reliability. Enersource has found through past experience that 20 years for transformer fault indicators is a typical useful life.

In addition, equipment condition is routinely assessed by operations personnel performing work on a transformer or switchgear, such as switching or other asset replacement. If a defective component is found, the crew notifies the Control Room and if the crew on site cannot make the necessary repairs then a maintenance crew is dispatched to perform necessary repairs.

### *Underground Cable and Splice Renewal Program*

Underground primary cables are another key component of the distribution power system. They are one of the most expensive components to replace, due to the high costs of both materials and installation.

Typically, underground cable failures are caused by degradation of the insulation, the dielectric medium that insulates the central conductor from the grounded concentric neutral wires. Insulation failure can be caused by several factors, for example:

- Contaminated materials during the manufacturing stage
- Poor adhesion of the extruded insulation shield
- Imperfections at the conductor shield-insulation interface
- Water inside the conductor strands or at the concentric neutral wires
- Fault currents
- Voltage surges from lightning and switching.

The impact on customers depends on whether the cable is a subtransmission cable, main feeder distribution cable, or local distribution feeder cable. The subtransmission cables typically supply an MS; therefore, a failure of a cable supplying a single station may result in a disruption of power for up to 5,000 customers.

The local distribution feeder cable is connected to a pad mounted switchgear or the overhead distribution system and typically will supply up to 500 customers. Cable failure will result in a power outage to all customers connected and typically will momentarily trip the substation breaker as the fuse isolates the fault affecting on average up to 1,000 customers.

In addition to cable spot replacement, this program also incorporates heat shrink splice replacement. In the past, several thousand heat shrink cable splices were installed on the system. Later, it was discovered that a vast majority of them failed prematurely. As a result, Enersource took a proactive approach and decided to replace all known heat shrink splices with new cold shrink splices that perform considerably better. Cable and splice failures remain the largest contributor to customer outage time.

### *Secondary Cable Renewal Program*

The distribution system has over 203,000 customers, the majority of which are connected to a distribution transformer via an underground secondary service cable. Based on past experience, secondary cables are less prone to failure compared to primary cables of the same age, which is mainly due to less electrical stress and fewer fault current spikes. However, when secondary cables fail, they need to be immediately repaired, as they are needed to supply customers with power. Every year a number of underground residential and industrial/commercial services fail beyond reasonable repair and require complete replacement. These failures typically result in outages to single residential or industrial/commercial businesses.

This renewal program does not target any specific area, but rather underground secondary cables, over various parts of the City that have been determined to be at the end of their useful lives. They are replaced individually. Under this program, rather than replacing secondary cables based on age or size, they are replaced based on their condition and number of failures. This program entails the spot replacement of secondary services, over various parts of the City that are at the end-of-life and are beyond reasonable repair.

Underground distribution renewal and sustainment program proposed investments from 2016 through 2021 are shown above in **Table 52**.

### *3.5.2.4 General Plant*

General plant investments are modifications, replacements or additions to Enersource's assets that are not part of its distribution system. These include land and buildings, tools and equipment, rolling stock and electronics devices and software used to support day to day business and operations activities.

This section has eight components:

- Engineering and Asset Systems
- Rolling Stock
- Information Technology
- JDE/ERP System
- Meter to Cash
- Grounds and Buildings
- Major Tools.

**Table 54** details Enersource's expenditures by Capital Program within General Plant from 2016 through 2021

**Table 54. General Plant Expenditures by Capital Program (2016-2021)**

| Description | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 |
|---|---|---|---|---|---|---|
| Engineering & Asset Systems | 1,510 | 1,187 | 1,391 | 1,228 | 1,345 | 1,293 |
| Rolling Stock | 2,775 | 2,244 | 2,033 | 3,011 | 2,298 | 1,946 |
| Information Technology | 671 | 456 | 572 | 1,040 | 870 | 560 |
| JDE / ERP System | 2,185 | 2,000 | 1,180 | 1,320 | 1,637 | 1,410 |
| Meter to Cash | 2,470 | 2,055 | 2,180 | 1,420 | 1,830 | 2,000 |
| Grounds & Buildings | 2,985 | 3,195 | 2,725 | 2,575 | 2,575 | 2,575 |
| Major Tools | 200 | 200 | 200 | 200 | 200 | 200 |
| **Total** | **12,796** | **11,337** | **10,281** | **10,794** | **10,755** | **9,984** |

#### Engineering and Asset Systems

The Engineering and Asset Systems (E&AS) capital budget provides information technology tools to assist in the management of field assets. These tools include software and hardware for 170 people, including both office and field personnel. The budget assists Enersource in improving efficiency and reliability, reducing costs, and ensuring the safety of staff and the public.

To ensure that all computer hardware is current, it is replaced on a three or four year cycle, depending upon the life-span of the equipment. Workstations (high-end PCs used for running engineering applications), monitors, servers and field computers are replaced on an appropriate schedule to ensure

that the equipment complies with current standards. Plotters, or wide-format printers for the output of drawings and maps, have a five to eight year life cycle.

If additional licenses of engineering software applications are required so that information and analysis capability can be made available to more of Enersource's internal and field personnel, the E&AS budget is utilized. Software upgrades for any of the engineering systems are funded through this budget.

The largest two software systems include the IOM and AM/FM systems. Any projects related to these two systems are funded through the E&AS capital budget.

SmartPlant Foundation (SPF) is the document management system for the engineering records, providing document security based on the user, the access type requested, and the document class. The system houses revisions, approved, and as-constructed drawings, easements and permits. It also issues location numbers for switches and transformers. There are dozens of workflows used to manage business processes and the system is integrated to both AM/FM and JDE.

Engineering and Asset Systems proposed investments from 2016 through 2021 are shown above in **Table 54**.

### Rolling Stock

Enersource requires a fleet of specialized vehicles to complete many daily activities, including the construction and maintenance of the electricity distribution system, and to allow for quick restoration of power due to electricity distribution system disturbances. Degradation of fleet assets could jeopardize worker safety and negatively affect electricity distribution system performance and response to outages.

Rolling stock proposed investments from 2016 through 2021 are shown above in **Table 54**.

### Information Technology

The IT infrastructure group provides and maintains the foundation on top of which the applications of the business operate. The team provides:

- Support and maintenance of the corporate network (which includes data, email, voice services, and web environments) and to provide a highly reliable and available environment;
- Security of the IT infrastructure, resources access, assets and data protection and availability;
- Availability of all servers supporting the many business critical applications used throughout the Company and provides service and support of these systems as required;
- Support to the end user community on all IT systems, applications and peripherals, as well as voice services related issues;
- Management of the corporate telecommunications infrastructure which includes telephone system, wireless devices platform, and the Call Centre voice queuing system; and



DRAFT

- Assistance in the implementation of new capital and operating projects by providing consulting, planning and implementation expertise in the commissioning of new applications and processes.

Information Technology proposed investments from 2016 through 2021 are shown above in **Table 54**.

### JDE/ERP System

As stated earlier, Enersource uses Oracle J.D. Edwards (JDE) as its Enterprise Resource Planning (ERP) tool. It is a modular, scalable, and integrated information management software system that facilitates the flow of information across the different divisions at Enersource.

JDE and its auxiliary applications automate business processes:

- Finance – General Ledger, Accounts Payable, Accounts Receivable, Fixed Assets
- Operations – Service Orders (program/project cost)
- Supply Chain – Inventory/Warehouse Management, Procurement
- Human Resources – Employee Management.

JDE also interfaces with other major applications within Enersource such as AM/FM/GIS and the Customer Care and Billing (CC&B) system to ensure data integrity and simplification of business processes.

In addition to JDE, the department is also responsible for the other enterprise applications that extend across other IT departments and are used by multiple business units. This includes:

- Business Intelligence systems (e.g., IBM Cognos)
- REVEAL – used as a centralized reporting repository
- SharePoint – for the corporate Intranet and external Internet site.

JDE/ERP System proposed investments from 2016 through 2021 are shown above in **Table 54**.

### Meter to Cash

The Meter to Cash team supports all meter to cash functions, providing on going day to day operations and maintenance, upgrades and implementation of new functionality (in accordance with business needs and regulatory requirements). The systems are comprised of all of those involved in the meter to cash process including Meter Reading, AMI systems, Meter Data Management, Wholesale and Retail Settlement, EBT transactions, MDM/R transactions, Billing, Cash, Collections, Business Intelligence and related field activity systems, including interfaces among these systems. Interfaces to JDE, CRM and AM/FM applications are also supported.

CC&B and the surrounding suite of applications address:

- Customer account management/premise management
- Cash and collections
- Customer contact tracking and management
- Metering/meter management
- Meter reading/estimating
- Rates engine
- Billing/bill creation
- Analyses and reporting.

Meter to Cash proposed investments from 2016 through 2021 are shown above in **Table 54**.

## Grounds and Buildings

Capital expenditures are required to acquire and maintain Enersource workspaces and service facilities to acceptable standards. The existing facilities allow for flexible work areas and a safe work environment. Some key projects will see major upgrades in the following areas: HVAC, asphalt replacement, building envelope and windows.

Enersource building facilities are required to be reasonably current and in good working order. Based on regular assessments of building condition, all buildings require various investments to maintain them in a good state of repair, improve productivity within the work environment, accommodate growth and change in the workforce, and address identified health and safety risks. As described above, the three facilities are of various ages.

The areas of concern for Enersource facilities that require expenditures are:

- HVAC (Heating & air conditioning)
- Structural (Building envelope, walls and windows)
- Equipment (Furniture, Elevators)
- Mechanical & Electrical (i.e., Plumbing, Electrical components)
- Security (Access Control, CCTV, Building Automation System);
- Life Safety (Fire suppression, Sprinklers, Fire Alarm Panels)
- Exterior (i.e., pavement, fencing, landscaping).

Grounds and Buildings proposed investments from 2016 through 2021 are shown above in **Table 54**.

Please see section 2.3.5 Facilities Remediation for more detail.

DRAFT

## Major Tools

In order to maintain and operate an electrical system and operate a fleet of over 200 vehicles, investment in quality tools is paramount. Each truck is furnished with basic hand tools and equipment while specialized items are limited to specific trucks, (examples include: chainsaws on Forestry vehicles, cable cutters and crimpers on underground vehicles). Funding for tool expenditures of $7,500 or more per item is classified as a 'major tool' and requires additional internal approvals. This category of funds covers the purchase of such items as:

- Mud tracks – to allow vehicles to traverse over wet ground and/or over buried pipelines
- Ground leads - to allow for the safe operation of personnel and equipment on isolated electrical equipment
- Battery operated devices – to allow for repair of underground cable in splice pits and provide better ergonomics for staff
- Cable locating equipment – to find buried operational cables so that other utilities can perform their construction work without causing cable damage
- Fault finding equipment – to aid in locating underground cable faults requiring repair.

Major Tools proposed investments from 2016 through 2021 are shown above in **Table 54**.

DRAFT

**BOMA-4**

**Reference(s): DSP, p22**

**Please provide a copy of the Enersource customer engagement process completed in 2016.**

**Response:**

Alectra Utilities' predecessor, Enersource, completed a customer engagement process in 2016 as part of Enersource's 2016 Price Cap IR Application (EB-2015-0065) to support the draft Distribution System Plan ("DSP").

Alectra Utilities has provided the customer engagement report as BOMA-4_Attach 1_Decision Partners Report. This report was previously as Undertaking JT 1.16, in the 2016 rate application proceeding.

# Enersource Hydro Mississauga, Inc.
# Research-Based Customer DSP Consultation

## Final Report

**By Decision Partners**

**January 15, 2016**

DECISION PARTNERS

Thorne Butte: Decision Partners Inc.
877 588 9106 • dprc@decisionpartners.com • www.decisionpartners.com

## Table of Contents


Section 1: Introduction ..... 3
Section 2: Consultation Executive Summary ..... 4
Section 3: Methodology and Approach ..... 6
Section 4: Mental Models Research Summary ..... 11
4.1 Executive Summary ..... 11
4.2 Bottom Line Up Front ..... 11
4.3 Summary Report ..... 13
Section 5: Interactive Decision Support Technology (IDST™) Research Summary ..... 24
5.1 Executive Summary ..... 24
5.2 Bottom Line Up Front ..... 24
5.3 IDST™ Content Overview ..... 25
5.4 Handling Customer Questions ..... 26
5.5 IDST™ Customer Research Summary ..... 28
Section 6: Key Learnings ..... 38
Section 7: Considerations ..... 43
Section 8: Appendix ..... 48
8.1 Expert Models ..... 48
8.2 Mental Models Sample Size ..... 53
8.3 Protocol Outlines ..... 54
8.3.1 Enersource Customer DSP Consultation Mental Models Research ..... 54
8.3.2 IDST™ Protocol Outline ..... 59
8.4 Observations of Other LDC's DSP Workbooks ..... 63
8.5 Print Survey ..... 65
8.6 Customer and Stakeholder Communications re IDST™ ..... 73
8.6.1 News Release - Enersource ..... 73
8.6.2 News Release – Decision Partners and MedRespond ..... 74
8.6.3 Email to OEB from Gia DeJulio ..... 75
8.6.4 Enersource Invitation ..... 76
8.6.5 Enersource Bill Insert ..... 77
8.6.6 Twitter Messages / Responses ..... 77
8.6.7 Facebook ..... 78
8.7 Judgment v. Opinion ..... 78
8.8 Decision Partners and MedRespond ..... 79

## Section 1: Introduction

In early 2013, Ontario's energy regulator, the Ontario Energy Board (OEB), implemented new requirements for rate application submissions calling for electricity distribution companies to solicit their customers' preferences and demonstrate that their Distribution System Plan (DSP) is responsive to these preferences.[1] The DSP is the foundation for rate increases over the next five years. While rate increases are a topic of great interest to most customers, the plan behind them and its rationale have not been transparent in the past.

Leaders at Enersource Corporation, the electricity distribution company for the City of Mississauga, Ontario, carefully weighed their approach to responsibly fulfilling this requirement. They considered traditional approaches for soliciting customer feedback, such as brochures, opinion surveys, focus groups and workbooks, but recognized the limitations of those tactics for complex topics such as electricity distribution.

In February 2015, following an RFP process, Enersource contracted Decision Partners to design and conduct a comprehensive customer consultation initiative to gain in-depth insight into customers' perspectives on their proposed DSP. The results are being used to develop "detailed, sophisticated and compelling evidence" that demonstrates the Enersource Team's commitment and obligation to engage, inform and seek customer input on key components of their draft DSP in a meaningful way, while listening to and incorporating customer feedback into their DSP submission.

The following is an overview of this Report:

- **Section 1: Introduction**
- **Section 2: Consultation Executive Summary,** including an overview of the two phases of Informed Engagement Step 1: Systematically Gathering Foundational Insight and Step 2: Conducting Thoughtful Conversations
- **Section 3: Methodology and Approach,** including details of the two phases of direct Customer Engagement
- **Section 4: Mental Models Research Summary,** including an Executive Summary, the Bottom Line Up Front and the Summary Report
- **Section 5: Interactive Decision Support Technology™ (IDST™) Research Summary,** including an Executive Summary, the Bottom Line Up Front, the IDST™ Content Overview, the IDST™ Customer Survey Summary and Handling Customer Questions
- **Section 6: Key Learnings**
- **Section 7: Key Considerations**
- **Section 8: Appendix,** including the Expert Models, Protocol Outlines, the Print Survey and Customer and Stakeholder Communications related to the IDST™

[1] http://www.ontarioenergyboard.ca/oeb/_Documents/Regulatory/Filing_Requirements_Tx_Dx_Applications_Ch5.pdf

## Section 2: Consultation Executive Summary

### *Informed Engagement Step 1: Systematically Gathering Foundational Insight*

Decision Partners designed and conducted a total of 40 one-on-one confidential mental models interviews with three cohorts of Customers[2]: Residential; Non-Residential and Large Use Customers from June 6 to October 16, 2015:

- Residential Customers: 15 interviews were conducted with Residential Customers between June 6 and July 20, 2105.
- Non-Residential Customers: 16 interviews were conducted with Non-Residential Customers between June 25 and August 10, 2015.
- Large Use Customers: Nine interviews were conducted with Large Use Customers between June 23 and October 16, 2015.

The research results were significant. The foundational research demonstrated that most Residential and Non-Residential Customers did not have sufficient understanding of the electricity system, to provide meaningful input into the DSP. Customers' mental models of the electricity system were incomplete and, in some cases, incorrect. Consequently, if customers do not understand the system, they could not reasonably be expected to understand the rationale behind investment decisions being proposed in the DSP or provide meaningful input on the key components.

The foundational research also underscored that Customers were unclear about the company's role in the electricity system and that there was significant confusion about costs associated with Enersource's distribution compared to costs of the overall electricity system. Consequently, Enersource's value proposition – what it takes to deliver electricity safely and reliably – was not understood by most Customers. The bottom line: If customers do not understand the basic value proposition, they can't make well-informed judgments about the need for, or acceptability of, Enersource's DSP and the resulting rate increase.

Clearly an intervention based on informed insight and customized to address customers' values, interests and priorities was required to effectively communicate the implications of the DSP for customers over the next five years and to improve the meaningfulness of any customer feedback on the DSP. Without an intervention, customers could not provide meaningful input into the development of Enersource's DSP, and Enersource could not achieve its consultation goals.

### *Informed Engagement Step 2: Conducting Thoughtful Conversations*

Enersource invited its approximately 200,000 Residential and Non-Residential customers to participate in the web-based Interactive Decision Support Technology™ (IDST™) Customer Engagement via multiple channels, including press releases sent and posted on the website, email and bill insert invitations sent to customers, Twitter announcements and Facebook reminders. Customers were also given the option to request a printed survey if they did not want to participate in the online engagement.

[2] Note when capitalized, Customers refers to those Enersource customers who participated in research.

As an incentive to participate, Customers who answered all 11 core survey questions about the Long Term Plan (LTP)[3] by the end of day December 23, 2015 were entered into a draw for one of eight Samsung Galaxy tablet computers.

Customer feedback on the LTP was collected between November 23 and December 30, 2015 and analyzed for this Report.[4] The IDST™ engaged a total of 3,779 Unique Visitors. Of those, 2,206 Customers went beyond the introductory videos to data collection segments of the IDST™, including: 2,157 Residential Customers and 49 Non-Residential Customers. In addition, 43 non-Customer Guest Users visited the site and provided feedback, which has not been included in our customer data analysis.

In total, 1,358 Customers responded to all 11 core LTP questions (required for entry into the promotional draw). The 3,779 Unique Visitors spent a total of 97,276 minutes in the IDST™ engagement, averaging 25.7 minutes per visitor. Those who provided feedback submitted 24,064 responses.

The results provided significant insight into Customers' judgments about Enersource's LTP. When Customers had an opportunity to understand the electricity system and then think through the components and rationale of the LTP, most judged the proposed investments to be both critical and appropriate. As two Customers described it:

> *"Kudos on the succinct explanation."35%" is a significant amount and at first, the proposition seems to apply to the whole bill (which would be outrageous). I believe in responsible investment... IF this applies solely to the single section - and would represent an approximate increase of $2/month to the average user, this seems reasonable to me."*
>
> *"The total proposed cost that would affect my bill on a regular basis being only $2 is acceptable for the proposed changes."*

Nearly all Customers (90%) expressed a "*Medium*" or "*High*" level of confidence that Enersource would do what is necessary to continue to provide safe, reliable, cost effective electricity by implementing the investments described in the LTP.

The IDST™ results were somewhat more positive than the mental models research results, possibly because Customers were engaging with "real" Enersource people or because the IDST™ provided more context on the LTP components compared to the mental models research. Based on the comments, the IDST™ experience appears to have been a positive one for most Customers.

### *Results*

The Enersource Team committed to adopting a behavioural science-based approach to customer engagement. They systematically worked through the consultation process, first to discover customer interests, preferences, priorities, and information needs, then use that insight to develop a state-of-the-science tool to engage a broader group of customers using a web-

[3] While we use the term DSP to reflect the regulatory terminology, during engagement with Customers, Enersource chose to use the terminology of "Long Term Plan" or LTP. We use LTP in our Report where it directly relates to the results of the Customer engagement.
[4] The site remained active until January 7, 2016.

based interface. In so doing, they demonstrated the company's leadership and progressive thinking. We believe the results speak for themselves.

In short, the Enersource Team successfully engaged more Customers in *meaningful* dialogue about the electricity system, the role of the LDC, the proposed activities under each of the key components of their DSP and the rationale for the required investment than is typical of consultations in this industry. In return, they received thoughtful *judgment* about their proposed DSP from over 1,400 IDST users and from 40 Customers who participated in the foundational research. The quality of customer input – thoughtful judgment and well-informed decisions – surpasses that typically gathered through traditional methods.

Based on the results of this engagement – the robust input from Large Use, Residential and Non-Residential Customers – *we do not recommend any substantive changes* to Enersource's draft DSP. By providing additional context on a few topics noted below, we believe Enersource's DSP addresses both direct and indirect customer preferences.

## Section 3: Methodology and Approach

To support the Enersource Team as they prepared the DSP, Decision Partners (DP) adapted its proprietary Mental Modeling Technology (MMT™) Approach to design and conduct two phases of direct Customer Engagement:

- Informed Engagement Step 1: Systematically Gathering Foundational Insights
- Informed Engagement Step 2: Conducting Thoughtful Conversations

### *Informed Engagement Step 1: Systematically Gathering Foundational Insight*

Given the complex social and technical issues inherent in the DSP, the Enersource Team determined that effective customer consultation had to be based on in-depth insight into people's values, interests and priorities; in short, their mental models.[5] Decision Partners' proprietary Mental Modeling Technology™ (MMT™) – evidence-based, science-informed processes, methods and tools – is specifically designed for understanding and influencing judgment, decision making and behaviour on such issues.

MMT™ is based on the foundational mental models research approach developed by a team at Carnegie Mellon University led by Dr. Baruch Fischhoff, Decision Partners' Chief Scientist.[6]

[5] For example: Johnson-Laird, P.N. (1983). Mental Models. Cambridge, MA: Harvard University Press. Atman, C.J., et al. (1994) Designing risk communications. Risk Analysis 14(5): 779-788; Bostrom, A. et al. (1992) Characterizing mental models of hazardous processes. J. Social Issues 48(4): 85-100; Fischhoff, B. et al. (1997) Risk perception and communication. In: Detels, R. et al. (eds.) Oxford textbook of public health. London: Oxford University Press, 1997. Pp. 987-1002.

[6] See Morgan, M.G., B. Fischhoff, A. Bostrom, and C.J. Atman. 2002. "Risk Communication: a Mental Models Approach." New York: Cambridge University Press; and Baruch Fischhoff, Noel Brewer and Julie S. Downs (editors) (2011) "Communicating Risks and Benefits: An Evidence Based User's Guide" Department of Health and Human Service, U.S. Food and Drug Administration. http://www.fda.gov/AboutFDA/ReportsManualsForms/Reports/ucm268078.htm

MMT™ is well established in the fields of decision sciences, cognitive behavioural psychology, risk analysis and risk communications. It is the premier method for eliciting, analyzing, and modeling people's thinking on complex issues and using that insight to inform the development of evidence-based strategies, policies and tools that address them. In February 2016, Decision Partners received a patent for its Mental Modeling Method. This patent reflects the essential intellectual property and software tools that comprise Mental Modeling Technology™.

*What are Mental Models?*

A person's "mental model" can be thought of as a complex web of deeply – and often subconsciously – held beliefs that affect how an individual defines a situation, reacts to information, forms judgments and makes decisions. These sets of beliefs may be complete and correct, or they may have gaps or misunderstandings that are consequential to decision making and action. People's mental models vary in important and often unpredictable ways. To address these issues, a systematic approach such as MMT™ was critical for this initiative, which required engaging three customer classes and eliciting their input in ways that were appropriate and meaningful to them.

*Expert Modeling*

Broadly, MMT™ works from the "inside out" of people's thinking. The approach relies on systematically collecting data from expert and appropriate non-expert stakeholders.

Accordingly, the first step was collecting and characterizing currently available knowledge and integrating it into a key management tool called an "expert model". The expert knowledge needed to produce the expert model was gathered from reference materials and from subject matter experts within the Enersource Team.

An influence diagram is commonly used to depict an expert model. It represents the experts' understanding or hypotheses of relevant influences in terms of variables, and the relationships among them, as they relate to the outcomes of interest to stakeholders. With respect to Enersource, the Expert Model illustrates the influences that the 'experts' believe affect customers' thinking – influences such as the economic, technical, social and environmental factors of interest to its customers with respect to the DSP.

For more detail, please refer to the Expert Models in Appendix 8.1, on page 48.

*Customer Mental Models Research*

The next step involves systematically collecting data to develop insight into what Customers already understand and believe about the electricity market in general, and the distribution sector in particular. At this stage, the variables that influence understanding and beliefs are also captured. Mental models research interviews, a key component of MMT™, enable deeper insight into individuals' beliefs and influences on their decision making than other research approaches.

Decision Partners used the expert model to design parallel mental models interview protocols for each of the three cohorts of customers: Residential, Non-Residential and Large Use Customers.

Once designed, Decision Partners conducted interviews with three cohorts of customers: residential; non-residential and large use customers. From June 6 to October 16, 2015, a total of 40 one-on-one, confidential interviews were conducted by phone, with 15 Residential Customers, 16 Non-Residential Customers and nine Large Use Customers.

A typical cohort for mental models interviews is 30 to 50 people within a population believed to have relatively similar beliefs. However, after about 20 interviews, very few new concepts tend to arise. One hears mostly familiar beliefs, while the new concepts are increasingly idiosyncratic. For more information about sample sizes, please see Appendix 8.2 on page 53.

The interviews followed a semi-structured interview protocol, based on the concepts identified in the Expert Model. In addition, while the protocol offered interviewees an agenda of topics, it also allowed for free expression and encouraged elaboration on topics of interest to interviewees, in order to reveal a full set of individual perspectives in greater depth while ensuring that key factors identified in the Expert Model were discussed.

Interview data were coded and analyzed against the Expert Model. The analysis was conducted using Decision Partners' proprietary CASS™ software specially designed for rich analyses of unstructured qualitative and quantitative data. These analyses enabled direct comparisons between the expert knowledge and the revealed "mental models" of Customers. This approach also identified themes that are important influences on Customers' decision making, even if they had not been anticipated or identified in the expert model. The coding of the interviews against the concepts illustrated in the Expert Model ensured that all data were systematically captured.

*Key Mental Models Research Results*

This foundational research demonstrated that most Residential and Non-Residential Customers did not have a sufficient understanding of the electricity system to provide meaningful input into Enersource's DSP. Customers' mental models of the electricity system were incomplete and, in some cases, incorrect. It can be reasonably concluded that if customers do not understand the electricity system, they cannot reasonably be expected to understand the rationale for investment decisions being proposed in the DSP or provide meaningful input on the key components of the DSP: System Access and System Renewal, System Service, and General Plant Investments.

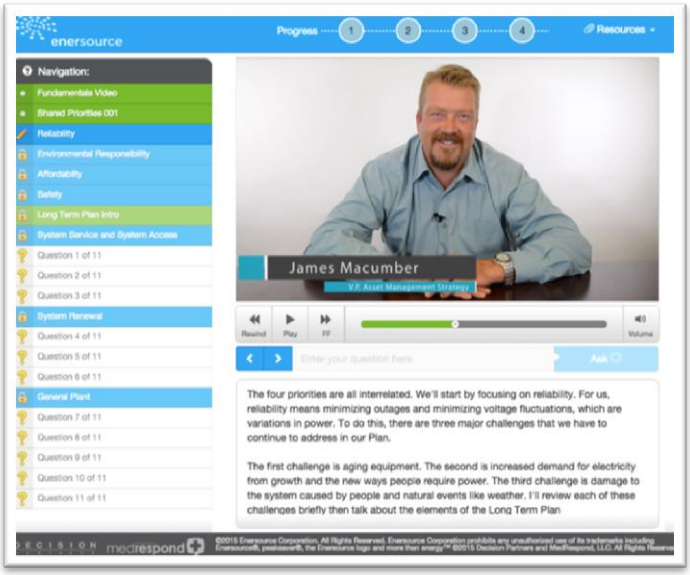
The foundational research also underscored that customers were unclear about the company's role in the overall Ontario electricity production and delivery system (i.e., generation, transmission and distribution), and that there was significant confusion about costs associated with Enersource's distribution system, as compared to costs of the overall electricity system. Consequently, Enersource's value proposition – what it takes for Enersource to deliver electricity safely and reliably – was not understood by most Customers.

The bottom line: if Customers do not understand the distributor's basic value proposition, they cannot be expected to be able to make well-informed judgments about the need for, or acceptability of, Enersource's DSP and the resulting rate increase.

The Enersource Team agreed that an intervention based on informed insight and customized to address customers' values, interests and priorities was required in order to effectively communicate the implications of the DSP for customers over the next five years and to improve the meaningfulness of any customer feedback on the DSP. They also agreed with Decision

Partners' conclusion, that the original design for the next phase of engagement – to use the results of the mental models research to conduct a web survey with customers – was inadequate.

### Informed Engagement Step 2: Conducting Thoughtful Conversations




Building on the findings of the foundational mental models research, Decision Partners, and its Interactive Decision Support Technology™ (IDST™) partner, MedRespond, proposed an engagement solution that would first clarify Enersource's power delivery role within the larger electricity system, then enable engagement of a broad range of Residential and Non-Residential Customers in thoughtful "conversations" with Enersource leaders about the LTP. Enersource leaders would listen and respond to participating Customers' questions and comments in an online, virtual Customer engagement environment. Working with Enersource's Team, MedRespond designed, developed and hosted a state-of-the-science website to bring Decision Partners' foundational research based on its Mental Modeling Technology™ to life using MedRespond's Synthetic Interview™ platform. This is the first full scale application of IDST™ worldwide, and a breakthrough customer engagement approach for the energy sector.

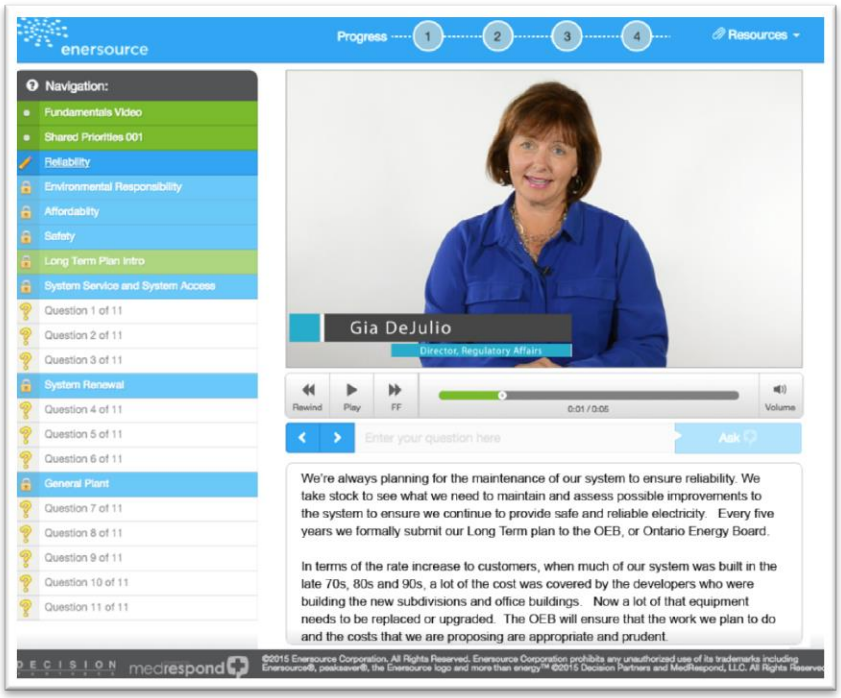
The Synthetic Interview is an interactive technology that simulates a one-on-one conversation through a combination of streaming video and artificial intelligence designed to enable a direct interaction with the video hosts. Customers feel as though they are engaging directly with the video hosts.

Customers listened to and watched descriptions of the various aspects of power distribution and aspects of the LTP presented by members of the Enersource Leadership Team, including:

- James Macumber, Vice President, Asset Management Strategy, (IDST™ Host)
- Peter Gregg, President and Chief Executive Officer
- Dan Pastoric, Executive Vice President and Chief Customer Officer
- Norm Wolff, Executive Vice President and Chief Financial Officer
- Kimberly Boyle, Vice President, People and Corporate Relations
- Chris Hudson, Vice President, Asset Operations
- Gia DeJulio, Director of Regulatory Affairs
- Natalie Yeates, Manager, Rates & Settlements

Customers were then asked for their feedback on the LTP. The content, built on the foundational mental models research results, was designed to address gaps in customers' understanding of the electricity system, while enabling Customers who participated in the

synthetic interview to provide meaningful input on the various components of the LTP. Customers could also ask their own questions about the specific elements of the Plan or other related topics that interested them.




This customer-centric approach provided information and gathered feedback from Customers in a way that was much more engaging and interactive than traditional approaches such as opinion surveys, focus groups and workbooks. It also offered several advantages. Information presented in a visual format is much easier for customers to understand and process cognitively; interaction with the Enersource leaders, underscores the company's commitment to meaningful engagement; the dialogue approach allowed for a two-way flow of a natural conversation compared to the one-way, "tell" process that is used in other approaches; and the synthetic interview format is significantly more convenient and less time consuming for customers, improving their willingness and ability to provide meaningful input on the Plan.

*Advantages over Conventional Customer Engagement Methods*

The Interactive Decision Support Technology™, a unique combination of cognitive modeling and artificial intelligence, is a powerful new technology for customer engagement. It is more customer-centric than traditional engagement tools because it is based on customers' mental models – *their* values, interests, priorities and information gaps and needs. The technology anticipates and responds to these in a conversational format. This dialogue-based technology enhances customer engagement through the proven Synthetic Interview™ medium that enables customers to gather the information they want and need to make well-informed judgments. At the same time, it enables real time, systematic collection of data about customer priorities and how they change over time.

Enersource's IDST™ site – www.electricitydialogue.ca – was launched November 23, 2015 and remained active until January 7, 2016. Customers were invited to log on to the site, view the Electricity Fundamentals video, then take part in the IDST™. Customers who completed the 11 IDST™ mandatory questions were eligible to be entered into a draw for one of eight tablet computers.

Based on the results of the mental models research, the site specifically addressed what customers know, what they don't know, what they misunderstand, what they want to know and the communications processes they prefer. This insight enabled a precise and tightly-focused

design of the IDST™ engagement tool. It was anticipated it would take customers about 20 - 25 minutes to complete the mandatory questions. This is significantly less time when compared to traditional "workbooks" with embedded opinion surveys that are based on assumptions about customers' interests and needs. The average time spent on the IDST™ was 25.7 minutes per user.

The site provided a series of very brief videos, each explaining, in as simple language as possible, the fundamentals of electricity generation, transmission and distribution. It also provided Enersource's justification for its spending over the next five years in each of the investment categories: System Access and System Renewal; System Service; and General Plant Investments. Additional segments addressed issues and topics of interest that were revealed in the mental models research; for example, one segment explained customer bills. The Enersource Team hoped that the interactive video-based presentation of information using language that a lay person could understand would be significantly more engaging than text-based "workbooks" and similar methods used by other LDCs.

The Mental Models Research Summary is included in Section 4.3 on page 13. The IDST™ Customer Research Summary is included in Section 5.5 on page 28.

# Section 4: Mental Models Research Summary

## 4.1 Executive Summary

***Informed Engagement Step 1: Systematically Gathering Foundational Insight***

Decision Partners designed and conducted a total of 40 one-on-one confidential mental models interviews with three cohorts of Customers: Residential; Non-Residential and Large Use Customers from June 6 to October 16, 2015:

- Residential Customers: 15 interviews were conducted with Residential Customers between June 6 and July 20, 2015.
- Non-Residential Customers: 16 interviews were conducted with Non-Residential Customers between June 25 and August 10, 2015.
- Large Use Customers: Nine interviews were conducted with Large Use Customers between June 23 and October 16, 2015.

A Summary Report of the research conducted, including recommendations, was developed and reviewed with Enersource on August 11, 2015. The Summary Report of the results is included in Section 4.3 on page 13.

## 4.2 Bottom Line Up Front

Large Use Customers and the larger, generally more sophisticated Non-Residential Customers placed high value on reliable electricity and recognized Enersource's need to invest in maintaining and upgrading their infrastructure to deliver it. They wanted reliable electricity, with minimal or no interruptions, at a reasonable cost that is relatively stable. Most believed the 35% increase in the overall level of investment was very or somewhat appropriate.

Nearly all Large Use Customers expressed a medium or high level of confidence in Enersource's ability to implement the investments they were recommending. These Customers reported having a very strong, positive relationship with Enersource through their Enersource contacts and Mike Gemin, Manager, Customer Relations, in particular. As a result, the need for a Long Term Plan and the nature of the components did not come as a surprise to them. Most Non-Residential Customers similarly expressed a high level of confidence, with some expressing a medium level of confidence in Enersource.

In terms of communications generally, Large Use Customers preferred direct contact and email. For communications about the LTP, they said they would also be interested in webinars. Non-Residential Customers mentioned a range of communications methods, from newsletters and bill inserts, to email, phone campaigns and direct contact. On the LTP, they preferred email and webinars, with some mentioning direct contact.

This foundational research assessed Customers' current knowledge about Enersource, electricity distribution and their reactions to descriptions of key elements of the LTP. It enabled Customers to discuss their priorities and interests and to expand on their thinking in depth. It also identified Customer information needs, what they wanted to know about the LTP and their preferred means of communication with Enersource.

The data from the Customer interviews was coded against the Expert Model, linking responses to specific issues and influences depicted in the Model. It was then analyzed to characterize Customers' values, interests, priorities and informational needs related to those concepts, as well as any emerging themes not anticipated or depicted in the Expert Model.

The foundational research results demonstrated that most Residential and Non-Residential Customers did not have a sufficient understanding of the electricity system to provide meaningful input into the LTP. Customers' mental models of the electricity system were incomplete and, in some cases, incorrect. Consequently, if customers do not understand the system, they cannot reasonably be expected to understand the rationale of the investment decisions being proposed in the LTP or provide meaningful input on the key components.

The foundational research also underscored that Customers were unclear about the company's role in the electricity system and that there was significant confusion about the costs associated with Enersource's distribution system compared to the costs of the overall electricity system. Consequently, Enersource's value proposition – what it takes to deliver electricity safely and reliably – was not understood by most Customers. The bottom line: If customers do not understand the basic value proposition, they cannot make well-informed judgments about the need for, or acceptability of, Enersource's LTP, and the resulting rate increase. Clearly an intervention based on informed insight and customized to address customers' values, interests and priorities was required to effectively communicate the implications of the DSP for customers over the next five years and to improve the meaningfulness of any customer feedback on the DSP.

## 4.3 Summary Report

The following are the key findings from the Enersource Customer Mental Models Research.

DECISION PARTNERS

# Enersource Hydro Mississauga, Inc. Research-Based Customer DSP Consultation

Foundational Customer Research

Phase 1 Mental Models Research – Final Summary Report

*Final Summary Report on Mental Models Research* October 30, 2015

## Contents


- Research Background
  - Research Opportunity
  - Mental Models Research Approach
  - Research Steps, Purpose, Overview and Sample
  - How to Read the Report
- Summary of Key Research Findings
  - Bottom Line Up Front
  - Key Research Findings
  - Considerations
- Detailed Expert Models
  - Base Model
  - Detailed Sub-models
  - Weighted Model
- Research Sample Statistics




# Research Background



## Research Purpose

- In April 2015, Enersource asked Decision Partners to conduct broad, professional and scientific research in support of Enersource's Customer Consultation on its Distribution System Plan (DSP).
- The Ontario Energy Board requires proof that Enersource's DSP – to be filed as part of the company's rate application – demonstrates that distribution services are provided in a manner responsive to customer preferences.
- The project goal is to seek the customer input and demonstrate, with sophisticated and compelling evidence, how Enersource has considered that input and, as necessary, revised its DSP in a way that confirms the company's commitment and obligation to educate and be responsive to its customers.



## Research Opportunity

- The following Opportunity Statement was developed to guide the Stakeholder Consultation Research:

*Design and implement a comprehensive Customer Consultation initiative that applies state-of-the-science Mental Modeling Technology™ to gain in-depth insight into customers' values, interests and priorities regarding Enersource's proposed Distribution System Plan (DSP). The results will be used to develop detailed, sophisticated and compelling evidence that demonstrates Enersource's commitment and obligation to engage, inform and to seek customer input on the design of its DSP submission. A summary of this research-based Consultation initiative will be submitted to OEB in 2016. Additionally, this in-depth understanding of customer preferences will enable the Enersource to strengthen relationships with its customers.*

*The research-based project was initiated in early April 2015 and will be completed by November.*



## Mental Models Research Approach

- Given the complex social and technical issues that Enersource must factor into its Distribution System Plan (DSP), effective customer consultation must be based on in-depth insight into people's thinking, their values, interests, priorities and concerns.
- Decades of research demonstrate that people's judgments about complex issues are guided by "mental models".
- Mental Models:
  - Are tacit webs of belief all people draw upon to interpret and make inferences about issues that come to their attention;
  - Cannot be determined without empirical research; and
  - Must be addressed through communications in order to change people's attitudes, beliefs and behaviours.
- When done well, mental models research enables discovery and characterization of:
  - In-depth salient beliefs and the underlying rationale for those beliefs that could not be anticipated by researchers, i.e., what people believe and why they believe it
  - Possible tradeoffs individuals are prepared to address
  - Different modes of expression
  - Sources of information and influence
  - Testable hypotheses concerning people's beliefs and behaviours



2016 Thorne Butte: Decision Partners Inc.

## Mental Models Research Approach

- Decision Partners' proprietary Mental Modeling Technology™ (MMT™) – evidence-based, science-informed process, methods and tools – is specifically designed for understanding and influencing judgment, decision making and behaviour.
- To support the Enersource team as they prepare the DSP, we have adapted our MMT™ Approach to include two phases of direct Customer Engagement:
  - Phase 1: Foundational Customer Research;
  - Phase 2: Customer Engagement on the DSP via the **Enersource Customer Online Engagement Conversation** technology – based on mental models and synthetic intelligence.
- **Phase 1: Foundational Customer Research entailed one-on-one, confidential interviews conducted over the phone. This exploratory research allowed Customers to identify *their priorities and interests* and to expand on their thinking in depth. The results of Phase 1: Foundational Customer Research are detailed in this Report.**



## Overview of Research Steps

- Developed Research Opportunity Statement: April 17, 2015
- Developed the Base Expert Model of Influences on Customers' Judgments of the Acceptability of the Enersource Distribution System Plan (DSP) and detailed Sub-models through:
  - Review of critical documents and studies;
  - Expert Model Review Meeting – April 28, 2015: Provided an opportunity for the Team to review and provide input on the draft Expert Models of Influences on Customers' Judgments of the Acceptability of the Enersource Distribution System Plan (DSP)
- Developed three Mental Models research interview protocols:
  - Residential Customers: June 8, 2015
  - Non-Residential Customers: June 22, 2015
  - Large Use Customers: June 17, 2015
- Developed the research sample
- Solicited and conducted 40 Mental Models interviews included in this Final Report: June 6 – October 16, 2015
- Coded, analyzed and reported on results of Mental Models interviews
- Developed two Preliminary Observations Reports based on the results of Mental Models interviews – July 2, 2015 and July 12, 2015
- Developed and presented recommendations for Enersource based on research results: August 11, 2015



## Research Sample

- In May, Decision Partners designed a Research Plan to conduct mental models interviews with 3 cohorts of Customers and stakeholders, including:
  - 15 Residential Customers,
  - 16 Non-Residential Customers,
  - 9 Large Use Customers.
- Decision Partners worked with the Enersource team to ensure a broad sampling of Customers within the Residential and Non-Residential cohorts on criteria such as: geographic location; dwelling type; income etc.
- For Residential Customers and some Non-Residential customers Enersource provided customer lists from which interview participants were solicited by Decision Partners' senior interviewers, oriented to the project.
- Residential and Non-Residential Customers were offered a $50 honorarium for participating. Large Use Customers were offered the choice of a $50 donation to Dixie Bloor Neighbourhood Centre or United Way of Peel.
- Some larger Non-Residential Customers and all Large Use Customers were contacted and invited to participate directly by Enersource, then referred to Decision Partners to schedule and conduct the interviews.



## Research Statistics

- One pre-test interview was conducted by phone in June and is included in the analysis.
- *Residential Customers*: Fifteen interviews were conducted with Residential Customers by phone between June 6 and July 20, 2015.
  - Interviews ranged from 27 minutes to 52 minutes and averaged 36 minutes in length.
  - The total length of time for all (15) interviews was 543 minutes.
- *Non-Residential Customers*: Sixteen interviews were conducted with Non-Residential Customers by phone between June 25 and August 10, 2015.
  - Interviews ranged from 28 minutes to 46 minutes and averaged 39 minutes in length.
  - The total length of time for all (16) interviews was 625 minutes.
- *Large Use Customers*: Nine interviews were conducted with Large Use Customers by phone between June 23 and October 16, 2015.
  - Interviews ranged from 34 minutes to 50 minutes and averaged 42 minutes in length.
  - The total length of time for all (9) interviews was 377 minutes.
- The sample criteria were met, and Interviewees represented a range of age categories, education levels, geographic locations and income levels. Details on the sample can be found in the Appendix.
- Interviews were recorded, with permission, to enable in-depth analysis.
- All the interviews were confidential, with only aggregate results reported.



## Research Sample Challenges

- *Residential*: Solicitation of Interviewees in the Residential cohort was challenging due to several factors, including:
  - Individuals who don't answer phone calls (potentially screening calls from numbers that they do not recognize);
  - Numbers that appear to not be valid; and
  - General lack of awareness, interest, or willingness to discuss electricity issues.
- *Non-Residential*: Solicitation of Interviewees in the Non-Residential cohort, particularly of the smaller retail Customers, was also challenging for a number of reasons, including:
  - It was often difficult to identify and gain access to the appropriate person to interview in these businesses (the individual who makes decisions that affect electricity usage and/or pays the electricity bills); and
  - These individuals were often very pressed for time due to the demands of operating a small business.
- In order to address these challenges, we took the following steps
  - Enersource provided additional names of both Residential and Non-Residential Customers beyond what is normally needed to solicit the number of interviews completed.
  - We also advised potential interview participants during the solicitation that they will be offered a $50 honorarium for completing an interview.
  - Enersource directly solicited 6 of the larger Non-Residential Customers currently included in the analysis.



## Interview Protocol Topics

- The protocols for all three cohorts followed the same outline, with some customization to make the questions specific to each cohort.
- The interview protocols offered Interviewees an agenda of topics to discuss in a way that allowed for free expression.
- Topic areas included:
  - Perceptions of the Ontario Electricity Industry – Including their awareness of recent changes in the industry, such as LDC consolidation, and their thoughts on priorities for the industry over the next five years.
  - Perceptions of Enersource – Including their experiences as a customer, their perceptions of reliability of their electricity service and what Enersource does to prevent outages.
  - Perceptions of the Enersource DSP – Including their thoughts on what Enersource is doing to manage the distribution system and the company's priorities regarding the various types of investments covered in the DSP.
  - Perceptions of Enersource Customer Consultation and Engagement – Including where they receive information about electricity system topics, what they would like to know about the DSP and how they would like to receive that information.
- Interviewees were encouraged to raise additional topics spontaneously and to elaborate on their perspectives.

## How to Read the Report

- Specific findings are ordered based on their frequency of mention, using the following qualitative terms:
  - "Nearly all" indicates a response by 80 to 100% of Interviewees;
  - "Most" indicates a response by 60 to 80% of Interviewees;
  - "Many" indicates a response by 40 to 60% of Interviewees;
  - "Some" indicates a response by 20 to 40% of Interviewees; and
  - "A few" indicates a response mentioned by less than 20% of Interviewees.
- Frequency of mention for specific findings is rounded to the nearest 5% to highlight the qualitative nature of the results.
- In addition we have reviewed the variances in frequency of mention among Customers and reported on these variances when the reported frequency of mention varied by 20% or greater.
- Specific findings are supported with example quotes from Customers to illustrate the finding being presented. Findings and quotes attributed to each cohort are designated as
  - Residential Customers (Res), designated in blue;
  - Non-Residential Customers (NR), in red; and
  - Large Use Customers (LU) in green.



## Summary of Key Research Findings



## Bottom Line Up Front

Large Use and larger Non-Residential Customers

- Large Use Customers and the larger, generally more sophisticated Non-Residential Customers placed high value on reliable electricity and recognized Enersource's need to invest in maintaining and upgrading the infrastructure to deliver it.
  - Some were very interested in the opportunity to integrate green initiatives such as conservation programs into the electricity system.
- LU and NR Customers expressed concerns about the rising costs of electricity and the impacts on their businesses. The Bottom Line: they want reliable electricity, with minimal or no interruptions, at a reasonable cost that is relatively stable.
- About 65% of both the Large Use and Non-Residential Customers believed the 35% increase in the overall level of investment was very or somewhat appropriate.
  - Some did not believe that Enersource's management practices have led to this need for a significant increase. We also heard this from some Residential Customers.



## Bottom Line Up Front

Large Use and larger Non-Residential Customers

- That being said, 90% of Large Use Customers expressed a medium or high level of confidence in Enersource's ability to implement the investments they were recommending.
  - These Customers report having a very strong, positive relationship with Enersource through their Enersource contacts and Mike Gemin in particular, so the need for a Long-Term Plan and the nature of the components did not come as a surprise to them.
- 50% of Non-Residential Customers similarly expressed a high level of confidence, with 25% expressing a medium level of confidence in Enersource.
- Overall, these Customer cohorts had more confidence in Enersource than in OEB.
- In terms of communications generally, Large Use Customers prefered direct contact and email. For communications about the LTP, they said they would also be interested in webinars.
- Non-Residential Customers mentioned a range of communications methods, from newsletters and bill inserts, to email, phone campaigns and direct contact. On the LTP, they preferred email and webinars, with some mentioning direct contact.



## Bottom Line Up Front

Residential and Smaller Non-Residential Customers

- Residential Customers (as well as the smaller and less sophisticated Non-Residential Customers) had very limited knowledge of the electricity system, many misperceptions, and were unclear about Enersource's role in the system.
- They did not appear to be paying much attention to changes in the industry. Some had read or heard something about Hydro One, or the merger, or consolidation, but their knowledge was limited.
- Most appeared to pay attention to their bills and thought the cost of electricity is pretty high. That being said, when prompted, they did believe electricity is of higher value than natural gas or, for Residential Customers, their cell phones.
- The Bottom Line: Regarding Residential and smaller Non-Residential Customers, the OEB has set up a very challenging task for LDCs.
  - If Customers don't have a understanding of the fundamentals of the electricity system→ they don't understand the role of an LDC → they cannot contribute in a meaningful way to the design of an appropriate Long-Term Plan.
  - These Customers don't have the foundation upon which to weigh the benefits, risks and tradeoffs of rate increases to enable system reliability. The value proposition is not clear to them.



## Bottom Line Up Front

Residential Customers

- Residential Customers confuse reliability with accessibility.
- The priority for most is to reduce the cost of their electricity bill, or at least keep it where it is today. They are very concerned about rising costs.
- Most had not experienced significant outages, so they had no first-hand experience of the impacts of an unreliable system. The status quo seemed just fine.
- When we introduced the elements of the LTP, Residential Customers did think through and seem to appreciate Enersource's need to invest in maintaining and upgrading the infrastructure to deliver it.
- Some were interested in the opportunity to integrate green technologies into the system, believing that these would reduce the cost of electricity and didn't perceive any impact on reliability.
- Once explained, 5% of Residential Customers believed the 35% increase in investment was very appropriate and 55% believed it was somewhat appropriate.
  - The complexity of their bills appears to be adding to their confusion about the electricity system, the role of an LDC, and the cost they are paying on their household bills.

## Bottom Line Up Front

### Residential Customers

- But they trust Enersource. Virtually all Residential Customers (95%) expressed a medium or high level of confidence in Enersource's ability to implement the investments they were recommending.
- Overall, these Customers had more confidence in Enersource than in OEB.
- In terms of communications generally, Residential Customers appeared to be passively getting most of their information from television news and newspapers, along with the company website. Regarding communications about the LTP, they listed a number of channels, none in particular.



Ontario Electricity Industry

## First Thoughts About Electric Industry

- When asked what first comes to mind when they think about electricity in Ontario, Customers offered a broad range of responses including: "light bulbs", "Niagara Falls", and "expensive".
- Some Customers (40% Overall) commented on the high cost of electricity, price increases, and high salaries paid to industry executives:
  - *"Whenever I think about it or talk to somebody about it, it's always about expense and how they rip us off and sell it back and forth." (Res)*
- Many Large Use Customers (45%), as well as a few Residential Customers (15%) and Non-Residential Customers (15%), commented negatively on the structure and policies of the industry and mismanagement influenced by political agendas that affect the industry:
  - *"It's a disaster to be quite honest. It's a complete mess as far as how it's managed for industry in Ontario. The situation has gotten much better since the Global Adjustment recalculation because, prior to that, the pricing was absolutely ridiculous but there's no recognition at the provincial level of how important electricity is to industry and it's a complete mess." (LU)*
  - *"The mismanagement at the various touch points with government and the Energy Boards and other special interests, and the false economy that's set up with the IESO through the Global Adjustment." (LU)*



Ontario Electricity Industry

## First Thoughts About Electric Industry

- Some Customers (20% Overall) commented on the reliability of electricity in Ontario, with Residential Customers generally referring to the availability of electricity, while Non-Residential and Large Use Customers talked about the "quality" of electricity:
  - "When I turn on the TV, the electricity is always there, so that part is great." (Res)
  - "Unreliable. The quality is somewhat problematic too. I know that in other sites I've been at, different parts of Canada, I've never had as many problems with electricity quality as I've had. We just didn't have the same number of interruptions that we've had here." (LU)
- Some Customers (20% Overall: 15% Res; 35% NR; 0% LU) commented on sources of energy (eliminating coal and increasing renewables), "supply and demand", and the future of power.
- A few Customers (15% Overall: 20% Res; 15% NR; 0% LU) mentioned their "confusion" about the charges on their bills or questioning "opaqueness" of the charges.



Ontario Electricity Industry

## Familiarity with Electricity System

- When Residential Customers were asked what they knew about the components involved in the electricity system, nearly all (80%) commented that they didn't know much. A few mentioned general system components such as "wires", "power lines", "breakers" and "power from Niagara Falls".
- Some (20%) spoke generally about methods of generation, generally renewable generation.
- Some (20%) spoke more broadly about the electricity system, mentioning infrastructure connecting the Provinces and the States, mostly at a general level, but one or two talking about more specific features such as nuclear generation and transformers.

*Note: Non-Residential and Large Use Customers were not specifically asked about their familiarity with the electricity system due to the desire to keep these interviews shorter and the expectation that they are more familiar with the system generally.*



Ontario Electricity Industry

## Changes in Electricity Industry

- When asked about their familiarity with changes in the electricity industry generally, most Customers (85% Overall: 80% Res; 80% NR; 100% LU), particularly Large Use Customers, expressed some awareness of changes in the industry, though they all focused on specific aspects:

**Residential Customers**
- Infrastructure improvements or changes in methods of generation (40%)
- The use of Smart Meters and the "drive to make individual users more aware of their electricity consumption" (25%)
- The privatization of Hydro One (20%)
- Price increases (20%)

**Non-Residential Customers**
- Recent changes to "some" regulations, subsidies and incentive programs (45%)
- The privatization of Hydro One (20%)
- Changes in the Global Adjustment calculation (20%)
- The IESO/OPA merger (15%)

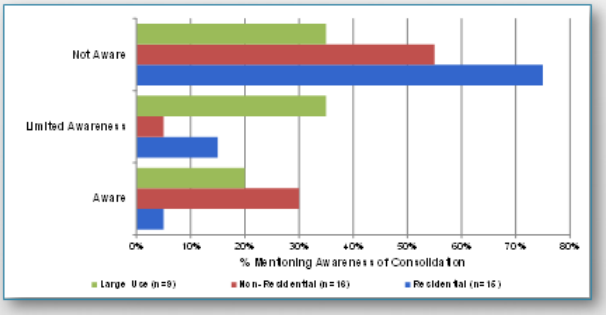
**Large Use Customers**
- Changes in the Global Adjustment calculation (35%)
- The privatization of Hydro One (20%)
- Their unhappiness about changes in regulations related to Class A users (15%)
- Infrastructure and generation changes (15%)



Ontario Electricity Industry

## Consolidation in the Industry

- When asked about their familiarity with consolidation in the industry, most Customers (60% Overall: 75% Res; 55% NR; 35% LU) said they were not aware of consolidation in the industry:



Ontario Electricity Industry

## Impacts of Consolidation

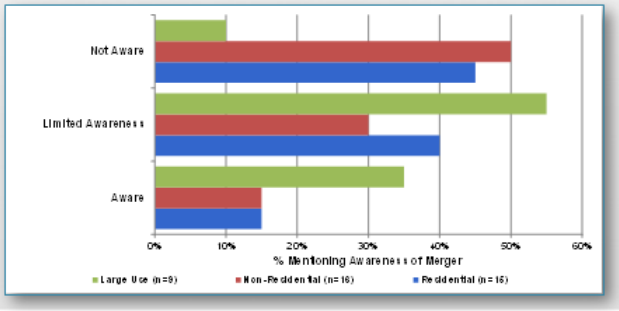
- When asked about the potential impacts of consolidation in the industry, some Customers (20% Overall) expressed concerns mentioning increased costs, increased brownouts and changes in the working relationships and/or the level of service:
  - » *"I hope it would be positive but on the flip side you might get some of these smaller LDCs and, at least for industry, there would be a little bit more of an intimate relationship with their users. You may lose that and you may lose some of the assistance you might get from some of their conservation people. There are pros and cons to both." (NR)*
- A few (10% Overall: 5% Res; 5% NR; 20% LU) spoke positively of the potential impact mentioning lowering the costs for customers and industry, the creation of "larger players", the potential for improvements to the infrastructure and removing redundancies in small organizations:
  - » *"In the GTA with the aging of the infrastructure and the need for strong capital investment, it's important I think to kind of get that side down right so that you're making better decisions and, secondly, the administrative burden that kind of becomes redundant throughout all these small organizations." (LU)*



Ontario Electricity Industry

## Proposed Enersource Merger

- When asked whether they were aware of the proposed merger of Enersource with three other LDCs, nearly all Large Use Customers (90%) had some awareness. Nearly all Residential (85%) and Non-Residential (80%) Customers either had no or very limited awareness.






Ontario Electricity Industry

## Benefits & Concerns of Proposed Merger

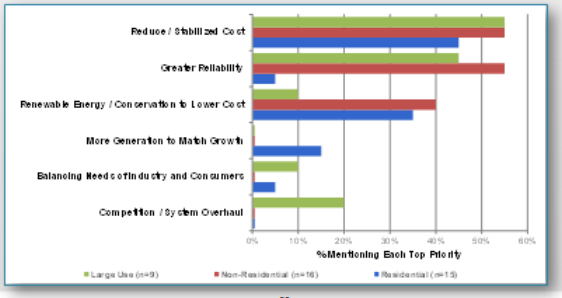
- When asked about the benefits of a potential merger, some Customers (30% Overall) spoke about cost savings, the potential to "strengthen the company" and "make improvements" and improve efficiencies and to make the LCDs more competitive:
  - » *"The benefit should be in terms of less employees, the duplication of work. They won't need so many CEOs." (Res)*
  - » *"The consolidation would lead to more efficient and reliable service. There may be some gains in terms of distribution rates because of the consolidation. There would be more efficiencies in terms of sharing experience, tools and equipment." (LU)*
- Many (50% Overall: 40% Res; 45% NR; 80% LU) raised concerns about a potential merger including, how it would create "a monopoly", increased costs, loss of jobs, and potential changes in distribution, "levels of service" and existing working relationships with Enersource:
  - » *"I don't see anything but cons to be honest because it would be a monopoly. It would literally just become where clients would just be numbers. If we had a problem or an issue, they have all the power in the world to do whatever they want with no big competition." (Res)*
  - » *"On the downside, we've enjoyed a great relationship with Enersource and we've obviously been high on their priority list. The downside for us would be we'd have a much larger organization and be way down their priority list and so therefore the levels of service might decrease for us." (LU)*



Ontario Electricity Industry

## Top Priorities for the Electric Industry

- When Customers were asked what the electricity industry's top priority should be over the next 5 years, reducing or stabilizing the cost of electricity was the top issue for all cohorts. Improving the reliability of electricity was the next most important priority for the Non-Residential and Large Use Customers, while the Residential Customers highlighted the need for more conservation and renewable energy.






Ontario Electricity Industry

## Top Priorities – Cost & Reliability

- Many (55% Overall) believed reducing or stabilizing the cost was the most important priority:
  - » *"Electricity is such a basic thing that is there no way that we can stabilize the cost in some way?" (Res)*
  - » *"We're a small business so we have to look at each dollar, we don't have high margins." (NR)*
  - » *"We've seen the peak demand for electricity reduced substantially over the last few years and a lot of that is due to manufacturing moving out of Ontario. That concerns us greatly. I would say the number one priority is to find a way to provide lower-cost electricity to manufacturing in Ontario." (LU)*
- While many Non-Residential and Large Use Customers (55% NR; 45% LU) believed improving the reliability of electricity delivery was the most important priority, only one Residential Customer shared that view:
  - » *"I think the number one priority should be that the supply is reliable and continuous." (NR)*
  - » *"The quality of power too is really important to me. We talked a little bit about how to minimize or eliminate small disturbances in the lines and just making sure that you're not forever bouncing the system." (LU)*



Ontario Electricity Industry – Top Priority

## Increased Renewable Generation to Reduce Costs

### Residential Customers

- Some Residential Customers (35%) believed that moving to renewable energy sources and conservation was a top priority, citing benefits to the environment and their belief that this would lower costs:
  - » *"To conserve because the prices of everything is going up. So as a consumer I need to be the most efficient so that it benefits me and the environment." (Res)*
  - » *"They should be focusing on different kinds of electricity, namely, more renewables, like getting electricity from other sources. I think the trend now is that houses are generating electricity." (Res)*
  - » *"Getting renewable resources coming for the environment. It would bring costs down. I think that it would be very good for everybody; for environment, for community, for pricing, for a lot of stuff." (Res)*

### Non-Residential Customers

- Many of the Non-Residential Customers (40%) echoed the sentiment:
  - » *"Clean energy power and something that everybody could afford and not to feel that every time you think of electricity, it's an increase in costs. That's my thing. I think efficiency." (NR)*
  - » *"Making sure that our power sources are responsible so that, at the end of five years we have planned appropriately for the next 30 to 50 years." (NR)*

### Large Use Customers

- One of the Large Use Customers spoke of the need to move to renewable energy sources as a priority.

Ontario Electricity Industry

## Awareness of the Cost of Distribution

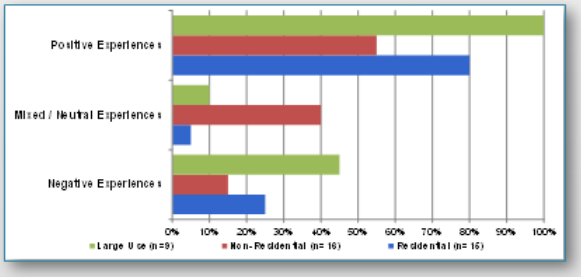
- When asked what percentage of their bill they thought was for the distribution of electricity, (i.e., Enersource's portion of the bill) Many (55% Overall: 75% Res; 40% NR; 45% LU), particularly the Residential Customers said that they had no idea
  - » *"No clue. All I see is the amount I have to pay every two months." (Res)*
- A single Customer in each of the Cohorts expressed criticism that the bill is itemized at all:
  - » *"When you divide up your bill, I just think it adds insult to injury. We have no time to say how much are you charging me for delivery and negotiating a contract with them on every individual charge." (NR)*
- When asked to estimate the portion of their bill associated with distribution, those few who responded frequently estimated higher than the actual fraction of their bill associated with distribution, sometimes significantly so.



Perceptions of Enersource

## Enersource Customer Experiences

- When asked to describe their experiences as an Enersource Customer over the past 5 years, and then to describe their positive and negative experiences with Enersource employees (when prompted), most Customers (75% Overall: 80% Res; 55% NR; 100% LU) said their experiences had been good, citing employees' responsiveness and helpfulness.






Perceptions of Enersource

## Customer Experiences

### Residential Customers

- Most (80%) said their experiences had been "good", citing reliability, responsive customer service and their "customer satisfaction":
  - » *"Even the people, when I have a hard time paying the bill are nice. They weren't pounding on your door looking for your furniture to pay the bill. They sent us to a senior's program I didn't know about. You wouldn't think they would have to do that or should do that." (Res)*
- Some (25%) had negative comments relating to their high bills, frustration with Smart Meters and lack of reliability:
  - » *"Smart Meters are the dumbest thing they ever did. There was an increase after the Smart thing was added. Every time they say it is only a little increase for the seniors; well, mine is about a 25% hike." (Res)*



Perceptions of Enersource

## Customer Experiences

### Non-Residential Customers

- Many (55%) said their experiences have been "really good", complimenting the employees, programs offered to customers, and the "good service" they receive:
  - » *"The Energy Manager Program that they have with Michael Gemin and a bunch of those other guys, it's really good. They've got some really good talent over there and we've been able to work together and really come up with some goals and plans in reducing energy. The rebate program to implement some of these capital projects with regards to energy initiatives such as HVAC or chillers or lighting, you guys do a really good job." (NR)*
  - » *"Enersource have been second to none in terms of supporting us. They are exceptional in terms of their management structure and their focus. They have been exceptional to us." (NR)*
- Many (40%) offered mixed or neutral reviews of their experiences, expressing satisfaction with reliability and responsiveness but dissatisfaction with the cost:
  - » *"They were okay. In terms of the cost, we are not satisfied, but in terms of the delivery I think we are." (NR)*
  - » *"I can't say that we have had either [positive or negative experiences]. Normally when we have an issue, we call and they respond fairly quickly or they can give us reasons for and we just have to wait out the time for the respondents." (NR)*
- A few (15%) spoke of negative experiences relating to paying a bill that was in arrears or accessing information on their account:
  - » *"The payment options available to you are very limited. You have to actually get a certified cheque and take it physically into the office. There are so many other ways that one can pay bills, it's hard to understand why one would have to do that." (NR)*
  - » *"We are a management company, however, I'm actually the person who set up all the hydro accounts and utilities. Any time I try to get a copy of the bill or any information, they will not grant me access and ask for a letter from the owners. It's very frustrating. Enersource is the only provider that does this." (NR)*



Perceptions of Enersource

## Customer Experiences

### Large Use Customers

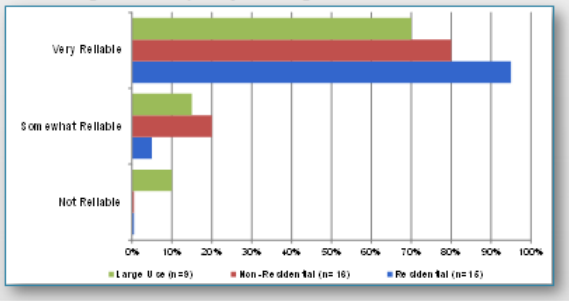
- All (100%) spoke positively of their good working relationships with their Account Managers and "many of the folks there", highlighting their responsiveness and support:
  - » *"From a communication and support perspective it has been excellent. They are always there for us. They are actually partners with us on virtually every building or high energy project that we do that requires high voltage or a transformer. They are our go-to people to get the work done." (LU)*
  - » *"They're often contacting me to ask me how things are going, if I need anything and asking me to get involved in discussions about curtailment." (LU)*
- Many (45%) mentioned negative experiences relating to billing and "infrastructure challenges" impacting the reliability of power:
  - » *"Lately we've been getting double billed at some sites. There have been some administrative hiccups that have been problematic for us as a corporation. We had a couple of meetings but I didn't leave with a full understanding of what the cause was and how we were going to prevent a recurrence." (LU)*
- One commented that "the people involved are very committed" and there has been "better engagement", but there is still "some opportunity" related to "development of reliability programs".



Perceptions of Enersource

## Reliability of Their Electric Power

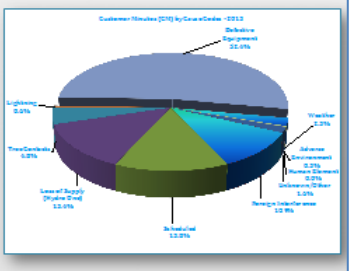
- When asked to rate the reliability of their electricity over the past 5 years (or, if under 5 years, the period they have been a customer), nearly all Customers (80% Overall: 95% Res; 80% NR; 70% LU) rated it as very reliable. One Large Use Customer said the electricity was "not reliable", commenting on the frequency of voltage variations.



Perceptions of Enersource

## Causes of Disruptions

- When asked what caused the power outages, the most frequent response by many Customers across all three Cohorts (40% Overall) was the outages were weather-related: due to an electrical storm, an ice storm or "caused by Mother Nature".
- Customers also attributed the outages to each of the following causes, each mentioned by one or two:
  - Issues with the "power grid" (Res), "transformers" (Res), or "something in the utility" (LU), "with their lines" (LU)
  - Animal contact (LU, NR)
  - A car accident affecting a telephone pole (NR)
- Many (40% Overall) did not know or did not specify the cause of the outage.



* Chart from Enersource Draft DSP: Chart 8.1 – Chart of Enersource Customer Minutes by Cause (2013)



Perceptions of Enersource

## Enersource's Response to Disruptions

- Some Customers across all three Cohorts (25% Overall: 15% Res; 25% NR; 45% LU) were generally satisfied with Enersource's response to the outages, commenting that power was restored quickly:
  - *"I guess getting it back in an hour if that's how long it was, they responded very well. Some people were out for 3 or 4 days." (Res)*
  - *"They had it back up and running in about ten or fifteen minutes. We called and they told us what the situation was and we just waited it out." (NR)*
  - *"The momentary outages are usually not an issue but when we had longer outages, they responded within minutes to either if the line wasn't coming back, if they put us on a different feeder, and they've been really responsive, pretty good." (LU)*
  - *"They respond well. They send out crews on a timely basis and they work collaboratively with us and they help us to restore our power." (LU)*
- A few (10% Overall), however, commented on the lack of communications relating to the outages:
  - *"Nothing was communicated." (Res)*
  - *"There was no communication. That's where it's lacking." (NR)*
- One LU spoke positively about Enersource using Twitter to communicate about outages.



Perceptions of Enersource

## Preventing Disruptions

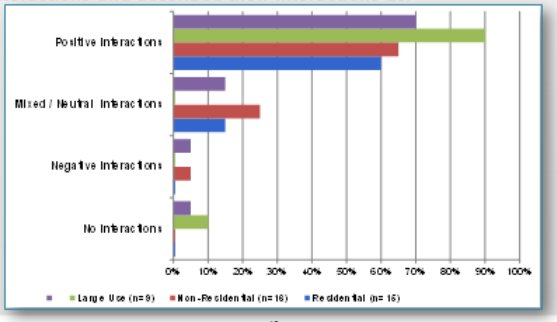
- When asked what Enersource does to prevent disruptions, most Customers across all three Cohorts (65% Overall: 75% Res; 70% NR; 45% LU) said they "had no idea" or couldn't comment "specifically":
  - *"I'm not aware of anything. I mean, I can only assume that they try to make sure they have a maintenance program going but specifically no." (NR)*
  - *"I believe they have good programs as you can see based on the reliability of their systems right now. I am not completely aware of their programs but they should have a good program." (LU)*
- Other prevention measures mentioned, each by a few Customers, included:
  - Burying the lines underground and making sure they have staff and a call in number (Res )
  - Carrying out preventive maintenance (NR, LU)
  - Rerouting the electricity (Res)
  - Replacing older wires (Res)
  - Improving the planning and monitoring of the systems (NR)
  - *"They carry out SCADA switching. SCADA switching is the automated and manual change of feed from one substation to another so that you minimize the impact to the end users." (NR)*
  - Enersource maps and investigates the outages and "takes an active part in managing the things they can control". (LU)



Perceptions of Enersource

## Interactions with Enersource Employees

- When asked whether they had interactions with Enersource employees, generally, or with Customer Service employees, specifically, nearly all Customers (85% Overall) said they have had interactions and described their interactions as:

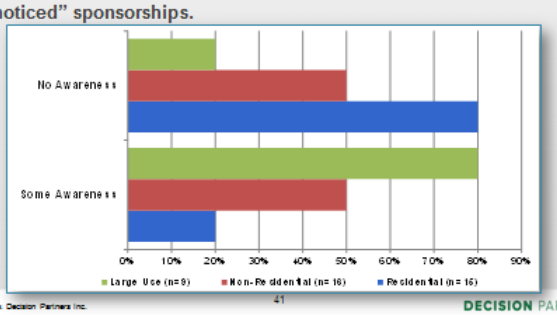





Perceptions of Enersource

## Enersource as Member of Community

- When asked specifically about what they know about the Enersource as a corporate member of the community, many Customers (55% Overall: 80% Res; 50% NR; 20% LU), particularly Residential Customers, said they didn't know, that "there's not much awareness" and that there were "unaware of" or "hadn't noticed" sponsorships.






## LTP Priorities for the Next 5 Years

- To understand Customers' perceptions relevant to the Long-Term Plan we started by asking an open question about what top priorities Customers thought Enersource should focus on over the next five years.
- The responses were similar to what they thought the industry's top priorities should be cost (especially for Residential Customers) and reliability (especially for Non-Residential and Large Use Customers) though one Non-Residential customer challenged the premise of asking for his input, saying:
  - *"They are in trouble if they are looking for the opinions of a bunch of people, their customers, to help figure out their own strategic plan. I am not going to ask them about my strategic plan." (NR)*






2016 Thorne Butte: Decision Partners Inc.

## Perceptions of LTP Components

- For each component of the components of the LTP, we:
  - » Read a description (provided by Enersource) of the focus of the component;
  - » Asked for Customers' unprompted thoughts about investments in the area;
  - » Asked Customers to rate how critical they though the investments in the area were; and
  - » Asked Customers to rate how appropriate they felt that investments in the area.



Perceptions of LTP Components

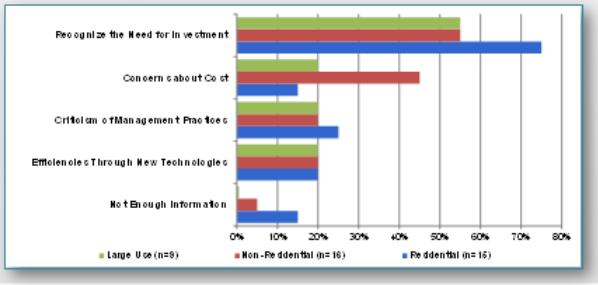
## Initial Thoughts

- System Service and System Access
  - » Some Customers (30% Overall; 35% Residential; 20% Non-Residential; 45% Large Use) suggested that the description did not provide enough information for them to comment in detail.
  - » Large Use and Non-Residential Customers in particular suggested that they recognized the need for investments in these areas. (35% Overall; 20% Residential; 45% Non-Residential; 35% Large Use)
  - » Residential and Non-Residential Customers in particular expressed immediate concerns about cost. (25% Overall; 25% Residential; 25% Non-Residential; 10% Large Use)
- System Renewal
  - » Residential Customers in particular suggested that they recognized the need for investments in the System Renewal area. (65% Overall; 75% Residential; 55% Non-Residential; 55% Large Use)
  - » Non-Residential and Large Use Customers in particular expressed immediate concerns about cost. (30% Overall; 15% Residential; 45% Non-Residential; 20% Large Use)
  - » Only a few Customers (10% Overall; 15% Residential; 5% Non-Residential; 0% Large Use) suggested that the description did not provide enough information for them to comment in detail.



## Thoughts on "System Renewal" Investments

- After describing the LTP regarding "System Renewal", Interviewees shared their unprompted thoughts regarding investments in this area. Most of the Customers (65% Overall) recognized the need for investment in this area. Many of the Non-Residential Customers (45% NR) were concerned about the cost of these investments although for the Residential and Large Use Customers (15% Res; 20% LU) cost was less of a concern. Some of the Customers (25% Overall) criticized past management practices requiring such heavy investment in this LTP.






## "System Renewal"

- There were harsh criticisms of the management practices at Enersource by some Customers (25% Overall) from all three cohorts:

**Residential Customers**
- » *"I think that Enersource should solely bear that cost. If they have been following accounting practices and standards, they might have planned for replacing their plants and equipment so it's not going to cost consumers." (Res)*
- » *"It is unfortunate that people are not proactive. They try to be competitive and use all their equipment until it drops dead. Try to maintain and rotate out their equipment in a more gradual way spending will be less over time." (Res)*

**Non-Residential Customers**
- » *"Probably they had waited too long and now they are forced to deal with it and so the expenditure has to go up." (NR)*

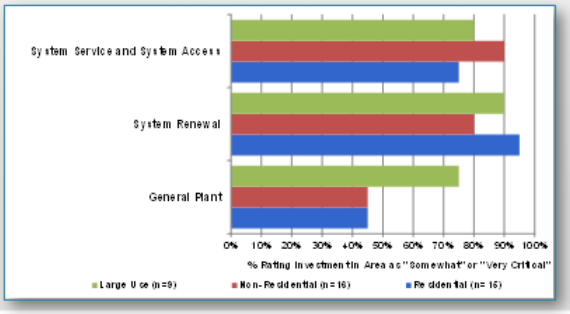
**Large Use Customers**
- » *"It is one of the things that I have to do is accrue for expenses that I know are going to be coming at me every five or ten years or whatever the cycle is for that. I put money aside so that I don't have to cripple my business for a period of time when I am rebuilding one aspect of it. So, that to me is a sign of mismanagement that a 20% increase because we haven't been putting money away." (LU)*



Perceptions of LTP Components

## Criticality of Investment

- When asked how critical were investments in each area of the LTP, Customers more frequently rated "System Service and System Access" and "System Renewal" investments as "Somewhat" or "Very Critical" compared to General Plant Investments.

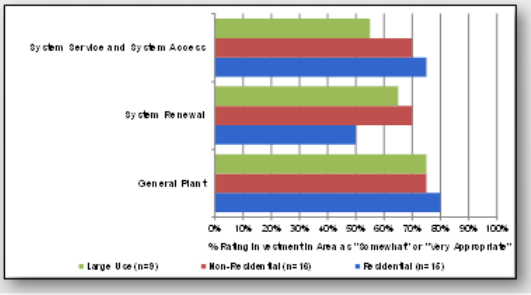





Perceptions of LTP Components

## Appropriateness of Level of Investment

- After being told of the proposed level of investment for each area, Customers were asked how appropriate the levels of investments in each area were. Most Non-Residential and Large Use Customers believed that the level of investment in all three areas of the LTP were appropriate. However, only 50% of the Residential customers thought that the investment in System Renewal was 'Somewhat' or 'Very Appropriate'.



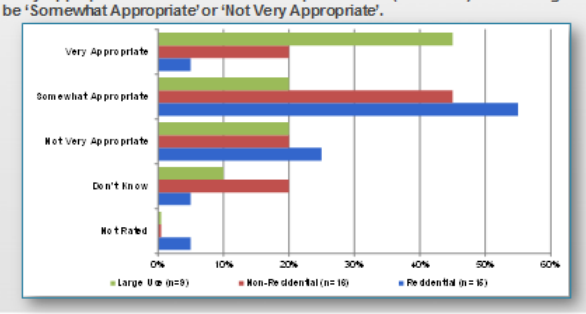



2016 Thorne Butte: Decision Partners Inc.

Perceptions of the LTP

## Perception of Overall Increase in Investments

- When asked to rate how appropriate the 35% overall increase in investments in the LTP, many Residential and Non-Residential Customers (55% R; 45% NR) rated it to be 'Somewhat Appropriate'. A few of those two Cohorts (25%) rated the investment as "Not Very Appropriate'. Many of the Large Use Customers (45%) believed it is 'Very Appropriate' and the balance were split between (20% each) considering it to be 'Somewhat Appropriate' or 'Not Very Appropriate'.

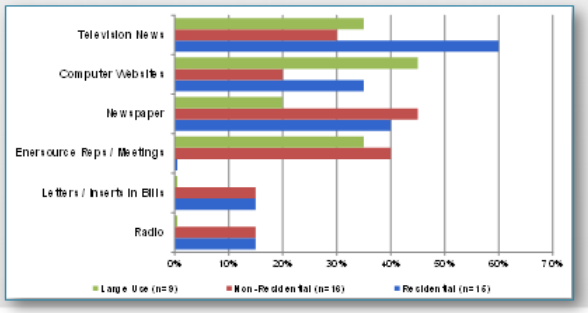





Customer Consultation and Engagement

## Sources of Information re Electricity System

- When asked how they typically hear about topics related to the electricity system in Ontario, Customers in all three Cohorts mentioned a range of ways and means including, national newspapers, television news, computer websites, inserts in their bills, and on the radio.






Customer Consultation and Engagement

## Sources of Information re Electricity System

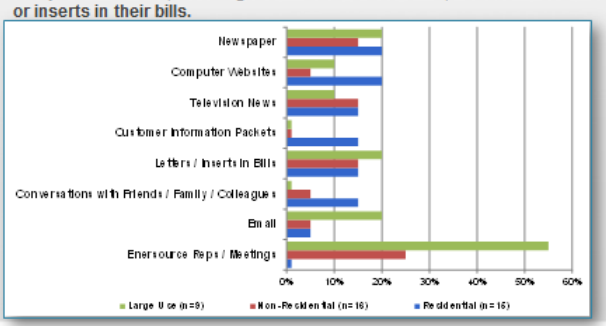
- Non-Residential (40%) and Large Use Customers (35%) also mentioned that they get information from their Enersource Contacts (Account Managers or Energy Managers) or from meetings with Enersource.
- Other sources of information each mentioned by one or two Customers included:
  - Conversations with friends and family (Res)
  - Conversations with colleagues (NR - 2)
  - Email (Res)
  - The Association of Power Producers of Ontario (LU)
  - Receiving updates from their media companies (LU)



Customer Consultation and Engagement

## Sources of Information about Enersource

- When asked how they hear about topics related to Enersource, Customers mentioned a range of sources of information including, newspapers (both the Globe and Mail and the Mississauga News), computer websites, including the Enersource website, email and letters or inserts in their bills.






Customer Consultation and Engagement

## Critical Questions

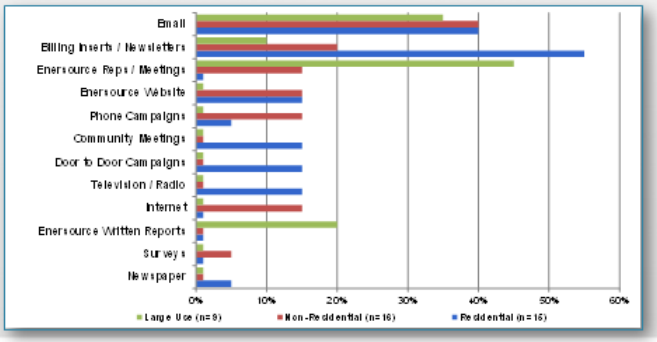
- Spontaneously throughout the interview, and when asked explicitly toward the end of the interview, Interviewees suggested a broad range of questions that the Enersource Team should be prepared to answer as they continue to engage the community about the LTP.
- Critical questions raised by Customers during the interview related to the following topics:
  - General electricity system & electricity industry
  - Reliability – causes of service disruptions
  - Potential merger of Enersource
  - Drivers for the cost of electricity (not specifically related to the LTP)
  - Extra charges beyond the cost of production and distribution of electricity (e.g., the Debt Retirement Charge)
  - Details of the LTP, including technical questions from the Large Use Customers
  - Measures of success for the LTP
  - Questions about billing
  - Smart Meters
  - Health and environmental impacts of new facilities or structures such as power lines
- *Note: A more detailed report on the questions is included in a separate report.*



Customer Consultation and Engagement

## Preferred Methods of Communications on LTP

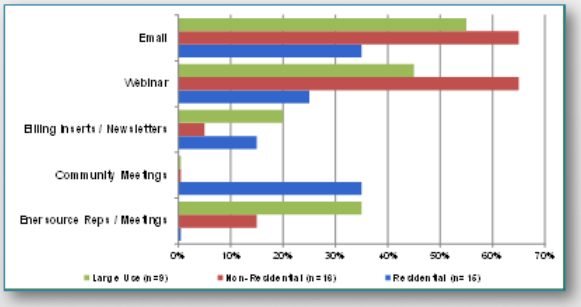
- When asked how they would like to hear from Enersource about the LTP, Customers from all Cohorts mentioned a range of sources of information including, billing inserts or newsletters, email, or on the internet:



Customer Consultation and Engagement

## Preferred Methods of Engagement for LTP

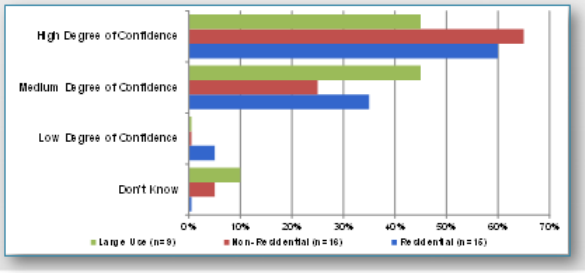
- When asked how they would like to be consulted or included in the LTP process going forward, Customers in all cohorts mentioned email, webinars, and billing inserts.






## Confidence in Enersource

- Considering all of the aspects of the LTP, Interviewees were asked to rate their level of confidence in Enersource in implementing the investments. Most of the Residential and Non-Residential Customers and many of the Large Use Customers had a 'High Degree' of confidence with the balance of the customers predominantly with a 'Medium Degree' of confidence. The Residential Customer with a 'Low Degree' of confidence said, ***"I don't think they are in the least cost effective." (Res)***






## Considerations



## Considerations

### The Challenge

- The value case that underlies the LTP is not understood by Residential Customers, most Non-Residential Customers and some Large Use Customers – that is, in order to continue to provide safe, reliable electricity, we need to continue to invest in the distribution system.
  - About 60% of all Customers think the cost of electricity is too high.
  - Most had no idea about the percentage of their bill that covers distribution costs.
  - About 65% had no idea of what Enersource does to prevent disruptions – critical context for the LTP.
  - About 80% reported they had reliable power, but they do not appear to be connecting this with infrastructure maintenance and development.
- Without this understanding, Customers cannot assess the investments Enersource is recommending, or make well-informed judgments of their acceptability.
- Most trust Enersource and have confidence that the company will do what is required.
- Still, rising costs, is a primary influence on Customers' judgment and an ongoing concern.



## Considerations

### The Opportunity

- The opportunity is to engage Customers in dialogue to:
  - Systematically build on where Customers are today in their thinking – build their mental models of the electricity system, the role of Enersource, the need for a Long-Term Plan, and then the three components of the LTP.
  - Reorder Customers' mental models, so they think first about reliability, then what is required to assure reliability, then the investment required and the value vs. focusing on the cost.
  - Enable Customers to provide meaningful input into the design of the LTP and make well-informed decisions about the acceptability of the LTP and the investment required for the next five years.
  - Reinforce Customers' positive perceptions of Enersource, while building or enhancing current relationships with them.



## Considerations

### The Plan

- Engage Residential and Non-Residential Customers primarily through the "Enersource Customer Online Engagement Conversation":
  - Personally invite Customers to participate in the ECOEC through direct (robo) calls and/or emails from James Macumber, reinforced through all regular print and social media, radio and newspaper advertising
    - *Advertise the videos and availability of the pamphlet and print survey through all communications channels*
  - Develop an Electricity System Fundamental video as a stand-alone piece for the website, as well as a component of the ECOEC – *in progress*
  - Develop a stand-alone video on Reliability and/or a dedicated segment in the ECOEC to help Customers understand the importance of a reliable electricity system, the many factors that can influence reliability, and what Enersource does every day to assure the reliability of their distribution system
  - Enable Customers to engage in dialogue with key Enersource people, on the topics related to the LTP of interest to them, in the sequence that makes sense to them through the ECOEC, while soliciting their input – *in progress*
    - Build the ECOEC content to address what Customers know, don't know, misunderstand, and want to know.
  - Consider hosting the ECOEC past the LTP data collection period, and adding modules for new topics as appropriate

## Considerations

### The Plan

- **Engage Large Use Customers and more larger Non-Residential Customers in dialogue, primarily through individual or small group meetings:**
  - » Hold one-on-one meetings with each of the Large Use Customers to review highlights of the LTP and discuss the implications for their businesses. Reinforce the value proposition – their priority for reliable electricity at a reasonable cost delivered by a company they trust.
  - » Consider holding small group meetings, perhaps through local business associations, to engage Non-Residential Customers directly:
    - It will be important to record and collect the data from all of these meetings and include it in the Customer Engagement component of the DSP
  - » Personally invite these Customers to review the ECOEC through direct calls and emails from Mike Gemin. Encourage them to invite others in their organizations to participate in the ECOEC.



## Considerations

### Communications Challenge

- **55% of all Customers and 80% of Residential Customers knew nothing of Enersource's involvement in or contribution to the Mississauga community. Enersource's community engagement is an important component of its value proposition.**

### The Opportunity

- **Use all communications channels to demonstrate Enersource's proactive engagement and involvement in community activities.**
- **Consider adding a segment in the ECOEC on Community Engagement.**



## Research Sample Statistics



| Residential Customer Statistics | |
|---|---|
| Interviews | 15 completed from 123 total individuals provided in sample – 22 declined to be interviewed |
| Interview Length | Average: 36; Minimum: 27; Maximum: 52; Total: 543 |
| Customer Genders | 7 Women / 8 Men |
| Customer Ages | 1 Customer Age 20s; 2 – Age 30s; 2 - Age 40s; 5 – Age 50s; 5 – Age 60 and above |
| Length of time living in Mississauga | 1 Customer – Less than 5 years; 2 – 5 to 10 years; 2 – 10 to 20 years; 3 – 20 to 30 years; 4 – 30 to 40 years; 2 – 40 to 50 years; 1 – 50+ years |
| Length of time living in current residence | 5 Customers – Less than 5 years; 2 – 5 to 10 years; 2 – 10 to 20 years; 4 – 20 to 30 years; 2 – 30 – 40 years |
| Length of time as Enersource customer | 5 Customers – Over 10 years; 3 – 5 to 10 years; 6 – Less than 5 years; 1 - unknown |
| Number of children under 18 living at home | 8 Customers: None<br>7 Customers: Yes (3 – 1 child; 1 – 2 children; 1 – 3 children; 2 – unspecified number of children) |



| Residential Customer Statistics | |
|---|---|
| Customer occupation | 5 Customers – Retired; 2 – Business Owners; 2 – Marketing Professionals; 1 – IT Professional; 1 – Lawyer; 1 – Homemaker; 1 – Design Consultant; 1 – Business Analyst; 1 – Not answered |
| Approximate amount of monthly Enersource bill | 3 Customers > $100; 5 - $100+; 3 - $200+; 1 - $300+; 2 – Unknown; 1 – Credit refund $450+ |
| Method of home heating | 7 Customers – Gas; 5 – Electricity; 3 - Unknown |



| Non-Residential Customer Statistics | |
|---|---|
| Interviews | 16 completed from a few hundred customer names provided in sample – 31 declined to be interviewed<br>GS LT 50: 3 Customers; GS 50 – 499: 3; GS 500-4999: 10 |
| Interview Length | Average: 39; Minimum: 28; Maximum: 46;<br>Total: 625 |
| Length of time as Enersource customer | 6 – Over 10 years; 3 – 5 to 10 years; 4 – Less than 5 years; 3 – Unknown or did not provide specific answer |

| Large Use Customer Statistics | |
|---|---|
| Interviews | 9 completed from 9 total customers included in the sample |
| Interview Length | Average: 42; Minimum: 34; Maximum: 50;<br>Total: 377 |
| Length of time as Enersource customer | 5 – Over 10 years; 1 – 5 to 10 years; 1 – unknown |

# Section 5: Interactive Decision Support Technology (IDST™) Research Summary

## 5.1 Executive Summary

***Informed Engagement Step 2: Conducting Thoughtful Conversations***

Enersource invited its approximately 200,000 Residential and Non-Residential Customers to participate in the web-based IDST™ via multiple channels, including:

- Press Release issued to media and posted on company website, November 23, 2015.
- Email invitation to about 60,000 customers whose email addresses were on file. (Invitation sent December 11; reminder sent December 18).
- Invitation sent in bill inserts mailed between November 30 and December 23.
- Multiple Twitter announcements (7) between November 24 and December 23.
- Reminder issued on Facebook.

Customers were also given the option of requesting a printed survey, but there were no requests for a printed survey.

As incentive to participate, customers who answered all 11 mandatory survey questions within the IDST™ about the Long Term Plan by end of day December 23rd, were entered into a draw for one of eight Samsung Galaxy tablet computers.

Customer feedback on the LTP[7] was collected between November 23 and December 30, 2015 and analyzed for this Report[8]. The IDST™ engaged 3,779 Unique Visitors. Of those, 2,206 Customers went beyond the introductory videos to data collection segments of the IDST™, including: 2,157 Residential Customers and 49 Non-Residential Customers. In addition, 43 non-Customer guest users visited the site and provided feedback, which has not been included in our customer data analysis.

In total, 1,358 Customers responded to the 11 mandatory questions. The 3,779 Unique Visitors spent a total of 97,276 minutes in the IDST™ engagement averaging 25.7 minutes per Visitor. Those who provided feedback submitted 24,064 responses.

A Summary Report of the research conducted is included in Section 5.5 on page 28.

## 5.2 Bottom Line Up Front

When Customers had an opportunity to understand the electricity system and then think through the components and rationale of Enersource's LTP, most judged the proposed investments to be critical and appropriate. After hearing the description of each of the components of the Long Term Plan and the level of investment required, nearly all Customers judged Enersource's planned investments to be *"Somewhat"* or *"Very"* critical. After hearing the description of each

[7] While we use the term DSP earlier to reflect the regulatory terminology, during the IDST™ engagement with Customers, Enersource chose to use the simpler terminology of "Long Term Plan" or LTP. We use LTP in our report where it is directly relates to the results of the Customer engagement.
[8] The site remained active until January 7, 2016.

component, and the level of investment required, nearly all Customers judged the level of investment in all three areas of the LTP as *"Somewhat"* or *"Very"* appropriate.

Through the IDST™ Customers were able to think with Enersource executives about what needed to be done and why. Through dialogue, they were able to better understand both the thinking process and the rationale that drove the Enersource Team to decide what investments were needed and what priority each should be given. When they did so, for most, the proposed LTP activities and required investments made sense. When asked to rate the appropriateness of the 35% overall increase in investments in the LTP, most Customers (77%) believed that the level of investment was *"Very"* or *"Somewhat"* appropriate.

Nearly all Customers (90%) expressed a "Medium" or "High" level of confidence that Enersource would do what is necessary to continue to provide safe, reliable, cost effective electricity by implementing the investments described in the LTP.

The IDST™ results were somewhat more positive than the mental models research results, possibly because Customers were engaging with "real" Enersource people.

The IDST™ experience appears to have been a positive one for most Customers as only a few noted negative comments. More noted positive comments with some directly relating that to their high level of confidence in Enersource moving forward on the LTP, saying:

> *"It seems like your numbers and facts are legitimate. It is evident a lot of work went into this website and planning for the increases."*
>
> *"This website and the people in the videos. All seems very credible. Plan appears to be well thought out."*
>
> *"I think the team looks well prepared and serious about this venture. By merely reaching to public/consumers to get feedback /inputs in itself shows the nature of Enersource's seriousness to get inputs and map accordingly the priorities."*

## 5.3 IDST™ Content Overview

Decision Partners and its partner in Interactive Decision Support Technology™, MedRespond, worked with the Enersource Team to design, develop and host the state-of-the-science Enersource IDST™ website. Content of the IDST™ was based on the results of the foundational mental models research described in Section 3. The content was designed to reflect and reinforce what Customers know that is correct; inform them of critical information that they did not know; correct misperceptions; and respond to Customers' interests and priorities regarding additional information.

While Customers could customize their engagement through the IDST™ to an extent, the following topics were offered as the core of the engagement. Building on the priorities Enersource shared with Customers, which were confirmed in the mental models research, they were then introduced to the various components of the DSP (called the Long Term Plan for simplicity) and asked for their input.

- Greeting and Introduction to the IDST™.

- (Optional) Fundamentals of the Electricity System – a 4.4 minute overview video that clarified Enersource's power delivery role within the larger electricity system.
- Enersource's Shared Priorities for management of the distribution system, including:
    - Priority #1 – Reliability: What Enersource does to minimize power outages and voltage fluctuations in light of challenges such as aging equipment, weather, load growth and damage to the system caused by accidents and natural events.
    - (Optional) Priority #2 – Environmental Responsibility: What Enersource does to respond to Customers' desires that electricity be produced and delivered in an environmentally friendly way.
    - (Optional) Priority #3 – Affordability: What Enersource does to keep electricity affordable while working to maintain a safe, reliable, and environmentally friendly electricity distribution system.
    - (Optional) Priority #4 – Safety: What Enersource does to maintain and repair its system to keep the public safe while providing reliable electricity.

After reviewing at least the Introduction and Reliability section of the IDST™ Customers were then engaged in thoughtful "conversations" and asked to provide feedback on the components of the LTP, specifically, the proposed:

- System Service and System Access Plan: Improvements and upgrades to the Enersource distribution system that will assure the delivery of electricity safely and reliability.
- System Renewal Plan: Repairs and replacement of lines, and equipment that was installed 20-40 years ago which is now wearing out.
- General Plant Investments Plan: Investments in things that are not direct parts of the distribution system, such as land and buildings, tools and equipment, vehicles, and software which support Enersource's day-to-day business.
- LTP Benefits/Value: A description of how these investments are going to affect Customers' bills.

Throughout the IDST™ engagement, Customers were invited to make comments or ask questions. If appropriate pre-recorded video responses were available, answers were provided. Customers were also provided the option to contact Enersource directly via a web link if they had additional questions for which they wanted a direct response.

A summary of the results of the IDST™ Customer Survey are provided in Section 5.5.

## 5.4 Handling Customer Questions

If IDST™ participants had a question not answered in the IDST™, they were instructed to click on the Resources Tab and then click "Contact Us". This took the participant directly to the Enersource Contact page (http://www.enersource.com/about-enersource/Pages/contact-us.aspx). Nine participants chose to contact Enersource this way. This information was sent to the IDST™ host, MedRespond. Of them, five had difficulty progressing through the contest and registering for the draw; MedRespond provided them with instructions on how to proceed and/or enrolled them. One person was using the wrong web link (they were sent the correct address). All contacts were responded to within 24 hours.

Participants could also contact MedRespond directly using the “Report a Bug” in the Resource Tab. Seven participants used this method. All seven were having difficulty completing the survey as they were not clicking on necessary buttons. All seven were given instructions on how to complete the survey. All were registered for the draw. These responses were also sent within 24 hours.

A few Customers provided negative comments about Enersource and/or the form of engagement:

- “Worst survey ever” (that was the entire text),
- “Does the pointy headed boss from Dilbert work for you?”
- One Customer complained about having to register.

## 5.5 IDST™ Customer Research Summary

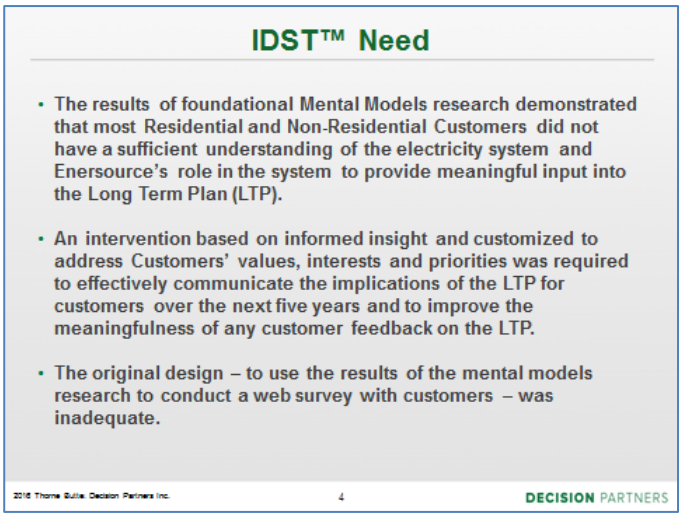
The following is a summary of the key findings from the IDST™ Customer Survey.

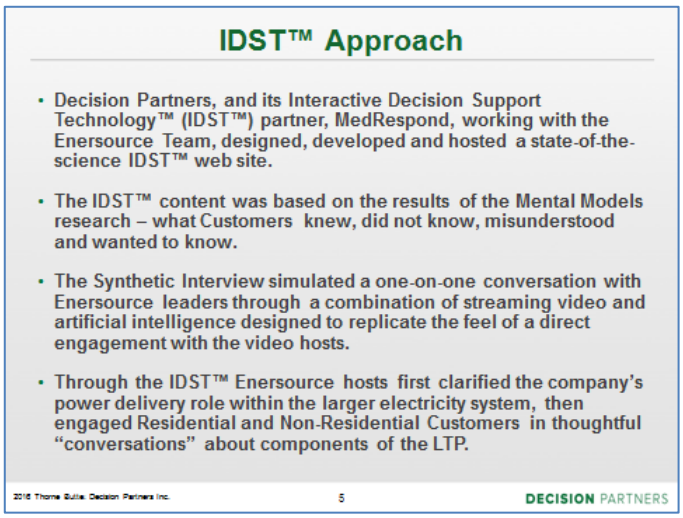


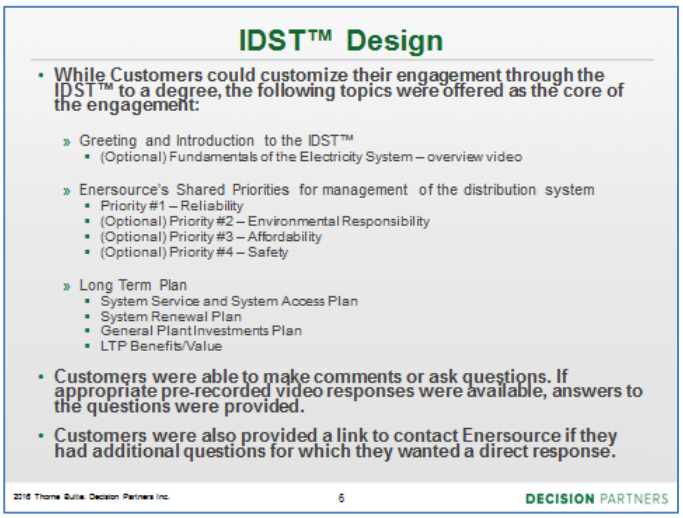






## Invitation to Participate in the IDST™

- Enersource invited its approximately 200,000 Residential and Non-Residential Customers to participate in the Enersource IDST™ to provide feedback to help shape the future of electricity distribution in Mississauga. Invitations were sent through many channels:
  - Press Release sent and posted on the website, November 23, 2015
  - Invitation sent via Email to about 60,000 Customers whose email addresses were on file. (Invitation sent December 11 and reminder sent December 18)
  - Invitation sent in customer bill inserts mailed between November 30 and December 23.
  - Multiple Twitter announcements (7) between November 24 and December 23.
- Customers were given the option to request a printed survey if they did not want to participate in the online engagement. No one requested a printed survey.



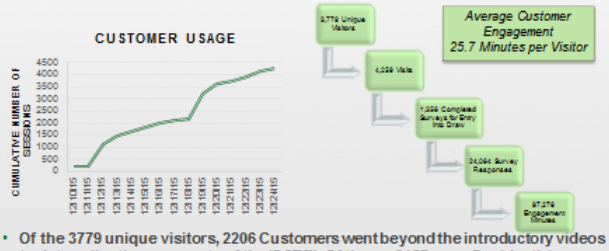
## Incentive to Participate in the IDST™

- As an incentive to participate, Customers who answered all of the 11 core survey questions within the IDST™ about the Long Term Plan by the end of day December 23rd, were entered into a draw for one of eight Samsung Galaxy tablet computers.
- Winner Selection Process:
  1. Respondents who reported as Enersource Customers and had completed the required questions were separated from those who were not customers, or who did not complete all of the required questions.
  2. Each eligible respondent was assigned an index number from 1 to 1358 – the total number of eligible respondents.
  3. Two sets of 8 unique random numbers between 1 and 1358 (winners and alternates) were generated from the website www.randomizer.org
  4. Respondents whose assigned index number matched the random numbers were provided to Enersource.
  5. Enersource verified that the respondents were customers and contacted the winners.



## IDST™ Sample

- The IDST™ was launched November 23 and Customer feedback was collected through December 30, 2015*.




- Of the 3779 unique visitors, 2206 Customers went beyond the introductory videos to data collection segments of the IDST™. Of those: 2157 were Residential Customers and 49 were Non-Residential Customers. In addition 43 non-Customer Guest Users visited the site and provided feedback (which was not included in the analysis).
- Nineteen Customers contacted MedRespond, the administrator of the IDST™, for technical assistance in using the site.

* The IDST™ site remained active until January 7, 2016.



## How to Read the Report

- This Report presents the results of Customers' feedback on the *criticality* of the LTP components and the *appropriateness* of the proposed increases in investments in each area.
- Specific findings are supported with example comments from Customers to illustrate the finding being presented and provide more in-depth insight into Customers' thinking.
- Not all Customers answered all questions in the IDST™, so the total number of respondents (n) for any particular finding may vary.
- The number of Non-Residential customers who participated in the IDST™ is too small to identify any significant variances between Residential and Non-Residential Customers, but illustrative quotes are identified as coming from Residential or Non-Residential Customers.



## Summary of Research Findings on Customer Perceptions of Long Term Plan Components



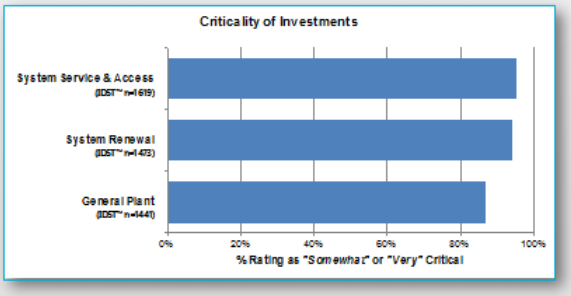
## The Bottom Line

- When Customers had an opportunity to understand the electricity system and then think through the components of Enersource's LTP and the rationale, most judged the proposed investments to be both critical and appropriate.
- Through their dialogue with Enersource Executives in the IDST™ they were able to think about what needs to be done and why. When they did so, for most, the proposed LTP activities and required investments made sense.
- Nearly all Customers (90%) expressed a "Medium" or "High" level of confidence that Enersource would do what is necessary to continue to provide safe, reliable, cost effective electricity by implementing the investments described in the LTP.
- The IDST™ results were somewhat more positive than the Mental Models results, perhaps because Customers were engaging with "real" Enersource people or because the IDST™ provided more context around the LTP.
- The IDST™ experience appears to have been a positive one for most Customers:
  - *"It seems like your numbers and facts are legitimate. It is evident a lot of work went into this website and planning for the increases."*
  - *"I think the team looks well prepared and serious about this venture. By merely reaching to public/consumers to get feedback /inputs in itself shows the nature of Enersource seriousness to get inputs and map accordingly the priorities."*
  - *"Because you ran this survey, I believe you'll live up to your word and to your clients' expectations! Good luck!"*
  - *"Going through this module, I can see how thorough and well thought the plan is. My experience with Enersource has also been one full of care for its customers. I appreciate plain and honest information like the information presented here."*

Bottom Line Up Front

## Criticality of Investment

- After hearing the description of each of the components of the Long Term Plan and the level of investment required, nearly all Customers judged Enersource's planned investments to be *"Somewhat"* or *"Very"* critical:

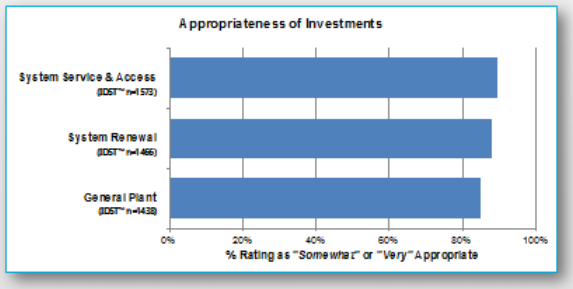





Bottom Line Up Front

## Appropriateness of Level of Investment

- After hearing the description of each of the components of the Long Term Plan and the level of investment required, nearly all Customers judged the level of investment in all three areas of the LTP were *"Somewhat"* or *"Very"* Appropriate:

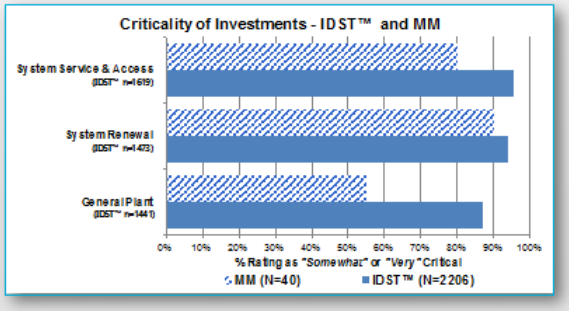





Bottom Line Up Front

## Criticality of Investment – IDST™ and MM

- The chart below compares Customers' assessment of criticality of investment from the Mental Models research and the IDST™:

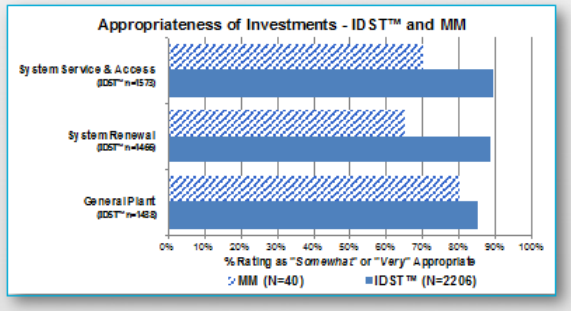





Bottom Line Up Front

## Appropriateness of Level of Investment – IDST™ and MM

- The chart below compares Customers' assessment of appropriateness of investment from the Mental Models research and the IDST™:

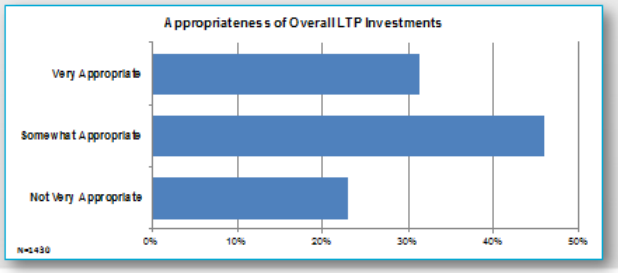





Bottom Line Up Front

## Appropriateness of Overall Increase In Investment

- When asked to rate how appropriate the 35% overall increase in investments in the LTP, most Customers (77%) believed that the level of investment was *"Very"* or *"Somewhat"* appropriate:
  - » *"A 35% increase over a five year timeline seems like a small price to pay to have peace of mind that the system is going to run effectively and efficiently."* (Res)






Bottom Line Up Front

## Confidence in Enersource

- Nearly All Customers (90%) said they had a *"High"* or *"Medium"* degree of confidence in Enersource in continuing to do a good job of providing safe, reliable, cost effective electricity by implementing the investments associated with the LTP:

Residential Customers

- » *"It seems well thought out. The information presented here increases my confidence. I know more now with the information provided."*
- » *"Enersource is seemingly trying to be transparent. We will see what the actual increase in the cost of electricity will be over the next 5 years, and I hope that in looking back, this doesn't turn out to be an empty effort to communicate with your customers."*
- » *"Reliability and safety is forefront. Cost effectiveness is shown in the proactive approach as related to replacing aged infrastructure, willingness to spread out the cost to minimize impact; long term planning in place with ongoing review, which is key to being flexible and agile in dealing with developments."*

Non-Residential Customers

- » *"In general your services are excellent and therefore I have high degree of confidence that your team is able to exceed such expectations."*
- » *"Enersource made a similar promise some 5-6 years ago.... and definitely delivered on the proposed reliability plan to replace end of life equipment with minimal interruption. Keep up the great job you do!"*

Bottom Line Up Front

## Positive Comments re: IDST™

- When speaking about their *"High Level"* of confidence in Enersource, some Customers made positive comments about the IDST™:
  - *"It seems like your numbers and facts are legitimate. It is evident a lot of work went into this website and planning for the increases."*
  - *"This website and the people in the videos. All seems very credible."*
  - *"Because you ran this survey and I believe you'll live up to your word and to your clients' expectations! Good luck!"*
  - *"Very clear presentation. Very user-friendly system. Plan had clear goals and investments were for a variety of different upgrades and efficiencies. Very professional."*
  - *"Firstly, I like this survey as it is getting your customers involved and it will be our money that is going to go from our pocket but since you are preparing us in advance of this increase in cost, there is no problem. We also know how Enersource works and they are the best."*
  - *"You seem to have taken this process very seriously, based on the efforts taken to solicit input. This survey/information project clearly took a lot of effort by many members of your team."*
  - *"Going through this module, I can see how thorough and well thought out the plan is. I appreciate plain and honest information like the information presented here."*



## Overview of the LTP

- To introduce the components of the Long Term Plan, the video host presented the following overview:

*There are three parts to our Long Term Plan: First, System Service and System Access which covers converting higher voltage electricity from the grid to the lower voltage electricity that you use. It also covers connecting new customers, and things like moving sections of our system to make way for expanded roads or the new Light Rail Transit system. System Service and System Access costs are expected to increase about 30% in total over the next 5 years, compared to spending in these areas over the previous five years. Next, System Renewal, which covers repairing and maintenance of our current distribution system. We expect our costs here to increase about 20% over the next 5 years. And finally, what we call General Plant, which covers things like our buildings, trucks, employee costs, training, computer equipment and other operating costs. This will use about 15% of our capital budget. We haven't planned any large, new investments in this area in the next five years, so there is no increase in this part.*



## Perceptions of LTP Components

- After presenting the overview, the IDST™ video host engaged the Customers on each component of the LTP:
  - Presenting a description of the focus of the component;
  - Asking for Customers' unprompted thoughts about investments in the area;
  - Asking Customers to rate how critical they thought the investments in the area were; and
  - Asking Customers to rate the appropriateness of the proposed level of investment in each area.



## System Service and System Access

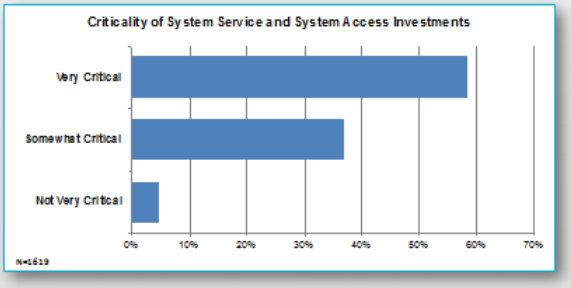
- The IDST™ video host presented the following description of the System Service and System Access component of the Enersource LTP:

*The System Service and System Access plan covers improvements and upgrades to our distribution system that will assure the delivery of electricity safely and reliability. To prepare for increased demand in Mississauga, our Plan covers the need to expand our system of substations, lines, and other equipment to connect new homes, especially condo developments, and businesses. And we need to tie in small renewable energy sources such as wind turbines and rooftop solar powered systems. These investments are among the most basic of the activities that we do as they are required to assure that we deliver electricity safely and reliably as we move forward.*



## Criticality of System Service & Access Investment

- When asked how critical investments in the System Service and System Access area of the LTP were, nearly all Customers (95%) rated the investments "Very" or "Somewhat" critical:






## Criticality of System Service & Access Investment

- **Most Customers (58%) rated investments in the System Service and System Access area of the LTP *"Very Critical":***

Residential Customers
- *"Because if you don't make investments you will likely not be able to keep up with demand. The world is reliant on, if not addicted to, energy."*
- *"Without the appropriate infrastructure the entire grid is in jeopardy. We need to ensure we have the most reliable and best system service and system access possible."*

Non-Residential Customers
- *"We need a dependable and consistent supply of energy."*
- *"Electricity is the next big thing. Everything is going electric so we have to cope with the market demand."*
- *"We need to ensure a sustainable system."*

## Criticality of System Service & Access Investment

- **Some Customers (37%) rated investments in the System Service and System Access area of the LTP as *"Somewhat Critical"*:**

Residential Customers
- *"System already functions well."*
- *"Mississauga is changing especially near the Square One area and it will create stress to our system if we aren't ready."*
- *"With everyone going more low energy with things like LED lights, there will be less burden on the system. Even with growth."*

Non-Residential Customers
- *"You need to be able to continue to provide service to existing customers, and new customers that will be added."*
- *"Not sure how important it is."*



## Criticality of System Service & Access Investment

- **A few Customers (5%) rated investments in the System Service and System Access area of the LTP as *"Not Very Critical"*:**

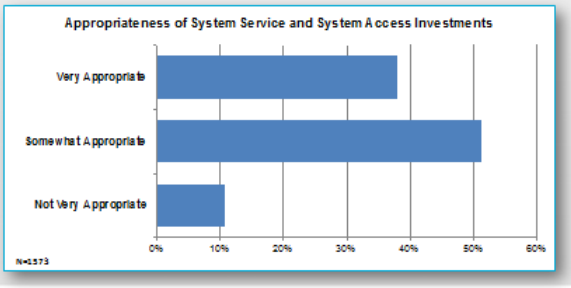
Residential Customers
- *"You didn't do anything to make the price lower."*
- *"As long as it will not sacrifice any of the promised services to the Consumers, any endeavours of the Company without any compromise in terms of providing the service to the people, for sure it would not make any problems."*

Non-Residential Customers
- *"Because you want to justify future price increases, now!"*
- *"Don't see this as a key priority."*



## Appropriateness of System Service & Access Investment

- Customers were next asked how appropriate the proposed 30% increase in investment over the next 5 years in System Service and System Access was. Nearly all Customers (89%) believed the level of investment was "Very" or "Somewhat" appropriate.






## Appropriateness of System Service & Access Investment

- **Some Customers (38%) rated the level of investment in the System Service and System Access area of the LTP as *"Very Appropriate"*:**

Residential Customers
- *"If we didn't invest now, we will have to pay more in the future."*
- *"The proposed LRT and adoption of electric vehicles makes a significant investment appropriate to support future needs."*

Non-Residential Customers
- *"Like anything, if don't plan and prepare for changes when outages and lack of demand are affected, by then it is too late."*
- *"Seems like a good proportional investment."*
- *"I run a company the relies on delivering 100% uptime. If power from Enersource is stable (this can only be achieved by having the right amount of capacity to demand ratio). Any degradation of power causes havoc for my customers and Enersource. The determination of a percentage of required efforts was based on previous growth and demand as well as end of life replacements. I feel it is extremely justified."*



## Appropriateness of System Service & Access Investment

- **Many Customers (51%) rated the level of investment in the System Service and System Access area of the LTP as *"Somewhat Appropriate"*:**

Residential Customers
- *"30% seems drastic, but it would depend on the funding sources. The costs cannot all be passed onto the consumer."*
- *"The investment is understandable for the City of Mississauga; however, could be costly to residents."*
- *"I am concerned of the cost that will be passed on to the consumer. This plan should have been in place long ago with costs more gradual to the consumer."*

Non-Residential Customers
- *"It is necessary but its costs will also increase."*
- *"The percentage of increase should be balanced by other key steps in the plan."*
- *"30% is a lot of investment."*



## Appropriateness of System Service & Access Investment

- **A few Customers (11%) rated the level of investment in the System Service and System Access area of the LTP as *"Not Very Appropriate"*:**

Residential Customers
- *"Expensive, no money."*
- *"Cost should be recovered from the builder unless it is for the City as a whole."*
- *"If that will be passed on to residential users, it's too high."*

Non-Residential Customers
- *"You should have been investing as the City was growing, not now. It's too late."*

## System Renewal

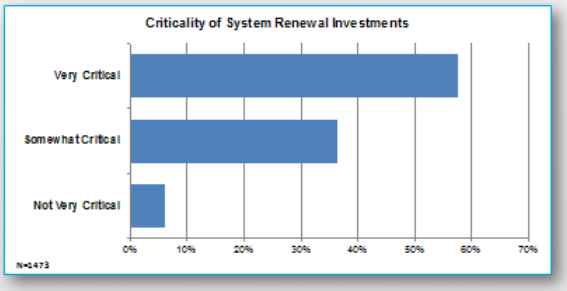
- The IDST™ video host presented the following description of the System Renewal component of the Enersource LTP:

*The System Renewal plan covers repairs and replacement of lines, and equipment that was installed 20-40 years ago and is now wearing out. Earlier James spoke with you about how most of the outages and voltage fluctuations people experience are caused by aging equipment. These investments will allow us to continue to provide safe and reliable power to you in an environmentally-friendly way.*



## Criticality of System Renewal Investment

- When asked how critical investments in the System Renewal area of the LTP were, nearly all Customers (94%) rated the investments *"Very"* or *"Somewhat"* critical:






## Criticality of System Renewal Investment

- Most Customers (58%) rated investments in the System Renewal area of the LTP *"Very Critical"*:

Residential Customers
- *"I would rather pay as the each year goes by than be hit in the future with costs that are disproportional, so the children in the future end up paying for our bad decisions."*
- *"I live in a very mature area of Mississauga that is often impacted by weather, aging wires and many trees. It is very important to our family that Enersource is prepared for as many of these situations as possible. While we do not need electricity for a medical appliance, we do have an active sump pump and it is comforting to know that there is ongoing awareness and plans to upgrade our systems, so when an outage occurs, we are as ready as we can be."*

Non-Residential Customers
- *"Reliability is key!"*
- *"The fluctuations in power and outages greatly affect business and the lives of residents. It has also caused costly repairs on our properties."*
- *"Proactive approach is more cost effective as well as more reliable."*



## Criticality of System Renewal Investment

- Some Customers (36%) rated investments in the System Renewal area of the LTP as *"Somewhat Critical"*:

Residential Customers
- *"While it's important to do regular maintenance on infrastructure, there is some leeway in terms of timing of repairs."*
- *"The system will always need maintenance and renewal to keep pace with demand."*
- *"Having invested this much in a survey about your Long Term Plan, it's hard to imagine that equipment has reached a state where it is extremely critical to replace it. On the other hand, you mention that some equipment is 40 years old. That seems quite outdated and more efficient equipment must be available."*

Non-Residential Customers
- *"Not clear where systems are still okay but could be improved vs in dire need of repair."*
- *"Only if it completely fails, then renew. Just like all of our home equipment, only if it's dead, then home owners choose to buy."*
- *"Need a balance in upgrading the system while maintaining reasonable rates."*



## Criticality of System Renewal Investment

- A few Customers (6%) rated investments in the System Renewal area of the LTP as *"Not Very Critical"*:

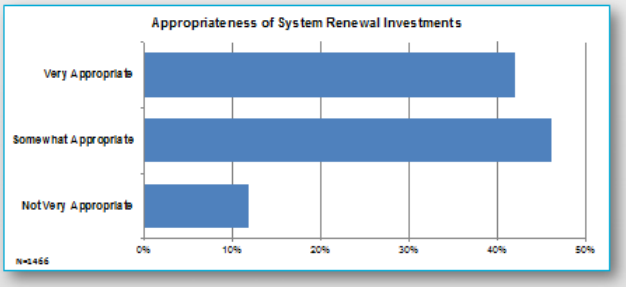
Residential Customers
- *"Because this will increase costs."*
- *"Not critical until the system fails."*
- *"Because Wynne will sell you for few bucks."*

Non-Residential Customers
- *"Because everybody knows that is very critical. The reason that you are collecting that answer (very critical) is because in the future when you will gouge me even more then now, you will tell me that I asked for it. So the answer is NO."*



## Appropriateness of System Renewal Investment

- Customers were next asked how appropriate the proposed 20% increase in investment over the next 5 years in System Renewal was. Nearly all Customers (86%) believed that the level of investment was *"Very"* or *"Somewhat"* appropriate.



## Appropriateness of System Renewal Investment

- **Many Customers (42%) rated the level of investment in the System Renewal area of the LTP as *"Very Appropriate"*:**

Residential Customers
- *"Renewal work always ends up costing more as surprises occur."*
- *"We need to catch up with a lot of our infrastructure issues and as long as the expenses are managed appropriately, I think we need to have a plan to update, upgrade and better prepare for the future."*

Non-Residential Customers
- *"This will help reduce our material costs by curtailing our scrap rate."*
- *"20% seems to reflect a projected trend I also follow. The cost of ensuring having the right tools, equipment and back up plans are necessary and the allocated spend is more than justified."*
- *"Need to ensure that reliable and affordable energy is available."*



## Appropriateness of System Renewal Investment

- **Many Customers (46%) rated the level of investment in the System Renewal area of the LTP as *"Somewhat Appropriate"*:**

Residential Customers
- *"Fiscal conservatism is paramount at this time."*
- *"Would rather spend gradually now than pass the more expensive cost into the future."*
- *"Need to balance sourcing and focusing more on operational efficiencies."*

Non-Residential Customers
- *"Difficult to answer without knowing extent of repair/renewal work that needs to be done."*
- *"There are other areas in the City which require investments, such as roads and sewage, etc. Therefore, all investments should be balanced."*



## Appropriateness of System Renewal Investment

- **A few Customers (12%) rated the level of investment in the System Renewal area of the LTP as *"Not Very Appropriate"*:**

Residential Customers
- *"Does 20% of the system fail or in need of renewal? Don't think so."*
- *"The price is already high."*

Non-Residential Customers
- *"What have you been doing for the past 50 years? The system should not be outdated! Period! Oh wait, the big fat bonuses. How could I forget that?"*
- *"You should privatize a portion of your company to a private company for investment."*



## General Plant Investment

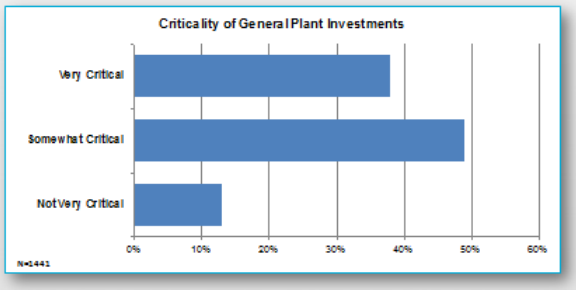
- **The IDST™ video host presented the following description of the General Plant Investment component of the Enersource LTP:**

*The General Plant plan describes the investments in things that are not direct parts of the distribution system, such as land and buildings, tools and equipment, the fleet of trucks and other vehicles, and software used to support our day-to-day business. Our reliability depends on having the systems to prevent outages and track maintenance and repairs. Our safety depends on tree trimming and the equipment that our crews use.*



## Criticality of General Plant Investment

- **When asked how critical were investments in the General Plant area of the LTP, nearly all Customers (87%) rated the investments as *"Very"* or *"Somewhat"* critical:**






## Criticality of General Plant Investment

- **Some Customers (38%) rated investments in the General Plant area of the LTP as *"Very Critical"*:**

Residential Customers
- *"This an area where costs can be controlled, especially with pending mergers with other utilities."*
- *Updates mean faster service to the consumer in case of power outages or emergencies."*
- *"I like peace of mind. I like the thought that if something bad happens, there will be qualified, organized, trained people who will help me in my time of need."*

Non-Residential Customers
- *"Keeping things running well is important. Vehicles, worker safety, and back up power plans are critical. So a need to invest here is very critical."*
- *"Without current tools and technology front line and support workers cannot meet the demands of their work."*
- *"Consumers don't often think of the tools, software, vehicle fleet, offices/warehouses required in the background to ensure the correct response to problems, issues or simply giving the workforce the right tools to get the job done right as quickly as possible."*

## Criticality of General Plant Investment

- **Many Customers (49%) rated investments in the General Plant area of the LTP as *"Somewhat Critical"*:**

Residential Customers
- *"It's important to have the appropriate software and trucks to ensure you're able to handle a problem on the grid."*
- *"Need to save for the rainy days and ensure you have what you need for future because you cannot predict what will come. You can never ensure you have enough – and taking too much is not right either – finding the right balance is important."*

Non-Residential Customers
- *"This area is not directly linked to the quality of services we are getting but these plans may be important as back up to those services."*
- *"It depends on the capital cost of new systems and replacements."*



## Criticality of General Plant Investment

- **A few Customers (15%) rated investments in the General Plant area of the LTP as *"Not Very Critical"*:**

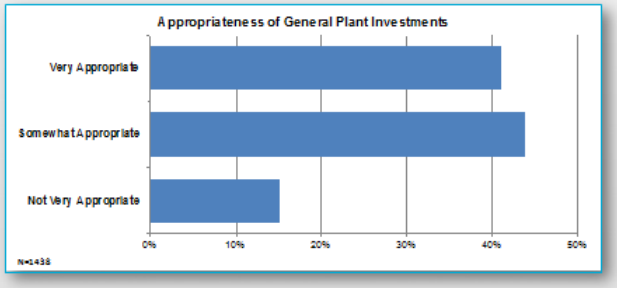
Residential Customers
- *"Don't have a clear idea of what current problems are (if any). Should be able to maintain with current programming and resources without major investments when so much is already being asked for already."*
- *"Fleet maintenance could probably be done for less by local garages."*

Non-Residential Customers
- *"Give me affordable hydro, (and I will tell you what affordable is) and then you think about investment. Simple math. You are charging me exorbitant amounts of money for hydro now, yet you need my approval for some massive spending. If you can't make money now, how much will you increase my Hydro to break even after this investments? Very scary."*
- *"If anything, the focus should be on reduction, not investment. Invest in talent quality, not quantity. Reduce real estate where possible."*



## Appropriateness of General Plant Investment

- **Customers were next asked how appropriate the unchanged level of investment over the next 5 years in System Renewal was. Nearly all Customers (85%) believed the level of investment was *"Very"* or *"Somewhat"* appropriate.**






## Appropriateness of General Plant Investment

- **Many Customers (41%) rated the level of investment in the General Plant area of the LTP as *"Very Appropriate"*:**

Residential Customers
- *"New building provides space for expansion and pending mergers should allow a reduction in overhead expenses and increased productivity."*
- *"The proposed merger will bring in economies of scale."*

Non-Residential Customers
- *"If it is sufficient for now, do not need to change."*
- *"We are in a time where there is definitely more elders than not and if the elders can depend on a lower charge… I'm all for that."*
- *"Funding for this plan is required and deferment to another time or budget cuts would absolutely hinder the other components of the Long Term Plan if not properly coordinated and budgeted. The General Plant described investments in things that are not part of distribution systems. Real estate, tools and equipment, vehicles and trucks as well as software to support day-to-day operations. Reliable equipment to prevent or minimize outages and the right tools for the crews to do their jobs, such as trimming trees, are required."*



## Appropriateness of General Plant Investment

- **Many Customers (44%) rated the level of investment in the General Plant area of the LTP as *"Somewhat Appropriate"*:**

Residential Customers
- *"As long as the expenses are well managed and deemed to be necessary, we need to have trust in Enersource to make the required change as necessary."*
- *"Change is always necessary in order to keep current. As long as there is minimal 'wasted spending', this type of investment is worthwhile."*

Non-Residential Customers
- *"Investments should be balanced. All expenses should tracked and be in line with other type of industries."*
- *"Tools and resources change and should they not be maintained, updated or replaced, workers cannot perform tasks efficiently."*
- *"There needs to be a balance in maintaining the general plant on how it will affect rate increases."*
- *"Every system needs to be upgraded to reduce costs in the future."*



## Appropriateness of General Plant Investment

- **A few Customers (15%) rated the level of investment in the General Plant area of the LTP as *"Not Very Appropriate"*:**

Residential Customers
- *"Can't keep up-to-date with technology."*
- *"Rising costs and requirements would probably have an impact of the monetary implications of managing and maintaining the general plant elements. So I find it a little confusing as to the non-increase in the investment."*

Non-Residential Customers
- *[No substantive comments]*

## Overall Cost Impact of LTP

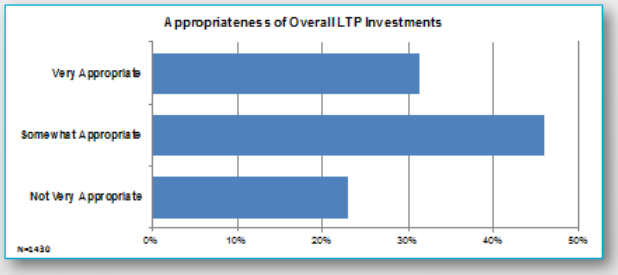
- The IDST™ video host then presented the following description of the overall cost impact of the Enersource LTP:

*We know our customers are keeping a close eye on their electricity bills, so you're probably wondering how these improvements are going to affect your bill. Controlling our costs and the impact on our customers' bills is a critical part of our proposed plan. Basically, we are asking the Ontario Energy Board to approve an increase of 35% over five years on one section of your bill. Allow me to explain how the billing system works. First your total electricity bill includes charges from the three different parts of the system: the generators who make the electricity, the high voltage transmission companies, and then our charges which cover the cost of bringing electricity across our low voltage distribution lines to your home or business. Our charges account for approximately 20% of your total bill. The 35% increase aligned in our Long Term Plan only applies to that one section of the bill. For the typical residential customer who consumes 800 kilowatt hours of electricity per month, this change will represent $2.00 on their total bill.*



## Appropriateness of Overall Increase In Investment

- When asked to rate how appropriate the 35% overall increase in investments in the LTP was, most Customers (77%) believed that the level of investment to be *"Very"* or *"Somewhat"* appropriate:






## Judgment of Overall Increase in Investment

- Some Customers (31%) rated the overall increase in investments in the LTP as *"Very Appropriate"*:

Residential Customers
- *"I have not always agreed with the provincial government's decisions on generation, as those decisions affect utilities as your own. But it is very important to have reasonable cost reliable system."*
- *"A 35% increase over a five year timeline seems like a small price to pay to have peace of mind that the system is going to run effectively, and efficiently."*
- *"Kudos on the succinct explanation. "35%" is a significant amount and at first, the proposition seems to apply to the whole bill (which would be outrageous). I believe in responsible investment... IF this applies solely to the single section - and would represent an approximate increase of $2/month to the average user, this seems reasonable to me."*
- *"The total proposed cost that would affect my bill on a regular basis being only $2 is acceptable for the proposed changes."*

Non-Residential Customers
- *"During winter times, our continuous production plant is badly affected by the power outrages and we have seen an increase in the number of incidents happened. So with a little increase in costs, we can be better off if that increase in investment in your infrastructure provides us continuous and uninterrupted services during this period."*
- *"You need to keep everything running smoothly and also consider the cost of inflation. I feel it's reasonable."*



## Judgment of Overall Increase in Investment

- Many Customers (46%) rated the overall increase in investments in the LTP as *"Somewhat Appropriate"*:

Residential Customers
- *"Again, do not have the detailed information to determine actual percentage increase but agree increases will be required. Who funds these increases will be important . Developers of City Centre who benefit from buildings and LRT should contribute their fair share and it should not be all tacked onto the residential consumer."*
- *"I would like to see added transparency regarding the allocation of the increased amount. It might be beneficial to detail them on the bill. It would also be expected to see these increases disappear once the infrastructure has been implemented. If the infrastructure needs to be enhanced to service new users, the revenue from these new users should offset the added maintenance cost."*

Non-Residential Customers
- *"Still not clear exactly where the money is going, in terms of amounts (understand reasoning behind, but not actual $$ figures), as well as where the accountability will be to ensure it does go to those programs."*
- *"Although this may be in line with inflation rates and demand, Enersource should consider reinvesting profits instead of over-payment to internal staff starting at the top."*
- *"Not clear what 35% represents in dollars, and how the cost is being allocated. Are bigger users getting a bigger share of the cost? How much is the LRT absorbing?"*
- *"It was explained that the 35% would only be applied to a small portion of the bill, not the generator, not the high voltage portion. Not crazy about an increase, but cost of living goes up, $2 on approximately 800kW/hours seems fair."*



## Judgment of Overall Increase in Investment

- Some Customers (23%) rated the overall increase in investments in the LTP as *"Not Very Appropriate"*:

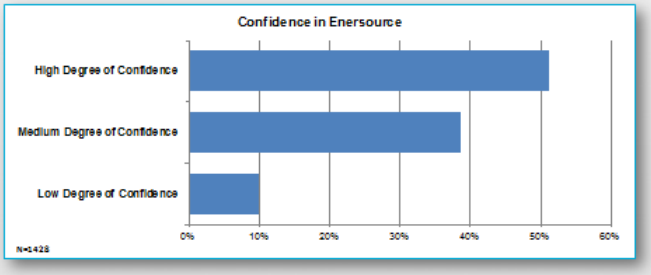
Residential Customers
- *"Energy costs are driving business base from Ontario. I don't agree in any plan to increase costs. Work on optimizing your cost base."*
- *"7% per year for 5 years is excessive."*
- *"It will [increase] my bill and the company does not help stay-at-home parents because they are being penalized for doing things during the day. They have to save things for at night which defeats the purpose of being a stay-at-home parent."*

Non-Residential Customers
- *"You are gouging me! While you are constantly increasing the price, I have to run a business where I am losing most of my work to China, and my prices are in decline, my income is in decline. Now there is only one way out for me. And that is to leave the province. For example, why did you move from your location on Mavis Road, and how much did that cost? Second, you are not an equal opportunity employer? And it just goes on and on. Your salaries, your bonuses etc. etc."*
- *"The 10% benefit was already lost, and the proposed increase would cause additional costs to all consumers."*
- *"People are struggling to pay their utility bills and saving by not using too much or shutting down during certain hours. What will we do when the cost rises by 35%?"*



## Confidence in Enersource

- Considering all of the aspects of the LTP, Interviewees were asked to rate their level of confidence that the Enersource team will continue to do a good job of providing safe, reliable, cost effective electricity by implementing the investments associated with the LTP. Nearly all Customers (90%) had a *"High"* or *"Medium"* degree of confidence.



## Confidence in Enersource

- Many Customers (51%) said they had a *"High Degree"* of confidence in Enersource in implementing the investments:

Residential Customers
- *"It seems well thought out. The information presented here increases my confidence. I know more now with the information provided."*
- *"Enersource is seemingly trying to be transparent. We will see what the actual increase in the cost of electricity will be over the next 5 years, and I hope that in looking back, this doesn't turn out to be an empty effort to communicate with your customers."*
- *"Our City wouldn't be so beloved and admired by the rest of the country if it wasn't for the professionalism that our utility companies display."*

Non-Residential Customers
- *"In general your services are excellent and therefore I have high degree of confidence that your team is able to exceed such expectations."*
- *"I have only been in Mississauga for 1 year, so I do not have historical data to compare to. But things have remained reliable at my facility, and I am pleased with the service. I have no reason to doubt that you guys know what is best for delivering, safe and reliable electricity."*
- *"Reliability and safety is forefront. Cost effectiveness is shown in the proactive approach as related to replacing aged infrastructure, willingness to spread out the cost to minimize impact; long term planning in place with ongoing review, which is key to being flexible and agile in dealing with developments."*
- *"Enersource made a similar promise some 5-6 years ago ... and definitely delivered on the proposed reliability plan to replace end of life equipment with minimal interruption. Keep up the great job you do!"*



## Confidence in Enersource

- Some Customers (39%) said they had a *"Medium Degree"* of confidence in Enersource in implementing the investments:

Residential Customers
- *"I have a high degree of confidence in existing management but I'm concerned that a larger regional utility may not be as focused on Mississauga's needs."*
- *"Because just like politicians those giving the speeches are receiving substantial salaries with little to no accountability/responsibility. Regular employees are held accountable for the work they perform and show initiative."*

Non-Residential Customers
- *"Hope that you will do what you have discussed, but accountability hasn't been discussed."*
- *"Consumers don't have a choice of service so cost increases are out of their control. Focus should be more on reducing energy consumption and renewable energy."*



## Confidence in Enersource

- A few Customers (10%) said they had a *"Low Degree"* of confidence in Enersource in implementing the investments:

Residential Customers
- *"Short on detail, long on cost increase."*
- *"Look at our electrical costs today!"*
- *"Enersource employees cannot answer simple questions from house painters without playing phone tag and ignoring inquiries and the company is too reliant on outside technical support to perform technical operations such as design, advice, and installation work."*

Non-Residential Customers
- *"What you are saying in your question is that you did a good job so far. No you did not, and you are not to say that. I am the customer. For the past 10 years in business I have blackouts on average 2 times a week, at my business. Good Job!"*
- *"Thinking of the "gas plant" situation and Liberal party involvement in this scheme, my confidence now is low in any proposed plans."*



## Positive Comments re: IDST™

- Some Customers when speaking of their *"High Level"* of confidence in Enersource made positive comments about the IDST™:

Residential Customers
- *"It seems like your numbers and facts are legitimate. It is evident a lot of work went into this website and planning for the increases."*
- *"This website and the people in the videos. All seems very credible. Plan appears to be well thought out."*
- *"I think the team looks well prepared and serious about this venture. By merely reaching to public/consumers to get feedback/inputs in itself shows the nature of Enersource's seriousness to get inputs and map accordingly the priorities."*
- *"Because you ran this survey and I believe you'll live up to your word and to your clients' expectations! Good luck!"*
- *"Well planned out and well explained."*
- *"Very clear presentation. Very user friendly system. Plan had clear goals and investments were for a variety of different upgrades and efficiencies. Very professional."*



## Positive Comments re: IDST™

- *"Firstly I like this survey as it is getting your customers involved and it will be our money that is going to go from our pocket but since your are preparing us in advance of this increase in cost there is no problem. We also know how Enersource works and they are the best."*
- *"You seem to have taken this process very seriously, based on the efforts taken to solicit input. This survey/information project clearly took a lot of effort by many members of your team."*
- *"Going through this module, I can see how thorough and well thought out the plan is. My experience with Enersource has also been one full of care for its customers. I appreciate plain and honest information like the information presented here."*
- *"I'd just like to say that this interactive site is a fantastic idea. Some might wonder why it's necessary or if it represents a spend where none is needed. I look at it as bringing customers closer to the electricity providers and distributers. Well done."*
- *"You are the only provider we've ever had who bothered to share this type of info, for one. It gives the impression that you are confident in your plan."*

Non-Residential Customers
- *[No substantive comments]*



## Negative Comments re: IDST™

- A few Customers made negative comments about the IDST™ when speaking of their *"Low Level"* of confidence in Enersource:

Residential Customers
- *"This whole exercise smacks of a very poorly disguised attempt to solicit public support without meaningful information and dialogue."*
- *"How do you expect me provide a useful comment when I haven't seen any details?"*
- *"Because this looks strictly like a marketing type engagement survey with three answer fields, HIGH/MEDIUM/LOW. You don't actually supply any details."*

Non-Residential Customers
- *"The options listed are not encompassing enough. Not enough information is provided. How can I validate your cost claims without hearing an unbiased opinion or being able to review the data or meta data myself? These questions appear to be very self-fulfilling."*

## Section 6: Key Learnings

*The Challenge*

The OEB required evidentiary proof that Enersource's DSP submission demonstrates that the company's distribution services are provided in a manner responsive to customer preferences. This, in turn, required Enersource to ensure that their customer engagement efforts were based on deep insight into customer values, needs interests and priorities. To accomplish this, the Enersource Team needed to demonstrate that the value proposition of the DSP for customers (economic efficiency and cost-effectiveness) was clear and that customers were given an opportunity to provide input on other factors relating to customer service preferences. This input needed to be considered by the Team as they finalized their investment projects and activities. In addition, the Team also had to assess the alignment of customer input with the draft DSP and determine if any changes were needed in their final submission.

The Enersource Team wanted to go beyond traditional consultation methods and tools – for example, opinion surveys, focus groups, detailed "workbooks" developed by some LDCs. They wanted a consultation approach that enabled customers to make thoughtful, well-informed *judgments*[9] about the need for and appropriateness of their proposed DSP investments. Decision Partners, and its science-informed, evidence-based Mental Modeling Technology™ (MMT™) approach, was selected to support the Enersource Team in this endeavour. MMT™ methods and tools are specifically designed for understanding and influencing judgment, decision making and behaviour. (See Section 3 for an overview of this methodology.)

At the outset of the engagement, Decision Partners worked with the Enersource Team to develop the following Opportunity Statement which articulates the Team's objectives and was used to design the DSP consultation process.

*Enersource Team's Customer Consultation Opportunity Statement*

*Design and implement a comprehensive customer consultation initiative that applies state-of-the-science Mental Modeling Technology™ to gain in-depth insight into customers' values, interests and priorities regarding Enersource's proposed Distribution System Plan (DSP). The results will be used to develop detailed, sophisticated and compelling evidence that demonstrates Enersource's commitment and obligation to engage, inform and to seek customer input on the design of its DSP submission. A summary of this research-based Consultation initiative will be submitted to OEB in 2016. Additionally, this in-depth understanding of customer preferences will enable Enersource to strengthen relationships with its customers.*

[9] See Judgment vs. Opinion in the Appendix, on page 78.

*Foundational Mental Models Research*

The first step in the consultation process was developing an Expert Model of *Influences on Customers' Judgment of Enersource's DSP* based on the Enersource Team's customer experience and data (see Appendix 8.1). The factors identified were then used to design and conduct mental models research with Residential (15), Non-Residential (16) and Large Use Customers (9). The purpose of the foundational mental models research was to *discover, and characterize in depth,* Customers' understanding of the electricity system and Enersource's role in it and to elicit input on the key components of the DSP, called the Long Term Plan.

The foundational research demonstrated that most Residential and Non-Residential Customers did not have a sufficient understanding of the electricity system, including distribution, to provide meaningful input into the Enersource's DSP. Customers' mental models of the electricity system were incomplete and, in some cases, incorrect. Many were unclear about Enersource's role in the system, and there was significant confusion about the electricity system costs that drive the overall price of electricity vs. Enersource's distribution costs. There is some evidence that the current design of electricity bills may be contributing to this confusion.

Consequently, if customers do not have sufficient understanding of the system and Enersource's role they cannot reasonably be expected to understand the investments proposed in the DSP or provide meaningful input on the key components. This lack of knowledge was consistent with other research we have conducted in the sector.

While reliable electricity and reasonable rates were very important to customers, Enersource's value proposition – what it takes to deliver electricity reliably – was not understood by most Residential and Non-Residential Customers because of their limited understanding of the system. (Large Use Customers had a more complete understanding of the system and Enersource's role as an LDC.)

From a decision science perspective, if customers do not understand the fundamental value proposition put forward by Enersource in its DSP because of a lack of knowledge of the electricity system, they cannot make well-informed judgments about the need for, or acceptability of, the rate increase required to support the level of investment proposed.

The initial consultation plan was to use the results of the mental models research to design a web-based survey to elicit input from a broader customer base. However, the foundational research underscored the need to provide this critical context in order to engage customers in a meaningful way. As one Residential Customer (age 91) said when asked what advice she would give Enersource: *"I would say expect people to be a little bit stupider than you think because we really are when it comes to things like electricity. Don't take for granted what we know and what we don't know."* While we don't agree that people are "stupid", this comment underscores how providing the information people want and need in order to make an informed judgment is fundamental to effective customer engagement.

As a result of the insight gained, the second phase of Enersource's consultation process was redesigned. We began customer engagement with a discussion of the electricity system basics and what the company does to ensure the reliability of their system. We used plain English and provided access to Enersource professionals if Customers didn't understand any portion of the explanations provided or wanted more information.

An important feature of this redesigned engagement approach was to provide customers with the background and context they needed to address what they did not know or misunderstood about the electricity system. To this end, we developed the Electricity Fundamentals video – a short, illustrated narrative of how the electricity system works and the role of Enersource within the system. The stand-alone video became the first module in Enersource's Customer Interactive Decision Support Technology™ (IDST™) website. This was followed by a discussion led by host, James Macumber, Enersource's Vice President, Asset Management Strategy, about the priorities Enersource shares with its customers, starting with reliability.

Based on our work in the sector over the past 20 years, we suggest this lack of understanding of the electricity system is a significant challenge. Providing this context – at a lay level – is essential if LDC customers are to provide meaningful input into LDCs' DSPs.

*Key Learnings from Our Assessment of Other LDC's DSP "Workbooks"*

In working with the Enersource Team to design the second phase of their consultation process, we reviewed the approaches of other mid-to large LDCs. In addition to opinion surveys and focus groups, some LDCs had prepared "workbooks" to provide background on the company, the industry and their DSP. These typically included a description of the topic followed by opinion survey questions; for example, the rationale for planned investment on a component of the DSP then questions about the level of investment.

Decision Partners conducted comprehensive reviews of three LDC's DSP workbooks: Toronto Hydro, PowerStream and Horizon – in order to make recommendations to the Enersource Team about developing a similar workbook. We reviewed these from a risk communication and decision science perspective, assessing how these documents support customer judgment and decision making about the respective LDCs' DSP.

The primary goal of risk communications is to help decision makers (the LDC, and ultimately, the OEB) and their stakeholders and customers make well-informed decisions and take appropriate actions. With that in mind, we designed the second phase of the consultation process to encourage customer engagement and elicit customer input in a way that demonstrated respect for their values, interests, priorities and time.

For a discussion on the observations from Decision Partners reviews of three LDC's DSP "Workbooks", see Appendix 8.4.starting on page 63.

*Addressing the Challenge with New Customer Engagement Technology – IDST™*

The results of the foundational mental models research and our assessment of other LDCs' engagement efforts, suggested the need for new, state-of-the-science methods and tools to support a broader, dialogue-based engagement. The approach had to be responsive to the specific Customer needs, interests and priorities identified in the foundational research and to provide further insight on the issues and topics raised. It also had to be designed to enable a larger number of customers to provide input to the DSP in a way they deemed to be meaningful and appropriate. The interface was important in enabling us to gather meaningful feedback, while being respectful of people's time and being accessible to the majority of Customers.

Given the Customers' preferences for web-based communication and meetings with Enersource representatives identified in the mental models research, we recommended the Enersource Team engage customers (primarily Residential, but Non-Residential were also invited to participate) in a virtual, interactive, *dialogue-based* conversation using a web-based interface. The new technology combines Decision Partner's Mental Modeling Technology™ with MedRespond's Synthetic Interview™ technology called Interactive Decision Support Technology™. The IDST™ is described in Section 3, page 9 as well as in Appendix 8.4, starting on page 63.

*Key Learnings from the IDST™*

The results of the IDST™ survey were consistent with and build on the findings from the foundational mental models research, though more positive, possibly because Customers had the opportunity to engage in dialogue with "real" Enersource Team members, or because the IDST™ provided more context around the DSP components compared to the mental models research. Some key results include the following:

- 2,157 Residential Customers and 49 Non-Residential Customers visited the site – more than double the response achieved by Horizon with visitors to their online workbook landing page. (Horizon has approximately 20,000 more customers than Enersource.)
- 1,358 Customers completed the DSP survey component of the IDST™ – more than a ten-fold increase over the workbook completion of the three LDCs whose workbooks we assessed.
- The average engagement time was 25.7 minutes per visitor – far less than the time required to complete a workbook or attend a focus group meeting, but sufficient time to think through the components of the DSP and provide meaningful input.
- The site design and content were developed based on the results of the mental models research. The focus was on addressing what Customers wanted to know along with what they didn't know or misunderstood in a flow that was logical to Customers, and aided their understanding. Very few negative comments were received on the site design or content.
- Very rich qualitative results were achieved: a total 97,276 engagement minutes and over 24,000 responses of feedback were received from IDST™ participants.
- Robust quantitative results were also achieved: Enersource sent direct email invitations to 60,000 Customers for whom they had email addresses; about 3,000 of these were no longer valid. Customers were also invited to participate through the Enersource website, social media and bill inserts. Looking at the 57,000 direct emails (which appears to have been the most expedient method, given the user enrollment data), the 1,358 Customers who completed the IDST™ survey component represent about a 4% response rate.

| | # of Cust. Completing Engagement | % of Cust. Base |
|---|---|---|
| **Toronto Hydro (workbook)** | 207 | 740K |
| **Horizon (workbook)** | 111 | 242K |
| **PowerStream (survey)** | 1,553 | 375K |
| **Enersource (IDST™)** | 1,398 | 200K |

*The Customer Experience*

Some Customers took the time to comment on their engagement with members of the Enersource Team through the IDST™. Their positive experiences may have influenced their assessment of the company's consultation process, along with the proposed DSP, as indicated by these representative quotes. At this point, we offer these as hypotheses that could be tested in future customer engagement efforts. Here they seem to be important leading indicators regarding the acceptability of Enersource's proposed DSP investments:

- *"It seems like your numbers and facts are legitimate. It is evident a lot of work went into this website and planning for the increases."*
- *"This website and the people in the videos. All seems very credible."*
- *"Very clear presentation. Very user-friendly system. Plan had clear goals and investments were for a variety of different upgrades and efficiencies. Very professional."*
- *"You seem to have taken this process very seriously, based on the efforts taken to solicit input. This survey/information project clearly took a lot of effort by many members of your team."*
- *"Going through this module, I can see how thorough and well thought out the plan is. I appreciate plain and honest information like the information presented here."*

Perhaps the most important result from our perspective is that the IDST™ enabled customers to work through the components of the DSP and the rationale for investment *with* an Enersource host, commenting or asking questions along the way. By so doing, they had an opportunity to think through the benefits, risks and trade-offs of the proposed activities and the level of investment being recommended and make *well-informed judgments* of their acceptability. In addition to such judgments being more thoughtful and meaningful, as discussed above, they are also more stable than "opinions"[10]:

- After hearing the description of each of the DSP components, nearly all Customers judged each of Enersource's planned investments to be *"somewhat"* or "very" critical and appropriate.
- When asked to rate the appropriateness of the proposed 35% overall increase in the investments in the DSP, 77% of Customers believed that the level of investment was *"very"* to *"somewhat"* appropriate.

Also significant, 90% of Customers said they had a "High" or "Medium" degree of confidence in Enersource continuing do a good job of providing safe, reliable, cost effective electricity by implementing investments associated with the DSP, in part due to the thoroughness of the presentation of the DSP through the IDST™.

- *"[I'm confident] Because you ran this survey and I believe you'll live up to your word and to your clients' expectations! Good luck!"*

[10] See Judgment vs. Opinion in the Appendix, on page 78.

## Section 7: Considerations

The Enersource Team's commitment to adopt a behavioural science-based approach to customer engagement and systematically work through the consultation process to first discover customer interests, preferences, priorities and information needs, then use that insight to develop a state-of-the-science tool to engage a broad number of customers using a web-based interface demonstrates the company's leadership and progressive thinking. We believe the results speak for themselves.

In short, the Enersource Team successfully engaged more Customers in *meaningful* dialogue about the electricity system, the role of the LDC, the proposed activities under each of the key components of their DSP and the rationale for the required investment than is typical of consultations in this industry. In return, they received thoughtful *judgment* about their proposed DSP from over 1,400 IDST™ users plus 40 Customers who participated in the foundational research. The quality of customer input – thoughtful judgment and well-informed decisions – surpasses that typically gathered through traditional methods.

Based on the results of this engagement – the robust input from Large Use, Residential and Non-Residential Customers – *we do not recommend any substantive changes* to Enersource's draft DSP. By providing additional context on a few topics noted below, we believe Enersource's DSP addresses both direct and indirect customer preferences.

The key result of this engagement process is that when given the opportunity and the context to think through important aspects of the DSP and the investment implications, most customers will make a well-informed *judgment* about the value, need and appropriateness of the investments being proposed. Given the results, the OEB may be interested in assessing this behavioural science approach and the Enersouce example as a model for other large and mid-sized LDCs.

The considerations that follow are offered to the Enersouce Team as they finalize their DSP and prepare for future endeavours requiring thoughtful customer input and judgment. We hope these considerations will also benefit other LDCs preparing to engage customers on their DSPs and other significant operational initiatives that could affect them.

*Behavioural Science-Based Methods and Tools*

Our overarching recommendation is that the Enersource Team continue to use behavioural science-based methods and tools when their stakeholder/customer engagement objectives require stakeholders and/or customers to judge the acceptability of new opportunities, changes to operations, long term plans, and other initiatives that ultimately affect them. Such methods and tools are best suited to initiatives where the judgment and decision making of stakeholders and/or customers is critical to success.

Drawing from the relevant sciences, decision support and communications tools can be designed to facilitate stakeholder/customer engagement, enable thoughtful judgment and decision making, and elicit input and feedback in a way that is meaningful to participants. The flow, logic and language level of such tools are specifically developed to support decision making and assure, for most, a positive engagement experience.

*Complete the Customer Dialogue on the DSP*

While customers don't want to be "educated" by their LDC, they do want and need basic contextual information about the electricity system in order to engage in *dialogue* about aspects of the company's business that affects them, including its DSP.

Dialogue is the conversational means of helping people think together in order to build shared understanding that leads to well-informed decisions and actions – in this case, about the acceptability of an LDC's DSP. Dialogue enables people to understand one another's thinking in depth. And it is practical – it focuses on: building relationships; exploring new proposals or ideas; identifying opportunities for improvement; and working together to solve problems.

- *Use a Dialogue Process to Engage Customers*

  The Enersource Team chose a dialogue approach for first conducting foundational research, then engaging a broader segment of their customer population through the interactive, web-based IDST™. Dialogue means *thinking with* and its purpose is to *build shared understanding*. The "Dialogue Process" is more open, transparent, and equitable than the traditional, top-down "Tell Process".

  The Enersource Team successfully used dialogue to engage customers, then talk *with* them about the components of the DSP, including sharing the Team's rationale – not just what activities were being proposed in each component, but *why* the proposed investments were required.

  The results were clear: When customers had an opportunity to think through the details of the DSP in each component, most *judged* the proposed plans and investments to be both *critical* and *appropriate*. And when asked to rate how appropriate the overall increase in investments in the DSP were, most Customers (77%) believed the level of investment was "Very" or "Somewhat" appropriate.

- *Continue the DSP Dialogue – Provide Feedback to Customers*

  Given the time and commitment of Customers who participated in the DSP consultation process, we suggest the Enersource Team use traditional media and social media, plus perhaps direct email, to thank customers for their active engagement and participation in shaping the DSP. It would be important to describe what the Enersource Team learned from Customers and how they used that insight to refine and finalize the DSP.

- *Address Important Topics Raised by Customers*

  Throughout the consultation process, Customers offered comments on topics directly related to the DSP and others on topics more generally related to Enersource's business. We suggest Enersource prepare communications materials for their website, bill inserts and other customer communications channels that address topics related to:

  - Reliability, safety and affordability
  - Conservation, the use of more renewables, and the impact on electricity costs

- Accountability for and communications about progress made to complete the activities described in the DSP
- Price increases, including what customers should expect after Enersource completes the investments described in the DSP
- Outage prevention activities undertaken since the ice storm and on a go forward basis
- The proposed merger: the impact on customer service; Enersource's commitment to complete the plans described in the DSP; and the impact on rates

- *Work with Others to Simplify Bills*

  While beyond the scope of Enersource alone, we recommend that members of the Enersource Team discuss with the OEB and possibly other LDC colleagues the need and opportunity to apply behavioural science to the challenge of making customer bills a) understandable; b) useful decision support tools that enable desired customer behaviour; and c) transparent.

  This should be a priority moving forward, given the confusion, misunderstanding and frustration expressed by Customers about their electricity bills. Their perception appears to be fueling misunderstanding of the role of the various industry players and the respective costs of their services. This issue is not specific to Enersource; from what we have seen in our work and that of others, this is endemic across the industry. The bill serves as a primary communication to the customer and consequently should be refined and pre-tested to ensure it communicates as intended with customers, in addition to meeting the needs of customers, the LDCs, the OEB and the industry.

*Continue Meaningful Customer Engagement and Consultation*

We recommend the Enersource Team continue to engage customers in dialogue on all key topics related to their operations, especially where customer judgment is critical to a successful outcome. Customers expect to be engaged and have input into decisions the company is making that could affect them. Having an appropriate and accessible interface to do so is a prerequisite for meaningful engagement.

- *Communicate Directly With Customers*

  Customers participating in the mental models research and the IDST™ web survey commented positively on the opportunity to communicate "directly" with Enersource staff, either through our researchers or through the IDST™ hosts. Large Use Customers and some of the larger Non-Residential Customers commented positively about the relationships they had with senior Enersource people.

  We recommend the Enersource Team continue building and expanding those personal relationships through all of their communications channels. Expanding direct contact by asking customers to share their email addresses would be one approach. Enersource had email addresses for approximately 57,000 of 200,000 customers. Email was a preferred means of communicating and the most efficient mechanism for engaging customers to participate in developing the DSP. Putting a human face on such correspondence, along with other print and social media communications, is another.

The Enersource Team may also want to consider engaging customers in future through an IDST™ format, either on an ongoing basis or for specific topics. This approach would provide current data on customer interests and priorities and might be considered, for example, when communicating with customers about the proposed merger or other significant topics of interest to customers.

- *Listen To and Learn From Customers*

  Through the foundational mental models research, followed by the IDST™, the Enersource Team was able to "hear" their Customers' thinking – not just what they thought about the various components of the DSP, but *why* they thought what they thought. The deep insight from the foundational research provided the Team with a clear understanding of Customers' mental models – what Customers knew, what they did not know, what they wanted to know and what communications processes they trusted. It also provided the base on which to build shared understanding of the DSP.

  The Team then used this insight to refine components of the draft DSP and to rethink and redesign the second phase of customer engagement and communication. A key change the Team made to the draft DSP was providing more context and rationale for their proposed activities and required investments.

  We recommend the Enersouce Team continue to use formal and informal research to systematically listen to and learn from customers on other topics of shared importance. Sharing the results and key learnings among the Team members is also recommended.

- *Context is Critical*

  One of the most critical gaps identified in the foundational mental models research was that customers need and want an understanding of the context – the electricity system, the players, and the role of an LDC – in order to provide meaningful input into their LDC's DSPs.

  In future communications about changes that could affect customers, we recommend the Enersource Team provide the context – both the *what* and the *why* – in addition to pre-testing the materials to ensure they are understood and interpreted as intended.

  We also recommend that the Team consider posting the *Electricity Fundamentals* video to their website and using it in presentations to lay the groundwork for a productive engagement. Other LDCs might benefit from a review of the video and preparation of similar content, in print or video formats, explaining the system and their role in it, at a lay level.

- *Framing is Important*

  Framing is the use of language to manage the meaning of messages. Framing is what helps people make sense of a subject and judge its relevance to them. How a topic is framed from the outset is critical because the initial framing sets up all subsequent interpretations of it.

In the Enersource Mental Models research and IDST™, a deliberate decision was made to use the language of “investment” not “cost” in order to elicit the fullest possible thinking from Customers about the benefits, costs and trade-offs of the activities being proposed in the DSP. We believe this framing achieved the objective. Most Customers were able to make thoughtful judgments about the need for and acceptability of the various activities and required investments. Interestingly, many echoed the investment framing in their response when they explained their rationale.

We recommend the Enersource Team continue to communicate about the investment required to achieve the objectives laid out in the DSP, which is a bigger concept than “cost” or “price”. We also suggest that in future, the framing of pivotal concepts like this be assessed and options pre-tested prior to broad communication.

# Section 8: Appendix

## 8.1 Expert Models

Expert models, or experts' mental models, summarize the relevant knowledge about the complex influences that affect the "system being managed". They represent and characterize experts' hypotheses of the issues of importance to stakeholders and the factors that influence customer knowledge and perceptions. Expert models identify the core pathways for action including options for strategies and communication. They are an essential management tool in the mental models research approach, serving as the analytical framework throughout the project, integrating inputs from all research activities.

There are many benefits of expert models, including:

- Providing a strong, flexible framework for obtaining systematic assistance from experts as well as documenting the assumptions underlying research materials and communications developed from them.
- Allowing an effective and respectful way for communicators and technical experts to ensure that they understand one another
- Fitting with a decision-making perspective
- Ensuring no critical knowledge is missed or overlooked
- Ensuring only decision-relevant information is included
- Being compatible with experts' conventional way of thinking
- Can be readily subjected to peer review
- Can be applied to virtually any situation

Expert models are technical diagrams and are not intended to be used for communications with lay stakeholders.

Based on a review of critical background documents and studies provided by the Enersource Team along with discussions with Enersource Team members, Decision Partners developed two Expert Models, illustrating the Influences on Customers' Judgments of the Acceptability of the Enersource Distribution System Plan (DSP). The Base Expert Models were reviewed and refined based on input from the Enersource Team. These Models were validated in an Expert Model Review Webinar held April 28, 2015 attended by the Enersource Team. The Models were then finalized based on input from participants.

The completed Expert Models led to a more comprehensive understanding of the system of influences on customers' judgments of the acceptability of the Enersource Distribution System Plan (DSP) and provided the analytical framework for the state-of-the-science behavioural (mental models and IDST™) research with Customers.

### How to Read an Expert Model

An expert model is often depicted as an influence diagram summarizing knowledge in terms of variables and the relationships among them (Morgan et al., 2002). An influence diagram is a directed graph in which arrows, or "influences", link related "nodes or the variables in the system – in this case, the system of influences on customers' judgments of the acceptability of the Enersource Distribution System Plan (DSP). Each node represents a variable in the system in such a way that it can be enumerated, measured or evaluated as needed. The arrows linking

the nodes represent the relationships and primary direction of influence among the variables with the node at the tail of an arrow “influencing” the variable at the head of the arrow. Other influences may exist among nodes even if no arrow is shown and some influence may exist going in the direction opposite of the primary direction of influence indicated by the arrows.

The nodes are positioned to create a logical flow, starting with driving or foundational contextual variables in the upper left corner and ultimate decisions and desired outcomes positioned in the lower right corner of the model.

Node shapes indicate the type of influence represented. Oval nodes represent standard variables, while rectangular nodes represent decisions made by stakeholders (e.g., a customer’s judgment of Enersource).

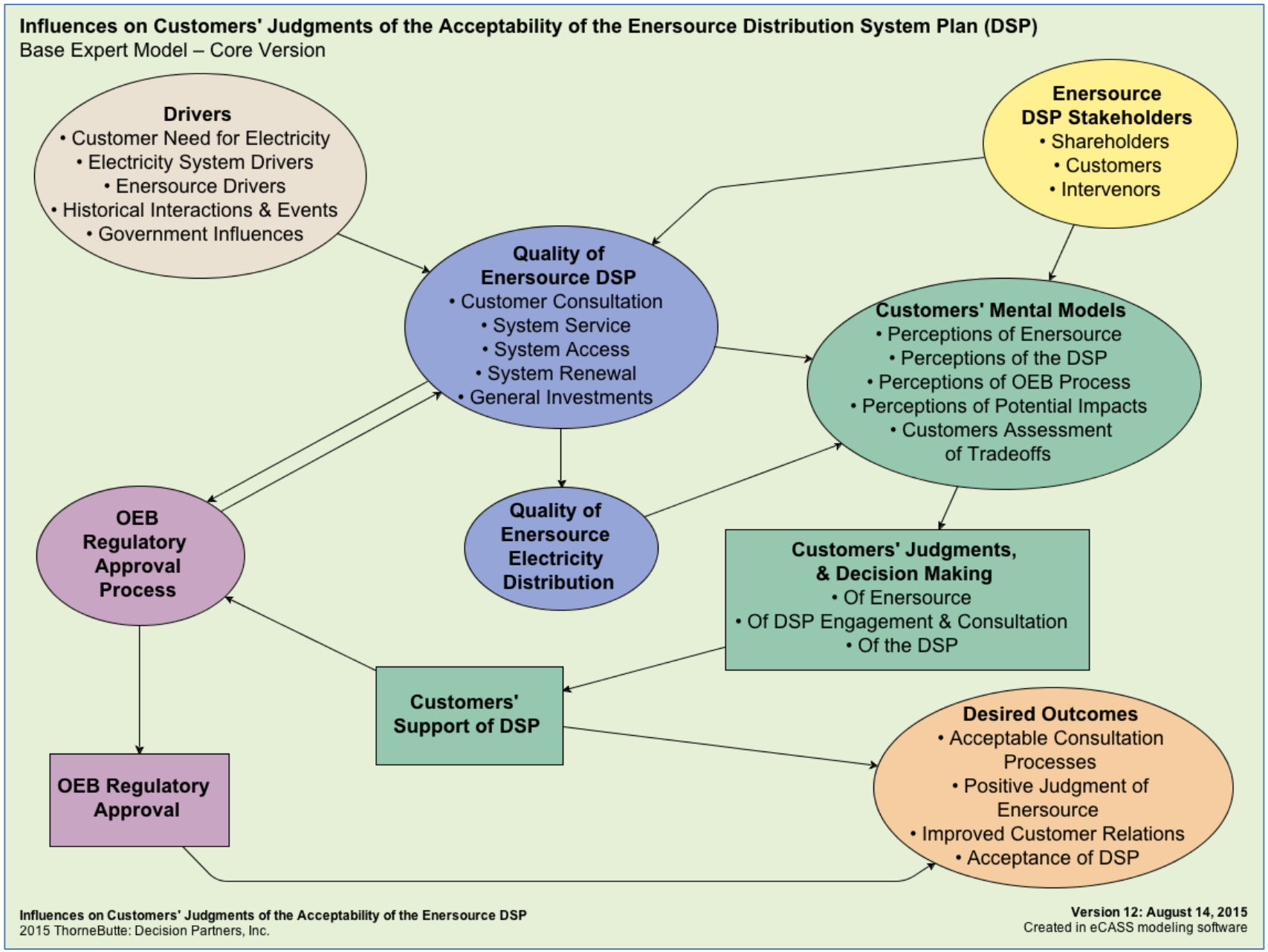
Bulleted lists within many of the nodes represent specific examples of the variable, or sub-variables, which are closely related variables that are primary influences on the parent variable. In the more detailed Base Expert Model, these sub-variables may be depicted separately.

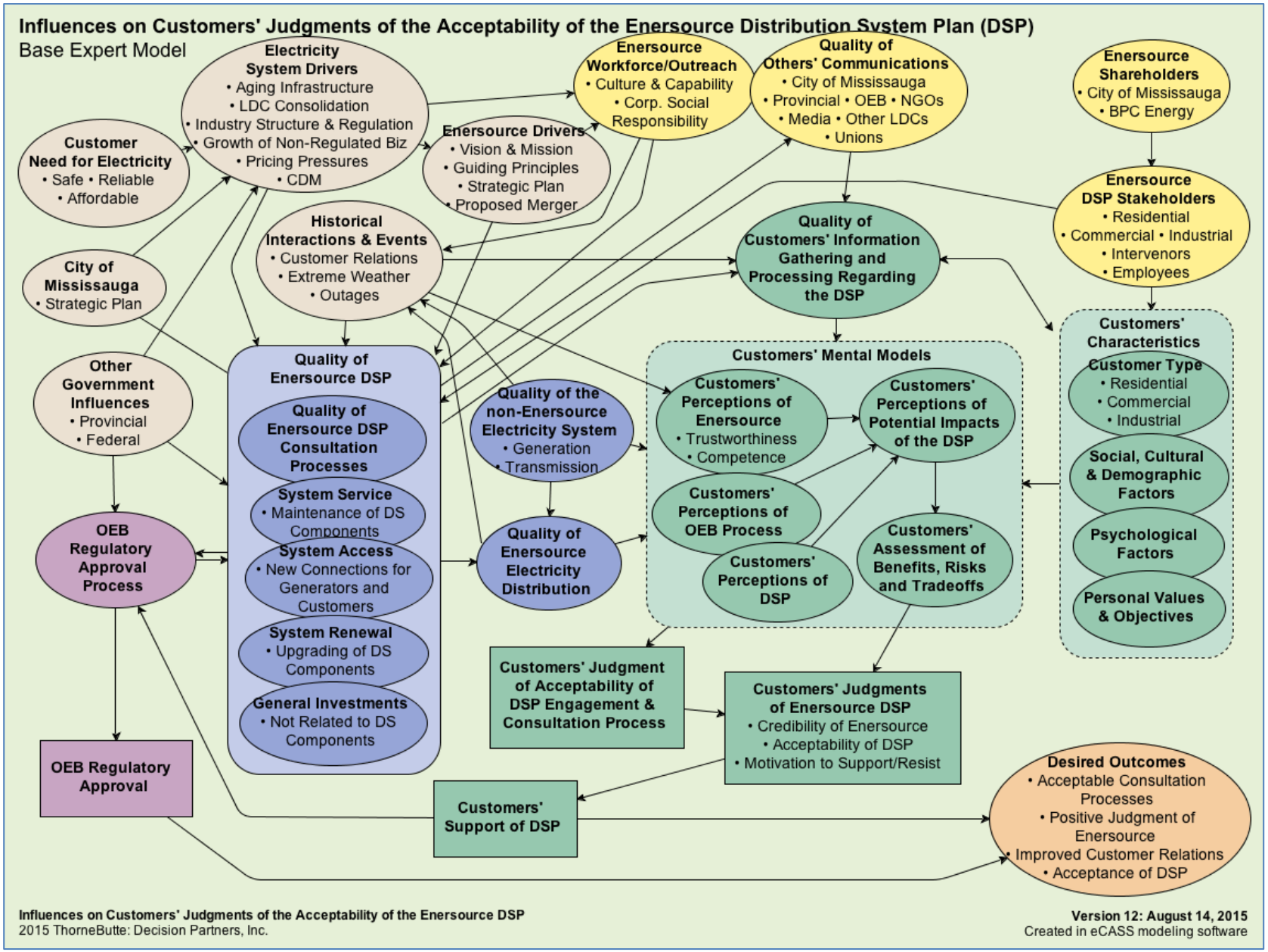
Note: All of the nodes depicted in the models are neutral, meaning that their relative weighting or importance is not hypothesized at this point. Following the mental models research conducted with Customers, the nodes in the Base Expert Model were weighted to illustrate their relative influence on the system.

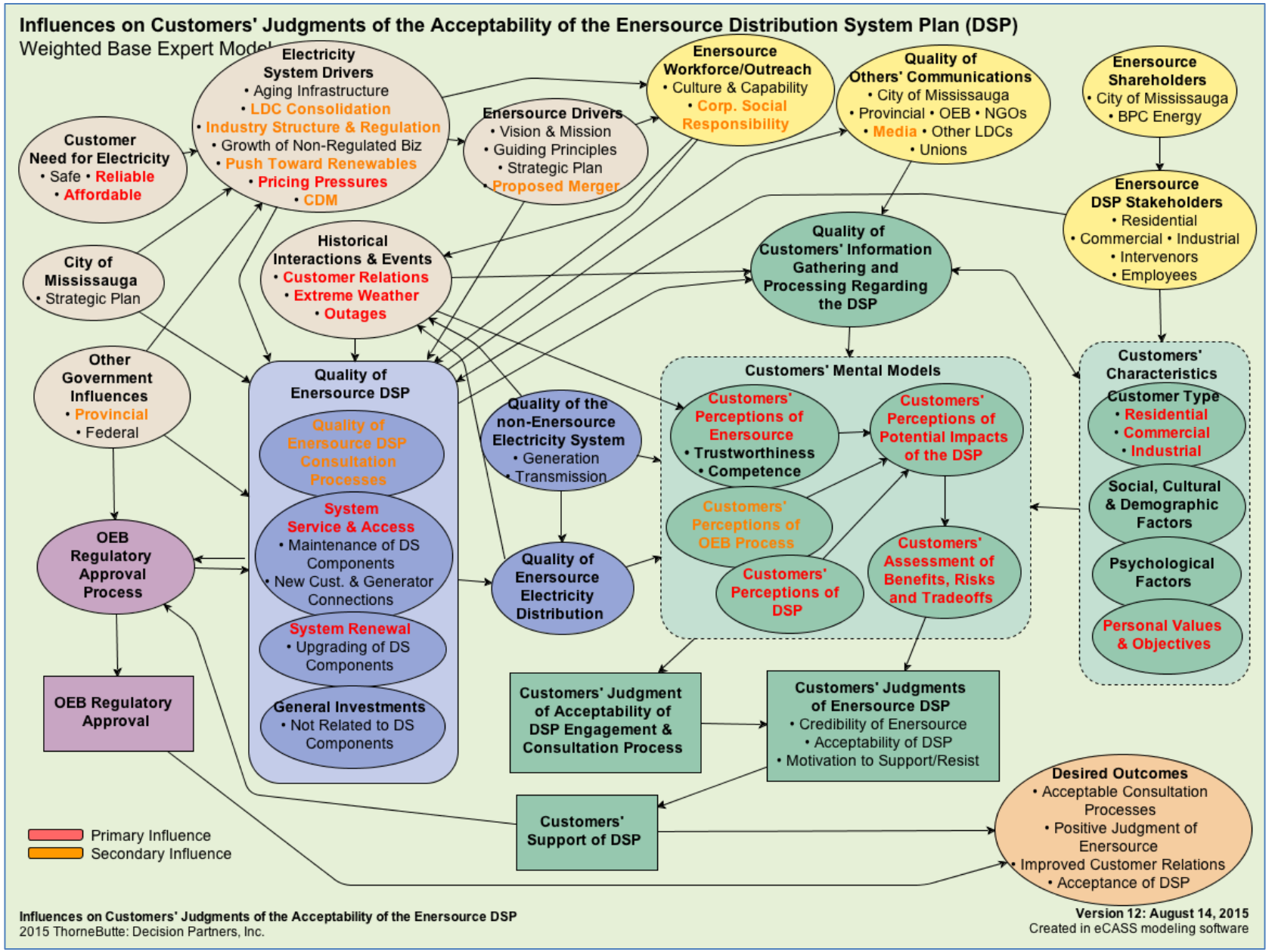
In the non-weighted Model, the nodes are colour-coded to illustrate the grouping of similar or most closely related variables:

- Tan nodes represent variables associated with drivers, those variables that set the context within which the system operates.
- Purple nodes represent variables associated with external technical influences applied to activities within the system, including OEB regulatory approval process.
- Yellow nodes represent variables associated with the key stakeholders, including shareholders, customers and intervenors.
- Green nodes represent variables associated with customers’ perceptions, judgments, decision making and behaviour.
- Orange nodes represent the desired outcomes related to acceptable consultation processes, customers’ positive judgment of Enersource, improved customer relations, and acceptance of the DSP.

In the weighted Model, colours are used to represent a semi-subjective weighting of the strength or importance of the nodes in their influence in the system, or on outcomes, and are based on the frequency of mention of specific concepts in the research and a subjective assessment of the researchers.


Influences on Customers' Judgments of the Acceptability of the Enersource Distribution System Plan (DSP)
Base Expert Model – Core Version
Drivers
• Customer Need for Electricity
• Electricity System Drivers
• Enersource Drivers
• Historical Interactions & Events
• Government Influences
Enersource DSP Stakeholders
• Shareholders
• Customers
• Intervenors
Quality of Enersource DSP
• Customer Consultation
• System Service
• System Access
• System Renewal
• General Investments
Customers' Mental Models
• Perceptions of Enersource
• Perceptions of the DSP
• Perceptions of OEB Process
• Perceptions of Potential Impacts
• Customers Assessment of Tradeoffs
OEB Regulatory Approval Process
Quality of Enersource Electricity Distribution
Customers' Judgments, & Decision Making
• Of Enersource
• Of DSP Engagement & Consultation
• Of the DSP
Customers' Support of DSP
Desired Outcomes
• Acceptable Consultation Processes
• Positive Judgment of Enersource
• Improved Customer Relations
• Acceptance of DSP
OEB Regulatory Approval
Influences on Customers' Judgments of the Acceptability of the Enersource DSP
2015 ThorneButte: Decision Partners, Inc.
Version 12: August 14, 2015
Created in eCASS modeling software


Influences on Customers' Judgments of the Acceptability of the Enersource Distribution System Plan (DSP)
Base Expert Model
Electricity System Drivers
• Aging Infrastructure
• LDC Consolidation
• Industry Structure & Regulation
• Growth of Non-Regulated Biz
• Pricing Pressures
• CDM
Enersource Workforce/Outreach
• Culture & Capability
• Corp. Social Responsibility
Quality of Others' Communications
• City of Mississauga
• Provincial • OEB • NGOs
• Media • Other LDCs
• Unions
Enersource Shareholders
• City of Mississauga
• BPC Energy
Customer Need for Electricity
• Safe • Reliable
• Affordable
Enersource Drivers
• Vision & Mission
• Guiding Principles
• Strategic Plan
• Proposed Merger
Enersource DSP Stakeholders
• Residential
• Commercial • Industrial
• Intervenors
• Employees
Historical Interactions & Events
• Customer Relations
• Extreme Weather
• Outages
Quality of Customers' Information Gathering and Processing Regarding the DSP
City of Mississauga
• Strategic Plan
Customers' Characteristics
Customer Type
• Residential
• Commercial
• Industrial
Social, Cultural & Demographic Factors
Psychological Factors
Personal Values & Objectives
Other Government Influences
• Provincial
• Federal
Quality of Enersource DSP
Quality of Enersource DSP Consultation Processes
System Service
• Maintenance of DS Components
System Access
• New Connections for Generators and Customers
System Renewal
• Upgrading of DS Components
General Investments
• Not Related to DS Components
Quality of the non-Enersource Electricity System
• Generation
• Transmission
Customers' Mental Models
Customers' Perceptions of Enersource
• Trustworthiness
• Competence
Customers' Perceptions of Potential Impacts of the DSP
Customers' Perceptions of OEB Process
Customers' Perceptions of DSP
Customers' Assessment of Benefits, Risks and Tradeoffs
OEB Regulatory Approval Process
Quality of Enersource Electricity Distribution
Customers' Judgment of Acceptability of DSP Engagement & Consultation Process
Customers' Judgments of Enersource DSP
• Credibility of Enersource
• Acceptability of DSP
• Motivation to Support/Resist
OEB Regulatory Approval
Customers' Support of DSP
Desired Outcomes
• Acceptable Consultation Processes
• Positive Judgment of Enersource
• Improved Customer Relations
• Acceptance of DSP
Influences on Customers' Judgments of the Acceptability of the Enersource DSP
2015 ThorneButte: Decision Partners, Inc.
Version 12: August 14, 2015
Created in eCASS modeling software


Influences on Customers' Judgments of the Acceptability of the Enersource Distribution System Plan (DSP)
Weighted Base Expert Model
Electricity System Drivers
• Aging Infrastructure
• LDC Consolidation
• Industry Structure & Regulation
• Growth of Non-Regulated Biz
• Push Toward Renewables
• Pricing Pressures
• CDM
Enersource Workforce/Outreach
• Culture & Capability
• Corp. Social Responsibility
Quality of Others' Communications
• City of Mississauga
• Provincial • OEB • NGOs
• Media • Other LDCs
• Unions
Enersource Shareholders
• City of Mississauga
• BPC Energy
Customer Need for Electricity
• Safe • Reliable
• Affordable
Enersource Drivers
• Vision & Mission
• Guiding Principles
• Strategic Plan
• Proposed Merger
Enersource DSP Stakeholders
• Residential
• Commercial • Industrial
• Intervenors
• Employees
City of Mississauga
• Strategic Plan
Historical Interactions & Events
• Customer Relations
• Extreme Weather
• Outages
Quality of Customers' Information Gathering and Processing Regarding the DSP
Other Government Influences
• Provincial
• Federal
Quality of Enersource DSP
Quality of Enersource DSP Consultation Processes
System Service & Access
• Maintenance of DS Components
• New Cust. & Generator Connections
System Renewal
• Upgrading of DS Components
General Investments
• Not Related to DS Components
Quality of the non-Enersource Electricity System
• Generation
• Transmission
Customers' Mental Models
Customers' Perceptions of Enersource
• Trustworthiness
• Competence
Customers' Perceptions of Potential Impacts of the DSP
Customers' Perceptions of OEB Process
Customers' Perceptions of DSP
Customers' Assessment of Benefits, Risks and Tradeoffs
Customers' Characteristics
Customer Type
• Residential
• Commercial
• Industrial
Social, Cultural & Demographic Factors
Psychological Factors
Personal Values & Objectives
OEB Regulatory Approval Process
Quality of Enersource Electricity Distribution
OEB Regulatory Approval
Customers' Judgment of Acceptability of DSP Engagement & Consultation Process
Customers' Judgments of Enersource DSP
• Credibility of Enersource
• Acceptability of DSP
• Motivation to Support/Resist
Customers' Support of DSP
Desired Outcomes
• Acceptable Consultation Processes
• Positive Judgment of Enersource
• Improved Customer Relations
• Acceptance of DSP
Primary Influence
Secondary Influence
Influences on Customers' Judgments of the Acceptability of the Enersource DSP
2015 ThorneButte: Decision Partners, Inc.
Version 12: August 14, 2015
Created in eCASS modeling software

## 8.2 Mental Models Sample Size

One of the fundamental questions determining the design of such research projects involves finding an appropriate trade-off between data quality (depth of insight) and data quantity (statistical representativeness). If the primary research objective is to estimate the prevalence with which specific beliefs are held by a target population, then conducting a statistical power analysis to estimate the appropriate sample size needed to provide the required precision may be the most suitable option. This typically requires a large sample and is likely best achieved through structured surveys.

If the primary objective of the research, however, is to explore an issue, to discover and understand in depth the spectrum of beliefs that are "out there" and only a reasonable level of precision is needed regarding the prevalence of such beliefs in the target population to advance to appropriate next steps (e.g., additional research, policy or planning options), then qualitative research with a much smaller sample size is reasonable and often preferred.

Many practical decisions do not require great precision. A misperception or concern would still need to be addressed whether its prevalence in the target population is 50%, 30% or even 10%. For example, if one's objective is to develop communications intended to address *any* significant misconception, even if it is held by a small fraction of the population (10%), then one has, roughly speaking, a 50:50 chance of identifying such misperceptions even with a sample of only 10 interviews.

## 8.3 Protocol Outlines

### 8.3.1 Enersource Customer DSP Consultation Mental Models Research

#### Residential Customer Interview Protocol Outline

*Note: The following protocol outline is for the Residential Customer interviews. Parallel protocols were developed for Commercial and Industrial customers.*

**Interview Solicitation:** Hi, my name is <*name*> I'm a researcher with Decision Partners. We're conducting research on behalf of your electricity supplier, Enersource Hydro Mississauga. They are currently developing a Distribution System Plan – or Long Term Plan – to submit to the Ontario Energy Board, which regulates the recovery of Enersource's costs. Basically, the Long Term Plan describes their plan for managing and investing in all aspects of the electricity system that they operate. As they develop their Long Term Plan, the Enersource Team needs input from customers such as you, on what is important to you. Would you be willing to participate in a 35-45-minute phone interview to provide your thoughts? The interview can be scheduled at your convenience and there is nothing you need to prepare for in advance.

***If yes,*** When would be a good time for you? I'd be happy to schedule an appointment.
***If no,*** Thank you for your time.

***Interviewer note:*** *If people say they don't think they know enough about the subject to participate, say:* The interview is very general in nature and doesn't require you to know anything specific beyond your experiences as an electricity user and customer of Enersource. If there are any questions that you can't or don't want to answer, we can just skip over them.

***Interviewer note:*** *If people ask how we got their name, say that it came from a large customer list provided by Enersource from which we selected names randomly. Enersource will not know who participated in the research.*

***If "yes":*** *proceed with introduction...;* ***If 'no':*** Thank you for your time.
***If "not now, but maybe later":*** W*hat time would be more convenient for you?*

**Interview Introduction:** Thank you for agreeing to participate in this research. Our conversation should take about 35 to 45 minutes. I have a list of questions to help guide our discussion, but please feel free to raise anything that comes to mind as we go along. In this kind of an interview, there are no right or wrong answers. We are interested in hearing your thoughts, whatever they might be. All of your comments will add value to our research.

I also want to assure you that this interview is confidential to our research team at Decision Partners. We will not identify you in our report back to Enersource as the source of any comments or even as a participant in the research. Instead, our report will combine the responses of everyone we speak with.

Before we start, in order to ensure that my notes are accurate and complete, I'd like to ask your permission to record our conversation. Again, I would like to stress that your responses will be kept confidential. You will not be identified as the source of anything in our report and you will not be identified as a participant in the research. The recording will only be used to help me with my notes and will be destroyed at the end of the project. May we proceed on that basis?

Thank you.

**Interview Outline**

**Introductory text:** *Our discussion will take place in four parts. We'll start by talking generally about the electricity industry in Ontario. Then I'll ask about your experiences as an Enersource customer. Then we'll talk about some specific elements of Enersource's Long Term Plan and then I'll finish up with any questions that you may have about the Long Term Plan and how you would like to receive information about it.*

**Section 1: Perceptions of the Ontario Electricity Industry**

**Introductory text for this section:** *So, to start off, let's talk a bit about the electricity industry.*

Questions in this section covered the following topics:

- Their thoughts on "electricity in Ontario"
- Their general familiarity with components of the electricity system
- Their awareness of recent changes in the Electric Industry, Green Energy and Energy Conservation, and consolidation
- Their awareness of the proposed Enersource merger and thoughts on benefits and concerns
- As an electricity user, their priorities for the Industry over the next 5 years, including their thoughts on need for maintaining and upgrading the system

**General, lay description of Electricity System to ensure that all interviewees have the same frame of reference:** *You may have noted that your electricity bill has separate charges for three different parts of the electricity system. One charge is for electricity generation: the power plants, wind turbines and solar energy that produce electricity. One charge is for electricity transmission, getting the electricity from generators and transporting it over high voltage power lines to local distribution companies. These local distribution companies, like Enersource, are the third charge on the bill, charging for connecting customers like you to the electricity system and delivering power through the network of lower voltage power lines and transformers that are in your community and neighbourhood.*

- Their perceptions of the portion of their bill associated with distribution
- Their thoughts about the cost of electricity
- Their thoughts on the relative value of electricity compared to other utility services

**Section 2: Perceptions of Enersource**

**Introductory text for this section:** *Now I'd like to talk with you as a customer of Enersource.*

Questions in this section covered the following topics:

- How long they have been a Residential Customer
- Their recent experiences as an Enersource Customer (past five years) including positive and negatives experiences
- Their perceptions of the reliability of their electricity service
- Their perceptions of power outages (cause, frequency, duration)

- Their perceptions of personal impacts of power outages
- Their perceptions of Enersource's responsibilities and response to outages
- Their thoughts on what Enersource does to prevent outages
- Their direct interactions with Enersource employees and with Customer Service
- Their familiarity with Enersource as a corporate member of the Mississauga community

**Section 3: Perceptions of the Enersource LTP**

**Introductory text for this section:** *In this section of the interview we will talk more specifically about Enersource's Long Term Plan. The Long Term Plan describes Enersource's plan for managing and investing in all aspects of the distribution system that they operate, including connections from the transmission system to connections to homes and businesses, and connections to local electricity generators too.*

Questions in this section covered the following topics:

- Initial, general thoughts on managing the distribution system and their priorities

**General, lay description of the LTP to ensure that all interviewees have the same frame of reference:** *To ensure that everyone that we speak with has the same understanding I'm going to read a brief description: The Long Term Plan describes Enersource's plan through to the year 2021 for managing and investing in all aspects of the business that they operate. It describes their plan for additions, replacement, disposal, and maintenance of various system components. Enersource's job is to do this work in the most efficient and cost effective manner and at the same time make sure that they continue to provide safe, secure, and reliable delivery of electricity to customers. The Long Term Plan covers four different types of investments. We'll go through these different types next.*

**Interviewees' Perspectives on Key Elements of the LTP:**

We presented each area one at a time and asked parallel questions (shown below):

**Lay description of System Service and System Access components of the LTP:** *The first two types of investments are called "System Service" and "System Access". Enersource determines these investments to be mandatory, and are required to meet additional power needs of its existing customers, allowing for the conversion of higher voltage electricity to a lower customer voltage, and providing electricity protection and controls. These investments also include the costs to connect new customers to Enersource's distribution system (such as new houses, new businesses, and even small generators like wind turbines and rooftop solar power systems). Expenditures in these two areas are expected to increase by about 30% in total over the next 5 years. This will take up about 40% of Enersource's total capital budget over that time.*

- Their general thoughts about investments in the areas of "System Service" and "System Access"
- Their perception of the criticality of investments in this area
- Their perception of the appropriateness of level of investment in this area

**Lay description of System Renewal component of the LTP:** *The next type of investment is called "System Renewal". This includes replacing or refurbishing existing components in the distribution system to allow Enersource to continue to provide safe and reliable power to its customers in an environmentally sustainable fashion. As time goes by, Enersource's equipment, such as poles, wires and transformers need to be replaced, similar to the roof on your house or replacement of your car.*

*Expenditures in this area are expected to increase by about 20% in total over the next 5 years. This will take up almost half of Enersource's total capital budget over that time. This is a significantly larger portion of the budget compared to the past 5 years. The main reason for increasing costs in this area is due to the fact that a large part of the distribution equipment was installed in the 1970s, 1980s, and early 1990s and have aged and reached the end of their expected useful lives.*

- Their general thoughts about investments in the areas of "System Renewal"
- Their perception of the criticality of investments in this area
- Their perception of the appropriateness of level of investment in this area

**Lay description of General Plant Investment component of the LTP:** *The last type of investments covered in the Long Term Plan are the "General Plant" investments. This includes any investments by Enersource that are not direct parts of the distribution system, such as land and buildings, tools and equipment, the fleet of trucks and other vehicles, and electronics devices and software used to support day-to-day business and operations activities. Over the next 5 years, expenditures in this area are expected to remain flat. This will take up about 15% of Enersource's capital budget over that time which is a slightly smaller portion of the budget compared to the past 5 years. There are no planned large investments in this area.*

- Their general thoughts about "General Plant" investments
- Their perception of the criticality of investments in this area
- Their perception of the appropriateness of level of investment in this area

After discussing the specific sections of the LTP, we asked for a few overall perceptions, including:

- Their perception of the appropriateness of the overall proposed level of expenditure in the next 5 years that is about 35% higher than for the previous 5 years
- Their confidence in Enersourse in continuing to do a good job of providing safe, reliable, cost effective electricity by implementing the investments associated with the Long Term Plan
- Their confidence in OEB to ensure a viable, sustainable and efficient electricity system through its oversight of the Long Term Plan (also known as the Distribution System Plan) process

**Section 4: Enersource Customer Consultation and Engagement**

**Introductory text for this section:** *To finish off the interview, I have just a few questions about communications and customer engagement.*

Questions in this section covered the following topics:

- Where they currently hear or receive information about topics related to the electricity system and Enersource
- Their current information needs with respect to the LTP
- How they prefer to receive such information
- How they prefer to be engaged with respect to the LTP going forward

**Closing**

- Any other thoughts/comments about the LTP or Enersource that may not have been discussed
- One piece of advice for the Enersource Team as they prepare the LTP.

*Demographic Questions:*

- Approximate age
- How long they have lived in Mississauga, at their current location
- How long they have been an Enersource customer
- Do they have children under 18 at home
- Their occupation
- Approximate amount of monthly Enersource bill
- Home heated by electricity, natural gas or oil
- [note] gender
- [note] cohort, geographical sub-cohort

**Closing text:** *Those are all the questions that I had. Thank you for your participation in our research. As a thank you for your time, we would like to send you an honorarium of $50. I'm going to turn off the recorder now so that I can get your address to mail that to you, or, if you'd prefer, we can donate your honorarium to the Dixie Bloor Neighbourhood Centre that administers Enersource's contributions to the Low Income Energy Assistance Plan in Mississauga or to the United Way of Peel instead.*

*You've been very helpful. Thank you for your time.*

*If they have questions about the research tell them the results will be used by Enersource to improve their communications with the community about the Distribution System Plan or Long Term Plan. Highlights from this research will be shared with residents through the Enersource website.*

*If people have questions about DP, or want to contact Enersource regarding the research, forward them to Jan Vonk <jvonk@decisionpartners.com> or 877-588-9106 (or take their number and have Jan contact them). Or forward them to Sarah Thorne <sthorne@decisionpartners.com.*

## 8.3.2 IDST™ Protocol Outline

### Introduction

*Welcome to the Enersource Long Term Plan Dialogue website. I'm Gia DeJulio. This site will allow you to give us some feedback on our Long Term Plan while also answering some of the questions that you may have. We know that your time is valuable, so this site lets you choose to hear about topics that are most of interest to you. If you like, you can start with a brief overview of how electricity gets to you. This provides some important background to understand our Long Term Plan. Or you can go directly to our introduction of the Long Term Plan. At any point, you can learn more about various topics by following the links along the right hand side. To be eligible for the draw for a Samsung Galaxy Tablet, Enersource customers will need to listen to a brief description of our Long Term Plan and then provide feedback on 11 core questions. These core questions are indicated by a question mark next to them. You can track your progress along the left hand side where the completed questions are shown with a checkmark. There are other places where you can provide feedback along the way, but these questions are optional. Overall, our discussion should take about 20 minutes, depending on how much information you want to know. Along the way you'll be able to explore other topics and ask questions of your own. If you don't have time to finish the discussion today, you can come back when you have some more time and we'll pick up where you left off.*

*Have you seen the video on Electricity Fundamentals? It discusses the different parts of our electricity system and how they work together to bring power to your homes and businesses. If you'd like to watch it, click on the Fundamentals link to the left. If you want to skip the Fundamentals video, click on Our Shared Priorities.*

### Our Shared Priorities

*As a customer, you need safe, reliable, affordable electricity. And we need to make sure our electricity delivery system keeps up with demand in Mississauga. To do this, we are constantly evaluating the system and planning for the future. Recently we reached out to some of our customers and asked them to share their thoughts on the electricity system. They told us that they want reliable and affordable electricity that is environmentally friendly. We share these priorities.*

#### *Reliability*

*The four priorities are all interrelated. We'll start by focusing on reliability. For us, reliability means minimizing outages and minimizing voltage fluctuations, which are variations in power. To do this, there are three major challenges that we have to continue to address in our Plan. The first challenge is aging equipment. The second is increased demand for electricity from growth and the new ways people require power. The third challenge is damage to the system caused by people and natural events like weather. I'll review each of these challenges briefly then talk about the elements of the Long Term Plan.*

*Aging Equipment*

*Let's start with aging equipment. Many of our substations and distribution lines were installed over 40 years ago as part of significant development that got underway in the late 1970s and 80s. Our territory covers over 288 square kilometers and includes about 5,200 kilometers of lines, 20,000 wood or concrete poles, and 25,000 transformers. People often think weather is*

*the primary cause of power disruptions, which tends to be true for the big outages like the ice storm of 2013. Most outages – like the ones that affect a small number of people for a short period of time – are typically caused by aging equipment. It is important that we maintain the system and keep it up to date so we can continue to reliably deliver power to our growing customer base.*

*Demand Growth*

*The second challenge is the demand for electricity due to growth since 1974 when Mississauga became a city, and the City's plans for future growth. Current growth in electricity demand is from construction of new townhouses, condominium high-rises, and business offices, along with the many new and changing ways we use electricity. Think of the number of electronic devices you use at home or at work: computers, cell phones, televisions, gaming systems to name just a few. In the next decade, we need to prepare for the increased demand for electricity from transportation, from electric cars, and from the electrification of the GO Train system. To meet this changing and growing demand, we need to maintain and replace the original equipment.*

*Responding to Damage*

*The third challenge is preparing for and responding to damage to the system caused by people and natural events like weather. Most people don't know that public vehicles colliding with and damaging our equipment are a more frequent source of outages than weather events! We have one of the lowest rates of outages in Canada, but still, service interruptions do occur. Our team is always prepared for outages. When there is a power disruption, our goal is to get our customers back online as soon as possible. We make sure our people are well trained; that our fleet of vehicles is well maintained; and that we have the equipment and technology needed to spot potential issues so we can prevent outages, and react as quickly as possible when they do occur.*

**Introduction to the Long Term Plan**

*Now that you've learned about our priorities and some of the challenges we face, let's talk about our Long Term Plan. There are 11 questions in this section that must be answered to put your name in the draw for a Samsung Galaxy Tablet. They will be highlighted in the list to your left as you go through the 3 sections of the Long Term Plan.*

*Every 5 years, all distribution companies, like us, must produce a Long Term Plan for the Ontario Energy Board or OEB, which regulates the electricity sector. The Plan is reviewed at a rate hearing where the Board decides what rates are appropriate to charge for our services over the next 5 years. A critical part of the process is getting our customers' input on our proposed Plan.*

*There are three parts to our Long Term Plan: First, System Service and System Access which covers converting higher voltage electricity from the grid to the lower voltage electricity that you use. It also covers connecting new customers, and things like moving sections of our system to make way for expanded roads or the new Light Rail Transit system. System Service and System Access costs are expected to increase about 30% in total over the next 5 years, compared to spending in these areas over the previous five years. Next, System Renewal, which covers repairing and maintenance of our current distribution system. We expect our costs here to increase about 20% over the next 5 years. And finally, what we call General Plant, which covers things like our buildings, trucks, employee costs, training, computer equipment and other*

*operating costs. This will use about 15% of our capital budget. We haven't planned any large, new investments in this area in the next five years, so there is no increase in this part. My colleagues will explain each of these parts in more detail. After each section we'll invite you to comment, answer any questions you have, and ask a couple of questions we have for you.*

***System Service and System Access***

*The System Service and System Access plan covers improvements and upgrades to our distribution system that will assure the delivery of electricity safety and reliability. To prepare for increased demand in Mississauga, our Plan covers the need to expand our system of substations, lines, and other equipment to connect new homes, especially condo developments, and businesses. And we need to tie in small renewable energy sources such as wind turbines and rooftop solar powered systems. These investments are among the most basic of the activities that we do as they are required to assure that we deliver electricity safely and reliably as we move forward.*

*Future plans for the City Centre include a light rail system, called an LRT, and new commercial and residential buildings. Expansion in the south of Mississauga is bringing new water and wastewater pumping stations online. That means we need to build more substations, and add more transformers and lines so we can continue to provide safe, reliable electricity.*

After viewing the summary of this component of the LTP, Customers were asked:

- Their thoughts about investments in the area;
- How critical they thought the investments in the area were; and
- The appropriateness of the proposed 30% increase in System Service and System Access area

***System Renewal***

*The System Renewal plan covers repairs and replacement of lines, and equipment that was installed 20 - 40 years ago and is now wearing out. Earlier James spoke with you about how most of the outages and voltage fluctuations people experience are caused by aging equipment. These investments will allow us to continue to provide safe and reliable power to you in an environmentally-friendly way.*

*For example: Our plans include purchasing the necessary equipment in advance when prices are lower rather than waiting to purchase equipment as needed, which would likely result in higher prices. By replacing some equipment before it fails, we can schedule our maintenance and repair teams more efficiently and avoid having to make emergency repairs that are more costly.*

After viewing the summary of this component of the LTP, Customers were asked:

- Their thoughts about investments in the area;
- How critical they thought the investments in the area were; and
- The appropriateness of the proposed 20% increase in investment in the System Renewal area

***General Plant Investment***

*The General Plant plan describes the investments in things that are not direct parts of the distribution system, such as land and buildings, tools and equipment, the fleet of trucks and other vehicles, and software used to support our day-to-day business. Our reliability depends on having the systems to prevent outages and track maintenance and repairs. Our safety depends on tree trimming and the equipment that our crews use.*

After viewing the summary of this component of the LTP, Customers were asked:

- Their thoughts about investments in the area;
- How critical they thought the investments in the area were; and
- The appropriateness of the proposed unchanged level of investment in the General Plant area.

***Impact on Your Electricity Bill***

*We know our customers are keeping a close eye on their electricity bills, so you're probably wondering how these improvements are going to affect your bill. Controlling our costs and the impact on our customers' bills is a critical part of our proposed plan.*

*Basically, we are asking the Ontario Energy Board to approve an increase of 35% over five years on one section of your bill. Allow me to explain how the billing system works. First your total electricity bill includes charges from the three different parts of the system: the generators who make the electricity, the high voltage transmission companies, and then our charges which cover the cost of bringing electricity across our low voltage distribution lines to your home or business. Our charges account for approximately 20% of your total bill. The 35% increase aligned in our Long Term Plan only applies to that one section of the bill. For the typical residential customer who consumes 800 kilowatt hours of electricity per month, this change will represent $2.00 on their total bill.*

After viewing the summary of the overall impact of the LTP, Customers were asked:

- The appropriateness of the proposed 35% increase in overall level of investment.

**Closing**

*On behalf of all of my colleagues at Enersource, I'd really like to thank you for taking the time to engage with us on our Long Term Plan. With your input, we're committed to putting the best possible plan forward to the OEB. And of course, we'll continue to work every day to bring you safe, reliable electricity at a reasonable price.*

## 8.4 Observations of Other LDC's DSP Workbooks

The following are some key challenges we noted in our review for the Enersource Team.

- **Respect:** A key principle of risk communications (and good customer relations) is treating stakeholders/customers with respect; that is, respecting their perspectives on a topic and their time:
    - **The "Assignment":** The task of completing a detailed (~30 page) workbook would be difficult and time-consuming task for most customers with a lay understanding of the sector. The task may be seen as disrespectful by some. A more customer-focused approach would be to invite customers to contribute the development of the DSP by using tools that enable participation in a way that is meaningful to customers, and through a more user-friendly interface.

    - **Language Level:** The language level of the documents we reviewed would typically be judged as too high a level for a lay person. Risk communication science suggests that documents for broad public dissemination should be written at a level that could be understood by an eighth grader. The language level may be interpreted by some as disrespectful – that is, that the LDC is talking down to its customers, or, as we have seen in low trust, high concern situations, interpreted as deliberately hiding things from readers by using language that they can't understand. In such cases, trust and credibility of the organization can be under pressure.

- **Comprehensibility:** In order to make a well-informed decision about the acceptability of a utility's DSP, customers need information that they can a) understand and b) process cognitively:
    - **Organization, Style and Content:** We found the style of the workbooks and the organization of the content difficult to follow, hard to understand and, consequently, likely cognitively challenging for lay readers. This was due in part to the language level, but also due to the complexity of the sentence structure, the undefined technical jargon, and the inconsistent use of technical terms.

    - **Linear, non-Interactive Format:** The workbooks are presented in a way that demands that customers work from the beginning to the end sequentially. They have limited ability to go to the parts that most interest them, or to delve into those sections at a higher or lower level that reflect their interests and priorities. A more flexible and interactive interface would enable customers to more easily find and engage in the material of most interest to them.

    - **Illustrations:** Many of the photos were of components familiar to industry people, but likely unfamiliar to lay people. In some cases, photos were used that could have been misunderstood, possibly raising customers' concerns and lack of confidence in the utility.

    - **Flow:** There were several places in the workbooks where the questions following the discussion did not align with the topic, used different lexicon, or were thematically different, which increased the complexity from a cognitive perspective. If the logic and flow of the content is not clear to the reader, it can become a barrier to understanding and to engagement.

- **Pre-testing:** We always recommend that communications materials be pre-tested to ensure they are understood and interpreted as intended. Given the challenges noted, we wonder if the workbooks were pre-tested.

- **Inside-Out:** The "voice" of the workbooks was "inside-out" – that is, the utility speaking from its own perspective *at* the customer, not engaging *with* the customer, from the customer's perspective.
  - **"Tell Process" vs "Dialogue Process":** Effective risk communications calls for engaging stakeholders, through dialogue – two-way conversation, supported by relevant information. A dialogue approach can be taken in the style and tone used in print materials as well. In the workbooks we reviewed, the process was clearly a traditional "Tell Process" – top down, one-way, similar to a teacher imparting information to a class, with a test that follows. This may approach may be seen as disrespectful and is likely not conducive to building and sustaining positive and productive relationships with customers.

  - **Talking Down:** In many cases, the voice of the utility may come across to customers as talking down to them or condescending.

  - **Meaningful Insight:** It is difficult to gain meaningful insight from customer feedback, such as that provided in a workbook or survey, when there is no opportunity to follow-up with customers to understand why they responded the way they did. Without a more foundational understanding of the context of customers' perceptions and knowledge of the industry and elements of the DSP, it is difficult interpret research results in a meaningful way – one that enables an LDC team to better understand the customers' feedback in order to incorporate it into their DSP.

## 8.5 Print Survey

Enersource Long Term Plan Survey

# Introduction

Dear Customer,

Every five years, all distribution companies, like Enersource, must produce a Long Term Plan for the Ontario Energy Board or OEB, which regulates the electricity sector. The Plan is reviewed at a Rate Hearing where the Board decides what rates are appropriate to charge for our services over the next five years. A critical part of the process is getting our customers' input on our proposed Plan. We appreciate your interest in taking a few minutes to learn about our Long Term Plan and providing some feedback through the attached survey.

I'd also like to invite you to enter our draw for a Samsung Galaxy Tablet! To be entered into the draw you will need to read a few brief descriptions of elements of our Plan and then provide feedback on 11 Core Questions in the attached survey. You will need to return the survey in the return envelope by December 23, 2015. Overall, the survey should take about 15 minutes, depending on how much feedback you want to provide.

Please be assured that your survey responses are confidential. The return envelope will send your survey responses to Decision Partners, an independent third-party research company hired by Enersource to conduct the survey. You will not be identified as the source of any feedback that you provide. Decision Partners will produce a combined report of the feedback collected that does not identify anyone as the source of any feedback. They will provide separately a list of those who have completed the 11 Core Questions and their contact information for entry into the draw. If you would like more information on Decision Partners' Privacy Policy, you can view it on their website at: www.decisionpartners.com/privacy-policy/



On behalf of my colleagues at Enersource, I'd like to thank you for taking the time to learn about our Long Term Plan and providing your comments on the survey that follows.

James Macumber
Vice President, Asset Management Strategy

# Our Shared Priorities

As a customer, you need safe, reliable, affordable electricity. And we need to make sure our electricity delivery system keeps up with demand in Mississauga. To do this, we are constantly evaluating the system and planning for the future. Recently we reached out to some of our customers and asked them to share their thoughts on the electricity system. They told us that they want reliable and affordable electricity that is environmentally friendly. We share these priorities.

All of these priorities are all interrelated, with reliability at the centre. For us, reliability means minimizing outages and minimizing voltage fluctuations, which are variations in power. By improving reliability, particularly through reduction of equipment failures, we improve safety and minimize costs associated with repairs and unscheduled replacement. To do this, there are three major challenges that we have to

continue to address in our Plan: aging equipment, increasing demand and damage to the system. I'll review each of these challenges briefly then talk about the elements of the Long Term Plan.

*Aging Equipment*

Let's start with aging equipment. Many of our substations and distribution lines were installed over 40 years ago as part of significant development that got underway in the late 1970s and 80s. Our territory covers over 288 square kilometers and includes about 5,200 kilometers of lines, 20,000 wood or concrete poles, and 25,000 transformers. People often think weather is the primary cause of power disruptions, which tends to be true for the big outages like the ice storm of 2013. Most outages – like the ones that affect a small number of people for a short period of time – are typically caused by aging equipment. It is important that we maintain the system and keep it up to date so we can continue to reliably deliver power to our growing customer base.

*Demand Growth*

The second challenge is the demand for electricity due to growth since 1974 when Mississauga became a city, and the city's plans for future growth. Current growth in electricity demand is from construction of new townhouses, condominium high-rises, and business offices, along with the many new and changing ways we use electricity. Think of the number of electronic devices you use at home or at work: computers, cell phones, televisions, gaming systems to name just a few. In the next decade, we need to prepare for the increased demand for electricity from transportation, from electric cars, and from the electrification of the GO Train system. To meet this changing and growing demand, we need to maintain and replace the original equipment, while we add to the system.

*Responding to Damage*

The third challenge is preparing for and responding to damage to the system caused by people and natural events like weather. Most people don't know that public vehicles colliding with and damaging our equipment are a more frequent source of outages than weather events! We have one of the lowest rates of outages in Canada, but still, service interruptions do occur. Our team is always prepared for outages. When there is a power disruption, our goal is to get our customers back online as soon as possible. We make sure our people are well trained; that our fleet of vehicles is well maintained; and that we have the equipment and technology needed to spot potential issues so we can prevent outages, and react as quickly as possible when they do occur.

## Background on the Long Term Plan

A number of customers have asked how we do our planning to come up with the Long Term Plan we submit to the Ontario Energy Board. We're always planning for the maintenance of our system to ensure reliability. We take stock to see what we need to maintain and assess possible improvements to the system to ensure we continue to provide safe and reliable electricity. Every five years we formally submit our Long Term plan to the OEB, or Ontario Energy Board.

There are three parts to our Long Term Plan:

***System Service and System Access*****,** which covers converting higher voltage electricity from the grid to the lower voltage electricity that you use. It also covers connecting new customers, and things like moving sections of our system to make way for expanded roads or the new Light Rail Transit system.

***System Renewal*****,** which covers repair and maintenance of our current distribution system.

***General Plant Investments*****,** which cover things like our buildings, trucks, employee costs, training, computer equipment and other operating costs.

We will explain each of these elements of the plan in more detail and after each section we'll invite you to answer a couple of questions for each.

## *System Service and System Access*

The System Service and System Access Plan covers improvements and upgrades to our distribution system that will assure electricity safety and reliability. To prepare for increased demand in Mississauga our Plan covers the need to expand our system of substations, lines, and other equipment to connect new homes, especially condo developments, and businesses. And we need to tie in small renewable energy sources such as wind turbines and rooftop solar power systems. These investments are among the most basic of the activities that we do as they are required to assure that we deliver electricity safely and reliably as we move forward.

Future plans for the City Centre include a light rail system, called an LRT, and new commercial and residential buildings. Expansion in the South of Mississauga is bringing new water and wastewater pumping stations online. That means we need to build more substations, and add more transformers and lines so we can continue to provide safe, reliable electricity.

**Q1. Given this brief description of what we are considering, what are your thoughts about our plans for the System Service and System Access components of our Long Term Plan?**

_____

_____

_____

**Q2. How critical would you say investments in the System Service and System Access areas are? Would you say (circle one):**

**very critical** **somewhat critical** **not very critical**

**Why do you say that?** _____

_____

_____

The new lines, substations, and other equipment needed to address the growth of electricity use in Mississauga result in a 30% increase in investment in the System Service and System Access area.

**Q3. To what degree do you think that this increase in investment is appropriate? Would you say (circle one):** **very appropriate** **somewhat appropriate** **not very appropriate**

**Why do you say that?** _____

_____

_____

## *System Renewal*

The System Renewal plan covers repairs and replacement of lines and equipment that was installed 20-40 years ago and is now wearing out. Most of the outages and voltage fluctuations people experience are caused by aging equipment. These investments will allow us to continue to provide safe and reliable power to you in an earth-friendly way.

For example: Our plans include purchasing the necessary equipment in advance when prices are lower rather than waiting to purchase equipment as needed, which would likely result in higher prices. By replacing some equipment before it fails, we can schedule our maintenance and repair teams more efficiently and avoid having to make emergency repairs that are more costly.

**Q4. Given this brief description what are your thoughts about our plans for System Renewal?**

_____

_____

_____

**Q5. How critical would you say investments in the System Renewal area are? Would you say (circle one):** **very critical** **somewhat critical** **not very critical**

**Why do you say that?** _____

_____

_____

We expect our costs in the System Renewal area to increase about 20% over the next 5 years.

**Q6. To what degree do you think that the proposed increase in investment in the System Renewal area is appropriate? Would you say (circle one):**

**very appropriate** **somewhat appropriate** **not very appropriate**

**Why do you say that?** _____

_____

_____

## *General Plant Investment*

The General Plant Plan describes the investments in things that are not direct parts of the distribution system, such as land and buildings, tools and equipment, the fleet of trucks and other vehicles, and software used to support our day-to-day business. Our reliability depends on having the systems to prevent outages and track maintenance and repairs. Our safety depends on tree trimming and the equipment that our crews use.

We are planning for the future by using new software and hardware to improve how we manage all of the information that is needed to supply you with electricity.

For example, we are implementing the Mobile Workforce Management system to ensure our crews have computer access to the Control Centre. This allows electronic tracking of work progress.

Also, we maintain three main buildings: our administration and operations centres as well as a back-up operations centre to ensure that we can continue to provide power to you in case of emergencies. We also maintain our fleet of vehicles in our own garage, and are implementing plans to spread the costs of replacements over time to lessen the impact this has on customers' rates.

**Q7. Given this brief description what are your thoughts about the work we have included in the General Plant plan?**

_____

_____

_____

**Q8. How critical would you say investments in the General Plant area are? Would you say (circle one):** **very critical** **somewhat critical** **not very critical**

**Why do you say that?** _____

_____

_____

General Plant Investments will use about 15% of our capital budget. We haven't planned any large new investments in this area in the next 5 years, so there is no increase in this part.

**Q9. To what degree do you think that the unchanged level of investment in the General Plant area is appropriate? Would you say (circle one):**

**very appropriate** **somewhat appropriate** **not very appropriate**

**Why do you say that?** _____

_____

_____

## *Impact on Your Electricity Bill*

We know our customers are keeping a close eye on their electricity bills. Controlling our costs and the impact on our customers' bills is a critical part of our proposed Plan. You're probably wondering how these improvements are going to affect your bill. To answer that, let us first break down the parts of your electricity bill. Your electricity bill includes charges from the 3 different parts of the system: the generators who make the electricity, the high voltage transmission companies, and then our charges, which cover the cost of bringing electricity across our low voltage distribution lines to your home or business. Our charges are approximately 20% of your total bill. As a part of our Long Term Plan, we are asking the Ontario Energy Board to approve an increase that only applies to the part of your bill for distribution, of 35% over 5 years versus costs for the previous five years. For the typical residential customer who consumes 800 kWh of electricity per month, this change will represent approximately $2.00 on their total bill.

When much of our system was built in the late 70s, 80s and 90s, a lot of the cost of building the system was paid for by the developers who were building the new subdivisions and office buildings. Now a lot of the equipment installed then needs to be replaced or upgraded and those costs are not covered except through our electricity rates. The OEB will ensure that the work we plan to do and the costs that we are proposing are appropriate and prudent.

**Q10. Given everything we've discussed in this brief backgrounder, to what degree do you think that the proposed increase in investment is appropriate? Would you say (circle one):**

**very appropriate** **somewhat appropriate** **not very appropriate**

**Why do you say that?** _____

_____

**Q11. Thinking about everything that we've discussed about the Long Term Plan, how confident are you that our team at Enersource will continue to do a good job of providing safe, reliable, cost effective electricity by implementing the investments associated with the Long Term Plan? Would you say you have a (circle one):**

**High degree of confidence** **Medium decree of confidence** **Low degree of confidence**

**Why do you say that?** _____

_____

Thank you for taking the time to engage with us on our Long Term Plan. With your input, we're committed to putting the best possible plan forward to the OEB. And of course, we'll continue to work every day to bring you safe, reliable electricity at a reasonable price. ***Please return your completed survey to Decision Partners in the included envelope or send it to them at the following address***:

**Decision Partners**
546 N. Christina Street
Suite 504
Sarnia Ontario N7T5W6
Canada

*The results of this research will be used by Enersource to improve their communications with the community about the Long Term Plan. Highlights from this research will be shared with residents through the Enersource website. If you have questions about the research contact Jan Vonk <jvonk@decisionpartners.com> or at 877-588-9106.*

## *Draw Entry*

If you wish to be included in the draw for the Samsung Galaxy Tablet! Please provide your name and contact information below and include with your survey response. Only those who complete the survey are eligible for entry into the draw. See full entry rules below. Your contact information will be separated from your survey responses before being forwarded to Enersource for entry into the draw.

Name: _____

Address: _____

Contact E-mail and Phone Number: _____

***Contest Rules:***

*Enersource Customer Survey Contest - Official Contest Rules*

*HOW TO ENTER:*
*During the Contest Period, visit the www.enersource.com/survey (or www.electricitydialogue.ca) website to register and participate in the online Enersource Customer Survey Contest (the "Contest"). To register, participants will need to provide a valid email address. Depending on the individual, it will take about twenty (20) minutes to watch the required videos on the components of our Long Term Plan and then answer the eleven (11) mandatory questions in order to be eligible for the contest. Once the questions have been answered, participants will complete a Contest entry form to receive one (1) entry into the Contest. In order to enter the Contest, participants will be required to provide an account number, first and last name and phone number. Limit: Only one (1) Contest entry will be permitted per Enersource account, regardless of the number of primary contacts on the account.*

*Enersource customers who wish to enter the Contest but do not have access to a computer may contact Enersource Hydro Mississauga by phone (905-283-4261) to request a paper copy of the Enersource Customer Survey to complete and mail in. Mail-in entries must be received by the end of the Contest Period to be eligible for the Contest draw.*

*WHO CAN ENTER*

*NO PURCHASE REQUIRED*
*To enter the Contest you must be an Enersource customer who is the age of majority and resides in Mississauga, Ontario, Canada, throughout the entire Contest Period (defined below), and have the ability to travel to Enersource Hydro Mississauga to claim your prize. Enersource Hydro Mississauga will not pay for or reimburse any expenses for travel to claim prize.*

*Employees of the Sponsor, the Agency, their affiliated companies and subsidiaries and their immediate family, as well as persons residing in their respective households, are not eligible to participate in the Contest. The Sponsor reserves the right, at its sole discretion, to eliminate any person from eligibility if he/she violates any term or condition of the Official Contest Rules. By entering the Contest, entrants agree to abide by the Official Contest Rules and the decisions of the Sponsor with respect to all aspects of the Contest, which are final.*
*CONTEST PERIOD - November 23 to December 23, 2015*
*The Contest runs from 12:01 a.m. Eastern Standard Time ("EST") November 23, 2015 to 11:59 p.m. EST on December 23, 2015 (the "Contest Period"). All entries must be received during the Contest Period.*

*DRAW DATES*
*All eligible entries received during the Contest will be entered into one random draw, which will occur within ten (10) business days after the Contest Period closes. To be eligible to participate in the draw, the eligible Contest entry must be received by the last day of the Contest Period.*

*PRIZES*
*There are eight (8) prize offerings consisting of a Samsung Galaxy Tablet.*

*WINNER NOTIFICATION AND PRIZE DELIVERY*
*The selected winners (the "Winner" or the "Winners") will be notified by phone and/or email (based on Enersource account contact information) by the Sponsor or the Agency within ten (10) business days of the draw occurring. In order to claim the prize, the selected Winners must correctly answer an unaided, time-limited, mathematical skill-testing question (the "Question"). Following which and within a further ten (10) business days, the selected Winners will be required to submit to the Sponsor a declaration and release form confirming compliance with the Official Contest Rules, acceptance of the prizes as awarded and releasing the Sponsor, the Agency and their respective shareholders, directors, officers, employees and representatives from any and all liability in connection with the prizes, use of the prizes or the Contest. The prize will be awarded to the primary contact on the Enersource account who entered the Contest, and the Winner must be able to pick-up the prize from the Sponsor's Head Office. There are no substitutions for prizes, and prizes are non-refundable and non-transferable except at the sole discretion of the Sponsor.*

*Inability of the Sponsor to reach a selected Winner within the above time frame, failure by a selected Winner to answer the Question correctly, failure by a selected Winner to return a signed declaration and release form within the above time frame or refusal to accept delivery of a prize, results in a forfeit of the prize and the right for the Sponsor to re-draw the prize.*

*ODDS OF WINNING*
*Odds of winning depend upon the number of eligible entries received.*

*GENERAL CONDITIONS REGARDING THE CONTEST*
*All individual program terms and conditions apply. By entering this Contest, the entrant acknowledges and agrees to the non-responsibility of the Sponsor and the Agency, its affiliates and their respective officers, directors, employees and agents with regard to any injury, accident, loss or misfortune relating to all aspects of this Contest, including costs associated with claiming and use of the prizes. The Sponsor and the Agency will not be responsible for any printing, administrative, technical, electronic, network, computer or software malfunction, or other error of any kind in connection with this Contest, including but not limited to errors in advertising, the Official Contest Rules, the selection and announcement of winners or the distribution of prizes. All entries and declaration and release forms are subject to verification, and will be declared invalid if they are incomplete, forged, falsified, altered, or tampered with in any way. Any attempt by a participant or any other individual to deliberately damage any website or undermine the legitimate operation of the Contest may be in violation of criminal and civil laws and should such an attempt be made, the Sponsor reserves the right to seek remedies and damages (including lawyers' fees) from any such participant or any other individual to the fullest extent permitted by law, including criminal prosecution. Any decision of the Sponsor will be final. Liability for any Contest material that is irregular or defective is limited to the replacement of the Contest material.*

*All entries become the property of the Sponsor and will not be acknowledged. By entering the Contest, entrants agree that they may be notified by email or telephone if they are drawn to receive a prize. The prize winners must also consent to the use of their name, city of residence, and/or photograph in any future publicity, including Internet publication, carried out by the Sponsor without compensation.*

*The Sponsor reserves the right, at its sole discretion, to terminate, discontinue, modify or suspend the Contest at any time. Information provided for the purpose of entering the Contest will only be used for the purpose of the Customer Survey and administering the Contest or the entrant's selected programs. By entering this Contest, participants agree to be bound by these Official Contest Rules and to the Sponsor's and Agency's collection, use and disclosure of personal information, as provided for in these Rules. Enersource respects your privacy. For a copy of our privacy policy, click here (Link to http://enersource.com/Pages/Privacy.aspx).*

*This Contest is subject to the laws of the province of Ontario and Canada applicable therein.*

*Contest Sponsors:*
*Enersource Hydro Mississauga Inc., 2185 Derry Road West, Mississauga, Ontario, L5N 7A6*
*Enersource® is a registered trademark of Enersource Corporation. All other service or product names are trademarks of their respective owners and the use herein does not imply that a license of any kind has been provided.*

*© 2015 Enersource Corporation. All rights reserved.*

## 8.6 Customer and Stakeholder Communications re IDST™

### 8.6.1 News Release - Enersource




NEWS RELEASE

CUSTOMER FEEDBACK WILL HELP SHAPE FUTURE OF
ELECTRICITY DISTRIBUTION IN MISSISSAUGA

*Take our interactive survey for a chance to win one of eight prizes*

November 23, 2015 – (MISSISSAUGA, Ontario) – Today, Enersource is launching a unique and interactive website that provides customers with an opportunity to learn more about Mississauga's electricity distribution system.

Visitors to the website will be introduced to information on how electricity is generated, how it gets to homes and businesses, and the factors that determine why a utility needs to build or upgrade its infrastructure.

The website will also feature an interactive survey, which will give customers an opportunity to provide their feedback by answering questions on the priorities they place upon investments in electricity distribution. Enersource will use this information to shape its Distribution System Plan, also known as the Long Term Plan.

Customers who answer all of the survey questions will be entered into a contest to win one of eight 16 GB Samsung Galaxy tablets. Enersource is adding the contest to the survey as a way to thank customers for helping the utility deliver the best possible plan for the next five years.

To participate in the survey or to learn more about the Long Term Plan, please visit www.enersource.com/survey.

Quotes

"The development of the Long Term Plan will shape the future of electricity distribution in Mississauga," said Peter Gregg, President and CEO of Enersource Corporation. "We invite our customers to participate in this process by completing our online survey."

About Enersource

Enersource is one of Ontario's most reliable energy providers, serving over 200,000 residential and commercial customers across Mississauga. It is a diversified energy and technologies company that serves customers through the distribution of electricity and the delivery of services related to the design, operation and maintenance of electrical systems.

Ninety per cent of Enersource Corporation is owned by the City of Mississauga, and ten per cent is owned by BPC Energy Corporation (Borealis), which is part of the Ontario Municipal Employees Retirement System (OMERS).

-30-

Media Contact:
Steve Scott
Enersource
905-283-4295

### 8.6.2 News Release – Decision Partners and MedRespond

**Enersource First to Use Innovative Technology to Engage Customers**

**Mississauga, November 24, 2015** – Decision Partners and MedRespond are pleased to announce the launch of the first application of their science-based Interactive Decision Support Technology™ (IDST™). This ground-breaking stakeholder engagement tool is being used by Enersource, Mississauga's local electricity utility, to engage customers in a meaningful dialogue on the company's Long Term Plan.

IDST™ integrates Decision Partner's Mental Modeling Technology™ with MedRespond's Synthetic Interview™ artificial intelligence and online communication products. The web-based IDST™ lets Enersource engage with a broad range of residential and non-residential customers through a "Synthetic Interview," which simulates a one-on-one conversation with the video hosts through a combination of streaming video and artificial intelligence. Customers can converse with Enersource leaders about their Long Term Plan (Distribution System Plan) and Enersource leaders can listen and respond to customer questions and comments in an online, virtual customer engagement environment – all in real time.

The site content is built on the results of mental models research that Decision Partners recently conducted with Enersource's residential, commercial and large-use customers. The research results showed that most customers don't understand the electricity system, the role of a distribution company or what is required to ensure safe, reliable electricity. Electricitydialogue.ca has been developed to help address this gap, while enabling customers to provide input on various components of the Long Term Plan or other related topics of interest to them. A short video explaining the electricity system – generation, transmission and distribution – in simple, understandable terms is the first component.

The data collected from the customer engagement site, along with Decision Partners' research report, will be included in Enersource's Distribution System Plan filing to the Ontario Energy Board in early 2016.

To sign into the interactive website as a Guest, please go to www.electricitydialogue.ca.

**For more information,** please contact Sarah Thorne, Co-founder and Partner, Decision Partners, at sthorne@decisionpartners.com or 1-877-588-9106.

**Decision Partners** is an international team of management professionals and scientists, and the only commercial provider, worldwide, of Mental Modeling Technology™, a unique evidence-based, science-informed management process for developing programs – policies, strategies and communications – for belief and behaviour change. The technology comprises integrated methods and tools on a software platform. www.decisionpartners.com

**MedRespond** is the leading innovator in scalable coaching solutions to drive behavioural change. MedRespond's solutions engage, empower and educate on critical issues affecting personal health, wealth and public policy. www.medrespond.com

### 8.6.3 Email to OEB from Gia DeJulio

**From:** Gia DeJulio
**Sent:** November-24-15 9:44 AM
**To:** lynne.anderson@ontarioenergyboard.ca; jane.scott@ontarioenergyboard.ca
**Subject:** FW: Enersource News Release: Customer feedback will help shape the future of electricity distribution in Mississauga

Lynne and Jane,

I thought you'd be intrigued to learn about Enersource's unique exercise in customer consultation on its DSP, or as we are calling it for the benefit of customers, our Long Term Plan. This interactive video "dialogue" method is the first of its kind in the energy industry anywhere, and we are pleased to be introducing this concept to Ontario. We retained Decision Partners to help us conduct customer consultation, and they in turn brought in the company MedRespond to create the video dialogue concept.

The survey exercise for customers is expected to take only about 20 minutes, and customers are not forced to read a 35+ page technical report that would put most of them to sleep in minutes. Instead we have provided many very brief videos, each explaining in as simple language as possible, the fundamentals of electricity generation, transmission and distribution, and why Enersource needs to increase its spending over the next five years in most but not all of the different investment categories. There are videos trying to explain the very complicated bill, and a video or two that talks about the OEB's role. No OEB staff were harmed in the making of these videos!

This unique survey method will provide Enersource with answers to our questions to customers about our planned DSP investments and the level of importance customers place on this proposed spending. We also provide customers with the opportunity to ask Enersource questions or to provide us with their comments in general.

If you want to visit the site, you are permitted to register as visitors (not customers), and peruse to your hearts' content.

Thanks for your interest.

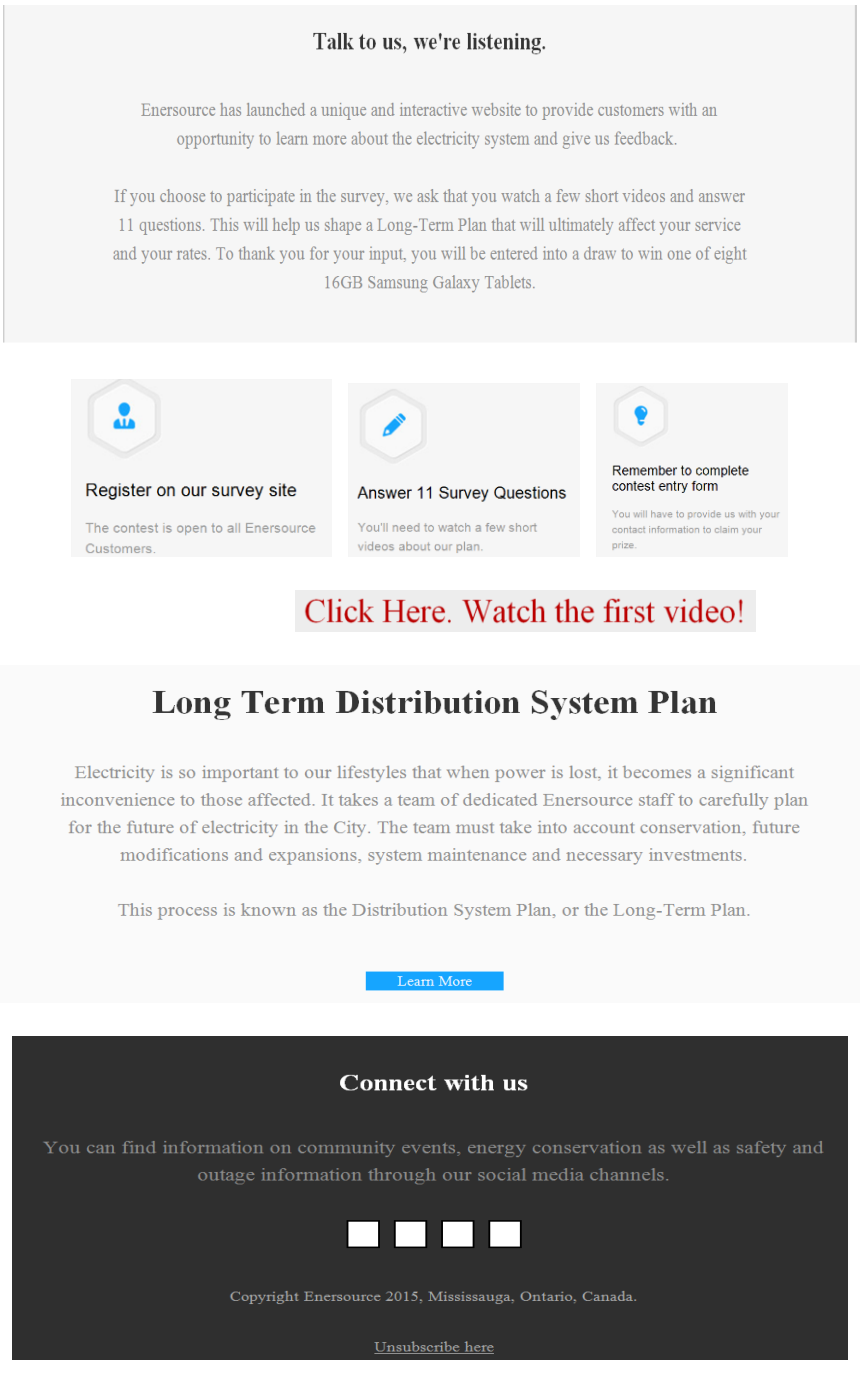
Gia

### 8.6.4 Enersource Invitation

The following invitation was sent by Enersource on December 11, 2015 inviting Enersource customers to participate in the IDST™. A reminder was sent on December 18, 2015.

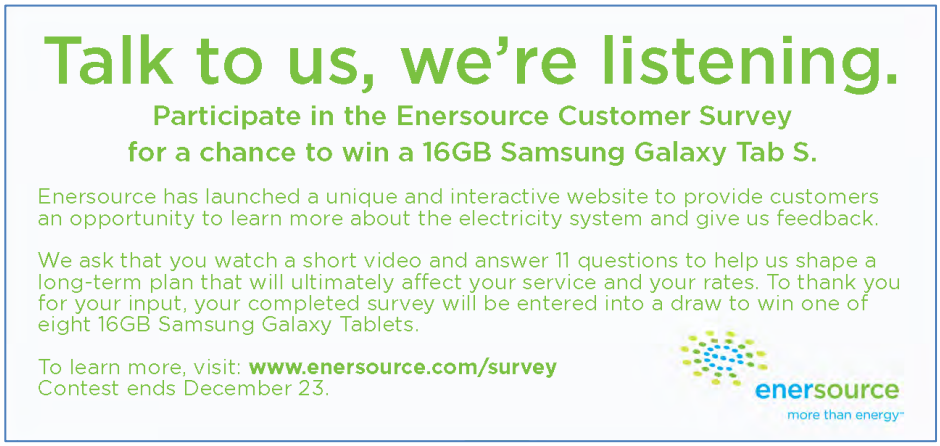
**Subject: Your opinion matters: Customer Survey and Contest**

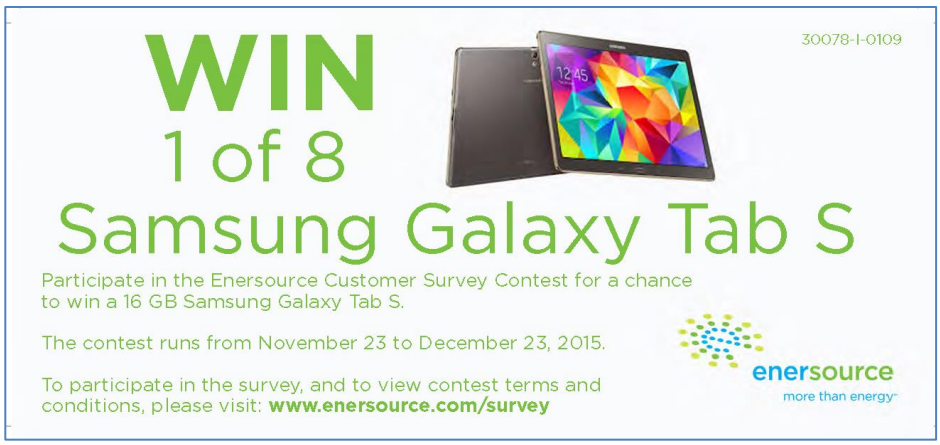
Enersource customers are invited to complete a survey and win a Samsung Tablet.



### 8.6.5 Enersource Bill Insert

Enersource sent out 80,000 bill inserts from November 30th through December 23rd.




### 8.6.6 Twitter Messages / Responses

Enersource rotated the following messages on Twitter.

- Take our interactive online survey for a chance to win one of eight Samsung Galaxy tablets. https://www.electricitydialogue.ca #Mississauga #Contest
- Help shape the future of electricity distribution in #Mississauga. http://www.electricitydialogue.ca #contest
- Your opinion matters. Complete our survey for a chance to #win a #tablet. #Mississauga #survey http://www.electricitydialogue.ca
- Anyone interested in a Samsung tablet? We have 8 to give away to those who complete our Customer Survey - https://www.electricitydialogue.ca/enr/login
- You only have until midnight tonight to participate in our #survey and #contest. http://www.electricitydialogue.ca #Mississauga #LongTermPlan

### 8.6.7 Facebook

Enersource also issued the following reminder on Facebook.

Last Chance - Contest ends December 23rd!!

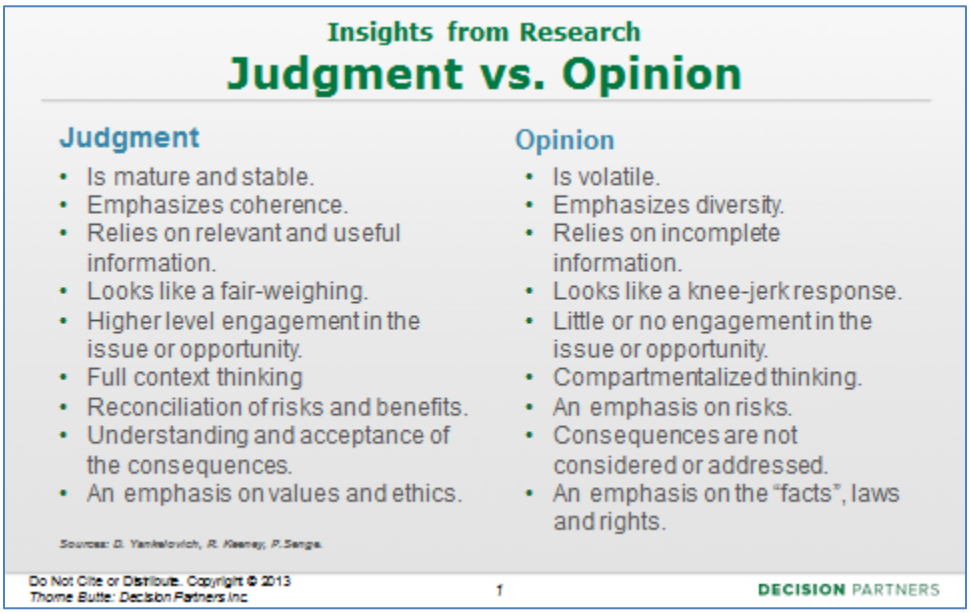
Mississauga residents who are Enersource Customers can participate in a short survey for a chance to WIN 1 of 8 Samsung Galaxy Tablets.

https://www.electricitydialogue.ca




## 8.7 Judgment v. Opinion

*Why Judgment Matters*



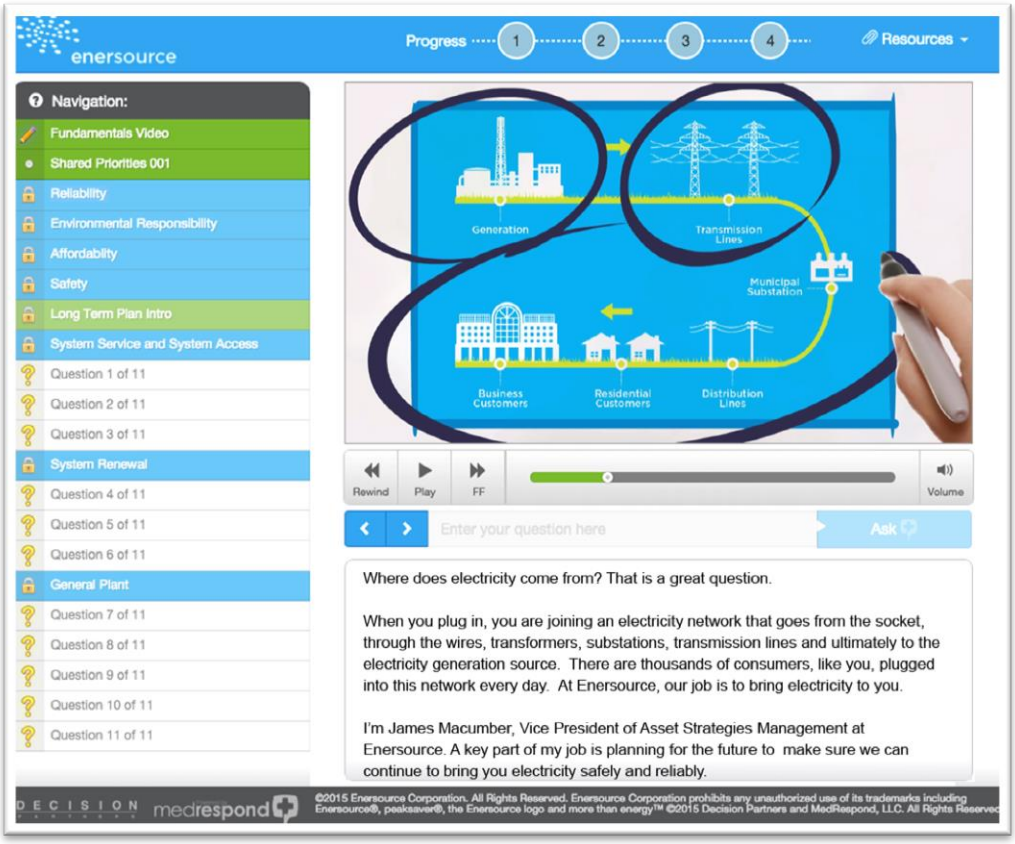
## 8.8 Decision Partners and MedRespond

### About Enersource, Decision Partners and MedRespond

**Enersource has been delivering safe, reliable energy to Mississauga since 1917. The company currently serves almost 200,000 customers across Mississauga, supporting them with one of the lowest service interruption rates in Canada.**

**Decision Partners** is an international team of management professionals and scientists, and the leading commercial provider, worldwide, of Mental Modeling Technology™, a unique evidence-based, science-informed management process for developing programs – policies, strategies and communications – for belief and behaviour change. The technology comprises integrated methods and tools on a software platform.

**MedRespond** is the leading innovator in scalable coaching solutions to drive behavioural change. MedRespond's solutions engage, empower and educate on critical issues affecting personal health, wealth and public policy.



**For More Information**

**For more information about Enersource's application of the Interactive Decision Support Technology™ to significantly improve customer engagement on their 5-Year Distribution System Plan, please contact:**

**Gia DeJulio**
**Director, Regulatory Affairs**
**Enersource Hydro Mississauga**
**905-283-4098**
**gdejulio@enersource.com**

**Sarah Thorne**
**Co-Founder and Partner**
**Decision Partners**
**416-473-7491**
**sthorne@decisionpartners.com**

**Virginia Flavin Pribanic**
**President**
**MedRespond, LLC**
**412-443-6776**
**virginia.pribanic@medrespond.com**

**BOMA-5**

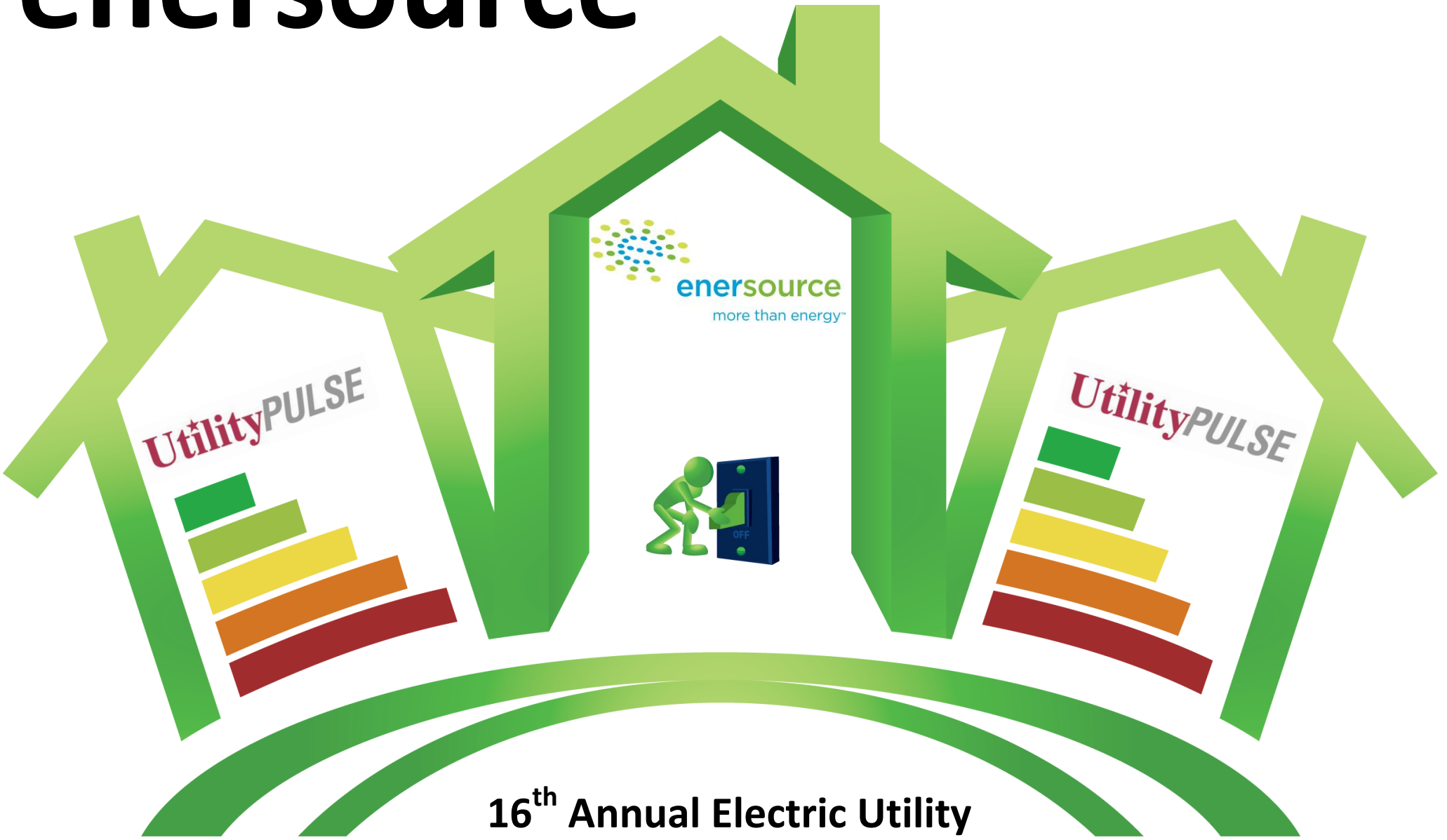
**Reference(s): DSP, p30**

**Please provide a copy of the most recent Enersource customer satisfaction survey.**

**Response:**

Alectra Utilities has provided BOMA-5_Attach 1-2014 Customer Survey. Please also see Alectra Utilities' response to BOMA-4 for further customer survey results.

# enersource




**16th Annual Electric Utility**
**Customer Satisfaction Survey**

**The purpose of this report is to profile the connection between Enersource and its customers.**

The primary objective of the Electric Utility Customer Satisfaction Survey is to provide information that will support discussions about improving customer care at every level in your utility.

The UtilityPULSE Report Card® and survey analysis contained in this report do not merely capture state of mind or perceptions about your customers' needs and wants - the information contained in this survey provides actionable and measurable feedback from your customers.

This is privileged and confidential material and no part may be used outside of Enersource without written permission from UtilityPULSE, the electric utility survey division of Simul Corporation.



All comments and questions should be addressed to:

Sid Ridgley, UtilityPULSE division, Simul Corporation

Toll free: 1-888-291-7892 or Local: 905-895-7900

Email: sidridgley@utilitypulse.com or sridgley@simulcorp.com

# Executive summary

Rosemarie LeClair, Chair of the Ontario Energy Board, in a recent presentation (Ontario Energy Network, April 28, 2014) said the OEB's consumer centric regulatory framework defines the utility's obligation for planning, obligations for customer engagement and its responsibilities for monitoring and measuring performance results.

**EB-2010-0379 Report of the Board: Scorecard Approach (ROB-SA) (March 5, 2014)**

Throughout this report are connections to the OEB's Report of the Board. Where possible we have addressed the specifics in the document and, the "spirit" of the Scorecard Approach.

We believe that the data from interviewing over 10,000 electric utility customers so far, in 2014, supports 3 main conclusions:

1- Customers, almost universally, are concerned about the cost of electricity

2- Customers are resilient and can adapt to adversity, in fact, they are very tolerant when a utility goes through a very difficult situation

3- In a utility world that is used to "pushing information out", it has to invest in and hone its competencies in having 2-way interactions with customers.



## Reasonable costs

9,943 Ontario survey respondents were asked if they agree or disagree with the following statement *"The cost of electricity is reasonable when compared to other utilities".* 50% agree in 2014, and 62% agreed in 2010. Satisfaction with the utility is about the same in those respective years.

We can also say that issues in the electricity industry, as a whole, show that satisfaction ratings and other important measures are lower in 2014 than they were in 2013. A customer may be upset with the amount that electricity costs, or what is going on in the industry, but that may not translate to being upset with their own local utility.

Data from the 2014 survey shows that respondents who give their utilities high marks for respect, trust, and social responsibility also give their utilities high marks for providing high quality services, and better marks for both cost efficiency and reasonableness of costs.

The attributes which help an LDC to be seen as trusted and highly credible are: knowledge, integrity, involvement and trust. On demonstrating Credibility and Trust, Enersource has done well.
Overall, Enersource 81% [Ontario 77%; National 80%].



## EB-2010-0379 ROB-SA: Comparability

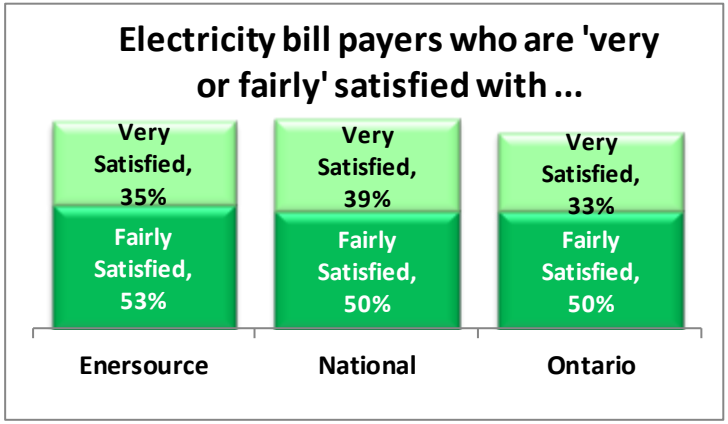
Your 2014 report contains data comparisons to:

- An Ontario-wide LDC benchmark
- A National LDC benchmark
- Previous year's ratings (where available)

- Ontario LDCs participating in the 2014 survey
- UtilityPULSE database

## EB-2010-0379 ROB-SA: Customer Focus

There are 2 identified Performance Categories in the OEB Report, they are Customer Satisfaction & Service Quality. Performance measurements for these areas range from *'relatively easy to attain production statistics'* to *'harder to define and measure qualitative items'*. None-the-less this survey provides you with insights about how customers perceive performance of the utility.




Base: total respondents

## EB-2010-0379 ROB-SA: Customer Focus - Customer Satisfaction - Satisfaction Survey Results

Customer satisfaction is one of the measures in the consumer centric regulatory framework. This rating is known as an effectiveness rating as it represents a sum total of perceptions and expectations that a customer has about their utility. Those expectations go far beyond "keeping the lights on", "billing me properly", and "restoring power quickly".

| Enersource SATISFACTION SCORES – Electricity customers' satisfaction | | | | | |
|---|---|---|---|---|---|
| **Top 2 Boxes: 'very + fairly satisfied'** | **2014** | **2013** | **2012** | **2011** | **2010** |
| **PRE: Initial Satisfaction Scores** | 88% | - | 89% | - | 91% |
| **POST: End of Interview** | 88% | - | 92% | - | 95% |

Base: total respondents / (-) not a participant of the survey year

- ***Satisfaction*** *happens when utility core services meet or exceed customer's needs, wants, or expectations.*
- ***Loyalty*** *(Affinity) occurs when a customer makes an emotional connection with their electric utility on a diverse range of expectations beyond core services.*

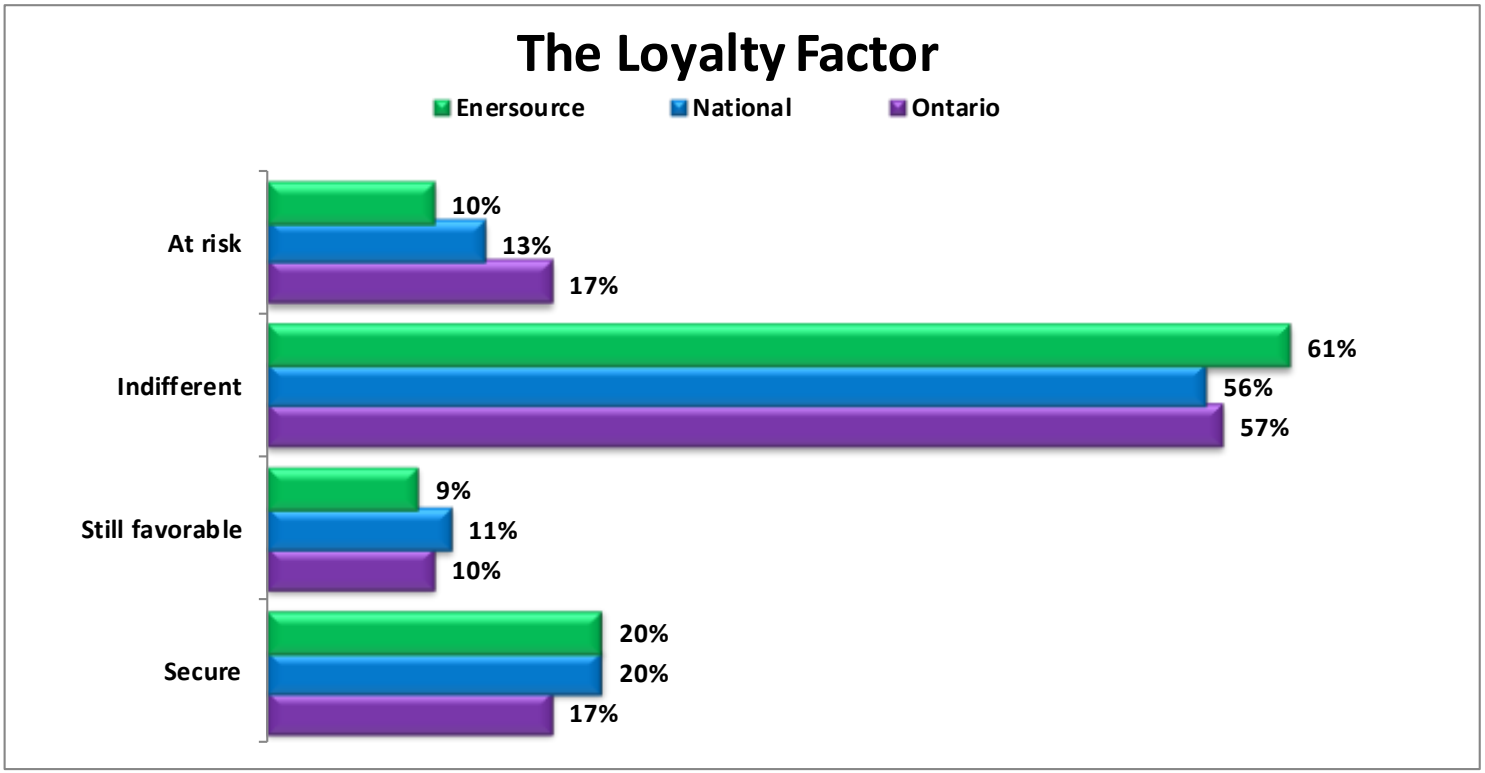
## Customer Affinity

Loyalty, for private industry, is a behaviourial metric. Loyalty, for natural monopolies (like LDCs) is an attitudinal metric.

| Customer Loyalty Groups | | | | |
|---|---|---|---|---|
| | **Secure** | **Favorable** | **Indifferent** | **At Risk** |
| | **Enersource** | | | |
| **2014** | 20% | 9% | 61% | 10% |
| **2013** | - | - | - | - |
| **2012** | 25% | 14% | 55% | 6% |
| **2011** | - | - | - | - |
| **2010** | 20% | 17% | 57% | 6% |

Base: total respondents / (-) not a participant of the survey year






Base: total respondents

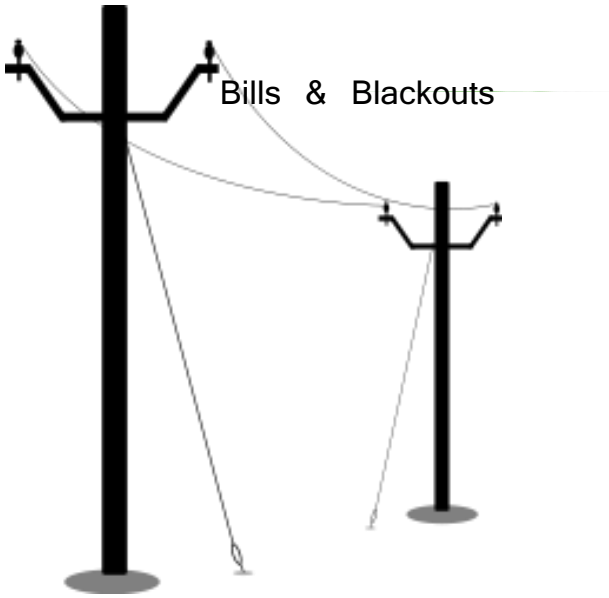
Utilities benefit from a trusted relationship with their empowered Customers. Higher levels of trust are the hallmarks of Secure customers. When people interact, either face-to-face, by telephone or on-line, if people do not trust each other, the interaction is not going to be efficient. Trust improves the

speed at which the interaction can be accomplished. At Risk customers recall experiencing more outages and more billing problems than Secure customers. What makes matters worse is, At Risk customers are about 2X more likely to contact the utility to deal with it.

None-the-less problems will happen.

## The Killer B's (Blackouts and Bills)

It is inevitable that there will be blackouts/power outages – the key is how a utility anticipates outages and more importantly, how it deals with them. It should also be noted that there is a disconnect between what a utility might call a "billing problem" and what a customer defines as a "billing problem". Though both viewpoints are valid, employees need to be trained to answer those which cause the most concern with customers.




| Percentage of Respondents indicating that they had a Blackout or Outage problem in the last 12 months | | | |
|---|---|---|---|
| | **Enersource** | **National** | **Ontario** |
| **2014** | 43% | 47% | 49% |
| **2013** | - | 41% | 35% |
| **2012** | 25% | 44% | 46% |
| **2011** | - | 43% | 43% |
| **2010** | 25% | 45% | 41% |

Base: total respondents / (-) not a participant of the survey year

| Percentage of Respondents indicating that they had a Billing problem in the last 12 months | | | |
|---|---|---|---|
| | Enersource | National | Ontario |
| **2014** | 15% | 16% | 25% |
| **2013** | - | 8% | 10% |
| **2012** | 10% | 12% | 13% |
| **2011** | - | 10% | 16% |
| **2010** | 8% | 10% | 12% |

Base: total respondents / (-) not a participant of the survey year

*What method did you use to contact your electric utility when you had a problem?*




Base: data from the full 2014 database

Customers may prefer a particular communication channel today (i.e., 88% telephone), however, that does not mean the customer who prefers the telephone will not want, or eventually want another channel for communications. In addition, there could be variances in preferences based on the type of issue or transaction.

## EB-2010-0379 ROB-SA: Customer Focus – Customer Satisfaction – Billing Accuracy

There is a difference between what a customer believes is a billing problem versus a technical or production level measurement. Without the benefit of production level numbers, 81% of respondents 'agree strongly + somewhat' that the utility has "accurate billing". The Ontario benchmark rating is 77%.

## EB-2010-0379 ROB-SA: Customer Focus – Customer Satisfaction – First Contact Resolution

This performance measure is not defined in the EB-2010-0379 ROB-SA March 5, 2014 document. First contact resolution is an outcome base measurement which is affected by: type of problem, competency levels of staff, empowerment levels of staff, and organization culture to name a few.

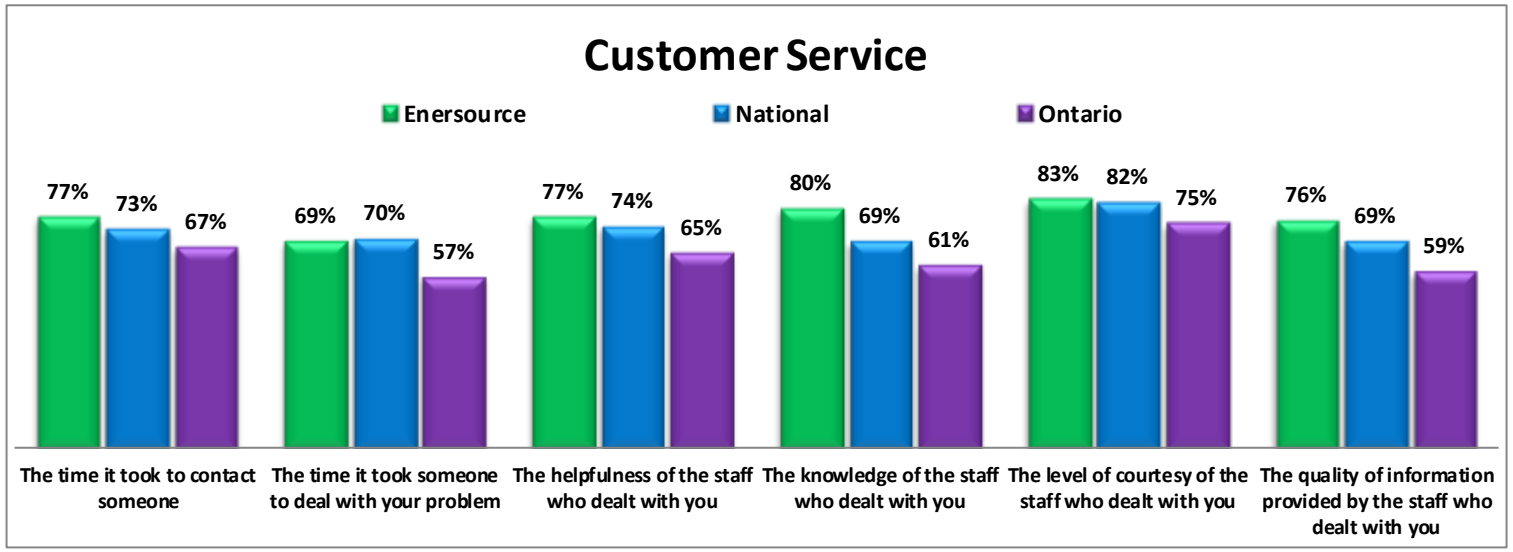
Your 2014 survey gives you the following information from respondents:

1- Satisfaction with the contact experience
2- A problem solved rating
3- A Customer Experience Performance rating (CEPr)



## Satisfaction with the contact experience

When there are problems, how they are handled can validate or invalidate a customer's perception about the utility's competency in handling the problem, and in running the operation. Here is how Customers, who contacted your LDC, rated their one-on-one transaction.




Base: total respondents who contacted the utility

Customer expectations are on the rise and continue to change. Customers expect their utility to have customer care practices and services that are in-line with any other organization that is important to their everyday life. Setting realistic expectations and consistently delivering to those expectations are keys to higher levels of Customer satisfaction. The setting of customer expectations is tough, but the harder part is to deliver consistency.

| Overall satisfaction with most recent experience | | | |
|---|---|---|---|
| | Enersource | National | Ontario |
| **Top 2 Boxes: 'very + fairly satisfied'** | 79% | 75% | 62% |

Base: total respondents who contacted the utility

## Problem solved rating

Respondents who said that they contacted the utility were also asked "Do you consider the problem solved or not solved?" 72% of your LDC's respondents said the problem was solved. The Ontario benchmark rating is 61%.




## Customer Experience Performance rating (CEPr)

What do customers anticipate contact will be with their local utility when they have a problem? Will it be adversarial, or cooperative, or pleasant, etc. High numbers in CEPr indicate that a large majority of customers would agree that their next contact will be a good or positive one.

| Customer Experience Performance rating (CEPr) | | | |
|---|---|---|---|
| | Enersource | National | Ontario |
| **CEPr: all respondents** | 83% | 82% | 79% |

Base: total respondents

## EB-2010-0379 ROB-SA: Customer Focus – Service Quality

The three performance measures identified are all time based measures. They are: New Residential Services Connected on Time; Scheduled Appointments Met on Time; and, Telephone Calls Answered on Time. These are good examples of efficiency measures. In addition to time, there are other dimensions of Service Quality that Customers value.

| Customer Service Quality | | | |
|---|---|---|---|
| **Top 2 boxes, 'strongly + somewhat agree'** | **Enersource** | **National** | **Ontario** |
| **Deals professionally with customers' problems** | 83% | 82% | 78% |
| **Pro-active in communicating changes and issues affecting Customers** | 77% | 74% | 73% |
| **Quickly deals with issues that affect customers** | 79% | 79% | 74% |
| **Customer-focused and treats customers as if they're valued** | 77% | 74% | 72% |
| **Is a company that is 'easy to do business with'** | 83% | 79% | 75% |
| **Cost of electricity is reasonable when compared to other utilities** | 60% | 60% | 55% |
| **Provides good value for money** | 68% | 67% | 63% |
| **Delivers on its service commitments to customers** | 85% | 84% | 82% |

Base: total respondents with an opinion

## EB-2010-0379 ROB-SA: Operational Effectiveness

With the exception of the Public Safety measure, which is yet to be defined, performance measures would typically take the form of a monitoring and measuring (quantitative) rating. Though customers may not have the benefit of numbers, they do have a perception.

| Management Operations | | | |
|---|---|---|---|
| **Top 2 boxes, 'strongly + somewhat agree'** | **Enersource** | **National** | **Ontario** |
| **Provides consistent, reliable electricity** | 90% | 89% | 86% |
| **Quickly handles outages and restores power** | 86% | 86% | 83% |
| **Makes electricity safety a top priority for employees and contractors** | 88% | 89% | 87% |
| **Operates a cost effective electricity system** | 69% | 69% | 62% |
| **Overall the utility provides excellent quality services** | 84% | 83% | 80% |

Base: total respondents with an opinion



## UtilityPULSE Report Card®

The purpose of the UtilityPULSE Report Card is to provide your utility with a snapshot of performance – it represents the sum total of respondents' ratings on 6 categories of attributes that research has shown are important to customers in influencing satisfaction and affinity levels with their utility.

## Enersource's UtilityPULSE Report Card®

*Performance*

| | CATEGORY | Enersource | National | Ontario |
|---|---|---|---|---|
| 1 | **Customer Care** | **B** | **B+** | **B** |
| | Price and Value | C+ | B | C+ |
| | Customer Service | B+ | B+ | B |
| 2 | **Company Image** | **B+** | **B+** | **B+** |
| | Company Leadership | A | B+ | B+ |
| | Corporate Stewardship | B+ | A | B+ |
| 3 | **Management Operations** | **A** | **A** | **A** |
| | Operational Effectiveness | A | A | B+ |
| | Power Quality and Reliability | A | A | A |
| | **OVERALL** | **B+** | **B+** | **B+** |

Base: total respondents



## Corporate Image

Reputation, image, brand have to be actively managed. Positive impressions beget positive perceptions. Marketing communication includes positioning the utility in a way that makes customers want your utility and its services. Every utility has a brand, why not have the brand you want?

| Attributes strongly linked to a hydro utility's image | | | |
|---|---|---|---|
| | Enersource | National | Ontario |
| Is a respected company in the community | 85% | 81% | 78% |
| A leader in promoting energy conservation | 80% | 78% | 77% |
| Keeps its promises to customers and the community | 81% | 79% | 76% |
| Is a socially responsible company | 82% | 78% | 77% |
| Is a trusted and trustworthy company | 83% | 82% | 77% |
| Adapts well to changes in customer expectations | 72% | 71% | 68% |
| Is 'easy to do business with' | 83% | 79% | 75% |
| Provides good value for your money | 68% | 67% | 63% |
| Overall the utility provides excellent quality services | 84% | 83% | 80% |
| Operates a cost effective hydro-electric system | 69% | 69% | 62% |

Base: total respondents with an opinion



Customers, as human beings, are both rational and emotional. The rational side of the customer holds the LDC accountable for doing its job (as contracted), thereby fulfilling the customer's basic needs. The emotional side of the customer is about fulfilling expectations. Meeting rational needs – at best – gets the customer to a neutral state and at worst creates dissatisfaction. Emotional needs, when met, assuming base level rational needs are met, can move a customer from neutral to higher levels of satisfaction. The

industry is obsessed with rational concerns about customer behaviour, but the real motivation for customer behaviour is emotional, not rational.

## What do customers think about electricity costs?

Ask a utility customer – anywhere in the province of Ontario – what do they think about electricity, there is a very high probability they will say electricity costs are too high or too expensive. For customers who said that they had a billing problem in the last 12 months, and stated that the problem was "high bills" or "high rates or charges", there was very little variability between customers who could be called Secure, Favourable, Indifferent or At Risk. There was also very little variability between age groupings or income groupings.

Our survey database shows 50% more customers in 2014 citing complaints with "high bills" or "high rates or charges" than in 2010. There is a growing concern over electricity costs, especially as it relates to its portion of a household budget. This means the industry needs to monitor "ability to pay".



| Is paying for electricity a worry or major problem … | | | |
|---|---|---|---|
| | **Enersource** | **National** | **Ontario** |
| **Not really a worry** | 60% | 69% | 59% |
| **Sometimes I worry** | 26% | 20% | 26% |
| **Often it is a major problem** | 8% | 7% | 11% |
| **Depends** | 3% | 3% | 2% |

Base: total respondents

## Supplemental Insights

Recognizing that customers' interests and needs continue to shift, we have provided data and insights, on a number of subjects such as e-care, e-billing, conservation and more.

## Electric Industry Knowledge & SMART Grid

Beyond knowing that they need electricity to maintain their day to day activities, does the average person feel that they are actually knowledgeable about the electric utility industry?

| Knowledge level about the electric utility industry | |
|---|---|
| | **Ontario** |
| **Extremely knowledgeable** | 2% |
| **Very knowledgeable** | 11% |
| **Moderately knowledgeable** | 47% |
| **Slightly knowledgeable** | 26% |
| **Not very knowledgeable** | 14% |
| **Don't know** | 1% |

Base: total respondents in the Ontario Benchmark survey



Two-thirds (60%) of those polled in the Ontario Benchmark survey considered themselves moderately to extremely knowledgeable about the electric industry.

While it is evident that the SMART grid is still not a much talked about concept, only 34% have a basic or good understanding of what it is, oddly enough, 60% still think that it is important to pursue SMART grid implementation. It is also clear that the majority of respondents are very + somewhat supportive of the utility working with neighbouring utilities on SMART grid initiatives.

| Level of knowledge about the SMART Grid | |
|---|---|
| | **Ontario** |
| **I have a fairly good understanding of what it is and how it might benefit homes and businesses** | 9% |
| **I have a basic understanding of what it is and how it might work** | 25% |
| **I've heard of the term, but don't know much about it** | 36% |
| **I have not heard of the term** | 29% |
| **Don't know** | 1% |

Base: total respondents in the Ontario Benchmark survey

## Efforts to reduce energy consumption



Do customers believe there is a real pay-off for trying to reduce their energy consumption? Does this impact overall efforts to reduce consumption? Respondents were asked *"How active have you been in trying to reduce your electricity consumption?"* (Base: total respondents in the Ontario Benchmark survey)

- 94% feel they are "very + somewhat active" in trying to reduce electricity consumption, and
- 81% of those do believe their efforts have resulted in reduced energy consumption, of which
- 44% estimate that they were able to offset an energy consumption reduction of more than 10%, and
- 72% believe that these efforts translated to savings on their electricity bills.

| Level of Activity in trying to reduce electricity consumption | |
|---|---|
| | Ontario |
| Very active | 52% |
| Somewhat active | 42% |
| Neither proactive or inactive | 0% |
| Not active | 2% |
| Not very active | 3% |

Base: total respondents in the Ontario Benchmark survey

| Estimate of percentage reduction in consumption | |
|---|---|
| | Ontario |
| 1 – 2 % | 5% |
| 3 – 5 % | 10% |
| 6 – 8 % | 4% |
| 9 – 10 % | 15% |
| More than 10% | 44% |
| Don't know | 21% |

Base: total respondents in the Ontario Benchmark survey whose active efforts have reduced consumption

**Active efforts have reduced energy consumption**




81%

16%

Base: total respondents in the Ontario Benchmark survey who have been active in trying to reduce energy consumption

**Efforts to conserve have translated into savings on your electricity bill**




72%

24%

Base: total respondents in the Ontario Benchmark survey whose active efforts have reduced consumption

## Energy Conservation & Efficiency




Energy efficiency can be broken down into two areas: *better use of energy through improved energy-efficient technologies;* and *energy saving through changes in customer awareness and behaviour.*

| Efforts to conserve energy | | | | |
|---|---|---|---|---|
| **Enersource** | **Yes** | **No** | **Already Done** | **Don't Know** |
| **Install energy-efficient light bulbs or lighting equipment** | 20% | 10% | 69% | 1% |
| **Install timers on lights or equipment** | 16% | 52% | 30% | 2% |
| **Shift use of electricity to lower cost periods** | 27% | 17% | 53% | 3% |
| **Install window blinds or awnings** | 15% | 24% | 59% | 2% |
| **Install a programmable thermostat** | 14% | 22% | 62% | 3% |
| **Have an energy expert conduct an energy audit** | 15% | 67% | 13% | 5% |
| **Removing old refrigerator or freezer for free** | 17% | 43% | 36% | 4% |
| **Join the peaksaverPLUS™ program** | 19% | 46% | 22% | 13% |
| **Replacing furnace with a high efficiency model** | 15% | 30% | 50% | 5% |
| **Replacing air-conditioner with a high efficiency model** | 19% | 34% | 43% | 4% |
| **Use a coupon to purchase qualified energy saving products** | 40% | 35% | 20% | 5% |

Base: 90% of total respondents from the local utility

## E-care and E-billing

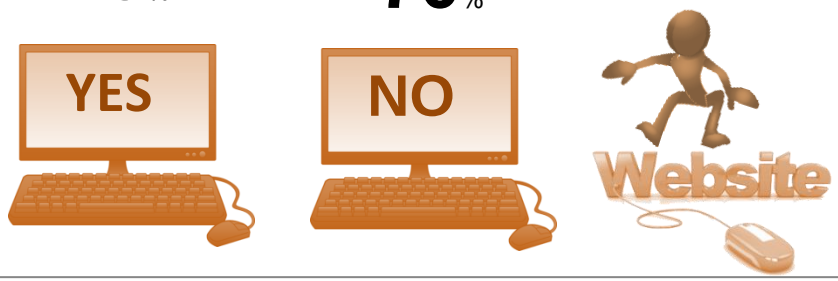
Technology – specifically the internet—has allowed people access to far more information than ever before and the ability to do more than ever before.

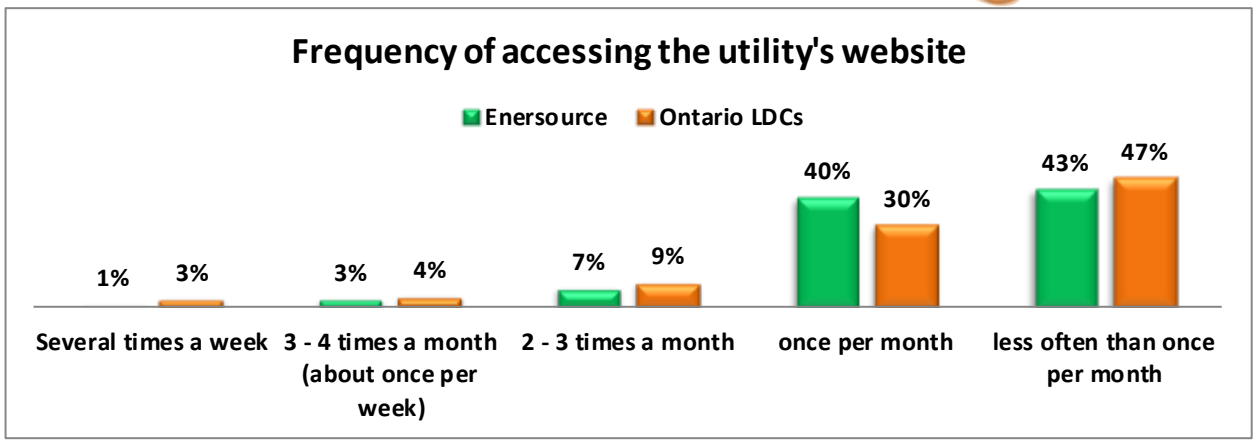
| Do you have access to the internet? | | |
|---|---|---|
| | Ontario LDCs | Enersource |
| Yes | 87% | 90% |
| No | 13% | 10% |

Base: 90% of total respondents from the local utility

Over the past six months have you accessed your local utility website?

Base: 90% of total respondents from the local utility




Base: An aggregate of respondents from 2014 participating LDCs / 90% of total respondents from the local utility

| Likelihood of using the internet for future customer care needs for things such as: | | |
|---|---|---|
| **Top 2 Boxes: 'very + somewhat likely'** | **Ontario LDCs** | **Enersource** |
| **Setting up a new account** | 31% | 36% |
| **Arranging a move** | 38% | 41% |
| **Accessing information about your bill** | 55% | 61% |
| **Accessing information about your electricity usage** | 54% | 62% |
| **Accessing energy saving tips and advice** | 45% | 56% |
| **Accessing information about Time Of Use rates** | 51% | 58% |
| **Maintaining information about your account or preferences** | 51% | 58% |
| **Paying your bill through the utility's website** | 32% | 39% |
| **Getting information about power outages** | 47% | 53% |
| **Arranging for service** | 40% | 48% |

Base: An aggregate of respondents from 2014 participating LDCs / 90% of total respondents from the local utility

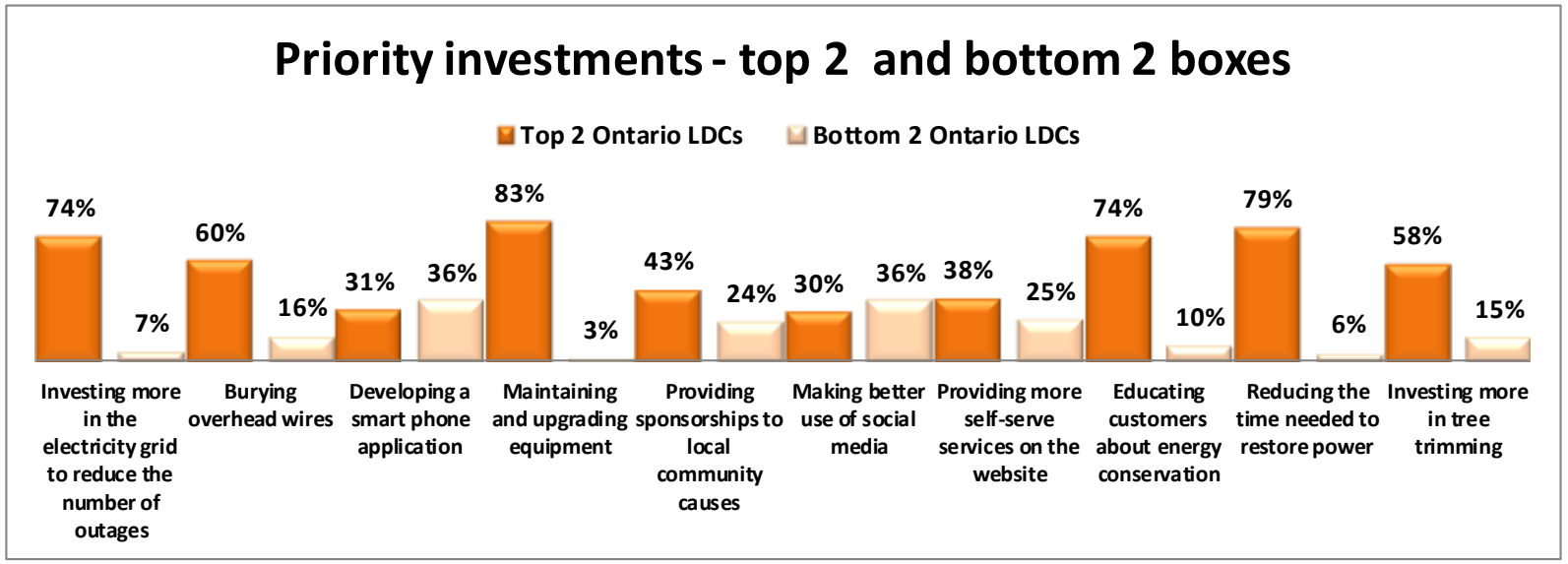


As society becomes increasingly more familiar with technology it will become a more popular medium for giving and receiving information. One could also say, demographics will also put more pressure on the technology channels. Unfortunately, customers adopt technology on their own timetable. This causes the utility to continue to improve existing channels while building the technological channels wanted by some today, but by the year 2020, demanded by many. Will your utility be ready?



## Priority Investments

While regulation and reliability are top concerns in the utility industry, aging infrastructure is now a top operational concern. Customers agree with industry insiders that infrastructure renewal is a high priority. This year, respondents were asked for their views about prioritizing investments.




Base: An aggregate of respondents from 2014 participating LDCs

Some findings shown above correlate with some of the suggestions made by respondents on things the utility could do to improve. Percentage of comments received from all Ontario respondents were:

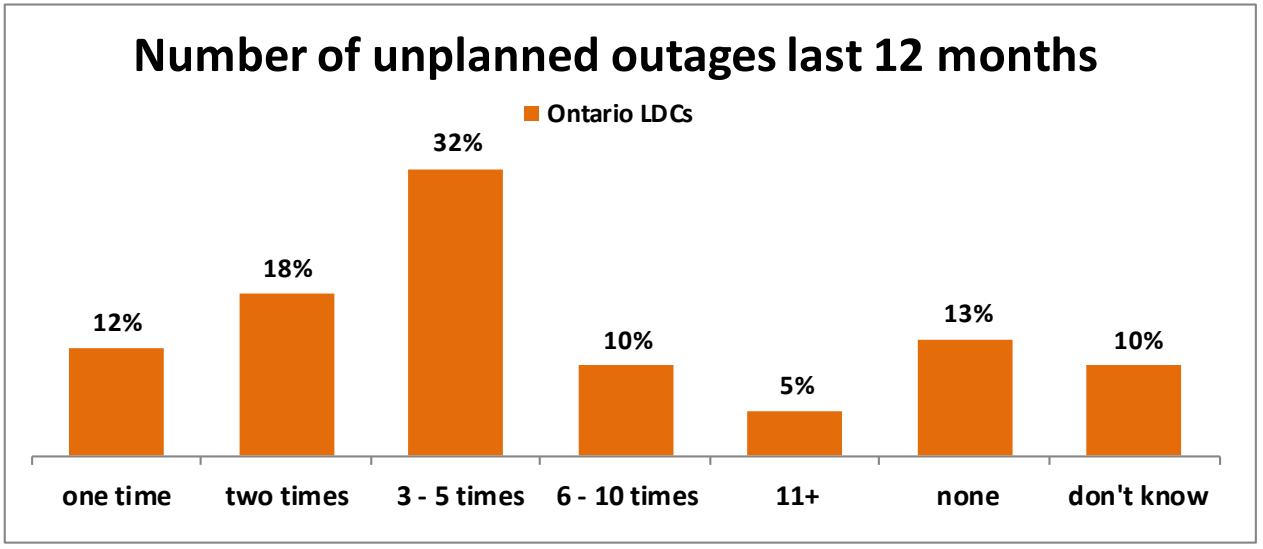
- 14% improve reliability (10% in 2010)
- 11% better maintenance (3% in 2010)

- 10% better communication (7% in 2010)

## Outage Management

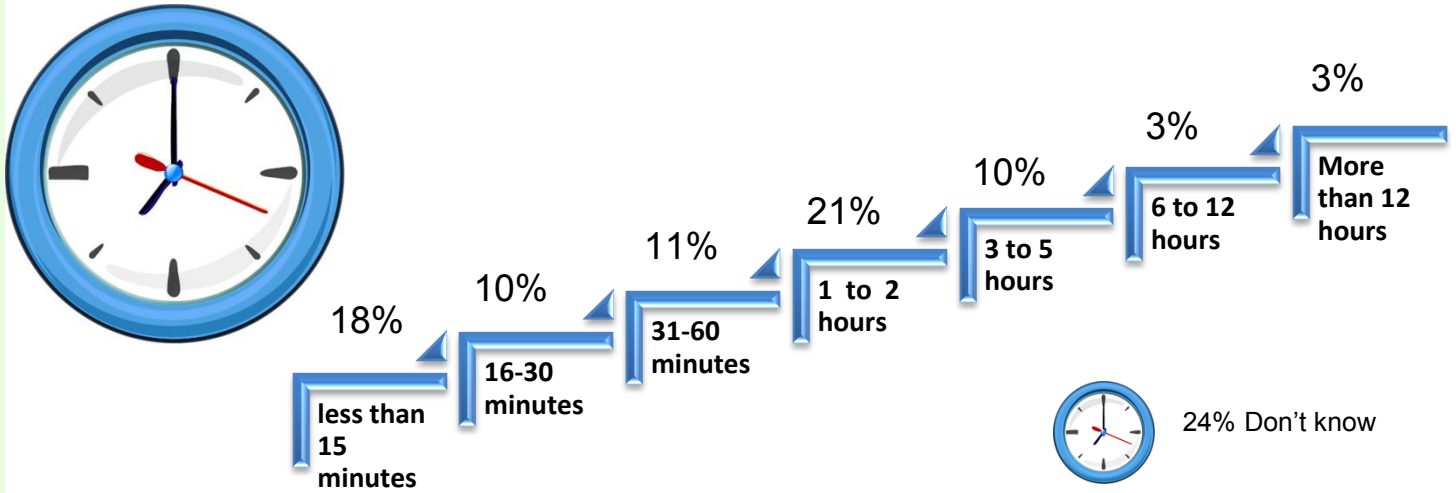
Whether an outage is planned or unplanned, the reality is that it is going to cause disruption and inconvenience under best case scenario and under worst case scenarios there could be safety and financial consequences.

However, one thing for certain, no matter what the scenario happens to be, customers are expecting their utility to keep them continually updated on the status of outages. Most importantly, and top priority, is to know the estimated restoration time. They also want to know the cause of the outage because they do not want to be a frequent outage customer.




Base: An aggregate of respondents from 2014 participating LDCs

*When an unplanned outage occurs, how long, on average, is the outage?*




Base: An aggregate of respondents from 2014 participating LDCs

How a utility chooses to handle, manage and communicate with customers during an outage situation does affect customers' satisfaction with their utility. Customers want timely, accurate and relevant information about an outage and customers expect a utility to use various communication channels to ensure their message is getting out there. This means not only obtaining information via the call centre and IVR but customers have increasing expectations for proactive two-way communication through social media, utility websites and modern communication devices (e.g. tablets, smartphones) and apps.

Inability to provide the above information accurately and in a timely manner will result in customer complaints, increased call volumes to your call centres, create unwanted public and media attention, and negatively impact customer satisfaction.

| Utility's effectiveness during an unplanned outage | |
|---|---|
| **Top 2 Boxes: 'very + somewhat effective'** | **Ontario LDCs** |
| **Responding to questions** | 61% |
| **Providing a reason for the outage** | 61% |
| **Providing an estimate when power will be restored** | 60% |
| **Responding to the power outage** | 81% |
| **Restoring power quickly** | 85% |
| **Communicating updates periodically** | 64% |
| **Posting information to the website** | 35% |
| **Using media channels for providing updates** | 53% |

Base: An aggregate of respondents from 2014 participating LDCs



On December 20, 2013, a severe ice storm struck the central and eastern portions of Canada and the northeastern United States. The storm's devastation caused major damage to utility distribution lines, towers, transformers, poles and entire substations and resulted in large scale outages and blackouts

for long periods of time. The data suggests that customers are both tolerant and understanding when major outages take place.

*Did you have a power outage during the ice storm in December 2013?*

Base: total respondents




38%

55%

| Percentage of Respondents who contacted their utility about the ice storm power outage | |
|---|---|
| | **Enersource** |
| **Yes** | 13% |
| **No** | 84% |

Base: total respondents affected by the ice storm

| Enersource<br>Length of outage (during Ice Storm 2013) | | | | | | | |
|---|---|---|---|---|---|---|---|
| **Less than 2 hours** | **2 – 4 hours** | **4+ hours or ½ day** | **12-18 hours or ½ - ¾ day** | **19-24 hours or 1 day** | **1 to 1.5 days** | **1.6 to 2 days** | **More than 2 days** |
| 24% | 21% | 25% | 5% | 6% | 3% | 1% | 2% |

Base: total respondents affected by the ice storm

Using social media and multi-channel communication modes still appear to be the exception when it comes to customers contacting their utilities. Results from this year's survey indicate that the telephone is still the most used and the preferred method of contact. Overall, 87% of all Ontario respondents affected by the ice storm who informed their local utility they were experiencing a power outage did so via telephone.

*In your view, what is an acceptable period of time to go without electricity in situations like the ice storm?*

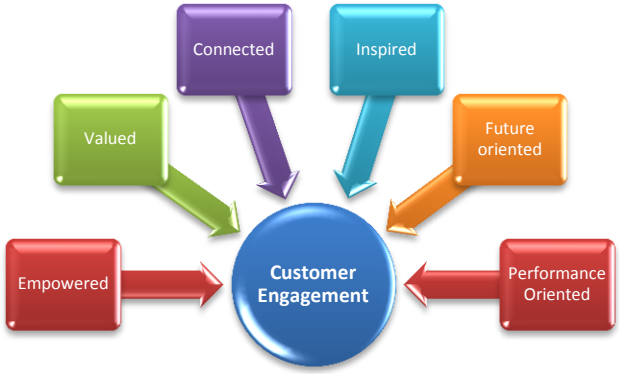


Base: total respondents affected by the ice storm

| | |
|---|---|
| •None (the power shouldn't be going out) | 10% |
| •Less than 2 hours | 21% |
| •2 - 4 hours | 21% |
| •4+ hours or 1/2 day | 13% |
| •12 - 18 hours or 1/2 day to 3/4 day | 5% |
| •19 - 24 hours or 1 day | 7% |
| •1 to 1.5 days | 6% |
| •1 .6 to 2 days | 3% |
| •More than 2 days | 0% |

## Customer Centric Engagement Index (CCEI)

The EB-2010-0379 ROB-SA report includes the following: "better engage with their customers to better understand and respond to their needs…" Conducting surveys (like this one), holding town hall meetings, focus groups, etc. are examples of engaging your customers. We call this an activity based definition of engagement. Asking 100 people to complete a survey is an engagement activity. This survey also provides you with an emotional look at engagement.



The CCEI index is a gauge of the amount of goodwill that has been generated. High numbers in CCEI suggests that there is a high level of goodwill amongst your customers – this is important for two reasons. First when something goes awry for the utility, goodwill helps the utility to be resilient. Second, goodwill encourages active participation in requests to participate in engagement activities or program offerings from the utility.

| Utility Customer Centric Engagement Index (CCEI) | | | |
|---|---|---|---|
| | **Enersource** | **National** | **Ontario** |
| **CCEI** | 79% | 79% | 76% |

Base: total respondents

In a world of chaos and confusion what will a customer do? Find someone to help. In the electricity industry, the vast majority of customers turn to, and rely on, their local utility. Knowing that customers will turn to their electric utility requires utilities to really know their customers. Not easy when customer expectations continue to shift.



The shift is on. 15 years ago a utility could think about their customers in terms of usage, now they have to think about them in terms of personas (i.e., customer type). Currently, customer segmentation, for most utilities, consists of a number of "personas". While this may be adequate today, in order to achieve high customer participation in programs and to optimize business processes there will be a need for granular targeting of communications.

Most utilities are quite comfortable “pushing” out communications in a one-way world. However, the shift is on because the new channels are 2-way; even without the new channels customers are expecting 2-way dialogue. The impact on a utility’s marketing-communications is significant.

Value is what a customer perceives they get in exchange for what they give up. The real challenge is educating customers on the value they receive. In the absence of a value proposition the primary thing people will talk about is cost.

We recommend having meaningful two-way dialogue with employees (and others) to leverage the results from your 2014 customer satisfaction survey derived from speaking with 624 Enersource customers [April 15 - April 26, 2014]. The electric utility business has demanding customers with high expectations.



UtilityPULSE

Sid Ridgley
Simul/UtilityPULSE
Email: sidridgley@utilitypulse.com or sridgley@simulcorp.com
June, 2014

# Table of contents


| | Page |
|---|---|
| Executive summary | 3 |
| Satisfaction (pre & post) | 33 |
| - Customer Service | 39 |
| Ice Storm 2013 | 45 |
| Bill payers' recent problems and problem resolution | 48 |
| Customer Experience Performance rating (CEPr) | 56 |
| Customer Engagement Index (CCEI) | 59 |
| UtilityPULSE Report Card® | 62 |
| The Loyalty Factor | 70 |
| - Customer commitment | 77 |
| - Word of mouth | 80 |
| Corporate Image | 83 |
| - Corporate Credibility & Trust | 86 |
| How can service to customers be improved? | 89 |
| What do customers think about electricity costs | 91 |
| What do small commercial customers think? | 95 |

| | Page |
|---|---|
| Supplemental Questions | 104 |
| Outage Communications | 105 |
| Priority Investments | 109 |
| Energy Conservation & Efficiency | 111 |
| E-care | 115 |
| Electric Utility Industry Knowledge & Smart Grid | 118 |
| Consumer Energy Use Behaviour | 121 |
| Purchasing an Electric vehicle | 123 |
| Method | 125 |
| About Simul | 128 |




# Satisfaction (pre & post)

Customer Satisfaction is an intangible as it is the sum total of real experience, or perceptions of what an experience may be like when a customer is dealing with their LDC. Satisfaction is not a program, it is an outcome. Satisfaction, as a measurement, is a part of the Ontario Energy Board's Performance Measurement for Electricity Distributors: A Scorecard Approach (Ontario Energy Board, EB-2010-0379, March 5, 2014).

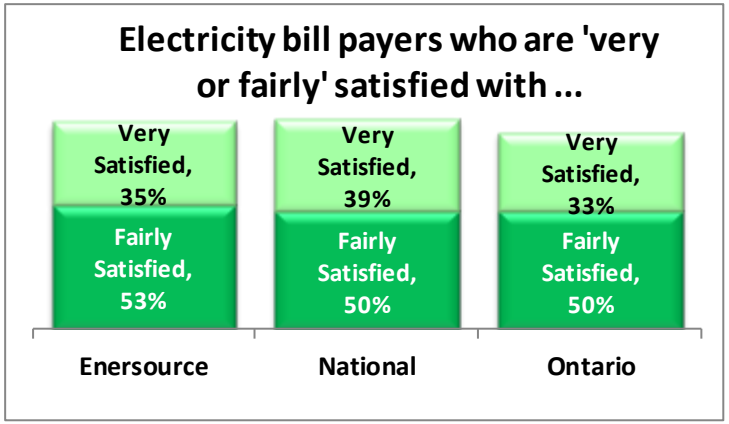
Satisfaction is an effectiveness rating of whether the objectives of process(s), service(s) or activities have been achieved. This makes Satisfaction, as a Scorecard measure, a rating that prompts discussion, planning, investing, and being connected to the Customer in order to effect an improved rating.

"Telephone calls answered on time" is an efficiency rating or a rating to assist in determining whether the right amount of resources have been used to deliver a process, service or activity. ***Efficiency*** *is about achieving objectives with the minimum amount of people, time, money and other resources.* For utilities reducing costs of delivering, supporting or maintaining a service is often the main driver for improving operational efficiency. While being obsessed with costs is important, the customer is also obsessed with quality. Finding the right balance between efficiency and effectiveness measures is difficult.

***Effectiveness*** *ratings are measures that keep the organization and its people more future focused than efficiency ratings.* This is not to say that efficiency ratings are not important, they are. The customer does care that their problem was solved and that the telephone was answered in less than 30 seconds. After 16 years of continued research with electric utility customers, expectations of their electric utility go far beyond "keeping the lights on", "billing me properly", and "restoring power quickly". However, acting quickly, yet not dealing with the customer concern, ultimately translates into a poor experience.

- **Satisfaction** happens when utility core services meet or exceed customer's needs, wants, or expectations.

- **Loyalty** occurs when a customer makes an emotional connection with their electric utility on a diverse range of expectations beyond core services.




Base: total respondents

Satisfaction alone does not make a customer loyal; a willingness to commit and advocate for a company along with satisfaction identifies the three basic customer attitudes which underpin loyalty profiles. While satisfaction is an important component of loyalty, the loyalty definition needs to incorporate more attitudinal and emotive components.

| Electricity bill payers who are 'very or fairly' satisfied with… | | | | | |
|---|---|---|---|---|---|
| | 2014 | 2013 | 2012 | 2011 | 2010 |
| **Enersource** | 88% | - | 89% | - | 91% |
| **National** | 89% | 90% | 88% | 89% | 86% |
| **Ontario** | 83% | 90% | 86% | 84% | 80% |

Base: total respondents / (-) not a participant of the survey year

As noted in previous reports:

Our research has found that in the utility industry environment, especially in Ontario, where most utilities are municipally owned, satisfaction is a strong driver of customer trust which in turn can impact employee engagement. The satisfaction of public customers/citizens both improves employee engagement and is improved by it.



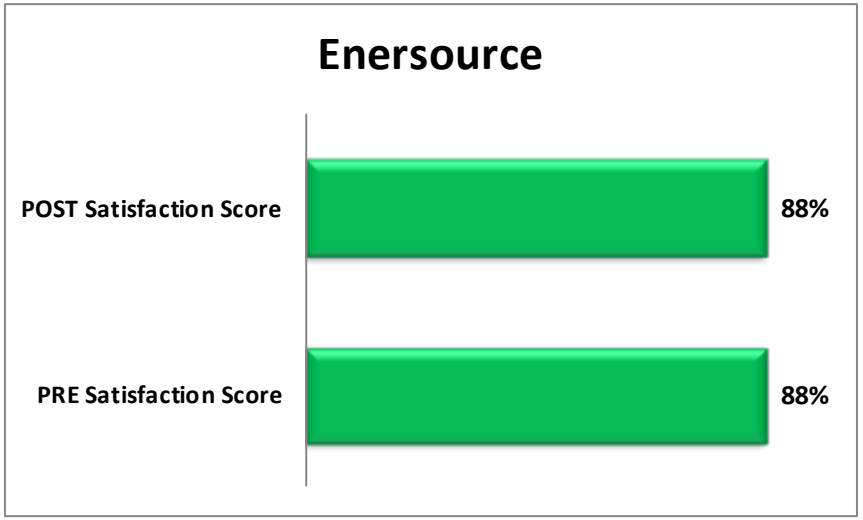

The synergy which exists between customer satisfaction and employee engagement has enormous implications for the performance of those who make up a utility's workforce. Many service personnel

are motivated by their desire to help others; succeeding at this task (and having clear evidence that they have satisfied their “customers”) can help keep them motivated and engaged.

Satisfied employees, who are working in an organizational culture which promotes service excellence is critical, too. Many companies make the mistake of measuring only customer satisfaction. Measuring organizational culture is the key because employees play an integral role in the customer relationship. Employees do more than deliver customer service – they personalize the relationship between customer and the utility.

Creating loyal customers and loyal employees go hand in hand and it is the leaders of organizations that must create this alignment. Implementing service excellence works best when its principles are well understood and widespread collaboration is encouraged by management’s visible actions. In our experience, this is best achieved by driving change from the ‘top down’ at the same time as inspiring and fully engaging employees from the ‘bottom up’.

In the Simul/UtilityPULSE Customer Satisfaction survey, the overall satisfaction question is asked both at the beginning (PRE) and the end (POST).




Base: total respondents

Asking the general satisfaction question at the start of the survey avoids bias and we obtain a spontaneous rating. This allows measurement of customers' overall impressions of the utility prior to prompting them to think of specific aspects of the relationship. After we have asked about specific aspects of the customer experience, we gain a more *considered* (or conditioned) response.

| SATISFACTION SCORES – Electricity customers' satisfaction | | | |
|---|---|---|---|
| **Top 2 Boxes: 'very + fairly satisfied'** | **Enersource** | **National** | **Ontario** |
| **PRE: Initial Satisfaction Scores** | 88% | 89% | 83% |
| **POST: End of Interview** | 88% | 87% | 80% |

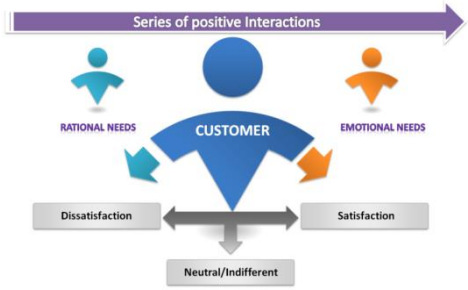
Base: total respondents

| SATISFACTION SCORES – Electricity customers' satisfaction | | | | | |
|---|---|---|---|---|---|
| **Top 2 Boxes: 'very + fairly satisfied'** | **2014** | **2013** | **2012** | **2011** | **2010** |
| **PRE: Initial Satisfaction Scores** | 88% | - | 89% | - | 91% |
| **POST: End of Interview** | 88% | - | 92% | - | 95% |

Base: total respondents / (-) not a participant of the survey year

Customers, as human beings, are both rational and emotional. The rational side of the customer holds the LDC accountable for doing its job (as contracted), thereby fulfilling the customer's basic needs. The emotional side of the customer is about fulfilling expectations. Meeting rational needs – at best –

gets the customer to a neutral state and at worst creates dissatisfaction. Emotional needs, when met, (assuming base level rational needs are met), can move a customer from neutral to higher levels of satisfaction.




| Attributes strongly linked to a hydro utility's image | | | |
|---|---|---|---|
| | Enersource | National | Ontario |
| **RATIONAL NEEDS** | | | |
| **Provides consistent, reliable electricity** | 90% | 89% | 86% |
| **Quickly handles outages** | 86% | 86% | 83% |
| **Accurate billing** | 81% | 83% | 77% |
| **Provides good value for money** | 68% | 67% | 63% |
| **Is 'easy to do business' with** | 83% | 79% | 75% |
| **Operates a cost effective hydro-electric system** | 69% | 69% | 62% |
| **EMOTIONAL NEEDS** | | | |
| **Deals professionally with customers' problems** | 83% | 82% | 78% |
| **Provides information to help customers reduce electricity costs** | 75% | 77% | 75% |
| **Pro-active in communicating changes** | 77% | 74% | 73% |
| **Quickly deals with issues that affect customers** | 79% | 79% | 74% |
| **Adapts well to changes in customer expectations** | 72% | 71% | 68% |
| **Overall the utility provides excellent quality services** | 84% | 83% | 80% |

Base: total respondents with an opinion

# Customer Service

Customer service is a series of activities grouped in processes designed to provide customers and other stakeholders with information or assistance which address customers' needs. Those needs are far more diverse than they have ever been thereby, compelling customer service to change in response to increasing customer demands. Given the increase in fragmentation of customer type and customer problems, the need for building a customer-centric culture in line with customers' needs, preferences and expectations is important when customer satisfaction is important to the organization.

Customers don't want to be passed from CSR to CSR, unnecessary bureaucracy, to keep repeating why they are calling, to duplicate information already given, or to have to understand the inner workings of the utility organization. Customers are expecting an intelligent and personalized experience.

Respondents, who contacted their utility via the telephone or in-person, were asked about six aspects of their most recent experience with a representative from Enersource.

- Information – quality of information provided
- Staff attitude – level of courtesy
- Professionalism – the knowledge of staff
- Delivery – helpfulness of staff
- Timeliness – the length of time it took to get what they needed
- Accessibility – how easy it was to contact someone




Base: total respondents who contacted the utility

| Satisfaction with Customer Service | | | |
|---|---|---|---|
| **Top 2 Boxes: 'very + fairly satisfied'** | **Enersource** | **National** | **Ontario** |
| **The time it took to contact someone** | 77% | 73% | 67% |
| **The time it took someone to deal with your problem** | 69% | 70% | 57% |
| **The helpfulness of the staff who dealt with you** | 77% | 74% | 65% |
| **The knowledge of the staff who dealt with you** | 80% | 69% | 61% |
| **The level of courtesy of the staff who dealt with you** | 83% | 82% | 75% |
| **The quality of information provided by the staff who dealt with you** | 76% | 69% | 59% |

Base: total respondents who contacted the utility

Respondents, who contacted their utility via an electronic means, e.g., email, website, social media, were asked about four aspects of their most recent experience with a representative.

| Satisfaction with Customer Service via electronic means | |
|---|---|
| **Top 2 Boxes: 'very + fairly satisfied'** | **Overall** |
| **The timeliness of response** | 68% |
| **The quality of information provided** | 65% |
| **The helpfulness of the information** | 63% |
| **The level of professionalism** | 72% |

Base: data from the full 2014 database

The customer service representative's role is essential to effectively handling customer issues/incidents/problems/requests. Having a skilled, trained representative is vital for a positive customer experience when a customer decides to make contact. Respondents who did have contact with a utility representative within the last 12 months were asked about their overall satisfaction with *that* experience.

| Overall satisfaction with most recent experience – Telephone & In-person | | | |
|---|---|---|---|
| | **Enersource** | **National** | **Ontario** |
| **Top 2 Boxes: 'very + fairly satisfied'** | 79% | 75% | 62% |

Base: total respondents who contacted the utility

| Overall satisfaction with most recent experience – Electronic means | |
|---|---|
| | **Overall** |
| **Top 2 Boxes: 'very + fairly satisfied'** | 68% |

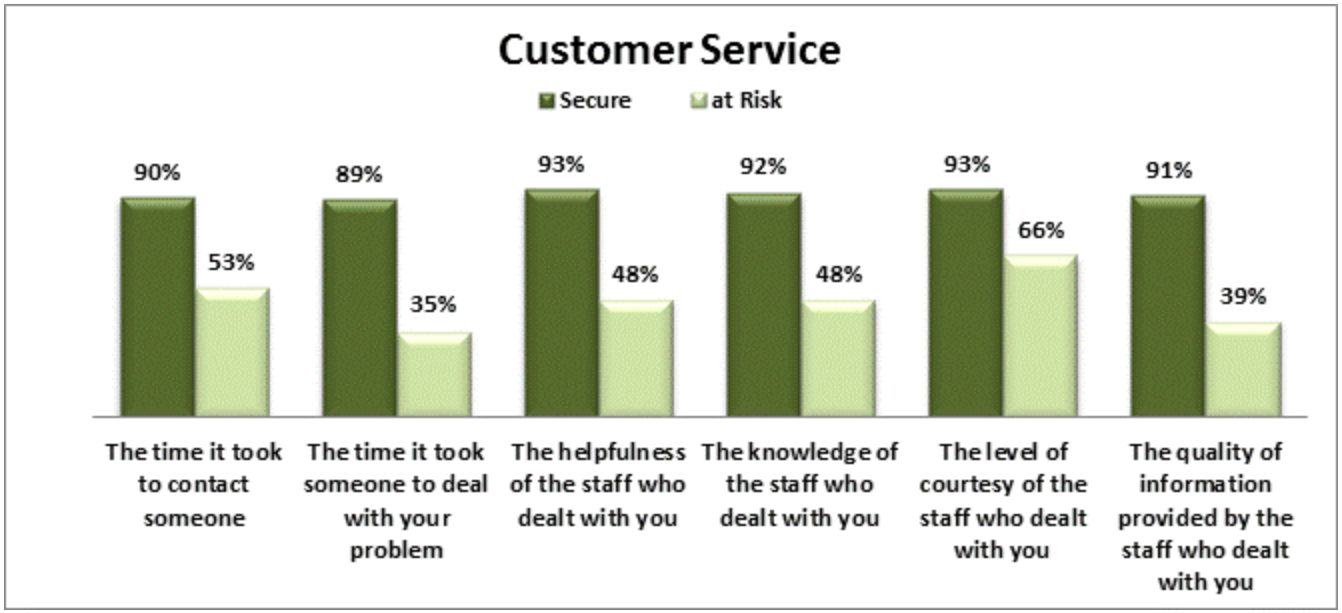
Base: data from the full 2014 database

Customers value speed and responsiveness especially as it relates to solving problems. The more flexibility you're able to offer and the more empowerment given to employees, the better able employees will be to meet those "speed" and "responsiveness" requirements. Customers benefit, too, when employees are able to resolve problem issues "on the spot" instead of having to "talk to my manager."

| SATISFACTION SCORES – Electricity customers' satisfaction | | | |
|---|---|---|---|
| | **Overall** | **Problems Solved** | **Problems Not Solved** |
| **Top 2 Boxes: 'very + fairly satisfied'** | 90% | 90% | 60% |
| **Bottom 2 Boxes: 'fairly + very dissatisfied'** | 7% | 7% | 35% |

Base: data from the full 2014 database

Empowerment is the backbone of the service recovery principle. In the face of error or problems, acting quickly and decisively, being empowered and turning a dissatisfied customer into a satisfied one tends to have a positive impact.




Base: data from the full 2014 database

| Satisfaction with Customer Service | | | |
|---|---|---|---|
| **Top 2 Boxes: 'very + fairly satisfied'** | **Overall** | **Recent Experience Satisfied** | **Recent Experience Dissatisfied** |
| **The time it took to contact someone** | 75% | 86% | 43% |
| **The time it took someone to deal with your problem** | 68% | 85% | 19% |
| **The helpfulness of the staff who dealt with you** | 76% | 90% | 33% |
| **The knowledge of the staff who dealt with you** | 73% | 88% | 32% |
| **The level of courtesy of the staff who dealt with you** | 82% | 92% | 56% |
| **The quality of information provided by the staff who dealt with you** | 71% | 88% | 21% |

Base: data from the full 2014 database

The service experience has a profound impact on customer service scores. The data shows a direct correlation between a satisfied customer experience and the ratings given across all six measures of person-to-person customer service. While there are a lot of things utilities cannot control, one thing they can control is the quality of service they provide.




| Important attributes which shape perceptions about service quality | | | |
|---|---|---|---|
| | Enersource | National | Ontario |
| **Deals professionally with customers' problems** | 83% | 82% | 78% |
| **Is pro-active in communicating changes and issues which may affect customers** | 77% | 74% | 73% |
| **Quickly deals with issues that affect customers** | 79% | 79% | 74% |
| **Customer-focused and treats customers as if they're valued** | 77% | 74% | 72% |
| **Is a company that is 'easy to do business with'** | 83% | 79% | 75% |
| **Cost of electricity is reasonable when compared to other utilities** | 60% | 60% | 55% |
| **Provides good value for money** | 68% | 67% | 63% |
| **Delivers on its service commitments to customers** | 85% | 84% | 82% |
| **Trusted and trustworthy company** | 83% | 82% | 77% |
| **Respected company in the community** | 85% | 81% | 78% |
| **Provides information and tools to help manage electricity consumption** | 77% | 77% | 75% |
| **Adapts well to changes in customer expectations** | 72% | 71% | 68% |

Base: total respondents with an opinion

# ICE STORM 2013

On December 20, 2013, a severe ice storm struck the central and eastern portions of Canada and the northeastern United States. The storm's devastation caused major damage to utility distribution lines, towers, transformers, poles and entire substations and resulted in large scale outages and blackouts for long periods of time. The data suggests that customers are both tolerant and understanding when major outages take place.

*Did you have a power outage during the ice storm in December 2013?*




**38%**

**55%**

Base: total respondents

Days after the storm passed through, thousands were left without power as crews worked around the clock in the affected areas, but difficult weather conditions -- including more snow and continued freezing temperatures -- was making power restoration a challenge.

**Enersource**
**Length of outage (during Ice Storm 2013)**

| Less than 2 hours | 2 – 4 hours | 4+ hours or ½ day | 12-18 hours or ½ - ¾ day | 19-24 hours or 1 day | 1 to 1.5 days | 1.6 to 2 days | More than 2 days |
|---|---|---|---|---|---|---|---|
| 24% | 21% | 25% | 5% | 6% | 3% | 1% | 2% |

Base: total respondents affected by the ice storm

A common communication channel used by customers is their website. Most utilities use their website to publish outage information to customers; timely information posted to your website could reduce the impact on other utility resources.

| Percentage of Respondents who contacted their utility about the ice storm power outage | |
|---|---|
| | **Enersource** |
| **Yes** | 13% |
| **No** | 84% |

Base: total respondents affected by the ice storm who contacted the utility about the outage during the storm

Some utilities websites provide customers with the start time of the outage, the number of customers impacted by the outage, and an outage map. Storm Centre landing pages on the utilities' websites have become a best practice where outage information is consolidated in one easy to access location. Social media will become increasingly important depending upon the severity of the outage. The reality is social media adoption rates are growing, which means, in time, these channels will become an additional means for providing information.










Using social media and multi-channel communication modes still appear to be the exception when it comes to customers contacting their utilities. Results from this year's survey indicate that the telephone is still the most used and the preferred method of contact. Overall, 87% of all Ontario respondents affected by the ice storm who informed their local utility they were experiencing a power outage did so via telephone.

*In your view, what is an acceptable period of time to go without electricity in situations like the ice storm?*



Base: total respondents affected by the ice storm

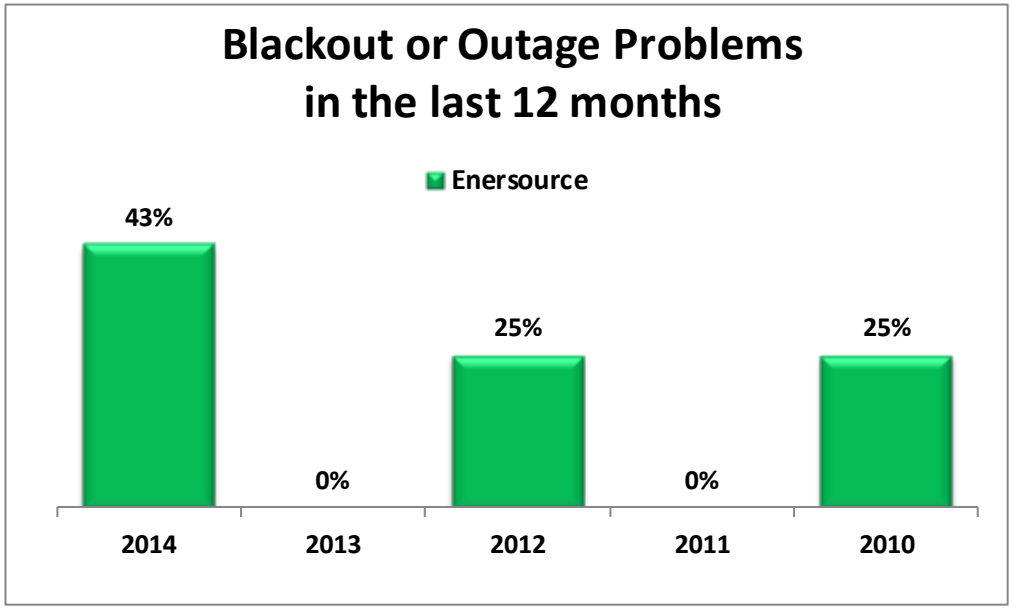
| | |
|---|---|
| •None (the power shouldn't be going out) | 10% |
| •Less than 2 hours | 21% |
| •2 - 4 hours | 21% |
| •4+ hours or 1/2 day | 13% |
| •12 - 18 hours or 1/2 day to 3/4 day | 5% |
| •19 - 24 hours or 1 day | 7% |
| •1 to 1.5 days | 6% |
| •1 .6 to 2 days | 3% |
| •More than 2 days | 0% |

During any outage (planned or unplanned) restoring power quickly and safely is a top priority. Consistent and effective communication will drive the customer experience during an outage. If the customer starts to get mixed messages i.e. website versus radio and television news versus public service announcements are not in sync, then a customer could potentially perceive the situation as being not in order and therefore could also question safe and quick restoration. The more disarray the customer senses from mixed communication messages, the more intolerant they will become of the duration of the outage. Consistent updates across all channels will at least provide a sense of security – that the utility is on top of it and working to get things back up and running.

# Bill payers' recent problems and problem resolution

Outages and billing problems, we call them the "Killer B's", the two issues that are most likely to cause grief to utility customers.

At one time, if the power went off for a few minutes, it was considered annoying and inconvenient. However, with so many devices hooked into the electricity system, even a small power outage can be truly aggravating. 86% of respondents with an opinion agree (top 2 boxes) Enersource "quickly handles outages and restores power".



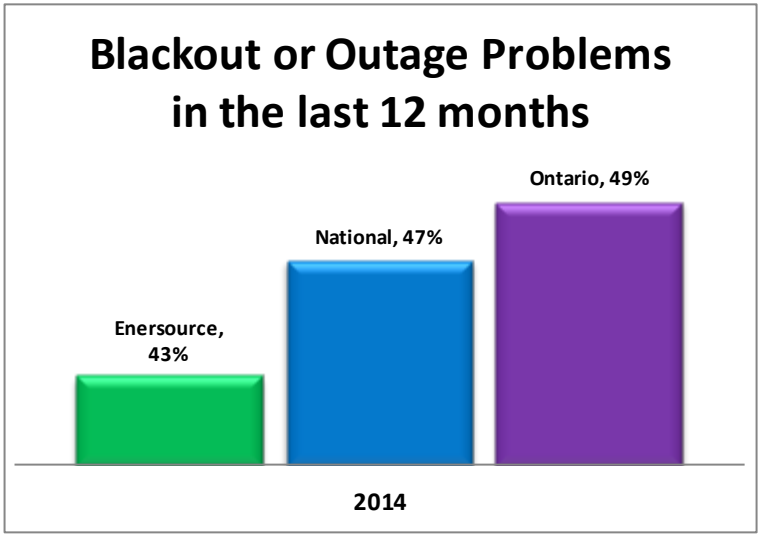

Base: total respondents / (-) not a participant of the survey year

Ideally, no one wants to go without electricity, however it is an inevitability that at some point the power will go out, especially during severe weather related events. During these instances, most customers will be somewhat flexible in their expectation for quick restoration. However, as an outage prolongs and impacts daily routines and when there is an uncertainty as to the expected restoration time, customers begin to become less understanding and more demanding.

Despite a utility's best efforts, there will be times when the power goes off.

| Percentage of Respondents indicating that they had a Blackout or Outage problem in the last 12 months | | | |
|---|---|---|---|
| | Enersource | National | Ontario |
| **2014** | 43% | 47% | 49% |
| **2013** | - | 41% | 35% |
| **2012** | 25% | 44% | 46% |
| **2011** | - | 43% | 43% |
| **2010** | 25% | 45% | 41% |

Base: total respondents / (-) not a participant of the survey year

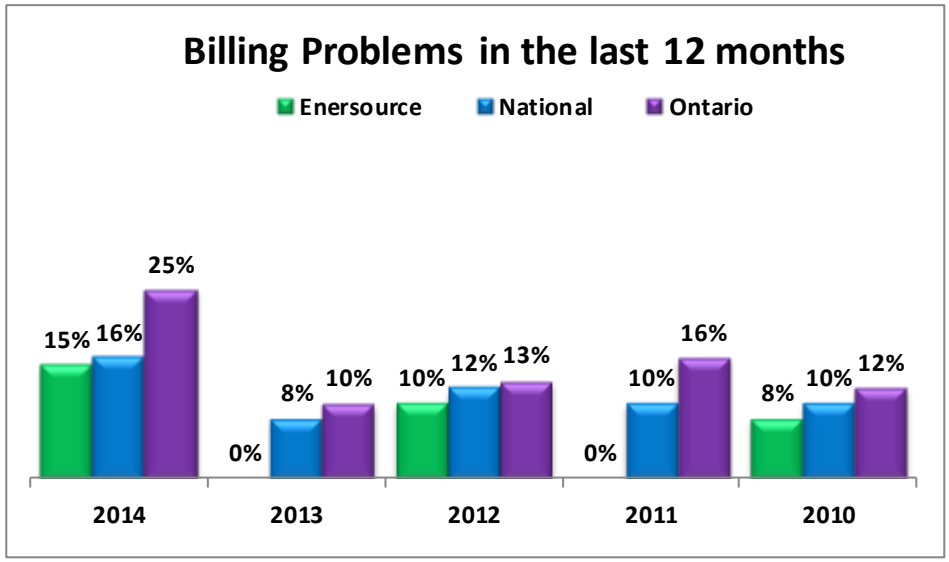



Base: total respondents

For most customers, their bill is the only thing they see (or pay attention to) from their utility provider. It not only tells them how much to pay, it documents their service usage, breaks down the various charges and provides

contact information for customer service. As the principal form of communication between a utility and its customers, utilities cannot underestimate the importance of billing.

When it comes to billing, customers expect zero-defect delivery. Customers expect timely and accurate billings which they understand. Incorrect information, miscalculated balances, bills that are too difficult to understand result in time logged by your CSR's as well as dissatisfied customers. Improving billing activities has an immediate impact on the revenue streams of a utility in terms of costs associated with managing call center applications.

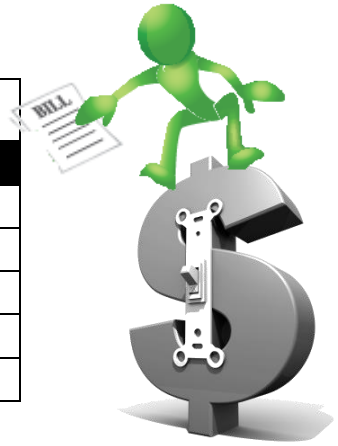



Base: total respondents / (-) not a participant of the survey year



| Percentage of Respondents indicating that they had a Billing problem in the last 12 months | | | |
|---|---|---|---|
| | Enersource | National | Ontario |
| **2014** | 15% | 16% | 25% |
| **2013** | - | 8% | 10% |
| **2012** | 10% | 12% | 13% |
| **2011** | - | 10% | 16% |
| **2010** | 8% | 10% | 12% |

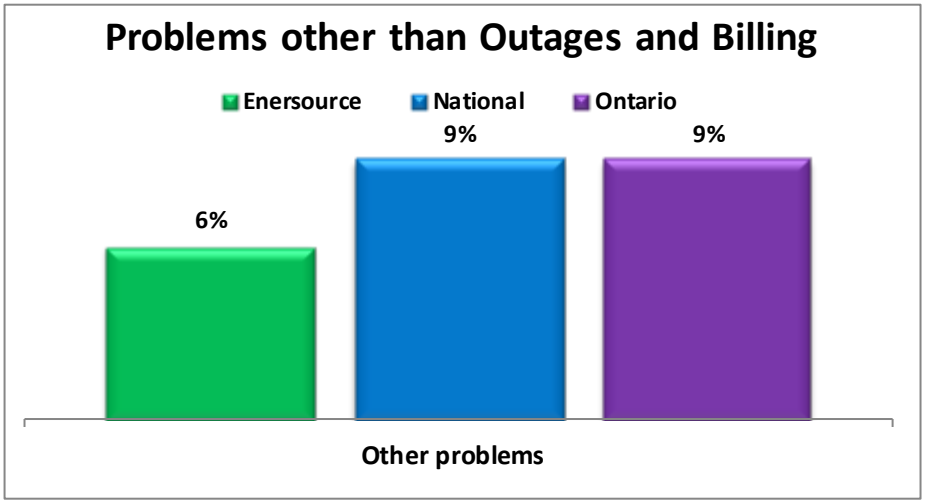
Base: total respondents / (-) not a participant of the survey year




| Types of Billing Problems | |
|---|---|
| | Enersource |
| **The amount owed was too high** | 75% |
| **Complaint about rates or charges** | 19% |
| **The bill was difficult to understand** | 3% |
| **The bill arrived late** | 2% |
| **The payment made was recorded incorrectly** | 1% |

Base: total respondents with billing problems

As it relates to problems, the Killer B's – Bills and Blackouts still occupy top ranking – while moving/setting up a new account, maintenance repairs, high bills, information on pricing, SMART meters and energy conservation are issues which also contribute to inbound call-centre calls.




Base: total respondents

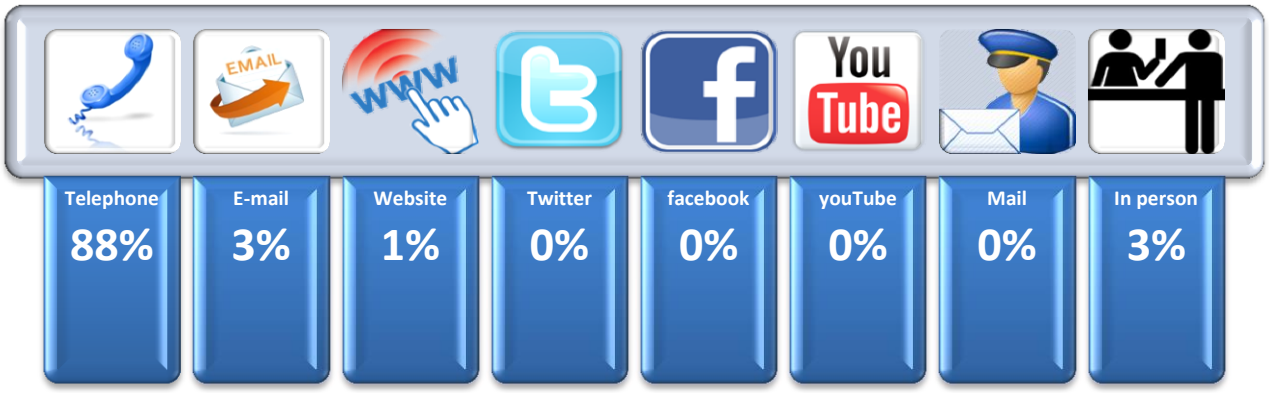
| Percentage of Respondents with problems other than billing or power outages in the last 12 months | | | |
|---|---|---|---|
| | **Enersource** | **National** | **Ontario** |
| **Yes** | 6% | 9% | 9% |
| **No** | 94% | 90% | 90% |

Base: total respondents

The reality is, there will be outages, there will be billing issues and there will be other problems. The key is how the customer is looked after when the problem(s) arises. By understanding the complaint process and customer complaint behaviour, a utility can learn how to reduce the impact of an unfavourable service experience or complaint.

*What method did you use to contact your electric utility when you had a problem?*

Base: data from the full 2014 database




Customers care more about getting their problem solved than they do about following or using the utilities processes. Solving the customer's problem with the first interaction (often called first call resolution) is a driver of perception. Customers want to deal with someone who understands what they are calling about, they want to have access to the correct person to talk to and they expect this person to have the ability to inform and or make decisions to work through the customer's concern. The reality is that customers know we do not live in a perfect world and problems will arise. What customers want however, is to ultimately have their problem solved. When the problem is solved the utility benefits.

| Percentage of Respondents who contacted their utility and had their problem solved in the last 12 months | | | |
|---|---|---|---|
| | **Enersource** | **National** | **Ontario** |
| **Yes** | 72% | 69% | 61% |
| **No** | 22% | 26% | 36% |

Base: total respondents

| Attributes describing operational effectiveness | | | |
|---|---|---|---|
| | Overall Score | Problem Solved | Problem Not Solved |
| **Provides consistent, reliable electricity** | 90% | 88% | 82% |
| **Delivers on its service commitments to customers** | 86% | 86% | 71% |
| **Accurate billing** | 85% | 83% | 66% |
| **Quickly handles outages and restores power** | 87% | 84% | 80% |
| **Makes electricity safety a top priority** | 88% | 88% | 86% |
| **Uses responsible environmental practices when completing work** | 85% | 85% | 75% |
| **Is efficient at managing the hydro-electric system** | 82% | 80% | 65% |
| **Is a company that is 'easy to do business with'** | 85% | 83% | 64% |
| **Operates a cost effective hydro-electric system** | 73% | 72% | 54% |
| **Overall the utility provides excellent quality services** | 85% | 84% | 70% |

Base: data from the full 2014 database from those respondents with an opinion

Technology is considered by many in the electricity utility industry to be both a blessing and a curse. On one hand, the LDC (and other service providers) can benefit from embracing technology to reduce costs and hopefully improve service thereby, putting control into the hands of the customer. However, technology can enable the customer's dissatisfaction to go viral.

Loyalty levels of customers (i.e., Secure, Favorable, Indifferent, At Risk) do have a different “recall” as it relates to problems encountered.

| Bill payers recalling a power failure or outage | | | | |
|---|---|---|---|---|
| | **Secure** | **Favorable** | **Indifferent** | **At Risk** |
| **Yes** | 31% | 35% | 46% | 48% |
| **No** | 68% | 64% | 52% | 51% |

Base: data from the full 2014 database

| Bill payers recalling a billing problem | | | | |
|---|---|---|---|---|
| | **Secure** | **Favorable** | **Indifferent** | **At Risk** |
| **Yes** | 4% | 6% | 15% | 46% |
| **No** | 95% | 93% | 83% | 51% |

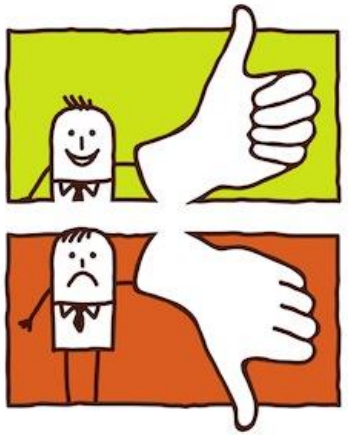
Base: data from the full 2014 database

| Bill payers who said their problem was solved | | | | |
|---|---|---|---|---|
| | **Secure** | **Favorable** | **Indifferent** | **At Risk** |
| **Yes** | 92% | 79% | 73% | 35% |
| **No** | 7% | 17% | 22% | 59% |

Base: data from the full 2014 database

# Customer Experience Performance rating (CEPr)

Every touch point with customers on the phone, website or in-person influences what customers think and feel about the organization. The key is handling every individual element of an interaction with a customer so that he/she feels good at the end of the whole interaction and the utility achieves its business objectives.



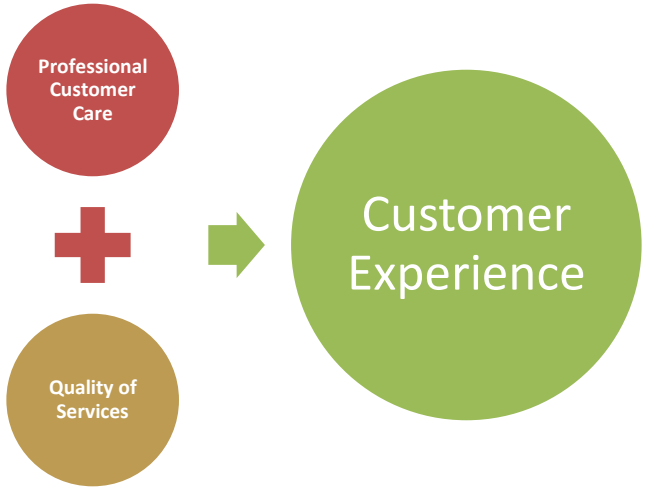
Great experiences occur when all functions of the organization align with one another to achieve the outcomes your customers seek. A good customer experience starts with understanding what your customers care about most and understanding which promises are most important to your customers.

At the heart of the CEPr are 4 central questions:

- Are interactions with the organization professional and productive?
- Is the organization 'easy to deal with'?
- Does the organization effectively meet your needs?
- Does the organization provide high quality services?

Some of the factors which contribute to the overall Customer experience:

- Delivering accessible and consistent customer service
- Understanding customer expectations
- Maintaining timely resolution timelines
- Providing effective communication(s) according to customer needs
- Demonstrating responsiveness
- Speeding up problem resolution
- Conducting problem analysis to prevent recurring issues
- Easy to do business with
- Seeking customer feedback and following through on recommendations




| Customer Experience Performance rating (CEPr) | | | |
|---|---|---|---|
| | **Enersource** | **National** | **Ontario** |
| **CEPr: all respondents** | 83% | 82% | 79% |

Base: total respondents

The CEPr (all respondents) for Enersource is 83%. This rating would suggest that a very large majority of customers have a belief that they will have a good to excellent experience dealing with a Enersource professional. However, the balance of respondents is not anticipating a good to excellent experience, and as such could be more challenging to serve.

The CEPr score is what we refer to as an effectiveness rating and is affected by many dimensions of service. While an excellent transaction today creates a positive experience today, the perception created is that future transactions will be excellent too, which is how you want your customers to feel. Of course a negative transaction creates the perception that future transactions will be negative. The key then is to emphasize problem resolution with a "one call" mindset.

| The impact of Satisfied or Dissatisfied experiences on some operational attributes | | | |
|---|---|---|---|
| | Enersource | Recent Experience Satisfied | Recent Experience Dissatisfied |
| **Provides consistent, reliable electricity** | 90% | 89% | 78% |
| **Delivers on its service commitments to customers** | 85% | 87% | 64% |
| **Accurate billing** | 81% | 78% | 48% |
| **Quickly handles outages and restores power** | 86% | 85% | 75% |
| **Makes electricity safety a top priority** | 88% | 87% | 83% |
| **Uses responsible environmental practices when completing work** | 85% | 85% | 84% |
| **Is efficient at managing the hydro-electric system** | 79% | 79% | 68% |
| **Overall the utility provides excellent quality services** | 84% | 83% | 72% |

Base: respondents who have contacted the utility

# Customer Centric Engagement Index (CCEI)

The EB-2010-0379 ROB-SA report includes the following: “better engage with their customers to better understand and respond to their needs…” Conducting surveys (like this one), holding town hall meetings, focus groups, etc. are examples of engaging your customers. We call this an activity based definition of engagement. Asking 100 people to complete a survey is an engagement activity.

This survey also provides you with an emotional look at engagement. The CCEI index is a gauge of the amount of goodwill that has been generated. High numbers in CCEI suggests that there is a high level of goodwill amongst your customers – this is important for two reasons. First when something goes awry for the utility, goodwill helps the utility to be resilient. Second, goodwill encourages active participation in requests to participate in engagement activities or program offerings from the utility.

The UtilityPULSE Customer Engagement Index (CCEI) is a metric designed to get a more in-depth look at the attachment a customer has with your LDC and its brand.



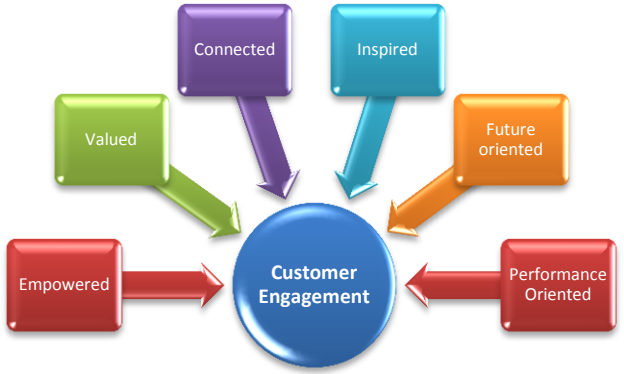
Your Annual UtilityPULSE survey tracks a customer's willingness to continue to do business, and willingness to recommend their local utility. Through a combination of calculations the end result is a Customer Loyalty index. That is, the number of customers that are: At risk, Indifferent, Favourable, Secure. The goal of every enterprise ought to be the creation of more Secure and Favourable customers. We believe that high levels of customer engagement correlate strongly to high levels of Secure and Favourable customer numbers.

We believe that a customer-centric definition of engagement is valuable to individuals, teams and executives in an LDC for determining what needs to be done to ensure that the organization is successful today and successful again tomorrow – in a changed world.

***Engagement is how customers think, feel and act towards the organization.*** As such, ensuring that customers respond in a positive way requires that they are rationally satisfied with the services provided AND emotionally connected to your LDC and its brand. The more frequently and consistently an organization's products and services can connect with a customer, especially on an emotional level, the stronger and deeper the customer becomes engaged with the organization.

**What does customer centric engagement look like?**

UtilityPULSE has identified the six key dimensions of what defines customer engagement. They are: empowered, valued, connected, inspired, future oriented and performance oriented.



They include:

- Does the utility allow their customers to feel ***empowered*** about their interactions with the company and decisions affecting their electricity usage
- Does the utility give customers the sense of being ***valued***
- Does the utility act in ways which allows customers to stay ***connected***
- Do customers get ***inspired*** by the way the utility conducts business
- Is the utility forward thinking enabling customers to be ***future oriented***
- Does the utility conduct operations in such a way that customers believe that they are truly ***performance oriented*** in achieving goals and results



| Utility Customer Centric Engagement Index (CCEI) | | | |
|---|---|---|---|
| | **Enersource** | **National** | **Ontario** |
| **CCEI** | 79% | 79% | 76% |

Base: total respondents

Customer centric engagement is a measure of “goodwill” towards the utility. Customers who are less engaged, as measured by the CCEI are more concerned about costs than customers who are highly engaged. Customers who are highly engaged are more inclined to look past costs and money issues and use thoughtful analysis to make values-based decisions.

# UtilityPULSE Report Card®

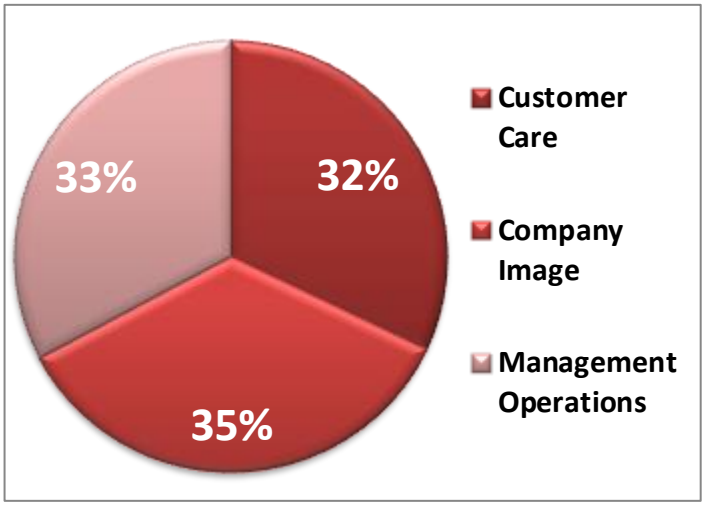
Simul's UtilityPULSE Report Card® is based on tens of thousands of customer interviews gathered over sixteen years. The purpose of the UtilityPULSE Report Card® is to provide electric utilities with a snapshot of performance – on the things that customers deem to be important. Research has identified over 20 attributes, sorted into six topic categories (we call these 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.

There are two main dimensions of the UtilityPULSE Report Card® the first is Customer psyche and the other is Customer perceptions about how the utility executes its business.

**The Psyche of Customers**

Every utility has virtually the same responsibility – provide safe and reliable electricity – yet not all customers are the same. The following chart shows the weight or significance of each category to the customer when forming their overall impression of the utility. Three major themes, each with two major categories make up the UtilityPULSE Report Card®. In effect the Report Card provides feedback about your customers' perception on the importance of each category and driver – as it relates to the benchmark.

## UtilityPULSE Report Card® for Enersource




Base: total respondents

The UtilityPULSE Report Card® also provides customer perceptions about how your utility executes or performs its responsibilities. This is different, very different, from what a customer might say about a major concern or worry that they have about electricity. As our survey has shown since its inception the primary suggestion for improvement is “reduce prices”, which is also a major concern which your customers have about municipal taxes, gas for the vehicle, and other utilities.

Readers of this report should note that the categories and drivers are interdependent. Which means that, for example, failure to provide high levels of power quality and reliability will have a negative impact on customer perceptions as it relates to customer service. Customer care, when it doesn’t meet customer expectations has a negative impact on Company Image, etc.

Defining the categories and major drivers:

**Category: Customer Care**

**Drivers: Price and Value; Customer Service**

Just because everyone likes good customer care, that in and by itself, is not a reason to provide it – though it may be important to do so. In highly competitive industries good customer service may be a differentiating factor. The case for electric utilities is simple, high levels of customer care result in less work (hence cost) of responding to customer inquiries and higher levels of acceptance of the utility's actions.

***Price and Value:***

Customers have to purchase electricity because life and lifestyle depend on it. This driver measures customer perceptions as to whether the total costs of electricity represent good value and whether the utility is seen as working in the best interests of its customers as it relates to keeping costs affordable.

***Customer Service:***

Customers do have needs and every now and again have to interface with their utility. How the utility handles various customers' requests and concerns is what this driver is all about. Promptly answering inquiries, providing sound information, keeping customers informed and doing so in a professional manner are the major components of this driver.

**Category: Company Image**

**Drivers: Company Leadership; Corporate Stewardship**

Utilities have an image even if they do not undertake any activities to try to build it. A company's image is both a simple and complex concept. It is simple because companies do create images that are easily described and recognized by their target customers. It is complex because it takes many discrete elements to create an image which includes, but is not limited to: advertising, marketing communications, publicity, service offering and pricing.

An electric utility trying to manage its image has one more challenge to deal with, and that is the electric industry itself. There are so many players that residential customers (in particular) don't know who does what or who is responsible for what. So when there are political or regulatory announcements, the local utility is often swept up into the collective reaction of the population.

***Company Leadership***

This driver is comprised of customer perceptions as it relates to industry leadership, keeping promises and being a respected company in the community.

***Corporate Stewardship***

Customers rely on electricity and want to know that their utility is both a trusted and credible organization that is well managed, is accountable, is socially responsible and has its financial house in order.

**Category: Management Operations**

**Drivers: Operational Effectiveness; Power Quality and Reliability**

Electrical power is the primary product which utilities provide their customers and, they have very high expectations that the power will be there when they need it. Customers have little tolerance for outages. The reality is, every utility has to get this part right…no excuses. It is the utility's core business. This category and its drivers are clearly the most important for fulfilling the rational needs of a utility's customers.

***Operational Effectiveness***

This driver measures customers' perceptions as they relate to ensuring that their utility runs smoothly. Attributes such as: accurate billing and meter reading, completing service work in a professional and timely manner and maintaining equipment in good repair are deemed as important to customers.

***Power Quality and Reliability***

Power outages are a fact of life – and, customers know it. They expect their utility to provide consistent, reliable electricity, handle outages and restore power quickly and make using electricity safely an important priority.

## Enersource's UtilityPULSE Report Card®

*Performance*

| | CATEGORY | Enersource | National | Ontario |
|---|---|---|---|---|
| 1 | **Customer Care** | **B** | **B+** | **B** |
| | Price and Value | C+ | B | C+ |
| | Customer Service | B+ | B+ | B |
| 2 | **Company Image** | **B+** | **B+** | **B+** |
| | Company Leadership | A | B+ | B+ |
| | Corporate Stewardship | B+ | A | B+ |
| 3 | **Management Operations** | **A** | **A** | **A** |
| | Operational Effectiveness | A | A | B+ |
| | Power Quality and Reliability | A | A | A |
| | **OVERALL** | **B+** | **B+** | **B+** |

Base: total respondents

As the UtilityPULSE Report Card® shows, the total customer experience with an electric utility is defined as more than “keeping the lights on”. Customers deal with your utility every day for a variety of reasons, most likely because they need someone to help them solve a problem, answer a question or take their order for service. All your employees, from customer service representatives to linemen, leave a lasting impression on the customers they interact with. In effect there are many moments of truth. Moments of truth are every customer touch point that a utility has with their customers. Therefore, managing these moments of truth creates higher levels of Secure customers while reducing the number of At Risk customers that exist.

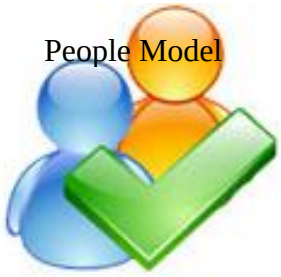
It's the small things done consistently that matter: Things like greeting every customer, whether on the phone or in person, in a friendly and helpful manner. Things like listening to the customer's needs, providing solutions to their problems and showing appreciation to the customer for their business.

Utilities now recognize customer communications as a valuable aspect of their business. The better a utility communicates with customers, in a manner that speaks to them, the more satisfied they are with their overall service. “Sending out information” is not the same as having a “conversation” with a customer. We believe that it is increasingly important to channel your communications to the various customer segments which exist.

Obviously employees – in every area – play a critical role in customer service success. Consequently how they feel about their job responsibilities and role in the company will be communicated indirectly through the level of service which they actually provide customers with whom they interact. The reality is engaged employees are the key to excellent customer care.

Our survey work with employees shows that there are many elements of an organizational culture to support the people model needed to achieve high levels of engagement.

Our research has identified 6 main drivers that promote and support people giving their best:




- **Empowered**
- **Valued**
- **Connected**
- **Inspired**
- **Growing**
- **Performance oriented**

There are 12 key processes from “attracting employees” to “saying goodbye to employees” that are part of your people model to get the best performance from every employee.

We believe that taking the time to understand the difference between employee satisfaction and organizational culture is worthwhile from a resourcing perspective and from a people development perspective. Every organization has a culture – we believe that it is a leadership imperative to install and maintain a culture that ensures that you attain the achievements and successes of your utility’s many investments in people, technology and equipment.

# The Loyalty Factor

If a customer is satisfied, it doesn't necessarily mean he or she is loyal. Satisfaction is about fulfilling promises/expectations; loyalty goes way beyond that by creating exceptional experiences and long-lasting relationships. There is a reason why marketing campaigns strive to build brand loyalty, not brand satisfaction. Measuring customer loyalty in an industry where many customers don't have a choice of providers doesn't make sense. Or does it?




© UtilityPULSE

The answer depends on how you define "customer loyalty."

Private industry often equates customer loyalty with basic customer retention. If a customer continues to do business with a company, that customer is, by definition, considered to be loyal. If this definition were applied to many companies in the utility industry, all customers would automatically be considered loyal. As such, measuring customer loyalty would appear to be unnecessary.

Natural monopolies (like LDCs) are not really different in what they should measure except that trying to determine which customers are "loyal" or "at risk" is not about their future behaviour but more about their "attitudinal" loyalty (are they advocates?).

Perhaps a better or more relevant way for utilities to approach the definition of customer loyalty is to further expand how they think about loyalty. Consider the following definition: Customer loyalty is an emotional disposition on the part of the customer that affects the way(s) in which the customer (consistently) interacts, responds or reacts towards the company – its products & services and its brand.

So what does it mean to respond favourably to a company? At a basic level, this can mean choosing to remain a customer. As previously mentioned however, this is essentially a non-issue for many utility companies. It then becomes necessary to think beyond just customer retention. One needs to consider other ways in which customers can respond favourably toward a company.

Other favourable responses or behaviours can be classified into one of three categories that reflect the concept of customer loyalty:

- Participation
- Compliance or Influence
- Advocacy




Specific examples of potential participatory behaviour in the electric utility industry include:

- Signing up for programs that help the customer reduce or manage their energy consumption
- Using the utility as a consultant when selecting energy products and services from a third party
- Participating in pilot programs or research studies

Specific examples of potential compliance or influence behaviours that utility customers might exhibit include:

- Seeking the utility's advice or expertise on an energy-related issue

- Voluntarily cutting back on electricity usage if the utility advised the customer to do so
- Accepting the utility's energy advice or referrals to energy contractors or equipment
- Being influenced by the utility's opinion regarding energy- management advice, equipment, or technologies
- Providing personal information that enables the utility to better serve the customer
- Paying bills online

Creating customer advocates can be especially important for a company in a regulated industry. In the absence of customer advocates, or worse, in a situation where customers speak unfavourably about a company or actively work to support issues that are counter to those the company supports, companies can suffer a variety of negative consequences like increased business costs, lawsuits, fines and construction delays. For an electric utility, specific examples of potential advocacy behaviour include:

- Supporting the utility's positions or actions on energy-related public issues, including the environment
- Supporting the utility's position on the location and construction of facilities
- Providing testimonials about positive experiences with the utility

In sum, loyal behaviour in the utility industry may not be as evident as it is in a more competitive environment. Measuring customer loyalty in a generally non-competitive industry requires one to think about loyalty in non-traditional ways. Customer loyalty is an intangible asset that has positive consequences or outcomes associated with it no matter what the industry. Properly measuring loyalty among utility customers requires thoughtful probing to thoroughly identify the range of participation, compliance, and advocacy behaviours that will ultimately benefit the company in meaningful ways, and foster happier and more loyal customers.

The UtilityPULSE Customer Loyalty Performance Score segments customers into four groups: **Secure** – the most loyal - **Still Favorable**, **Indifferent**, and **At risk**.

**Secure** customers are "very satisfied" overall with their local electricity utility. They have a very high emotional connection with their utility and definitely would recommend their local utility.

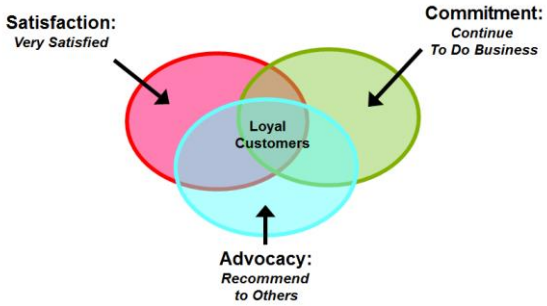
**Still favorable** customers are "very satisfied" overall, "definitely" or "probably" would recommend their local utility and not switch if they could.

**Indifferent** customers are less satisfied overall than secure and still-favorable customers and less inclined to recommend their local utility or say they would not switch.

**At risk** customers, who are "very dissatisfied" with their electricity utility, "definitely" would switch and "definitely" would not recommend it.

**Loyalty is driven primarily by a company's interaction with its customers and how well it delivers on their wants and needs.**

**Customer Loyalty Model**

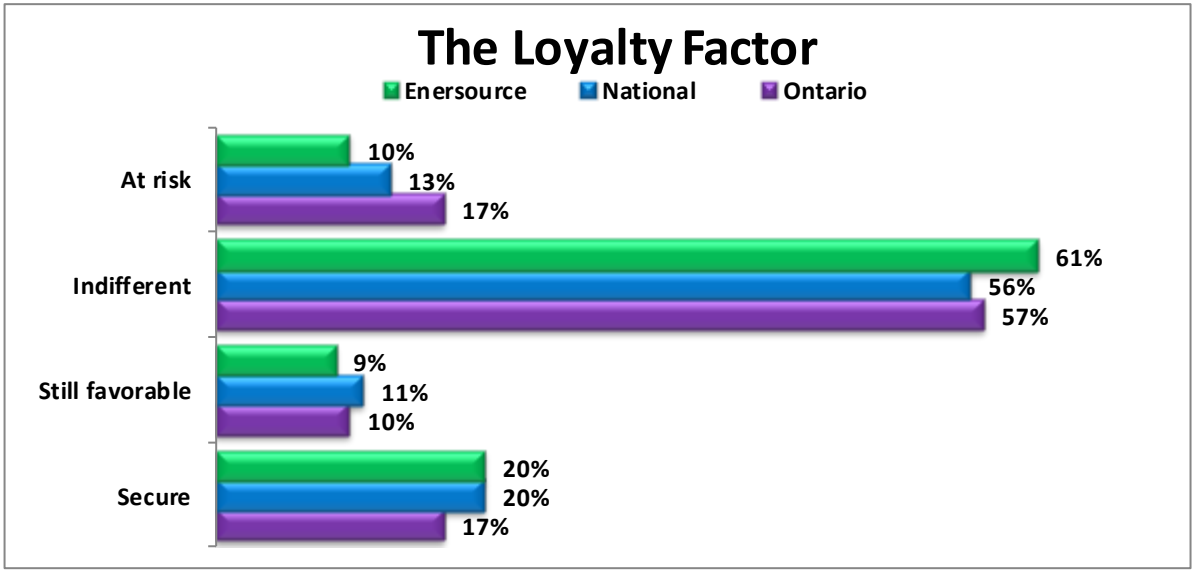



**Loyalty is based on likelihood to:**

- ***Satisfaction: overall satisfaction***
- ***Commitment: continue as a customer***
- ***Advocacy: willingness to recommend***

| Customer Loyalty Groups | | | | |
|---|---|---|---|---|
| | **Secure** | **Favorable** | **Indifferent** | **At Risk** |
| **Enersource** | | | | |
| **2014** | 20% | 9% | 61% | 10% |
| **2013** | - | - | - | - |
| **2012** | 25% | 14% | 55% | 6% |
| **2011** | - | - | - | - |
| **2010** | 20% | 17% | 57% | 6% |

Base: total respondents / (-) not a participant of the survey year



| Customer Loyalty Groups | | | | |
|---|---|---|---|---|
| | **Secure** | **Favorable** | **Indifferent** | **At Risk** |
| **Ontario** | | | | |
| **2014** | 17% | 10% | 57% | 17% |
| **2013** | 24% | 15% | 51% | 11% |
| **2012** | 20% | 13% | 53% | 14% |
| **2011** | 17% | 13% | 54% | 16% |
| **2010** | 21% | 12% | 52% | 15% |
| **National** | | | | |
| **2014** | 20% | 11% | 56% | 13% |
| **2013** | 26% | 17% | 47% | 10% |
| **2012** | 30% | 13% | 46% | 11% |
| **2011** | 28% | 14% | 46% | 12% |
| **2010** | 17% | 14% | 60% | 9% |

Base: total respondents



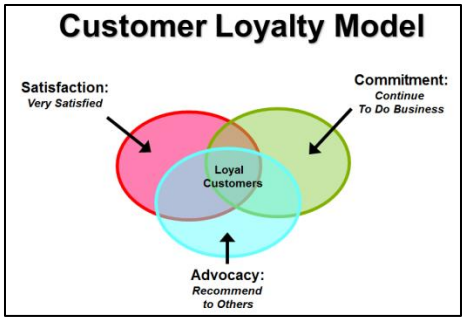
Secure customers' experiences and perceptions are distinct from those of Indifferent customers. There is yet an even greater gap between those identified as Secure versus At Risk.

- Problems are experienced and remain unresolved far more often by the Indifferent or At Risk segments in comparison to others. This is not an unusual finding.
- Other areas of interaction also revealed considerable differences among the segments. Consistently, Secure customers' perceptions are most positive.

| Important attributes which shape perceptions about customer affinity | | | |
|---|---|---|---|
| | **Overall** | **Secure** | **At Risk** |
| **Customer focused and treats customers as if they're valued** | 80% | 95% | 49% |
| **Is pro-active in communicating changes and issues which may affect customers** | 79% | 93% | 56% |
| **Deals professionally with customers' problems** | 85% | 96% | 61% |
| **Provides information to help customers reduce their electricity costs** | 79% | 92% | 55% |
| **Quickly deals with issues that affect customers** | 82% | 95% | 56% |
| **Delivers on its service commitments to customers** | 86% | 97% | 67% |
| **Provides information and tools to help manage electricity consumption** | 79% | 92% | 56% |
| **Is 'easy to do business with'** | 85% | 98% | 55% |
| **Adapts well to changes in customer expectations** | 75% | 90% | 45% |
| **The cost of electricity is reasonable when compared to other utilities** | 62% | 79% | 37% |
| **Provides good value for your money** | 70% | 89% | 38% |
| **Provides consistent reliable electricity** | 90% | 99% | 77% |
| **Operates a cost effective hydro-electric system** | 73% | 91% | 41% |
| **Overall the utility provides excellent quality services** | 85% | 98% | 62% |

Base:data from the full 2014 database from those respondents with an opinion

# Customer commitment




Customer loyalty is a term that can be used to embrace a range of customer attitudes and behaviours. One of the metrics used to gauge loyalty is the measure of **retention,** or intention to buy again; this loyalty attitude is termed **commitment.**

Customer commitment to the local electricity supplier is a very important driver of customer loyalty in the electricity service industry. In a similar way to trust, commitment is considered an important ingredient in successful relationships. In simpler terms, commitment refers to the motivation to continue to do business with and maintain a relationship with a business partner i.e. the local utility.

For electric utilities, this measurement is about identifying the number of customers who feel that they “want to” vs “have to” do business with you. Potential benefits of commitment may include word of mouth communications - an important aspect of attitudinal loyalty. Committed customers have been known to demonstrate a number of beneficial behaviours, for example committed customers tend to:

- Come to you. One of the key benefits of establishing a good level of customer loyalty is that customers will come to you when they need a product or service.

- Validate information received from 3rd parties with information and expertise that you have.
- Try new products/initiatives.
- Perhaps they will even trust you when recommendations are made.
- Be more price tolerant.
- More receptivity of utility viewpoints on various issues.
- More tolerance of errors or issues that inevitably take a swipe at the utility.
- Stronger levels of perception regarding how the utility is managed.

Though customers can not physically leave you, they can emotionally leave you and when they do, it becomes an extreme challenge to garner their participation or support for utility initiatives.

| Electricity customers' loyalty – … Is a company that you would like to continue to do business with | | | |
|---|---|---|---|
| | **Enersource** | **National** | **Ontario** |
| **Top 2 Boxes: 'Definitely + Probably' would continue** | 78% | 74% | 72% |
| **Definitely would continue** | 41% | 41% | 35% |
| **Probably would continue** | 37% | 32% | 37% |
| **Might or might not continue** | 7% | 8% | 7% |
| **Probably would not continue** | 3% | 4% | 5% |
| **Definitely would not continue** | 5% | 8% | 10% |

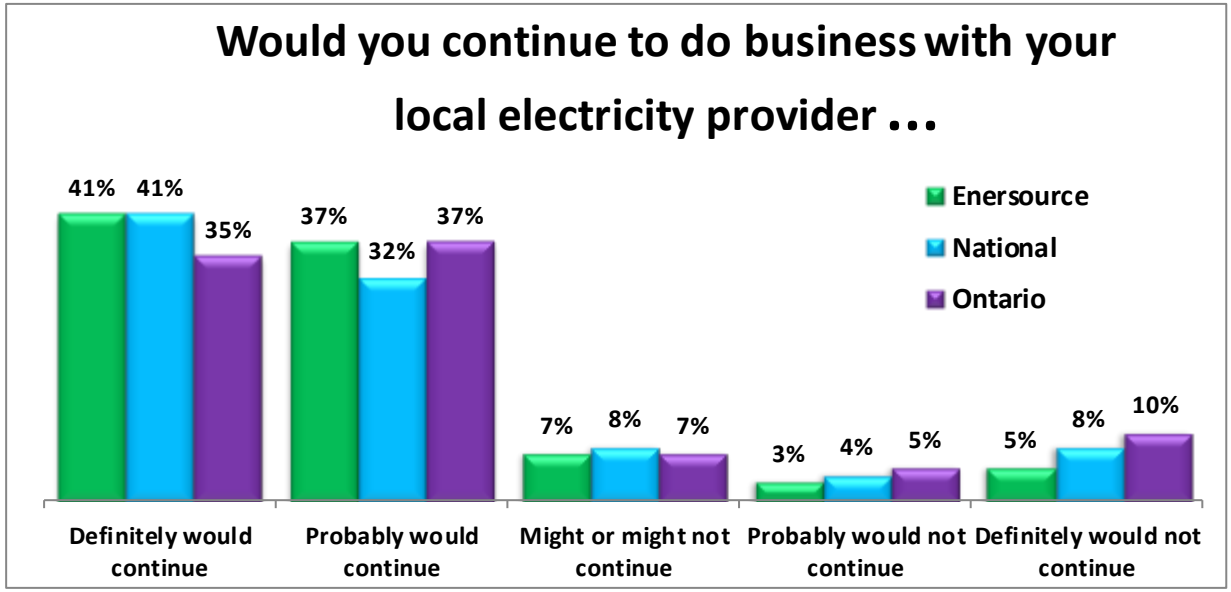
Base: total respondents

| Electricity customers' loyalty – … Is a company that you would like to continue to do business with | | | | |
|---|---|---|---|---|
| **Enersource** | **<$40K** | **$70K+** | **18-34** | **55+** |
| **Top 2 Boxes: 'Definitely + Probably' would continue** | 77% | 83% | 80% | 75% |

Base: total respondents

| Electricity customers' loyalty – Is a company that you would like to continue to do business with | | | | | |
|---|---|---|---|---|---|
| **Enersource** | **2014** | **2013** | **2012** | **2011** | **2010** |
| **Top 2 boxes: 'Definitely + Probably' would continue** | 78% | - | 82% | - | 84% |

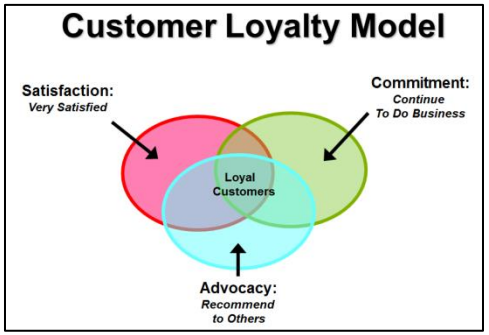
Base: total respondents / (-) not a participant of the survey year



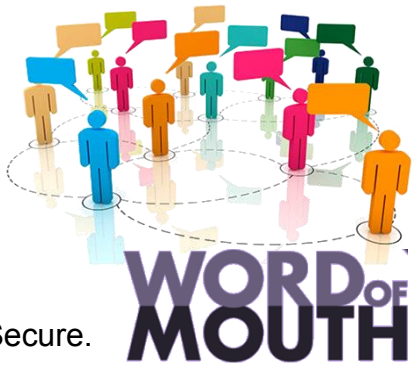

Base: total respondents

# Word of mouth

Advocacy is one of the metrics measured in determining customer loyalty. Essentially, companies believe that a loyal customer is one that is spreading the value of the business to others, leading new people to the business and helping the company grow. Customer referrals, endorsements and spreading the word are extremely important forms of customer behaviour. For LDCs this is about generating positive referants about the LDC as a relevant and valuable enterprise.




When customers are loyal to a company, product or service, they not only are more likely to purchase from that company again, but they are more likely to recommend it to others – to openly share their positive feelings and experiences with others. In today's world, thanks to the Internet, they can tell and influence millions of people. That equates to new customers and revenue. The same holds true, if not more, when customers are disloyal. Disgruntled customers could share their negative experiences with an ever-widening audience, jeopardizing a company's reputation and resulting in fewer engaged customers and/or customers who are Favourable or Secure. Secure customers, typically are advocates and they are deeply connected and brand-involved.



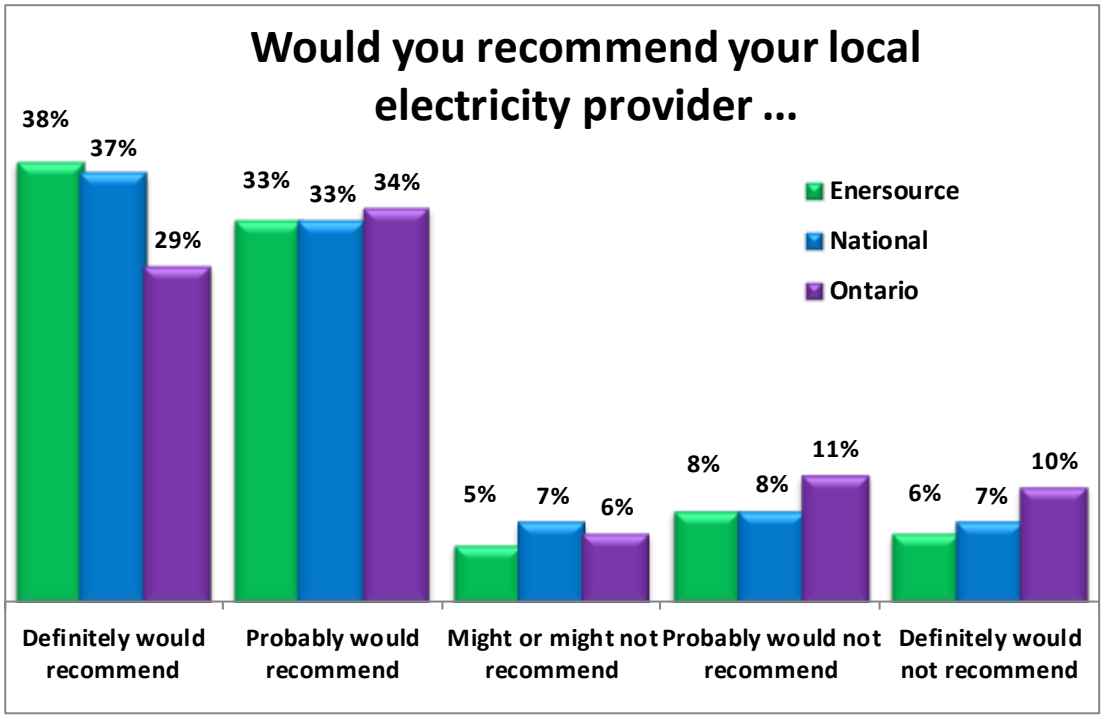
*There are two forms of word of mouth which utilities need to understand. The first is Experience-based word of mouth which is the most common and most powerful form. It results from a customer's direct experience with the utility or the re-statement of a direct experience from a trusted source.*

*The second is Relay-based word of mouth. This is when customers pass along important messages to others based on what they have learned through the more traditional forms of communications. For example, if the utility was communicating an offer for "free LED lights" chances are high that the offer will be "relayed" to others through word of mouth.*

*For an electric utility, specific examples of potential positive advocacy behaviour include:*

- *Recommending that other customers specifically locate in the geographic area that is serviced by that utility*
- *Supporting the utility's positions or actions on energy-related public issues, including the environment*
- *Supporting the utility's position on the location and construction of facilities*
- *Providing testimonials about positive experiences with the utility*

*Would you tell me if you agree or disagree with the following statement? Enersource is a company that you would recommend to a friend or colleague …*




Base: total respondents

Word of mouth communication is a very powerful form of communication and influence. When customers are speaking to other customers (or their peers) it is more credible, goes through less perceptual filters and can enhance the view of services or products better than marketing communication.

| Electricity customers' loyalty – … is a company that you would recommend to a friend or colleague | | | |
|---|---|---|---|
| | Enersource | National | Ontario |
| **Top 2 boxes: 'Definitely + Probably' would recommend** | 71% | 69% | 63% |
| **Definitely would recommend** | 38% | 37% | 29% |
| **Probably would recommend** | 33% | 33% | 34% |
| **Might or might not recommend** | 5% | 7% | 6% |
| **Probably would not recommend** | 8% | 8% | 11% |
| **Definitely would not recommend** | 6% | 7% | 10% |

Base: total respondents

| Electricity customers' loyalty – is a company that you would recommend to a friend or colleague | | | | |
|---|---|---|---|---|
| Enersource | <$40K | $70K+ | 18-34 | 55+ |
| **Top 2 boxes: 'Definitely + Probably' would recommend** | 70% | 75% | 70% | 66% |

Base: total respondents

| Electricity customers' loyalty – is a company that you would recommend to a friend or colleague | | | | | |
|---|---|---|---|---|---|
| Enersource | 2014 | 2013 | 2012 | 2011 | 2010 |
| **Top 2 boxes: 'Definitely + Probably' would recommend** | 71% | - | 80% | - | 73% |

Base: total respondents / (-) not a participant of the survey year

# Corporate image

Customers may dislike what is going on in the electricity industry and they may have an intense dislike for the amount that they have to pay – but they may not dislike their local utility. We hear comments in the interviews such as: *"I hate how much electricity costs, but my utility does a good job."; "Electricity is so expensive these days and it keeps going up and up, but thank goodness for XYZ hydro."* Customers who are connected to the brand, respect the brand, are more likely to look favourably on their utility. The opposite is also true, customers who do not connect or respect the brand and who are upset with the industry produce very challenging customers when things go wrong.

Corporate Image/Brand, as a factor for influencing a customer's perception about their utility has grown significantly in importance to customers. In 2006, Corporate Image/Brand had about an 18% weighting, Customer care had about a 26% weighting and Management operations had about a 56% weighting as it relates to affecting customer's perceptions. Today, in 2014 all three areas are about equal in weighting.




Data from the 2014 survey show that respondents who give their utilities high marks for respect, trust, and social responsibility also give their utilities high marks for providing high quality services, and better marks for both cost efficiency and reasonableness of costs.

Reputation, image, brand has to be actively managed. Nothing is private anymore. Positive impressions beget positive perceptions. Below are some of the attributes measured in the annual UtilityPULSE survey which are strongly linked to a utility's image.

| Attributes strongly linked to a hydro utility's image | | | |
|---|---|---|---|
| | **Enersource** | **National** | **Ontario** |
| **Is a respected company in the community** | 85% | 81% | 78% |
| **A leader in promoting energy conservation** | 80% | 78% | 77% |
| **Keeps its promises to customers and the community** | 81% | 79% | 76% |
| **Is a socially responsible company** | 82% | 78% | 77% |
| **Is a trusted and trustworthy company** | 83% | 82% | 77% |
| **Adapts well to changes in customer expectations** | 72% | 71% | 68% |
| **Is 'easy to do business with'** | 83% | 79% | 75% |
| **Provides good value for your money** | 68% | 67% | 63% |
| **Overall the utility provides excellent quality services** | 84% | 83% | 80% |
| **Operates a cost effective hydro-electric system** | 69% | 69% | 62% |

Base: total respondents with an opinion

Every LDC has a brand and a brand image, while that image can be affected by events in the industry beyond the control of the LDC, the reality is there is a cost benefit to improving the customer experience, generating higher levels of customer engagement and growing the numbers of Favourable and Secure customers. Providing consistent reliable electricity while being seen as 'easy to do business with', along with providing

information and support for customers to use electricity more efficiently are core components of a successful relationship with customers. The reality is, every utility has an image – why not have the image you want? While keeping the lights on builds a customer's belief that their utility is competent at what it does, image is about building a customer's belief that they can be confident that their utility is successful today and will be successful again tomorrow.

| Marketing – Communications | | | |
|---|---|---|---|
| | Enersource | National | Ontario |
| **Topics that require more pro-active communication** | | | |
| Cost of electricity is reasonable when compared to other utilities | 60% | 60% | 55% |
| Provides information to help customers reduce electricity costs | 75% | 77% | 75% |
| Adapts well to changes in customer expectations | 72% | 71% | 68% |
| Operates a cost effective hydro-electric system | 69% | 69% | 62% |
| Provides good value for money | 68% | 67% | 63% |
| **Topics that your utility scores very well on** | | | |
| Is a trusted and trustworthy company | 83% | 82% | 77% |
| Respected company in the community | 85% | 81% | 78% |
| Accurate billing | 81% | 83% | 77% |
| Overall the utility provides excellent quality services | 84% | 83% | 80% |
| Provides consistent, reliable energy | 90% | 89% | 86% |

Base: total respondents with an opinion

# Corporate Credibility & Trust

The foundation of every relationship is trust. Without it, engaging customers becomes a large challenge and when trust is low, or non-existent, feedback may not be truthful. Recognizing the myriad of events that have taken place in the industry, it has become increasingly important for a utility to be credible and trusted.

Establishing trust and credibility, whether with business partners, customers or regulators, is not achieved overnight. Creating credibility is a process, which advances only through honest, continuous communication between the utility, its regulators, and the public at large. Pro-active and credible communications from an LDC should do three things for its customers: 1- demonstrate competency 2- build confidence and 3- show a future orientation.

| Attributes strongly linked to Credibility & Trust | | | |
|---|---|---|---|
| | Enersource | National | Ontario |
| **Overall the utility provides excellent quality services** | 84% | 83% | 80% |
| **Keeps its promises to customers and the community** | 81% | 79% | 76% |
| **Customer-focused and treats customers as if they're valued** | 77% | 74% | 72% |
| **Is a trusted and trustworthy company** | 83% | 82% | 77% |

Base: total respondents with an opinion

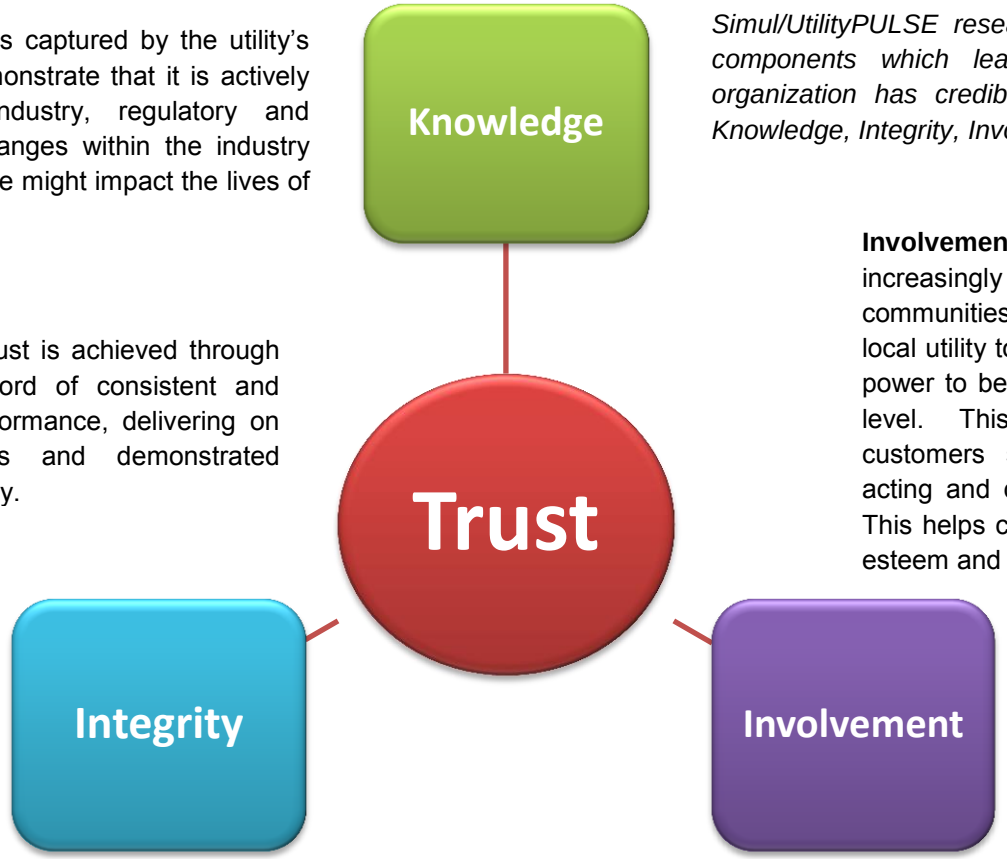
Public trust in their local utility is the degree to which the public believes that the utility will act in a particular manner because the utility has incorporated the public's interest into its own. Utilities benefit from a trusted relationship with their empowered Customers. Trust and credibility can be thought of as indicators of the degree of confidence stakeholders have in your organization's ability to deliver on its commitments. Trust and credibility are outcomes based on what your utility actually does, not what it might be doing.

**Knowledge** is captured by the utility's ability to demonstrate that it is actively aware of industry, regulatory and economic changes within the industry and how these might impact the lives of customers.

*Simul/UtilityPULSE research shows the under-pinning components which lead customers to believe an organization has credibility and can be trusted are: Knowledge, Integrity, Involvement and Trust.*

**Trust** — Trust is achieved through a track record of consistent and reliable performance, delivering on commitments and demonstrated accountability.

**Involvement** — Corporate Involvement is increasingly important to Canadian communities as it is an opportunity for their local utility to use their resources and man-power to benefit people at the community level. This helps to build credibility as customers see that the organization is acting and delivering on its commitments. This helps customers regard the utility with esteem and respect.




**Integrity** is established by demonstrating adherence to a code of conduct. It requires consistently acting in accordance with the values and goals that have been communicated to customers.

Using the four components of demonstrating Credibility and Trust, the resultant index shows that LDCs enjoy a high level of credibility and trust. "It takes 20 years to build a reputation and five minutes to ruin it. If you think about that, you'll do things differently." [Warren Buffet]

| *Credibility and Trust Index* |
|---|
| **Knowledge**<br><br>The utility is seen as being knowledgeable about the services it provides, about what is happening in the industry, and how customers can reduce costs or create more value. |
| **Integrity**<br><br>The utility is seen as an organization that will act in the best interests of its customers and can be counted on to provide services and resolve problems in a professional manner. |
| **Involvement**<br>The utility is actively involved in the industry, in the community and in things that affect the customer. |
| **Trust**<br><br>The utility is an organization that can be trusted and is worthy of respect. |
| **Overall Enersource 81%  [Ontario 77%; National 80%]** |



# How can service to customers be improved?

Every business, even natural monopolies, need to keep a focus on its customers, its standards of operations and being responsive to problems. Insights into what isn't working or what can be done to improve often come from customers. Continuous improvement is the new normal.

Customers are more informed, more aware, more conscious of what's going on around big issues in the world around them and in this age of internet and social media, they are better equipped to influence service quality and outcomes. They have learned to compare products and services, to document and monitor customer service and satisfaction, and to request or demand higher quality. And, when things go wrong, customers also know that they are "one click" away from the world knowing about it.

As a further way to identify pressure points and areas of concern, respondents were asked to give their top two priorities for improvement to their local utility's service.

For 2014 there is heightened awareness for the need to maintain equipment, keep things up to date, improve reliability, and communicate effectively.

*And we are interested in knowing what you think are the one or two most important things Enersource could do to improve service to their customers?*

| One or two most important things 'your local utility' could do to improve service | |
|---|---|
| **Enersource** | **% of all suggestions** |
| **Better prices/lower rates** | 53% |
| **Improve reliability of power** | 10% |
| **Information & incentives on energy conservation** | 9% |
| **Eliminate SMART meters** | 8% |
| **Better communication with customers** | 7% |
| **Be more efficient** | 7% |
| **Improve/simplify/clarify billing** | 6% |
| **Remove hidden costs on bills** | 5% |
| **Better online presence** | 5% |
| **Don't charge for previous debt** | 5% |
| **Staff related concerns** | 4% |
| **Extend service hours/availability of hydro representative** | 3% |
| **Better maintenance** | 3% |

Base: total respondents with suggestions

# What do customers think about electricity costs?

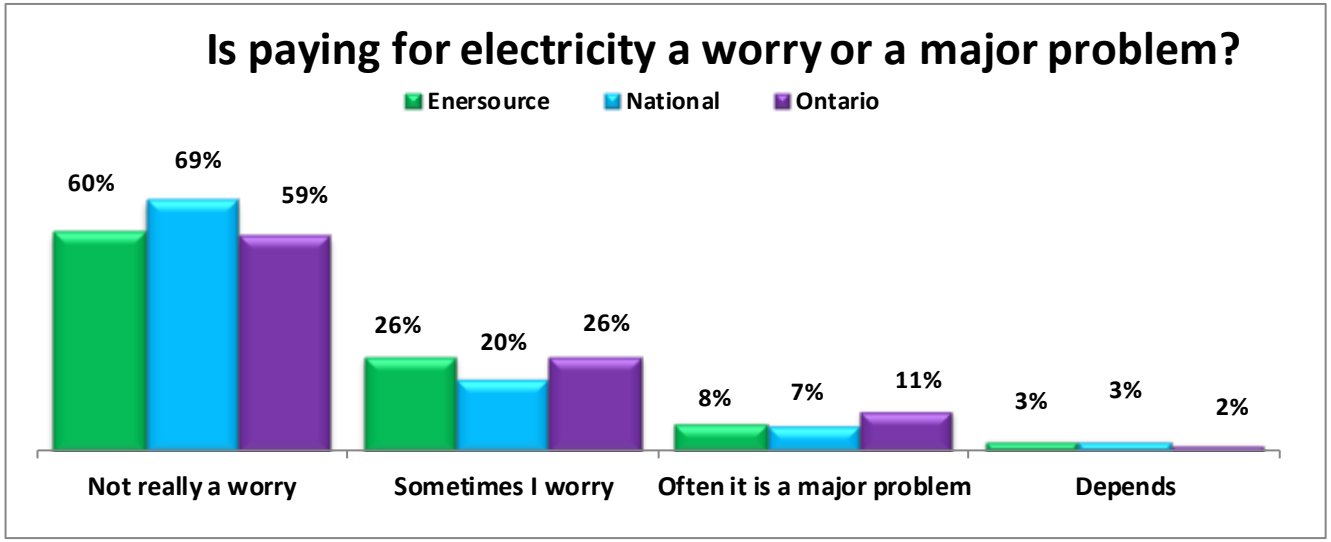
Ask a utility customer – anywhere in the province of Ontario – what do they think about electricity, there is a very high probability that they will say that electricity costs are too high or too expensive. For customers who said that they had a billing problem in the last 12 months, and stated that the problem was “high bills” or “high rates or charges”, there was very little variability between customers who could be called Secure, Favourable, Indifferent or At Risk. There was also very little variability between age groupings or income groupings.

In 2010, 44% of customers who said they had a billing problem cited “high bills” or “high rates or charges” as being the culprit. Our survey database for 2014 tells us the comparable number is 68%. In 5 years there has been much shift towards the issue being high bills and/or high rates. There is a growing concern over costs, which means that the industry needs to monitor “ability to pay”.

*Next I am going to read a number of statements people might use about paying for their electricity. Which one comes closest to your own feelings, even if none is exactly right? Paying for electricity is not really a worry, Sometimes I worry about finding the money to pay for electricity, or Paying for electricity is often a major problem?*

| Is paying for electricity a worry or a major problem? | | | | |
|---|---|---|---|---|
| | Not a worry | Sometimes | Often | Depends |
| | Enersource | | | |
| **2014** | 60% | 26% | 8% | 3% |
| **2013** | - | - | - | - |
| **2012** | 64% | 23% | 7% | 3% |
| **2011** | - | - | - | - |
| **2010** | 72% | 17% | 7% | 1% |

Base: total respondents / (-) not a participant of the survey year




Base: total respondents

| Is paying for electricity a worry or a major problem? | | | | |
|---|---|---|---|---|
| | Not a worry | Sometimes | Often | Depends |
| | | Enersource | | |
| **<$40,000** | 42% | 43% | 13% | 1% |
| **$40<$70,000** | 48% | 36% | 12% | 3% |
| **$70,000+** | 74% | 16% | 6% | 2% |

Base: total respondents

The UtilityPULSE database for 2014 shows respondents who have an income less than $40,000 have almost 2X more billing problems than those who have income in excess of $70K per year. 20% of customers <40K said they had a billing problem compared to 11% of respondents who had income over $70K. However respondents in the lower income bracket are more likely to shift use of their electricity to lower cost periods.

Our data also shows that lower income customers are less likely to utilize energy conservations methods that cost money. More important however is the difference the <$40K respondents vs the >$70K as it relates to taking action or who have “already done” a conservation action. Installed a programmable thermostat? 44% “Done” <$40K, 70% “Done” ?$70K. Installed timers: 26% vs 38% “Done”. Replaced Furnace: 43% vs 57% “Done”. Replaced air-conditioner: 35% vs 49%.

Ability to pay then has an impact on conservation.

| Is paying for electricity a worry or a major problem? | | | | |
|---|---|---|---|---|
| | Not a worry | Sometimes | Often | Depends |
| **Ontario** | | | | |
| **2014** | 59% | 26% | 11% | 2% |
| **2013** | 66% | 21% | 11% | 1% |
| **2012** | 59% | 27% | 11% | 2% |
| **2011** | 52% | 31% | 13% | 3% |
| **2010** | 67% | 23% | 8% | 2% |
| **National** | | | | |
| **2013** | 69% | 20% | 7% | 3% |
| **2013** | 70% | 18% | 8% | 2% |
| **2012** | 67% | 22% | 8% | 2% |
| **2011** | 63% | 25% | 8% | 2% |
| **2010** | 71% | 20% | 6% | 1% |

Base: 2014 Ontario and National benchmark surveys

# What do small commercial customers think?

Residential and small business customers create the bulk of a utility's service transactions every day—and account for more than half of the energy consumed — understanding their needs and expectations is becoming more important than ever before.

Interestingly the definition for small commercial customers is defined based on usage. While this definition is used for regulatory purposes, the reality is small commercial customers have many "personas". Unfortunately customer information on small commercial customers rarely contains enough data to truly develop targeted communications.

**Small Commercial Customer (General Service < 50kW Demand)**

A small commercial customer is defined by the OEB as a non-residential customer in a less than 50 kW demand rate class. These customers are similar to the residential customer in that their bill does not have a demand component to it and their charges are based upon KWH of consumption. Most of these customers would occupy small storefront locations or offices

Data from the 2014 full database shows small commercial customers with higher satisfaction and having less outages than residential customers. However commercial customers are 2X more likely to contact their utility when the power goes off or when there is a billing problem.



Deposit requirements, monthly energy bills (and, therefore, energy usage), power quality, and reliability all directly impact a small business's financial situation. Unlike residential customers who tend to describe the cost of power interruptions in terms of a "inconvenience", commercial (and industrial) customers associate power interruptions with the cost of lost business, i.e., a loss in production is a loss in profits.

Likewise, based on the requirement of electricity to sustain business operations, there exists a difference in actual levels of demand response. For instance, small business and commercial users are unlikely to choose to decrease their electricity consumption if it is incompatible with efficient management of their business processes or threatens contracted deliveries to their primary product markets. In some cases, electricity consumption is a relatively small proportion of total input and operating costs, which substantially reduces the financial incentive for shutting down production during off peak pricing.

The tables associated with this report will contain Ontario LDC specific information as it relates to residential and commercial customers. Recognizing that smaller data samples are susceptible to greater data swings, for most LDCs there would be 60 or 90 responses from small commercial customers. We have compiled the following based on a group composite of all of our 2014 discussions with small commercial and residential customers.

| Satisfaction: Pre & Post | | |
|---|---|---|
| **Satisfaction (Top 2 Boxes: 'very + somewhat satisfied')** | **Residential** | **Commercial** |
| **Initially** | 89% | 91% |
| **End of Interview** | 90% | 93% |

Base: total respondents from the full 2014 database

As it relates to the six attributes associated with customer service:

| Very or fairly satisfied with… | Residential | Commercial |
|---|---|---|
| **The time it took to contact someone** | 73% | 78% |
| **The time it took someone to deal with your problem** | 66% | 76% |
| **The helpfulness of the staff who dealt with your problem** | 74% | 83% |
| **The knowledge of the staff who dealt with your problem** | 71% | 82% |
| **The level of courtesy of the staff who dealt with your problem** | 81% | 89% |
| **The quality of information provided by the staff member** | 70% | 79% |

Base: total respondents from the full 2014 database



Commercial respondents had higher satisfaction levels with customer service versus Residential respondents.

| Overall satisfaction with most recent experience | | |
|---|---|---|
| | Residential | Commercial |
| **Top 2 Boxes: 'very + somewhat satisfied'** | 73% | 79% |
| **Bottom 2 Boxes: 'somewhat + very dissatisfied'** | 24% | 19% |

Base: total respondents from the full 2014 database

| Comparisons between Residential and Commercial | | |
|---|---|---|
| **Loyalty Groups** | **Residential** | **Commercial** |
| **Secure** | 22% | 26% |
| **Still Favourable** | 10% | 12% |
| **Indifferent** | 60% | 55% |
| **At risk** | 7% | 7% |

Base: total respondents from the full 2014 database

| **Loyalty Model Factors** | ***Residential*** | ***Commercial*** |
|---|---|---|
| **Very/somewhat satisfied** | 89% | 91% |
| **Definitely/probably would continue** | 82% | 84% |
| **Definitely/probably would recommend** | 75% | 77% |

Base: total respondents from the full 2014 database

| Outages & Bill problems | Residential | Commercial |
|---|---|---|
| **Respondents with outage problems** | 43% | 28% |
| **Respondents with billing problems** | 14% | 13% |

Base: total respondents from the full 2014 database

| Attempts to contact local utility… | Residential | Commercial |
|---|---|---|
| **Respondents with outage problems** | 18% | 33% |
| **Respondents with billing problems** | 31% | 63% |

Base: total respondents from the full 2014 database

Residential respondents reported a considerably higher incidence of outages.



Commercial respondents were more likely to call in about billing and outage problems.

| Important attributes which describe operational effectiveness | | |
|---|---|---|
| | Residential | Commercial |
| **Provides consistent, reliable electricity** | 90% | 91% |
| **Delivers on its service commitments to customers** | 86% | 87% |
| **Accurate billing** | 85% | 86% |
| **Quickly handles outages and restores power** | 87% | 88% |
| **Makes electrical safety a top priority** | 88% | 90% |
| **Uses responsible environmental practices when completing work** | 85% | 88% |
| **Is efficient at managing the hydro-electric system** | 81% | 83% |
| **Is a company that is 'easy to do business with'** | 84% | 85% |
| **Operates a cost effective hydro-electric system** | 73% | 74% |

Base: total respondents with an opinion from the full 2014 database

| Important attributes which shape perceptions about corporate image | | |
|---|---|---|
| | Residential | Commercial |
| Is a respected company in the community | 86% | 87% |
| Maintains high standards of business ethics | 84% | 85% |
| A leader in promoting energy conservation | 81% | 83% |
| Keeps its promises to customers and the community | 83% | 84% |
| Is a socially responsible company | 84% | 85% |
| Is a trusted and trustworthy company | 85% | 86% |
| Adapts well to changes in customer expectations | 75% | 77% |
| Overall the utility provides excellent quality services | 85% | 86% |

Base: total respondents with an opinion from the full 2014 database

| Important attributes which shape perceptions about service quality and value | | |
|---|---|---|
| | Residential | Commercial |
| Is pro-active in communicating changes and issues which may affect customers | 79% | 83% |
| Provides good value for money | 70% | 71% |
| Customer-focused and treats customers as if they're valued | 79% | 81% |
| Deals professionally with customers' problems | 85% | 86% |
| Quickly deals with issues that affect customers | 82% | 84% |
| Provides information and tools to help manage electricity consumption | 80% | 79% |
| Provides information to help customers reduce their electricity costs | 79% | 71% |
| The cost of electricity is reasonable when compared to other utilities | 62% | 64% |

Base: total respondents with an opinion from the full 2014 database

| Is paying for electricity a worry or a major problem? | | |
|---|---|---|
| | Residential | Commercial |
| **Not really a worry** | 66% | 67% |
| **Sometimes I worry** | 22% | 21% |
| **Often it is a major problem** | 7% | 8% |
| **Depends** | 2% | 2% |

Base: total respondents from the full 2014 database



When a weather related event occurs there is no distinction as to whom it will target – basically all those in its path will be affected. As it relates to the Ice Storm of 2013, the following are responses taken from all residential and commercial respondents who said they were affected by the storm.

| Percentage of Respondents who contacted their utility about the ice storm power outage | | |
|---|---|---|
| | Residential | Commercial |
| **Yes** | 17% | 22% |
| **No** | 82% | 75% |

Base: total respondents from the full 2014 database who were affected by the ice storm



| Length of outage (during Ice Storm 2013) | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | Less than 2 hours | 2 – 4 hours | 4+ hours or ½ day | 12-18 hours or ½ - ¾ day | 19-24 hours or 1 day | 1 to 1.5 days | 1.6 to 2 days | More than 2 days |
| **Residential** | 21% | 19% | 21% | 8% | 5% | 5% | 4% | 7% |
| **Commercial** | 17% | 20% | 15% | 7% | 6% | 4% | 4% | 9% |

Base: total respondents from the full 2014 database who were affected by the ice storm

While technology has provided various channels for communications, the telephone remains the predominant means of communication at this point in time.

| What method did you use to contact your electric utility about the outage during Ice Storm 2013? | | |
|---|---|---|
| | Residential | Commercial |
| **Telephone** | 86% | 94% |
| **E-mail** | 1% | 1% |
| **Social media - Twitter** | 1% | 0% |
| **In person** | 1% | 0% |
| **Other** | 2% | 2% |
| **Don't know** | 3% | 2% |

Base: total respondents from the full 2014 database who were affected by the ice storm



While there is no doubt a power outage will cause disruption in day to day events, the tolerance level in the wake of an outage is related to the amount of dependency on electricity in day to day workings. Regardless, respondents in this year's survey be they residential or commercial shared a common tolerance level for the length of time to go without electricity during an extreme event or situation.

| In your view, what is an acceptable period of time to go without electricity in situations like Ice Storm 2013? | | |
|---|---|---|
| | **Residential** | **Commercial** |
| **None (the power shouldn't be going out)** | 7% | 8% |
| **Less than 2 hours** | 11% | 12% |
| **2-4 hours** | 17% | 17% |
| **4+ hours or ½ day** | 16% | 14% |
| **12 – 18 hours or ½ day to ¾ day** | 8% | 6% |
| **19 – 24 hours or 1 day** | 10% | 10% |
| **1 to 1.5 days** | 5% | 4% |
| **1.6 to 2 days** | 5% | 7% |
| **More than 2 days** | 4% | 4% |
| **Other** | 2% | 1% |
| **Don't know** | 14% | 17% |

Base: total respondents from the full 2014 database who were affected by the ice storm



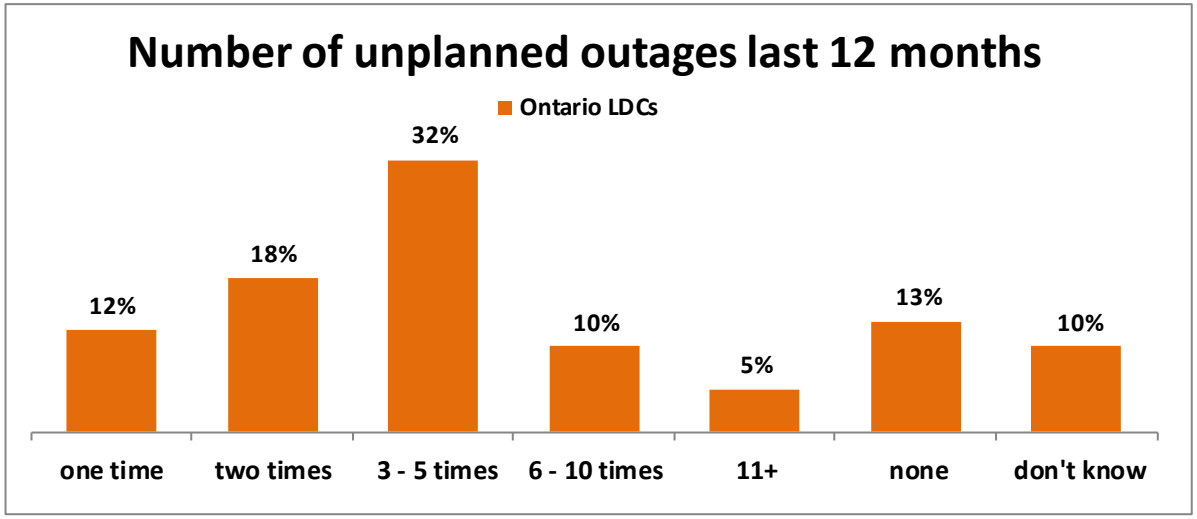
# SUPPLEMENTAL QUESTIONS



# Outage Communications

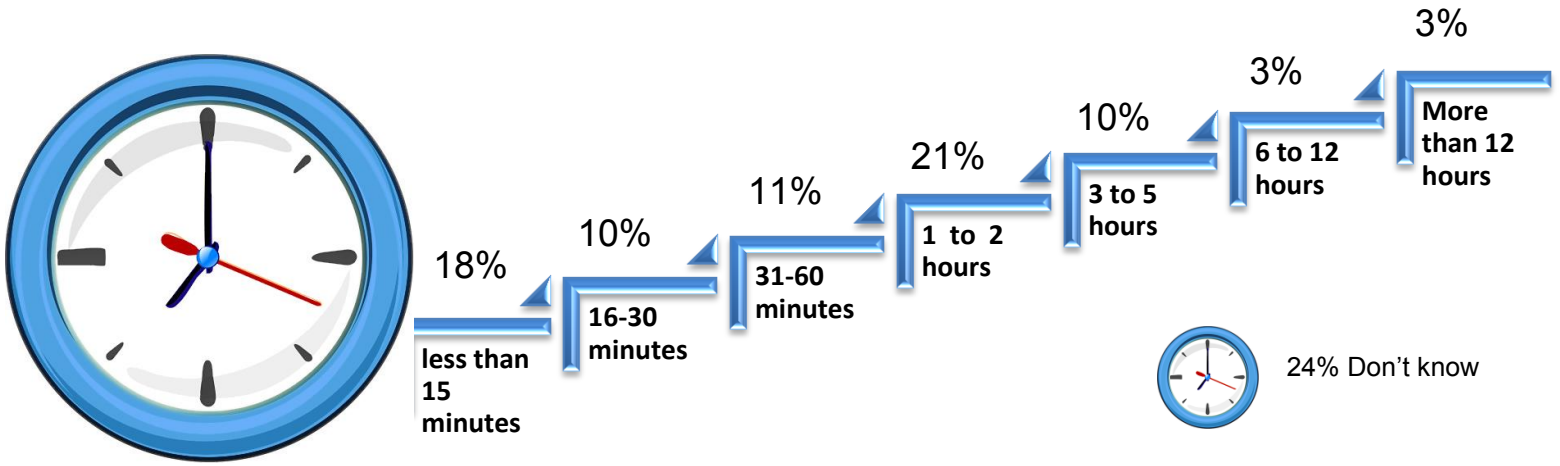
Whether an outage is planned or unplanned, the reality is that it is going to cause disruption and inconvenience under best case scenarios and under worst case scenarios there could be safety and financial consequences.

The impact of severe weather such as storms and other outage events are causing longer duration and more frequent outages.




Base: An aggregate of respondents from 2014 participating LDCs

*When an unplanned outage occurs, how long, on average, is the outage?*




Base: An aggregate of respondents from 2014 participating LDCs

However, one thing for certain, no matter what the scenario happens to be, customers are expecting their utility to keep them continually updated on the status of outages. Most importantly, and top priority, is to know the estimated restoration time. They also want to know the cause of the outage because they do not want to be a frequent outage customer.

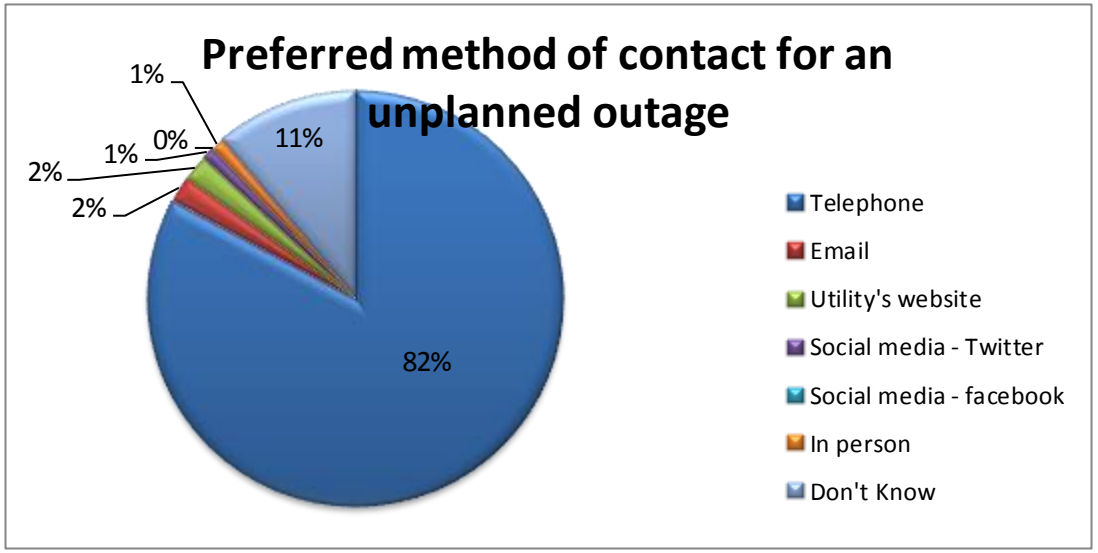
How a utility chooses to handle, manage and communicate with customers during an outage situation does affect customers' satisfaction with their utility. Customers want timely, accurate and relevant information about an outage and customers expect a utility various communication channels to ensure their message is getting out there. This means not only obtaining information via the call centre and IVR but customers have increasing

expectations for proactive two-way communication through social media, utility websites and modern communication devices (e.g. tablets, smartphones) and apps.

The types of information that customers require during an outage include:

- When will their power be restored?
- What areas are affected?
- How many customers are impacted?
- Have work crews been dispatched to the affected area and is the utility working to restore power?
- What was the cause of the power outage?
- What can customers do to cope during the outage?

Inability to provide the above information accurately and in a timely manner will result in customer complaints, increased call volumes to your call centres, create unwanted public and media attention, and negatively impact customer satisfaction.




Base: An aggregate of respondents from 2014 participating LDCs

| Utility's effectiveness during an unplanned outage | |
|---|---|
| **Top 2 Boxes: 'very + somewhat effective'** | **Ontario LDCs** |
| **Responding to questions** | 61% |
| **Providing a reason for the outage** | 61% |
| **Providing an estimate when power will be restored** | 60% |
| **Responding to the power outage** | 81% |
| **Restoring power quickly** | 85% |
| **Communicating updates periodically** | 64% |
| **Posting information to the website** | 35% |
| **Using media channels for providing updates** | 53% |

Base: An aggregate of respondents from 2014 participating LDCs

Customer expectations during an unplanned (and even planned) outage event:

- Communication about when they can expect their power to be restored
- Detailed information about what is happening in their community or service area
- Easy access to information – ideally from a familiar source

Keeping customers in the loop will help ease tensions during an outage event. An informed customer will be a less angry customer.

# Priority Investments

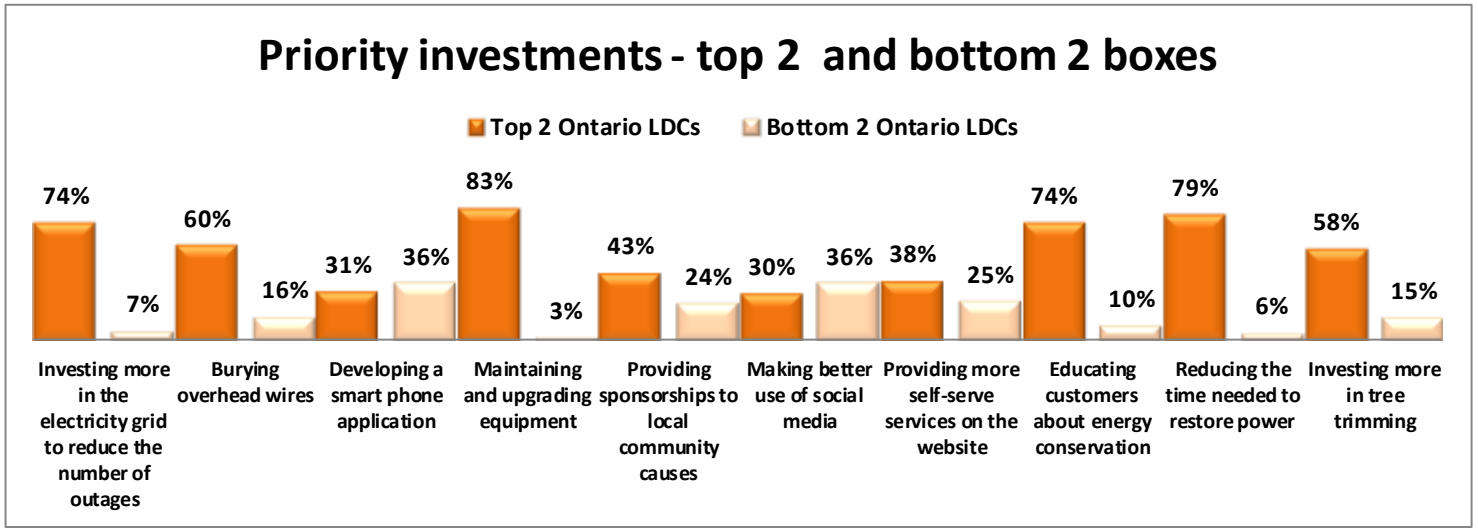
While regulation and reliability are top concerns in the utility industry, aging infrastructure is now a top operational concern. Major issues around electricity are that generation investment has been deferred and major improvements are needed in distribution and transmission. Customers agree with industry insiders that infrastructure renewal is a high priority.

When most people turn on a light, they rarely give much thought to the vast networks and complex systems behind them. Electricity networks are aging. A significant rise in the level of upgrades and renewals of network infrastructure is needed so that the infrastructure will be fit for its current and future purposes. The costs of the components of providing electricity – generation, transmission, distribution and retail – are all increasing, adding upward pressure on utility rates. Canadians are noticing infrastructure more than usual, and at least some are trying to think about it—because when it fails, it has disturbing consequences.

This year, respondents were asked for their views about prioritizing investments and activities since ensuring sustainability of infrastructure and maintaining affordable electricity costs is becoming more of a challenge.

| Priority Investments | |
|---|---|
| **Top 2 Boxes: 'Very high priority + High priority'** | **Ontario LDCs** |
| **Investing more in the electricity grid to reduce the number of outages** | 74% |
| **Burying overhead wires** | 60% |
| **Developing a smart phone application** | 31% |
| **Maintaining and upgrading equipment** | 83% |
| **Providing sponsorships to local community causes** | 43% |
| **Making better use of social media** | 30% |
| **Providing more self-serve services on the website** | 38% |
| **Educating customers about energy conservation** | 74% |
| **Reducing the time needed to restore power** | 79% |
| **Investing more in tree trimming** | 58% |

Base: An aggregate of respondents from 2014 participating LDCs



# Energy Conservation & Efficiency

Addressing homeowner and small business energy conservation behaviours is a vital part of the success or failure of this country's energy future. Local utilities play an important role for shaping energy efficiency and energy conservation behaviours.

| Attributes linked to energy conservation | | |
|---|---|---|
| **Top 2 Boxes: 'agree + strongly agree'** | **Ontario LDCs** | **Enersource** |
| **Provides information to help customers reduce electricity costs** | 79% | 75% |
| **Provides information and tools to help manage electricity consumption** | 79% | 77% |
| **A leader in promoting energy conservation** | 81% | 80% |

Base: total respondents with an opinion

With arguably more responsibility for energy use and energy conservation falling to consumers, two questions arise: (1) What factors affect whether individuals decide to conserve energy? (2) How might the knowledge of these factors be used to impact energy conservation decision-making processes to convince consumers to adopt energy conservation behaviours?



Individual choices to conserve are constrained by individual factors including technological availability, financial resources, and individual knowledge and abilities. The critical factor in the creation of comprehensive energy conservation education programs is the recognition that the consumer's culture, attitudes, and household demographics are driving forces behind consumer actions.

| Efforts to conserve energy | | | | |
|---|---|---|---|---|
| **Enersource** | **Yes** | **No** | **Already Done** | **Don't Know** |
| **Install energy-efficient light bulbs or lighting equipment** | 20% | 10% | 69% | 1% |
| **Install timers on lights or equipment** | 16% | 52% | 30% | 2% |
| **Shift use of electricity to lower cost periods** | 27% | 17% | 53% | 3% |
| **Install window blinds or awnings** | 15% | 24% | 59% | 2% |
| **Install a programmable thermostat** | 14% | 22% | 62% | 3% |
| **Have an energy expert conduct an energy audit** | 15% | 67% | 13% | 5% |
| **Removing old refrigerator or freezer for free** | 17% | 43% | 36% | 4% |
| **Join the peaksaverPLUS™ program** | 19% | 46% | 22% | 13% |
| **Replacing furnace with a high efficiency model** | 15% | 30% | 50% | 5% |
| **Replacing air-conditioner with a high efficiency model** | 19% | 34% | 43% | 4% |
| **Use a coupon to purchase qualified energy saving products** | 40% | 35% | 20% | 5% |

Base: 90% of total respondents from the local utility

Since conservation usually implies inconvenience or sacrifice ie. an individual must use less energy, change a pattern of the time certain chores are done, a motivational factor needs to exist to really incite a change in behaviour i.e. a self-interest or social responsibility or monetary gain.

But focusing on the "vital few" changes you're asking for has to be coupled with immediate and obvious feedback on the effects of change – especially at the start. If neither the dollar impact nor the environmental impact is significant at the level of individual change *and* the behaviour requires inconvenience or loss—it is unlikely that people will make the change.

As Rosemarie LeClaire stated in a presentation to the Ontario Energy Network (April 28, 2014), the industry has changed from a static energy system with largely passive and powerless consumers to one where customers want to be, expected to be, and should be more active in their energy use. Control has shifted from the utility to the customer. Like any major change there are early adopters, i.e., people who want to be proactive in the managing and monitoring of electricity use, and very late adopters i.e., people who resist having to actively manage their electricity use.

However there is a growing skepticism amongst customers who have made some energy conservation changes because they haven't seen a decline in their utility bills. The danger of encouraging someone to make a behaviour change with no real resultant reward for the change, the unintended consequence is what is called "learned helplessness". In other words, when people take action to solve a problem that fails, they almost always end up concluding that they have no control.

What is important then is to:

- Communicate effectively and realistically (it isn't all about saving money)
- Demonstrate the ease by which individuals can participate in various energy efficiency or energy conservation activities
- Provide testimonials from real people who have made changes
- Educate, educate, educate
- Address the biggest barrier to energy conservation efforts i.e., the costs involved in making a change, with financial incentives.



# E-care

As customers pursue new, technology-enabled experiences with other service providers in the retail, telecommunications, and banking industries, they will expect the same from their utility.

Technology – specifically the internet—has allowed people access to far more information than ever before and the ability to do more than ever before: receive and pay bills on the internet, sign up for and change their services using the internet, find answers to their questions online about their accounts, i.e. statements, payments, balances and learn about products, services and topics, i.e., green energy, electricity pricing, etc.




| Do you have access to the internet? | | |
|---|---|---|
| | **Ontario LDCs** | **Enersource** |
| **Yes** | 87% | 90% |
| **No** | 13% | 10% |

Base: An aggregate of respondents from 2014 participating LDCs / 90% of total respondents from the local utility

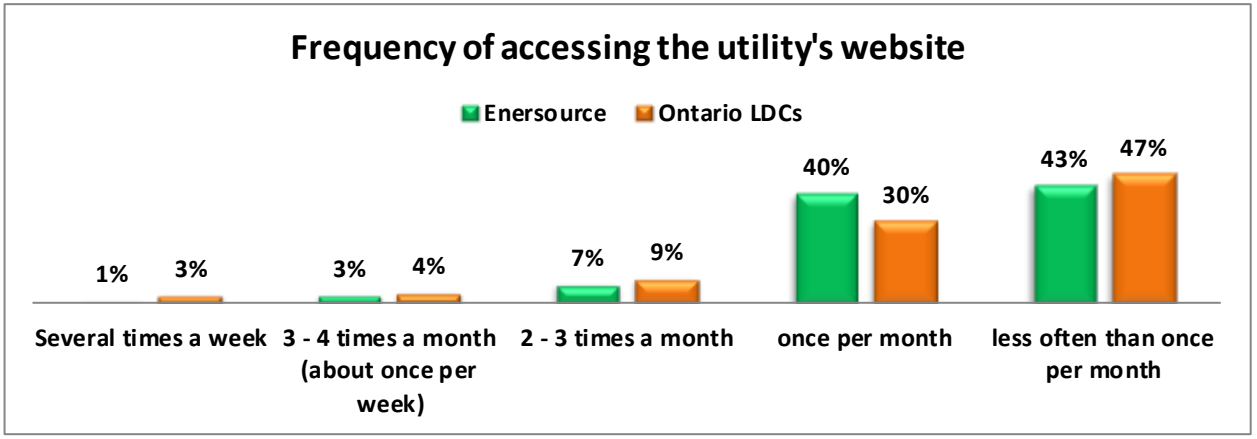
Utilities that provide their customers with access to information and empowerment tools will likely be better positioned to remain relevant and in touch with their customers. A challenge facing utilities right now is determining which tools and information delivery capabilities to build, and how to do so in a cost effective manner.

We asked respondents who were currently connected or had access to the internet if they in fact visited their local utility website.

**Over the past six months have you accessed your local utility website?**




Base: An aggregate of respondents from 2014 participating LDCs / 90% of total respondents from the local utility




Base: An aggregate of respondents from 2014 participating LDCs / 90% of total respondents from the local utility

The convenience and capability brought on by the internet allows customers to be empowered. Customers have the tools and knowledge to manage energy usage at their disposal. Empowerment also implies self-service and instant access to information.

| Likelihood of using the internet for future customer care needs for things such as: | | |
|---|---|---|
| **Top 2 Boxes: 'very + somewhat likely'** | **Ontario LDCs** | **Enersource** |
| **Setting up a new account** | 31% | 36% |
| **Arranging a move** | 38% | 41% |
| **Accessing information about your bill** | 55% | 61% |
| **Accessing information about your electricity usage** | 54% | 62% |
| **Accessing energy saving tips and advice** | 45% | 56% |
| **Accessing information about Time Of Use rates** | 51% | 58% |
| **Maintaining information about your account or preferences** | 51% | 58% |
| **Paying your bill through the utility's website** | 32% | 39% |
| **Getting information about power outages** | 47% | 53% |
| **Arranging for service** | 40% | 48% |

Base: An aggregate of respondents from 2014 participating LDCs / 90% of total respondents from the local utility

To keep up, utilities should develop a better understanding of their future customer, focus on the overall customer, stay current with the latest trends and technologies, and use information to create a more personalized, one-to-one experience.

# Electric Utility Industry Knowledge & SMART Grid

Beyond knowing that electricity is needed to maintain their day to day activities, does the average person feel that they are actually knowledgeable about the electric utility industry?

| Knowledge level about the electric utility industry | |
|---|---|
| | **Ontario** |
| **Extremely knowledgeable** | 2% |
| **Very knowledgeable** | 11% |
| **Moderately knowledgeable** | 47% |
| **Slightly knowledgeable** | 26% |
| **Not very knowledgeable** | 14% |
| **Don't know** | 1% |

Base: total respondents in the Ontario Benchmark survey



Two-thirds (60%) of those polled considered themselves moderately to extremely knowledgeable about the electric industry.

In recent years, the concept of the “SMART Grid” has emerged—first using information technology as a means of improving electricity reliability—and then more recently—to improve efficiency, reduce pollution, and to incorporate more renewable and sustainable sources of generation. A smarter grid will become the SMART Grid over time, as new technologies bring us more benefits. However, what is the “SMART Grid” knowledge level held by consumers currently?

Once again, this year’s survey probed around the concept of SMART Grid. While it is evident that the SMART Grid is still not a much talked about concept, only 34% have a basic or good understanding of what it is, oddly enough, 60% still think that it is important to pursue SMART Grid implementation. It is also clear that the majority of respondents (78%) are ‘very + somewhat supportive' of the utility working with neighbouring utilities on SMART Grid initiatives.

| Level of knowledge about the SMART Grid | |
|---|---|
| | **Ontario** |
| **I have a fairly good understanding of what it is and how it might benefit homes and businesses** | 9% |
| **I have a basic understanding of what it is and how it might work** | 25% |
| **I’ve heard of the term, but don’t know much about it** | 36% |
| **I have not heard of the term** | 29% |
| **Don’t know** | 1% |

Base: total respondents in the Ontario Benchmark survey

| Importance of pursuing implementation of the SMART Grid | |
|---|---|
| | **Ontario** |
| **Very important** | 26% |
| **Somewhat important** | 34% |
| **Neither important or unimportant** | 6% |
| **Somewhat unimportant** | 5% |
| **Unimportant** | 8% |
| **Don't know** | 21% |

Base: total respondents in the Ontario Benchmark survey




| Support towards working with neighbouring utilities on SMART Grid initiatives | |
|---|---|
| | **Ontario** |
| **Very supportive** | 41% |
| **Somewhat supportive** | 37% |
| **Neither supportive or unsupportive** | 4% |
| **Somewhat unsupportive** | 4% |
| **Unsupportive** | 4% |
| **Don't know** | 10% |

Base: total respondents in the Ontario Benchmark survey

# Consumer Energy Use Behaviour

Canadian consumers, like people throughout the rest of the world, have faced rapidly rising energy prices during the past decade, and they have had to become more focused on energy conservation and efficiency. The cost of heating and cooling homes, along with negative fallout from an economic recession, has forced individuals to focus on their energy use and expenditures.

Do customers believe there is a real pay-off for trying to reduce their energy consumption? Does this impact overall efforts to reduce consumption? Respondents were asked *"How active have you been in trying to reduce your electricity consumption?"*

- 94% feel they are "very + somewhat active" in trying to reduce electricity consumption, and
- 81% of those do believe their efforts have resulted in reduced energy consumption, of which
- 44% estimate that they were able to offset an energy consumption reduction of more than 10%, and
- 72% believe that these efforts translated to saving on their electricity bills.

Of course, there are a number of factors (external environment, individual attitudes, household demographics, and consumer choice) which contribute to consumer energy use behaviours and consequences. Identifying these factors which contribute to consumer energy conservation practices and using these factors to tailor energy conservation education programs to change consumer energy use attitudes and behaviours is one essential step to reduce overall energy use and expenditures.

| Level of Activity in trying to reduce electricity consumption | |
|---|---|
| | Ontario |
| Very active | 52% |
| Somewhat active | 42% |
| Neither proactive or inactive | 0% |
| Not active | 2% |
| Not very active | 3% |

Base: total respondents in the Ontario Benchmark survey

| Estimate of percentage reduction in consumption | |
|---|---|
| | Ontario |
| 1 – 2 % | 5% |
| 3 – 5 % | 10% |
| 6 – 8 % | 4% |
| 9 – 10 % | 15% |
| More than 10% | 44% |
| Don't know | 21% |

Base: total respondents in the Ontario Benchmark survey whose active efforts have reduced consumption

**Active efforts have reduced energy consumption**




81%

16%

Base: total respondents in the Ontario Benchmark survey who have been active in trying to reduce energy consumption

**Efforts to conserve have translated into savings on your electricity bill**




72%

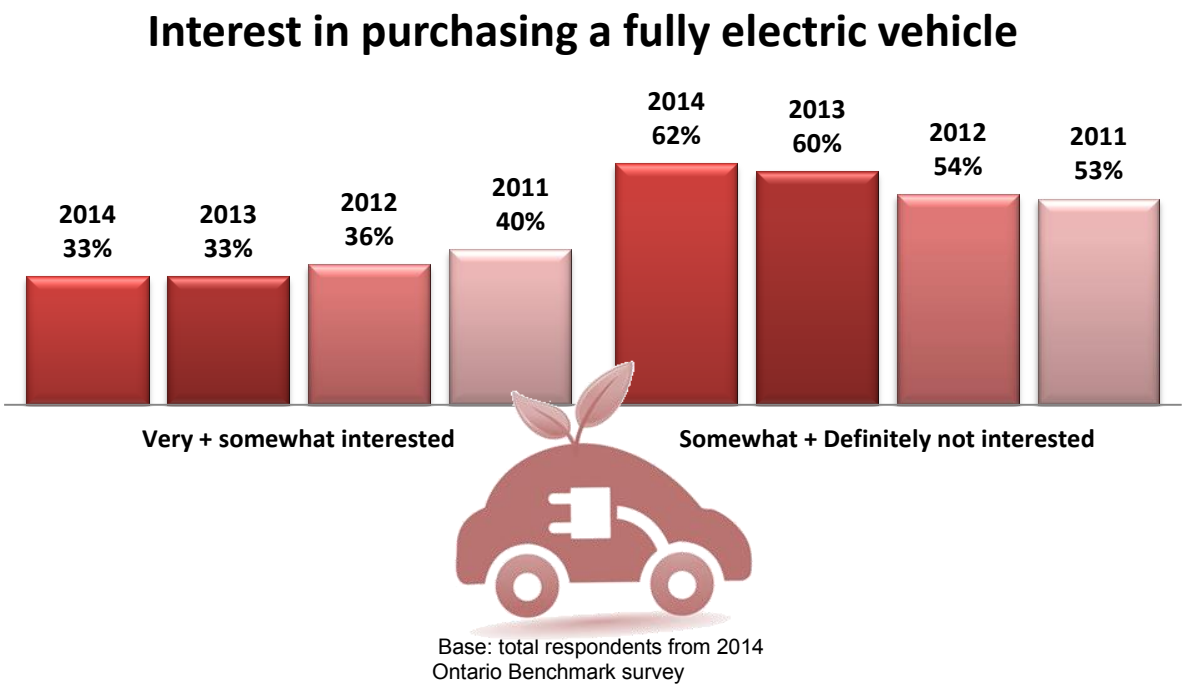
24%

Base: total respondents in the Ontario Benchmark survey whose active efforts have reduced consumption

# Purchasing an Electric Vehicle

There is enormous uncertainty about just how quickly the number of EVs on the road is set to grow over the long term. Mass commercialization of EVs has still not taken hold in today's public mindset. 33% of respondents indicated interest in purchasing a fully electric vehicle, consistent with 2013 findings of 34% but a drop since 2011 where 41% expressed interest in replacing conventional vehicles with EVs. 61% expressed little or no interest in EVs, virtually no change since last year, at 60%, however an since 2011, where 53% claimed disinterest in the electric vehicle.

A breakdown of gender support shows that 38% of men vs 27% of women are interested in the EV. There has been a drop in the "positive support" from respondents in the $40k-$70k income range from 45% interested in 2013 to just 28% in 2014.




Base: total respondents from 2014 Ontario Benchmark survey

Looking at age demographics, again, shows a shift in thinking about wanting to purchase an electric vehicle. 22% of older respondents (55+) versus 47% of respondents aged 35-54 are in favour of EVs replacing conventional cars. 43% of those aged 18-34 are receptive to the idea of purchasing an electric vehicle.

When asked how long it would be before they would consider an EV as an option for their next car purchase, only 1 in 10 (11%) would consider an EV within the next 24 months.

| Interest in purchasing a fully electric vehicle | | | | | | |
|---|---|---|---|---|---|---|
| | Income <$40K | Income $40K<$70K | Income $70K + | Age 18-34 | Age 35-54 | Age 55+ |
| **Top 2 Boxes: 2014 'very + somewhat interested'** | 30% | 28% | 42% | 27% | 39% | 28% |
| **Top 2 Boxes: 2013 'very + somewhat interested'** | 22% | 45% | 43% | 43% | 47% | 22% |

Base: total respondents from 2014 Ontario Benchmark survey

| Length of time before purchasing a fully electric vehicle | |
|---|---|
| | Ontario |
| **Immediately to next 6 months** | 2% |
| **7 to 12 months** | 2% |
| **13 to 24 months** | 9% |
| **Over 24 months** | 79% |
| **Depends** | 5% |
| **Don't know** | 3% |

Base: total respondents from 2014 Ontario Benchmark survey



# Method

The findings in this report are based on telephone interviews conducted for Simul Corp. by Greenwich Associates between April 15 - April 26, 2014, with 624 respondents who pay or look after the electricity bills from a list of residential and small and medium-sized business customers supplied by Enersource.

The sample of phone numbers chosen was drawn randomly to insure that each business or residential phone number on the list had an equal chance of being included in the poll.

The sample was stratified so that 85% of the interviews were conducted with residential customers and 15% with commercial customers.

In sampling theory, in 19 cases out of 20 (95% of polls in other words), the results based on a random sample of 624 residential and commercial customers will differ by no more than ±3.92 percentage points where opinion is evenly split.

This means you can be 95% certain that the survey results do not vary by more than 3.92 percentage points in either direction from results that would have been obtained by interviewing all Enersource residential and small and medium-sized commercial customers if the ratio of residential to commercial customers is 85%:15%.

The margin of error for the sub samples is larger. To see the error margin for subgroups use the calculator at http://www.surveysystem.com/sscalc.htm.

Interviewers reached 2,311 households and businesses from the customer list supplied by Enersource. The 624 who completed the interview represent a 27% response rate.

The findings for the Simul/UtilityPULSE National Benchmark of Electric Utility Customers are based on telephone interviews conducted March 3 through March 21, 2014, with adults throughout the country who are responsible for paying electric utility bills. The ratio of 85% residential customers and 15% small and medium-sized business customers in the National study reflects the ratios used in the local community surveys. The margin of error in the National poll is ±2.7 percentage points at the 95% confidence level.

For the National study, the sample of phone numbers chosen was drawn by recognized probability sampling methods to insure that each region of the country was represented in proportion to its population and by a method

that gave all residential telephone numbers, both listed and unlisted, an equal chance of being included in the poll.

The data were weighted in each region of the country to match the regional shares of the population.

The margin of error refers only to sampling error; other non-random forms of error may be present. Even in true random samples, precision can be compromised by other factors, such as the wording of questions or the order in which questions were asked.

Random samples of any size have some degree of precision. A larger sample is not always better than a smaller sample. The important rule in sampling is not how many respondents are selected but how they are selected. A reliable sample selects poll respondents randomly or in a manner that insures that everyone in the population being surveyed has an equal chance of being selected.

How can a sample of only several hundred truly reflect the opinions of thousands or millions of electricity customers within a few percentage points?

Measures of sample reliability are derived from the science of statistics. At the root of statistical reliability is probability, the odds of obtaining a particular outcome by chance alone. For example, the chances of having a coin come up heads in a single toss are 50%. A head is one of only two possible outcomes.

The chance of getting two heads in two coin tosses is less because two heads are only one of four possible outcomes: a head/head, head/tail, tail/head and tail/tail.

But as the number of coin tosses increases, it becomes increasingly more likely to get outcomes that are either close to or exactly half heads and half tails because there are more ways to get such outcomes. Sample survey reliability works the same way but on a much larger scale.

As in coin tosses, the most likely sample outcome is the true percentage of whatever we are measuring across the total customer base or population surveyed. Next most likely are outcomes very close to this true percentage. A statement of potential margin of error or sample precision reflects this.

Some pages in the computer tables also show the standard deviation (S.D.) and the standard error of the estimate (S.E.) for the findings. The standard deviation embraces the range where 68% (or approximately two-thirds) of the respondents would fall if the distribution of answers were a normal bell-shaped curve. The spread of responses is a way of showing how much the result deviates from the "standard mean" or average. In the Enersource data on corporate image, Simul

converted the answers to a point scale with 4 meaning agree strongly, 3 meaning agree somewhat and so on (see in the computer tables).

For example, the mean score is 3.59 for providing consistent, reliable electricity. The average is 3.01 for providing information to help customers reduce their energy costs.

For reliable electricity the standard deviation is 0.61. For affordable energy the S.D. is 0.96. These findings mean there is a wider range of opinion – meaning less consensus – about whether Enersource provides information to help customers to reduce their energy costs than about whether Enersource energy supplies are reliable.

Beneath the S.D. in the tables is the standard error of the estimate. The S.E. is a measure of confidence or reliability, roughly equivalent to the error margin cited for sample sizes. The S.E. measures how far off the sample's results are from the standard deviation. The smaller the S.E., the greater the reliability of the data.

In other words, a low S.E. indicates that the answers given by respondents in a certain group (such as residential bill payers or women) do not differ much from the probable spread of the answers "predicted" in sampling and probability theory.

Certain questions pertaining to conservation and conservation efforts used an aggregate data approach whereby similar data sets were accumulated to form a larger sample size establishing a higher confidence interval, forecasting value and modeling data.

In these instances, all of the sub-datasets from the entire UtilityPULSE database for 2014 were concatenated in order to use the average of all the control samples for comparison. The cumulated population base for these questions was in excess of 6,500.

At a 95% confidence level the margin of error is ±1.22 and at a 99% confidence level the margin of error would be ±1.6 . So the aggregate strategy has given a very good population sample size which better, or more accurately, reflects the true feelings and beliefs of the population as a whole.

Copyright © 2014 Simul/UtilityPULSE. All rights reserved. Brand, logos and product names referred to in this document are the trademarks or registered trademarks of their respective companies.

Simul

UtilityPULSE

Good things happen when work places work. You'll receive both strategic and pragmatic guidance about how to improve Customer satisfaction & Employee engagement with leaders that lead and a front-line that is inspired. We provide: training, consulting, surveys, diagnostic tools and keynotes. The electric utility industry is a market segment that we specialize in. We've done work for the Ontario Electrical League, the Ontario Energy Network, and both large and small utilities. For sixteen years we have been talking to 1000's of utility customers in Ontario and across Canada and we have expertise that is beneficial to every utility.

| **Culture, Leadership & Performance – Organizational Development** | **Focus Groups, Surveys, Polls, Diagnostics** | **Customer Service Excellence** |
|---|---|---|
| Leadership development | Diagnostics ie. Change Readiness, Leadership Effectiveness, Managerial Competencies | Service Excellence Leadership |
| Strategic Planning | Surveys & Polls | Telephone Skills |
| Teambuilding | Customer Satisfaction and Loyalty Benchmarking Surveys | Customer Care |
| Organizational Culture Transformation | Organization Culture Surveys | Dealing with Difficult Customers |

Benefit from our expertise in Customer Satisfaction, Leadership development, Strategy development or review, and Front-line & Top-line driven-change. We're experts in helping you assess and then transform your organization's culture to one where achieving goals while creating higher levels of customer satisfaction is important. Call us when creating an organization where more employees satisfy more customers more often, is important.

**Your personal contact is:**

**Sid Ridgley, CSP, MBA**

**Phone: (905) 895-7900 Fax: (905) 895-7970 E-mail: sidridgley@utilitypulse.com or sridgley@simulcorp.com**

**BOMA-6**

**Reference(s): DSP, p36**

**Please provide a copy of the workbooks for the residential and small commercial customers consultation.**

**Response:**

Please see the Customer Engagement Appendix 5.0 – *Alectra Utilities Online Feedback Portal Layout*. Exhibit 3, Tab 1, Schedule 1, Attachment 51.

**BOMA-7**

**Reference(s): DSP, p37**

**Please confirm that the group of small business customers that completed the online questionnaire are too small to be statistically significant.**

**Response:**

Alectra Utilities cannot confirm this statement. The concept of statistical significance cannot be applied to voluntary, online surveys. Statistical significance can only be applied to surveys where respondents are randomly selected from known populations (i.e. where a representative group of customers have the same likelihood of being selected to respond to a survey). Given the voluntary (and non-random) nature of Alectra Utilities' online feedback portal, statistical significance cannot be applied to either the group of small business or residential respondent.

Directional feedback collected from the online feedback portal was used to help inform Alectra Utilities' capital investment planning and, in some cases, the design of the subsequent rate application telephone surveys. The number of responses to the online portal was unprecedented at 17,595 (n=289 small businesses). This is, by far, the largest amount of online feedback collected (among both residential and small business customers) ever witnessed by Innovative Research Group or, to our knowledge, the OEB.

In addition to providing an online feedback portal for small businesses to provide input on Alectra Utilities' proposed capital investment plan, a generalizable telephone survey was conducted among n=200 Enersource RZ small businesses and n=201 PowerStream RZ small businesses. Within each rate zone, the margin of error is accurate ±6.8%, 19 times out of 20, among the small business groups.

**BOMA-8**

**Reference(s): Distributed Generation (General)**

**(a) Please provide the following information on Distributed Generation in your service area, the total capacity in kW, and the total production in kWh in the last three years, up to and including 2016. Please provide the information broken down into the following categories:**

- **(i) renewable energy (solar);**
- **(ii) gas-fired cogeneration (engine or turbine);**
- **(iii) demand response;**
- **(iv) microgrid;**
- **(v) storage/solar;**
- **(vi) storage plus cogeneration;**
- **(vii) storage plus demand response;**
- **(viii) other.**

**(b) Please provide the number of customers, by rate class, that are purchasing electricity (kW) from a party other than the distributor, in each of the last three years, ending in 2016.**

**Response:**

| a) | TECHNOLOGY | YEAR | | |
|---|---|---|---|---|
| | | **2014** | **2015** | **2016** |
| i) | microFIT | 306 | 1142 | 1537 |
| | FIT | 4412 | 2994 | 1712 |
| | Netmeter | 0 | 3 | 74 |
| | Wind | 0 | 0 | 0 |
| | **TOTAL RENEWABLE (kW)** | **4718** | **4139** | **3323** |
| | **TOTAL kWh** | **9,578,623** | **17,267,173** | **21,678,795** |
| | | | | |
| ii) | Combined Heat & Power (CHP) | **0** | **2000** | **0** |
| | | | | |
| iii) | Demand Response | **0** | **0** | **0** |
| | | | | |
| iV) | microgrid | **0** | **0** | **0** |
| | | | | |
| v) | storage/solar | **0** | **0** | **0** |
| | | | | |
| vi) | storage + cogeneration | **0** | **0** | **0** |
| | | | | |

| | | | | |
|---|---|---|---|---|
| vii) | Storage + Demand Response | **0** | **0** | **0** |
| | | | | |
| viii) | Other: Biogas | **1400** | **0** | **0** |

* All values above expressed in kW unless otherwise indicated.

b) The number of Enersource RZ customers who are Wholesale Market Participants are shown in Table 1 below for the years 2014 to 2016.

**Table 1: Number of Wholesale Market Participants by Rate Class**

| Customer Class | 2014 | 2015 | 2016 |
|---|---|---|---|
| GS 50-499kW | 1 | 1 | 1 |
| GS 500-4999kW | 4 | 4 | 4 |

## BOMA-9

**Reference(s): Enersource DSP**

**Please confirm that the following excerpt from the Enersource DSP accurately states the reduction and project deferrals undertaken to pace the proposed $367,890,000 over the same period:**

**"The total net impact of such pacing and deferral adjustments is a $6.81MM reduction in capital expenditures over the 2017 to 2022 period."**

**Response:**

Alectra Utilities confirms that it has incorporated the identified customer priorities and preferences into the Enersource Rate Zone DSP by pacing and deferring certain system expansion projects. The total net impact of such pacing and deferral adjustments is a $6.81MM reduction in capital expenditures over the 2017 to 2022 period.

**BOMA-10**

**Reference(s): Energy Conservation**

**Given that one of the four required RRFE outcomes for electricity distributors is responsiveness to policy directives and initiatives, and given that the Filing Requirements for Consolidated Distribution System Plan Filing Requirements dated March 28, 2013, at 5.04, require that:**

**"A distributor's DSP must explain how the expenditure process has been integrated and rationalized so as to permit timely and appropriate expenditure in relation to a distributor's government-mandated obligation".**

**and that**

**"non-distribution system alternatives to relieving system capacity or operational constraints are considered".**

**5.4.5.2.B, pp21, 22 and 25; impact on conservation**

**"(ii) the proposed project also considered other technically feasible options to the proposed project that meet the same objectives".**

**Please describe any non-demand side options that were considered for each of the projects proposed to be funded by the incremental/advanced capital modules. Please discuss each project separately.**

**Response:**

Alectra Utilities has considered and incorporated conservation and demand side impacts for capacity related initiatives to optimize investments. Alectra Utilities has deferred the implementation of certain system service expansion projects such as Webb MS and will focus on increasing focus on conservation and demand side management in the Downtown Core to enable the pacing of expansion as outlined in section 2.3.2.2 of the Alectra Utilities DSP for the Enersource RZ (Exhibit 3, Tab 1, Schedule 1, p. 222).

Enersource Rate Zone

1. Road Widening Project – QEW (Evans to Cawthra): This project address the need to relocate electrical infrastructure to accommodate road work. Energy conservation initiatives were determined not to be technically feasible option.

2. Overhead Rebuild – Lake/John – This project address the renewal needs of an overhead distribution system that services existing customers. Energy conservation initiatives were determined not to be technically feasible option.
3. Overhead Rebuild – Church: This project address the renewal needs of an overhead distribution system that services existing customers. Energy conservation initiatives were determined not to be technically feasible option.
4. Leaking Transformer Replacement Project: This project address the renewal needs due to the environmental risk as a result of leaking transformers. Energy conservation initiatives were determined not to be technically feasible option.
5. Subdivision Rebuilds – Multiple Projects (Credit Woodlands Crt/Wiltshire, Glen Erin & Montevideo, Tenth Line Main Feeder, Folkway & Erin Mills Main Feeder, Glen Erin & Battleford, City Centre Drive Rebuild) - These projects address the renewal needs of an underground distribution system that services existing customers. Energy conservation initiatives were determined not to be technically feasible option.
6. Substation Upgrade – York MS: This project is driven by the both the growth in the Meadowvale Business Park Area as well as the need to update the equipment and configuration at the station to bring these in line with current standards. Conservation was incorporated and deducted into the load forecasts for the area. To address the secondary driver to update the equipment and configuration at the station which services existing customers was determined not to be a technically feasible option.

**BOMA-11**

**Reference(s): Enersource Distribution Licence**

**Licence ED-2016-0360, s. 21.2 – Given the obligation to do the Conservation First Project and the customer survey results that show that assistance with CDM is third most important customer need, why does the utility not address CDM and DR alternatives to the requested distribution capital projects in this application?**

**Response:**

The projects that comprise the ICM for ERZ do not have Conservation and Demand Management ("CDM") or Demand Response ("DR") based alternatives. Please see Alectra Utilities' response to BOMA-10.

## BOMA-12

**Reference(s): DSP, Appendix F, Customer Engagement Report**

**(a) Please confirm that:**

1

- **(i) The Innovative Customer Engagement Report (the "Report") was filed on June 23, 2017.**
- **(ii) Innovative Research Group telephone survey activity commenced May 8, 2017 and ended May 26, 2017 (Appendix 1 to Report).**
- **(iii) The Large Use Customer Online Survey was filed between May 26, 2017 and June 9, 2017.**

**(b) When was Innovative Research Group retained by Alectra? When did it commence work? Please provide a copy of the engagement letter (contract) and the RFP used to solicit bids to conduct the work.**

**Response:**

2 a) i) – iii) Alectra Utilities confirms that the research field dates listed above are correct.

3

4 b) Innovative Research Group was retained by Alectra Utilities in March 2017 through a
5 competitive procurement process. Work commenced as soon as the contract was awarded.

6

7 Alectra Utilities has provided a copy of the RFP used to solicit vendor bids for the customer
8 engagement component of Alectra Utilities' rate application as BOMA-12_Attach
9 1_Customer Engagement RFP.

10

11 The engagement letter (contract) will be filed confidentially to protect Innovative Research
12 Group's competitive pricing information as BOMA-12_Attach 2_Customer Engagement
13 Letter.

14

15 Relevant information pertaining to the customer engagement approach and methodology
16 can be found under "About this Consultation", in Exhibit 3, Tab 1, Schedule 1, Attachment
17 51, p.4.

**REQUEST FOR PROPOSALS**

**For**

**Customer Consultation Services**

Request for Proposals No.: AU-RFP-2017-003

Issued: Thursday, February 23, 2017

Submission Deadline: Friday, March 03, 2017 3:00 p.m.

## CONFIDENTIAL MATERIAL

Alectra Utilities Corporation Proprietary. Terms of Use and Disclosure as per Section 3.5 of enclosed.

# Table of Contents

**PART 1 – INVITATION AND SUBMISSION INSTRUCTIONS....3**
1.1 Invitation to Proponents....3
1.2 RFP Contact....3
1.3 Type of Contract for Deliverables....3
1.4 RFP Timetable....3
1.5 Intention to Respond to RFP....4
1.6 Submission of Proposals....4
**PART 2 – EVALUATION AND NEGOTIATION....6**
2.1 Stages of Evaluation and Negotiation....6
2.2 Stage I – Mandatory Submission Requirements....6
2.3 Stage II – Evaluation....6
2.4 Stage III – Pricing....6
2.5 Stage IV – Ranking and Contract Negotiations....7
**PART 3 – TERMS AND CONDITIONS OF THE RFP PROCESS....8**
3.1 General Information and Instructions....8
3.2 Communication after Issuance of RFP....9
3.3 Notification....9
3.4 Conflict of Interest and Prohibited Conduct....9
3.5 Confidential Information....10
3.6 Procurement Process Non-binding....11
3.7 Governing Law and Interpretation....12
**APPENDIX A – FORM OF AGREEMENT....13**
**APPENDIX B – SUBMISSION FORM....14**
**APPENDIX C – PRICING FORM....17**
**APPENDIX D – RFP PARTICULARS....18**
A. THE DELIVERABLES....18
B. MATERIAL DISCLOSURES AND PRE-CONDITIONS OF AWARD....21
C. MANDATORY TECHNICAL REQUIREMENTS....22
D. RATED CRITERIA....22

# PART 1 – INVITATION AND SUBMISSION INSTRUCTIONS

## 1.1 Invitation to Proponents

This Request for Proposals ("RFP") is an invitation by Alectra Utilities Corporation ("Alectra Utilities or Alectra") to prospective proponents to submit proposals for the provision of Customer Consultation Services, as further described in the RFP Particulars (Appendix D) (the "Deliverables").

Alectra Utilities is seeking the services of a third party Consultant in customer consultation, pursuant to the Ontario Energy Board (OEB) Chapter 5 Filing Requirements regarding the OEB's evaluation of Alectra's Distribution System Plans (DSPs) for its different rate zones.

Alectra Utilities is the largest municipally owned electricity distribution company by customer base in Ontario, delivering electricity and related utility services to more than 1,000,000 residential and commercial customers in Ontario. The company is committed to providing best value to its customers through the cost effective delivery of a safe, and reliable supply of electricity. Alectra Utilities is owned by Alectra Inc. and operates out of facilities in within a 1,800 square kilometre service territory comprising 15 communities including Alliston, Aurora, Barrie, Beeton, Bradford, Hamilton, Markham, Mississauga, Penetanguishene, Richmond Hill, St. Catharines, Thornton, Tottenham and Vaughan. Alectra will be one of the largest municipally-owned electric utilities in North America by number of customers, second only to Los Angeles Water and Power. For more information, visit: http://www.alectrautilities.com.

## 1.2 RFP Contact

For the purposes of this procurement process, the "RFP Contact" will be:

**Sherri Giles, CSCMP, C.P.M., C.I.M., P.Mgr, C.Mgr**
**Email: sherri.giles@alectrautilities.om**

Proponents and their representatives are not permitted to contact any employees, officers, agents, Board members, shareholders, appointed officials or other representatives of Alectra, other than the RFP Contact, concerning matters regarding this RFP. Failure to adhere to this rule may result in the disqualification of the proponent and the rejection of the proponent's proposal.

## 1.3 Type of Contract for Deliverables

The selected proponent will be requested to enter into direct contract negotiations to finalize an agreement with Alectra for the provision of the Deliverables. The terms and conditions found in the Form of Agreement (Appendix A) are to form the basis for commencing negotiations between Alectra and the selected proponent. It is Alectra's intention to enter into an agreement with only one (1) legal entity. The term of the agreement is to be from March 13, 2017 to May 1, 2017.

## 1.4 RFP Timetable

| | |
|---|---|
| Issue Date of RFP | February 22, 2017 |
| Notify RFP Contact of Intention to Respond | February 23, 2017 |
| Deadline for Questions | February 28, 2017 |
| Deadline for Issuing Addenda | March 1, 2017 |
| Submission Deadline | March 3, 2017 3:00 p.m. |
| Rectification Period | 1 day |

| | |
|---|---|
| Presentations | TBD week of March 7, 2017 |
| Contract Negotiation Period | 3 days |
| Anticipated Execution of Agreement | March 10, 2017 |

The RFP timetable is tentative only, and may be changed by Alectra at any time.

Proponents may be required to prepare an oral presentation and/or Alectra Utilities may request a site visit at the Proponent's location to assist Alectra in understanding the full scope of services as required. Dates for presentations will be advised if required.

### 1.5 Intention to Respond to RFP

Proponents are requested to confirm their intention to respond to this RFP by emailing their confirmation to the RFP Contact by the date set out in the RFP Timetable above.

Proponents declining to submit a proposal in response to this RFP are asked to ensure destruction of this RFP document immediately after declining to submit a proposal, and will advise Alectra Utilities in writing that the RFP and the associated documentation has been destroyed..

### 1.6 Submission of Proposals

#### 1.6.1 Proposals to be Submitted at Prescribed Location

Proposals must be submitted electronically at:

**sherri.giles@alectrautilities.com**

#### 1.6.2 Proposals to be Submitted on Time

Proposals must be submitted at the location set out above on or before the Submission Deadline.

Proposals submitted after the Submission Deadline will be rejected. Onus and responsibility rest solely with the proponent to deliver its proposal on or before the Submission Deadline. Alectra does not accept any responsibility for submissions delivered to any other location by the proponent or its delivery agents. Proponents are advised to make submissions well before the deadline. Proponents making submissions near the deadline do so at their own risk. For the purposes of this Section, "Business Day" means any working day between 9:00 a.m. and 4:30 p.m., local time at the Prescribed Location, Monday to Friday inclusive, but excluding statutory and other holidays on which Alectra is closed for business.

#### 1.6.3 Proposals to be Submitted in Prescribed Format

Proponents must submit one (1) electronic copy of their proposal in Word format and one (1) electronic copy of their proposal in PDF format. If there is a conflict or inconsistency between the Word and PDF copy of the proposal, the PDF copy of the proposal will prevail. Proposals should be prominently marked with the RFP title and number (see RFP cover), with the full legal name and return address of the proponent.

#### 1.6.4 Amendment of Proposals

Proponents may amend their proposals prior to the Submission Deadline by submitting the amendment in the Prescribed Format prominently marked with the RFP title and number and the full legal name and return address of the proponent to the location set out above. Any amendment should clearly indicate which part of the proposal the amendment is intended to amend or replace.

### 1.6.5 Withdrawal of Proposals

At any time throughout the RFP process until the execution of a written agreement for provision of the Deliverables, a proponent may withdraw a submitted proposal. To withdraw a proposal, a notice of withdrawal must be sent to the RFP Contact and must be signed by an authorized representative of the proponent. Alectra is under no obligation to return withdrawn proposals.

[End of Part 1]

# PART 2 – EVALUATION AND NEGOTIATION

## 2.1 Stages of Evaluation and Negotiation

Alectra will conduct the evaluation of proposals and negotiations in the following stages:

## 2.2 Stage I – Mandatory Submission Requirements

Stage I will consist of a review to determine which proposals comply with all of the mandatory submission requirements. If a proposal fails to satisfy all of the mandatory submission requirements, Alectra may in its sole discretion issue the proponent a rectification notice identifying the deficiencies and providing the proponent an opportunity to rectify the deficiencies within a rectification period (the **"Rectification Period")**. If the proponent fails to satisfy the mandatory submission requirements within the Rectification Period, its proposal will be excluded from further consideration. The Rectification Period will begin to run from the date and time that [Alectra] issues a rectification notice to the proponent. The mandatory submission requirements are as set out below.

### 2.2.1 Submission Form (Appendix B)

Each proposal must include a Submission Form (Appendix B) completed and signed by an authorized representative of the proponent.

### 2.2.2 Pricing Form (Appendix C)

Each proposal must include a Pricing Form (Appendix C) completed according to the instructions contained in the form.

### 2.2.3 Other Mandatory Submission Requirements Not Applicable

## 2.3 Stage II – Evaluation

Stage II will consist of the following two sub-stages:

### 2.3.1 Mandatory Technical Requirements

Alectra will review the proposals to determine whether the mandatory technical requirements as set out in Section C of the RFP Particulars (Appendix D) have been met. Questions or queries on the part of Alectra as to whether a proposal has met the mandatory technical requirements will be subject to the verification and clarification process set out in Part 3.

### 2.3.2 Rated Criteria

Alectra will evaluate each qualified proposal on the basis of the rated criteria as set out in Section D of the RFP Particulars (Appendix D).

## 2.4 Stage III – Pricing

Stage III will consist of a scoring of the submitted pricing in accordance with the price evaluation method set out in the Pricing Form (Appendix C). The evaluation of price will be undertaken after the evaluation of mandatory requirements and rated criteria has been completed.

## 2.5 Stage IV – Ranking and Contract Negotiations

### 2.5.1 Ranking of Proponents

After the completion of Stage Stage I, II and III, proponents will be ranked based on best value. The top-ranked proponent will receive a written invitation to enter into direct contract negotiations to finalize the agreement with Alectra.

### 2.5.2 Contract Negotiation Process

Any negotiations will be subject to the process rules contained in the Terms and Conditions of the RFP Process (Part 3) and will not constitute a legally binding offer to enter into a contract on the part of Alectra or the proponent and there will be no legally binding relationship created with any proponent prior to the execution of a written agreement. The terms and conditions found in the Form of Agreement (Appendix A) are to form the basis for commencing negotiations between Alectra and the selected proponent. Negotiations may include requests by Alectra for supplementary information from the proponent to verify, clarify or supplement the information provided in its proposal or to confirm the conclusions reached in the evaluation, and may include requests by Alectra for improved pricing or performance terms from the proponent.

If a Proponent wishes to discuss or negotiate any part of the Contract, it shall state such Points of Discussion in the Proponent's submission and shall include draft replacement wording for each Point of Discussion. Alectra will not consider or discuss any issues relating to the Contract unless they have been included in a Proponent's Points of Discussion. A Proponent which submits a Proposal which does not contain or attach any Points of Discussion will be deemed to make no Points of Discussion.

The Proponent's discussions or negotiations respecting the Contract will be limited to the Points of Discussion submitted as part of its Proposal.

### 2.5.3 Time Period for Negotiations

Alectra intends to conclude negotiations and finalize the agreement with the top-ranked proponent during the Contract Negotiation Period, commencing from the date Alectra invites the top-ranked proponent to enter negotiations. A proponent invited to enter into direct contract negotiations should therefore be prepared to provide requested information in a timely fashion and to conduct its negotiations expeditiously.

### 2.5.4 Failure to Enter into Agreement

If the parties cannot conclude negotiations and finalize the agreement for the Deliverables within the Contract Negotiation Period, Alectra may discontinue negotiations with the top-ranked proponent and may invite the next-best-ranked proponent to enter into negotiations. This process will continue until an agreement is finalized, until there are no more proponents remaining that are eligible for negotiations or until Alectra elects to cancel the RFP process.

### 2.5.5 Notification to Other Proponents

Other proponents that may become eligible for contract negotiations may be notified at the commencement of the negotiation process with the top-ranked proponent. Once an agreement is finalized and executed by Alectra and a proponent, the other proponents will be notified directly in writing.

[End of Part 2]

# PART 3 – TERMS AND CONDITIONS OF THE RFP PROCESS

## 3.1 General Information and Instructions

### 3.1.1 Proponents to Follow Instructions

Proponents should structure their proposals in accordance with the instructions in this RFP. Where information is requested in this RFP, any response made in a proposal should reference the applicable section numbers of this RFP.

### 3.1.2 Proposals in English

All proposals are to be in English only.

### 3.1.3 No Incorporation by Reference

The entire content of the proponent's proposal should be submitted in a fixed form, and the content of websites or other external documents referred to in the proponent's proposal but not attached will not be considered to form part of its proposal.

### 3.1.4 References and Past Performance

In the evaluation process, Alectra may include information provided by the proponent's references and may also consider the proponent's past performance or conduct on previous contracts with Alectra or other institutions.

### 3.1.5 Information in RFP Only an Estimate

Alectra and its advisers make no representation, warranty or guarantee as to the accuracy of the information contained in this RFP or issued by way of addenda. Any quantities shown or data contained in this RFP or provided by way of addenda are estimates only, and are for the sole purpose of indicating to proponents the general scale and scope of the Deliverables. It is the proponent's responsibility to obtain all the information necessary to prepare a proposal in response to this RFP.

### 3.1.6 Proponents to Bear Their Own Costs

The proponent will bear all costs associated with or incurred in the preparation and presentation of its proposal, including, if applicable, costs incurred for interviews or demonstrations.

### 3.1.7 Proposal to be Retained by Alectra

Alectra will not return the proposal or any accompanying documentation submitted by a proponent.

### 3.1.9 No Guarantee of Volume of Work or Exclusivity of Contract

Alectra makes no guarantee of the value or volume of work to be assigned to the successful proponent. The agreement to be negotiated with the selected proponent will not be an exclusive contract for the provision of the described Deliverables. Alectra may contract with others for goods and services the same as or similar to the Deliverables or may obtain such goods and services internally.

## 3.2 Communication after Issuance of RFP

### 3.2.1 Proponents to Review RFP

Proponents should promptly examine all of the documents comprising this RFP, and may direct questions or seek additional information in writing by email to the RFP Contact on or before the Deadline for Questions. No such communications are to be directed to anyone other than the RFP Contact. Alectra is under no obligation to provide additional information, and Alectra is not responsible for any information provided by or obtained from any source other than the RFP Contact. It is the responsibility of the proponent to seek clarification from the RFP Contact on any matter it considers to be unclear. Alectra is not responsible for any misunderstanding on the part of the proponent concerning this RFP or its process.

### 3.2.2 All New Information to Proponents by Way of Addenda

This RFP may be amended only by addendum in accordance with this section. If Alectra, for any reason, determines that it is necessary to provide additional information relating to this RFP, such information will be communicated to all proponents by addendum. Each addendum forms an integral part of this RFP and may contain important information, including significant changes to this RFP. Proponents are responsible for obtaining all addenda issued by Alectra. In the Submission Form (Appendix B), proponents should confirm their receipt of all addenda by setting out the number of each addendum in the space provided.

### 3.2.3 Post-Deadline Addenda and Extension of Submission Deadline

Alectra may extend the Submission Deadline for a reasonable period of time if Alectra determines that it is necessary to issue an addendum after the Deadline for Issuing Addenda

### 3.2.4 Verify, Clarify and Supplement

When evaluating proposals, Alectra may request further information from the proponent or third parties in order to verify, clarify or supplement the information provided in the proponent's proposal, including but not limited to clarification with respect to whether a proposal meets the mandatory technical requirements set out in Section C of the RFP Particulars (Appendix D). Alectra may revisit and re-evaluate the proponent's response or ranking on the basis of any such information.

## 3.3 Notification

### 3.3.1 Notification to Other Proponents

Once an agreement is executed by Alectra and a proponent, the other proponents may be notified directly in writing of the outcome of the procurement process.

## 3.4 Conflict of Interest and Prohibited Conduct

### 3.4.1 Conflict of Interest

Alectra may disqualify a proponent for any conduct, situation or circumstances, determined by Alectra, in its sole and absolute discretion, to constitute a Conflict of Interest, as defined in the Submission Form (Appendix B).

### 3.4.2 Disqualification for Prohibited Conduct

Alectra may disqualify a proponent, rescind an invitation to negotiate or terminate a contract subsequently entered into if Alectra determines that the proponent has engaged in any conduct prohibited by this RFP.

### 3.4.3 Prohibited Proponent Communications

Proponents must not engage in any communications that could constitute a Conflict of Interest and should take note of the Conflict of Interest declaration set out in the Submission Form (Appendix B).

### 3.4.4 Proponent Not to Communicate with Media

Proponents must not at any time directly or indirectly communicate with the media in relation to this RFP or any agreement entered into pursuant to this RFP without first obtaining the written permission of the RFP Contact.

### 3.4.5 No Lobbying

Proponents must not, in relation to this RFP or the evaluation and selection process, engage directly or indirectly in any form of political or other lobbying whatsoever to influence the selection of the successful proponent(s).

### 3.4.6 Illegal or Unethical Conduct

Proponents must not engage in any illegal business practices, including activities such as bid-rigging, price-fixing, bribery, fraud, coercion or collusion. Proponents must not engage in any unethical conduct, including lobbying, as described above, or other inappropriate communications; offering gifts to any employees, officers, agents, Board members, appointed officials or other representatives of Alectra; deceitfulness; submitting proposals containing misrepresentations or other misleading or inaccurate information; or any other conduct that compromises or may be seen to compromise the competitive process provided for in this RFP.

### 3.4.7 Past Performance or Past Conduct

Alectra may prohibit a supplier from participating in a procurement process based on past performance or based on inappropriate conduct in a prior procurement process with any of Horizon Utilities Corporation, Powerstream Inc., Enersource Mississauga Hydro Inc., or Alectra, including but not limited to the following:

(a) illegal or unethical conduct as described above;

(b) the refusal of the supplier to honour its submitted pricing or other commitments; or

(c) any conduct, situation or circumstance determined by Alectra, in its sole and absolute discretion, to have constituted an undisclosed Conflict of Interest.

## 3.5 Confidential Information

### 3.5.1 Confidential Information of Alectra

All information provided by or obtained from Alectra in any form in connection with this RFP either before or after the issuance of this RFP

(a) is the sole property of Alectra and must be treated as confidential;

(b) is not to be used for any purpose other than replying to this RFP and the performance of any subsequent contract for the Deliverables;

(c) must not be disclosed without prior written authorization from Alectra; and

(d) must be returned by the proponent to Alectra immediately upon the request of Alectra.

### 3.5.2 Confidential Information of Proponent

A proponent should identify any information in its proposal or any accompanying documentation supplied in confidence for which confidentiality is to be maintained by Alectra. The confidentiality of such information will be maintained by Alectra, except as otherwise required by law or by order of a court or tribunal. Proponents are advised that their proposals will, as necessary, be disclosed on a confidential basis to advisers retained by Alectra to advise or assist with the RFP process, including the evaluation of proposals. If a proponent has any questions about the collection and use of personal information pursuant to this RFP, questions are to be submitted to the RFP Contact.

## 3.6 Procurement Process Non-binding

### 3.6.1 No Contract A and No Claims

This procurement process is not intended to create and will not create a formal, legally binding bidding process and will instead be governed by the law applicable to direct commercial negotiations. For greater certainty and without limitation:

(a) this RFP will not give rise to any Contract A–based tendering law duties or any other legal obligations arising out of any process contract or collateral contract; and

(b) neither the proponent nor Alectra will have the right to make any claims (in contract, tort, or otherwise) against the other with respect to the award of a contract, failure to award a contract or failure to honour a proposal submitted in response to this RFP.

### 3.6.2 No Contract until Execution of Written Agreement

This RFP process is intended to identify prospective suppliers for the purposes of negotiating potential agreements. No legal relationship or obligation regarding the procurement of any good or service will be created between the proponent and Alectra by this RFP process until the successful negotiation and execution of a written agreement for the acquisition of such goods and/or services.

### 3.6.3 Non-binding Price Estimates

While the pricing information provided in proposals will be non-binding prior to the execution of a written agreement, such information will be assessed during the evaluation of the proposals and the ranking of the proponents. Any inaccurate, misleading or incomplete information, including withdrawn or altered pricing, could adversely impact any such evaluation or ranking or the decision of Alectra to enter into an agreement for the Deliverables.

### 3.6.4 Cancellation

Alectra may cancel or amend the RFP process without liability at any time.

### 3.7 Governing Law and Interpretation

These Terms and Conditions of the RFP Process (Part 3):

(a) are intended to be interpreted broadly and independently (with no particular provision intended to limit the scope of any other provision);

(b) are non-exhaustive and will not be construed as intending to limit the pre-existing rights of the parties to engage in pre-contractual discussions in accordance with the common law governing direct commercial negotiations; and

(c) are to be governed by and construed in accordance with the laws of the province of Ontario and the federal laws of Canada applicable therein.

[End of Part 3]

# APPENDIX A – FORM OF AGREEMENT

## LOA Customer Consultation Consultant Services_AU-RFP-2017-003




LOA Customer
Consultation Service

# APPENDIX B – SUBMISSION FORM

## 1. Proponent Information

**COMPANY HISTORY**

| Proponent Company History | |
|---|---|
| **Number of Locations:** | |
| **Number of Employees:** | |
| **Number of Years in the Business:** | |
| **Are you Unionized? If so, which Union:** | |
| **Describe any previous dealing with Alectra or any of Horizon Utilities Corporation, Enersource Hydro Mississatuga Inc., or PowerStream Inc.:** | |
| | |

**COMPANY PROFILE**

| Company Profile | |
|---|---|
| **Company Office Address:** | |
| **Your designated representative and contact info for this RFP:** | |
| **Your designated representative for all ongoing operating issues:** | |
| **Other employees and resources to be assigned to this project and their positions:** | |
| **The specific resources that you propose to use for this project, including any subcontractors:** | |

## 2. Acknowledgment of Non-binding Procurement Process

The proponent acknowledges that the RFP process will be governed by the terms and conditions of the RFP, and that, among other things, such terms and conditions confirm that this procurement process does not constitute a formal, legally binding bidding process (and for greater certainty, does not give rise to a Contract A bidding process contract), and that no legal relationship or obligation regarding the procurement of any good or service will be created between Alectra and the proponent unless and until Alectra and the proponent execute a written agreement for the Deliverables.

## 3. Ability to Provide Deliverables

The proponent has carefully examined the RFP documents and has a clear and comprehensive knowledge of the Deliverables required. The proponent represents and warrants its ability to provide the Deliverables in accordance with the requirements of the RFP for the rates set out in the completed Pricing Form (Appendix C).

## 4. Non-binding Pricing

The proponent has submitted its pricing in accordance with the instructions in the RFP and in the Pricing Form (Appendix C). The proponent confirms that the pricing information provided is accurate. The proponent acknowledges that any inaccurate, misleading or incomplete information, including withdrawn or altered pricing, could adversely impact the acceptance of its proposal or its eligibility for future work.

## 5. Addenda

The proponent is deemed to have read and taken into account all addenda issued by Alectra prior to the Deadline for Issuing Addenda. The proponent is requested to confirm that it has received all addenda by listing the addenda numbers, or if no addenda were issued by writing the word "None", on the following line: _____. If this section is not completed, the proponent will be deemed to have received all issued addenda.

## 6. No Prohibited Conduct

The proponent declares that it has not engaged in any conduct prohibited by this RFP.

## 7. Conflict of Interest

For the purposes of this RFP, the term "Conflict of Interest" includes, but is not limited to, any situation or circumstance where:

(a) in relation to the RFP process, the proponent has an unfair advantage or engages in conduct, directly or indirectly, that may give it an unfair advantage, including but not limited to (i) having, or having access to, confidential information of Alectra in the preparation of its proposal that is not available to other proponents, (ii) communicating with any person with a view to influencing preferred treatment in the RFP process (including but not limited to the lobbying of decision makers involved in the RFP process), or (iii) engaging in conduct that compromises, or could be seen to compromise, the integrity of the open and competitive RFP process or render that process non-competitive or unfair; or

(b) in relation to the performance of its contractual obligations under a contract for the Deliverables, the proponent's other commitments, relationships or financial interests (i) could, or could be seen to, exercise an improper influence over the objective, unbiased and impartial exercise of its independent judgement, or (ii) could, or could be seen to, compromise, impair or be incompatible with the effective performance of its contractual obligations.

For the purposes of section (a)(i) above, proponents should disclose the names and all pertinent details of all individuals (employees, advisers, or individuals acting in any other capacity) who (a) participated in the preparation of the proposal; **AND** (b) were employees of Alectra within twelve (12) months prior to the Submission Deadline.

If the box below is left blank, the proponent will be deemed to declare that (a) there was no Conflict of Interest in preparing its proposal; and (b) there is no foreseeable Conflict of Interest in performing the contractual obligations contemplated in the RFP.

Otherwise, if the statement below applies, check the box.

☐ The proponent declares that there is an actual or potential Conflict of Interest relating to the preparation of its proposal, and/or the proponent foresees an actual or potential Conflict of Interest in performing the contractual obligations contemplated in the RFP.

If the proponent declares an actual or potential Conflict of Interest by marking the box above, the proponent must set out below details of the actual or potential Conflict of Interest:

_____

_____

_____

_____

**8. Disclosure of Information**

The proponent hereby agrees that any information provided in this proposal, even if it is identified as being supplied in confidence, may be disclosed where required by law or by order of a court or tribunal. The proponent hereby consents to the disclosure, on a confidential basis, of this proposal by Alectra to the advisers retained by Alectra to advise or assist with the RFP process, including with respect to the evaluation of this proposal.

| | |
|---|---|
| Signature of Witness | Signature of Proponent Representative |
| Name of Witness | Name of Proponent Representative |
| | Title of Proponent Representative |
| | Date |

I have the authority to bind the proponent.

# APPENDIX C – PRICING FORM

## Instructions on How to Complete Pricing Form

(a) Rates shall be provided in Canadian funds, inclusive of all applicable duties and taxes except for HST, which should be itemized separately.

(b) Rates quoted by the proponent shall be all-inclusive and shall include all labour and material costs, all travel and carriage costs, all insurance costs, all costs of delivery, all costs of installation and set-up, including any pre-delivery inspection charges, and all other overhead, including any fees or other charges required by law.

(c) Proponents are required to provide a detailed description of the number of hours that will be required by the consultant(s) and the hourly rate associated with each team member. Please be sure to indicate the number of hours required by Alectra staff. Please use own document for providing fee structure.

## FIXED FEE PRICING

| Cost Category | $ Cost per Unit | (#) Units | Total Cost for (#) Units |
|---|---|---|---|
| Sample Category 1 | $50.00/hour | 2 | $100.00 |
| Sample Category 2 | $75.00/hour | 10 | $750.00 |
| | | | |
| | | | |
| | | **TOTAL FIXED FEE:** | $850.00 |

# APPENDIX D – RFP PARTICULARS

## A. THE DELIVERABLES

### A.1 Brief Description

Alectra Utilities is seeking the services of a third party Consultant in customer consultation, pursuant to the Ontario Energy Board ("OEB") Chapter 5 Filing Requirements regarding the OEB's evaluation of Alectra's Distribution System Plans ("DSPs") for its different rate zones. The customer consultation for the Brampton and PowerStream rate zones will be a confirmation of the existing DSP. The customer consultation for the Enersource rate zone must provide evidentiary support to finalize the full Enersource DSP for filing with the OEB. That is, the OEB is seeking evidentiary proof that Alectra's DSPs, to be filed by June 30, 2017, as part of Alectra's 2018 Incentive Regulation Mechanism and Incremental Capital Module ("IRM/ICM") rate application, demonstrates that distribution services are provided in a manner that responds to identified customer preferences. This is accomplished by providing evidence in the IRM/ICM rate application on customer engagement to identify preferences; the value proposition the DSPs represent for customers (economic efficiency and cost-effectiveness); and on the factors relating to customer preferences or input from customers that were considered in the course of planning investment projects and activities. Further, Alectra Utilities must show an indication of whether the consultation(s) have or are expected to affect the distributor's DSPs as filed and if so, an explanation as to how. Alectra will endeavour to provide draft DSPs for use by the Proponent by April 1, 2017.

### A.2 Specifications

**Project Objective**

The goal is to be able to draft detailed, sophisticated, and compelling evidence to be filed with the OEB that confirms Alectra Utilities' commitment and obligation to educate and to seek the input of its customers, and how it considered that input to revise, if and as necessary, its DSPs.

The successful Proponent is needed to help conduct broad, professional, and scientific research on the input of customers with respect to the DSPs. Input must be sought from every customer class, and via different methods. Proponents are to note that Alectra Utilities will provide current customer information from its database. As well, Alectra Utilities will also provide subject matter experts to provide support during the process.

These methods may include one on one consultation, online surveys prompted by the posting of detailed information explaining the proposed DSPs and following with appropriate questions; focus groups which use the detailed DSP information for customer education and guidance; random scientific telephone polls; Open Houses or Town Hall sessions; Large User validation surveys; and stakeholder workshops. Alectra is amenable to other forms of education, customer outreach and input, and would be interested to receive such proposals from qualified respondents.

Alectra Utilities provides here a responsibility matrix which is intended to indicate to the Bidder what the expectations are of the awarded Proponent and Alectra Utilities. This matrix

complements the RFP document and may not capture all aspects of responsibilities reflected throughout the RFP.

| Program Element | Responsibility | |
|---|---|---|
| | **Delivery Agent** | **Alectra Utilities** |
| Assist and Design consultation process | X | |
| Provide consistent and senior personnel throughout the contract | X | |
| Provide advice as to appropriate communication methods by customer class and any other stakeholders | X | |
| Conduct pre-testing of materials prior to consultations | X | |
| Provide database of customers by class for survey selection | | X |
| Determine actual customers to survey by class | X | |
| Provide advice as to what communication methods would work best for each customer type | X | |
| Design survey methods including random scientific survey | X | |
| For the purpose of educating customers, document information about Alectra Utilities including the services it provides | | X |
| Draft content of detailed distribution system information to use in explanations to customers | X | X |
| Review draft detailed information and provide feedback on as many drafts as necessary | X | |
| Logistics for (if any) focus groups, workshops, Town Hall meetings, specifically booking facilities and refreshments | | X |
| Analysing the raw data collected and presentation of results | X | |
| Regular reporting (as defined in Responsibilities) and identify and address issues and risks | X | |
| Lead any focus groups, workshops or surveys as recommended for all customer classes | X | |
| Make available subject matter experts to provide support during the process | | X |
| Draft Distribution System Plans and other evidence | | X |
| Review and provide comments on drafts of DSP and other evidence (incl. responses to IRs) for accuracy and appropriateness in reflecting customer consultation results | X | |
| Provide senior level expert to testify before the OEB | X | |
| Meet project budgets and timelines | X | |
| Provide final report/recommendations and amendments of DSP | X | |

**Responsibilities of the Consultant are included but not limited to:**

1. Assisting with the design and the consultation process which captures all of the methods indicated, and/or others if appropriate;

2. Making available subject matter experts to provide support during the process;

3. Determining a subset database of actual customers to survey by class as selected from Alectra Utilities' customer databases;

4. Ensuring complete understanding of Alectra Utilities and its service offerings and responsibilities;

5. Helping craft the detailed distribution system information and other materials to be used in explaining the DSPs to customers, or providing advice as to what communication methods would work best with the different customer classes;

6. Conducting pre-testing of the materials before they are utilized for the actual consultations;

7. Educating the customer about Alectra Utilities and the services it provides to the community, and documenting all information;

8. Leading any focus groups, workshops or surveys as recommended for all customer classes;

9. Leading (if any) Town Hall meetings and Open Houses, etc.,

10. Analysing raw data collected and presenting the results;

11. Assisting Alectra Utilities with the provision of the revised DSPs, as necessary, to customers and other stakeholders. The customer consultation for the Brampton and PowerStream rate zones will be a confirmation of the existing DSP. The customer consultation for the Enersource rate zone must provide evidentiary support to finalize the full Enersource DSP for filing with the OEB;

12. Reviewing and providing comments on drafts of the DSPs and other evidence for accuracy and appropriateness in reflecting customer consultation results;

13. Deploying consistent and senior personnel resources throughout the contract;

14. Providing regular communications and status updates to Alectra Utilities, in both written and oral form, as needed; these communications may need to be as frequent as daily during the intense consultation phase;

15. Tracking project performance, monitoring project activities and timelines in relation to set target/milestones;

16. Identifying and promptly addressing issues and risks associated with the overall project, resources, and individual tasks;

17. Organizing project documentation for all aspects of the project;

18. Providing project close out duties and final reporting, recommendations, and amendments of Alectra Utilities' DSPs with customer and other stakeholder input, providing specific evidence to support such recommendations;

19. Writing a final report(s) which is formal, professional, and of evidence-quality;

20. Providing a senior level expert to provide evidence, responses to interrogatories, and testify at the OEB if necessary;

21. Working with identified external parties, if any, in the interest of Alectra Utilities; and

22. Meeting project budgets and timelines.

**Qualifications**

1. The Consultant must have the professional qualifications to be able to conduct scientific surveying, and provide analysis and assistance in interpreting the results, as well as providing advice and recommendations on how to consider stakeholder input and possibly make changes to the DSPs, if necessary;

2. Experience working with Ontario distributors and/or other Ontario electricity entities in conducting customer and stakeholder consultation;

3. Significant experience in customer engagement processes for the purpose of extracting pertinent information necessary to obtain information relative to this project;

4. Demonstrated success in regulatory proceedings in providing evidence and, as necessary, testifying to its validity; experience with OEB proceedings is preferred;

5. Must be able to understand and have a working knowledge of the technical aspects of an a electricity distributor and its services;

6. The ability to translate technical information for the purpose of educating customers as to the operations, limitations, and obligations (among other things) of Alectra; and

7. Report writing capabilities.

**Timelines**

The final report for the purpose of drafting evidence will be completed by **May 1, 2017.**

## B. MATERIAL DISCLOSURES AND PRE-CONDITIONS OF AWARD

The material disclosures that apply to this RFP, if any, are set out below.

Not Applicable

### B.2 Pre-conditions of Award

The pre-conditions of award that apply to this RFP, if any, are set out below.

(a) Proponent must provide proof of insurance in the form of valid insurance certificates that confirm the insurance coverage required in the Standard Terms and Conditions in Appendix A of this RFP.

(b) Proof of workers' compensation coverage demonstrating non-expired clearance certificate from the Ontario Workplace Safety & Insurance Board or Independent Operators Certificate.

## C. MANDATORY TECHNICAL REQUIREMENTS

The mandatory technical requirements that apply to this RFP, if any, are set out below.

Not Applicable

## D. RATED CRITERIA

The following is an overview of the categories and weighting for the rated criteria of the RFP. Proponents who do not meet a minimum threshold score for a category will not proceed to the next stage of the evaluation process.

| **Rated Criteria Category** |
|---|
| D.1 Experience and Qualifications |
| D.2 References |
| D.3 Understanding of the Project |
| D.4 Project Management |
| **Appendix C Pricing** |

### D.1 Experience and Qualifications

Alectra will be relying on the professional expertise of the Consultant firm in order to fulfill the goals and objectives of this project. Each proponent should provide the following in its proposal:

(a) a brief description of the proponent;

(b) a detailed statement of the firm's qualification and previous experience in providing project services in relation to the Customer Consultation Services project;

(c) a detailed submission of the goods and services the proponent has previously delivered and/or is currently delivering for similar services relevant to the Deliverables, and where the project has been delivered on time and on budget. Include any information which illustrates your experience, expertise or special insight relevant to the Deliverables.

(d) a detailed statement of the demonstrated success of regulatory proceedings in providing evidence and, as necessary, testifying to its validity; experience with OEB proceedings;

(e) a full description of the proponent's experience working in the Utility Sector.

## D.2 References

Each proponent is requested to provide three (3) references from clients who have obtained goods or services similar to those requested in this RFP from the proponent in the last five (5) years. Proponents are not to use Alectra as a reference for this project.

Provide the company name, industry segment, contract person name, title and phone number, approximate size ($$ Rev), address, and a brief description of the work performed.

## D.3 Understanding of the Project

(a) Each proponent is to provide a written description of their understanding of the expected deliverables and subsequent services that addresses the goals and objectives of this project. Proponents are asked to describe:

   a. its firm's methodology, approach and work plan in order to meet the deliverables and timelines of this project.

   b. identify your process for survey participants, size of survey base;

   c. its understanding of the functional/technical requirements of the project

   d. issue tracking methodology;

   e. issue escalation methodology;

   f. change management methodology; and

   g. Alectra's resource utilization; explain in detail the skill set requirements and time expectations for Alectra staff;

(b) list the name of the single point of contact and any other primary individual(s) who would be responsible for Alectra's account and provide brief biographies including titles, functions, academic credentials, relevant experience, and an indication of their ability to manage and lead similar types of projects to a successful conclusion revelevant to the Deliverables. Identify and explain the role of any back up personnel that may be working on this project. Identify if staff are employed by your company or sub-contracted;

(c) a contingency resource plan must be identified should the proposed Project Manager and any other individuals relating to the project not be able to fulfill their role on the project as well as your plan for dealing with personnel changes; and

(d) the number of hours required by Alectra staff for this project.

## D.4 Project Management

### Start date of Project

(e) proponents are to provide a statement as to when the earliest date available would be to undertake this project.

### Changes to Scope of Work

(f) Alectra has provided as much detail as possible; however, there may be some circumstances where a scope change may be considered. Discuss your methodology to keep the work within scope while managing specific timelines. Also, discuss your process, policy and methodology for the determination and identification of scope change requirements throughout the project to ensure that the project stays on track. Any changes to the scope of the project will have to be reviewed and have written approval by the Alectra Project Manager prior to any action performed.

**Risk Management**

(g) describe any technical and non-technical risks that may be associated with this project and indicate how your firm is in the position to mitigate or reduce those risks. Please provide your comments on the risk strategy that is optimal at your company.

**Security of Information**

(h) identify what security measures and processes you have in place to secure and protect customer information.

**Schedule/ Milestones**

(i) Alectra's intention is to have a final report by May 1, 2017. Please describe the work plan, phases and timelines required in order to meet this date. The work plan shall be of such detail to demonstrate the proponent's ability to accomplish the project objectives and overall schedule.

**Value Add**

(j) clearly identify other services that are included in the overall scope of services they provide and that would add value to the project.

[End of RFP Particulars]

**BOMA-13**

**Reference(s): DSP; Appendix F; Appendix 1.0, Enersource Ratepayer Telephone Survey, p31**

**Please confirm that on p18, the "be wise with spending" is not translated into a maximum rate increase, rather than using the comment, which is open to many different interpretations. Why was a more precise answer sought?**

**Response:**

This question sought to understand general customer preferences as they relate to the trade-offs between general plant investments and bill impact. The intention was not to ask about specific costs impact related to general plant. This was addressed later in the customer consultation process in the telephone survey with a question that explored the aggregate bill impact of the Enersource RZ DSP through alternative scenarios.

Based on its experience, the view of Innovative Research Group is that in a telephone survey, customers prefer to comment on the aggregate rate impact of a DSP. Providing disaggregated bill impacts for system renewal, system service, system access, and general plant investments often leads to customer confusion in a telephone survey.

**BOMA-14**

**Reference(s): Ibid, p8-9**

**BOMA is unable to understand the presentation on pp8 and 9. On p8, please explain:**

**(a) "Well-served by the system" – Agree 85%, Disagree 83%, and on p9, please explain the same module "well-served by the system" – Agree 82%, Disagree 64%.**

**(b) Please compare those numbers to the responses to "well-served by the system" – Agree 40%, Disagree 46%, on p7.**

**(c) See p10 and p17 for same discrepancy in answers. Please explain.**

**Response:**

a) Under the "segmentation sidebars" (found on the right-hand side of many slides throughout the presentation), Innovative Research Group has shown how subgroups of customers have answered the same questions. The 3 categories used for customer segmentation are: "Annual Consumption" (ref: ibid, p5), "Bill Impact on Finances" (ibid, p6), and "Well Served by System" (ibid, p6).

On p8, the segmentation sidebars for "Well served by the system" indicate that the 85% of customers who feel they are well served by the electricity system in Ontario are familiar with their former utility, Enersource. On the other hand, of the customers who do not feel well served by the electricity system, 83% are familiar with Enersource.

b) Please see Alectra Utilities' response to part a), above.

c) Please see Alectra Utilities' response to part a), above.

**BOMA-15**

**Reference(s): DSP; Appendix F; Appendix 1.0, Enersource Ratepayer Telephone Survey**

**Please confirm that the first and second questions on rate increase do not specify the annual rate increase in each of 2017, 2018, 2019, 2020, and 2021. Why was this not done, rather than simply selecting a rate increase to 2022?**

**Response:**

The question refers to DSP Investment Alternatives (ibid, p21).

Based its experience, it is the opinion of Innovative Research Group that in a telephone survey, customers prefer to comment on, and better comprehend, the aggregate rate impact of a DSP over a 5-year period in actual dollars estimates as opposed to percentage change over the same period of time. Providing annual rate increases year-over-year is more likely to lead to customer confusion in a telephone survey.

**BOMA-16**

**Reference(s): DSP; Appendix F; Appendix 1.0, Enersource Ratepayer Telephone Survey. p26**

**Is the increase of 1.7% in the Enersource distribution rate in 2018 incremental to the $3.99 and $1.40 increases, referred to on pp 22 and 23? If yes, why is that not stated?**

**Response:**

Yes, the 1.7% in the Enersource RZ distribution rate in 2018 is incremental to the $3.99 and $1.40 increase scenarios. The incremental nature of the ICM impact on the typical Enersource RZ residential bill is clearly stated in the question preamble (ibid, p26).

**BOMA-17**

**Reference(s): DSP; Appendix F; Appendix 1.0, Enersource Ratepayer Telephone Survey, p26**

**The response demonstrates the very high concern customers have with the existing level of rates/bills. What are the current monthly distribution service charges (total amount, not the unit distribution rate) for each of the four residential customer consumption categories, and the amount of the total bill amount for the same four consumption categories.**

**Response:**

The current monthly distribution service charges and total bill amount for each of the fours residential customer consumption categories is provided in Table 1. The consumption related to each of the four consumption quartiles is provided in Alectra Utilities response to BOMA-25. The distribution service charge amount corresponds to 'Sub-Total A (excluding pass through)' on the Bill Impact tab of the IRM Model. The total bill impact incorporates the 8% provincial rebate.

**Table 1 – Current monthly distribution service charges and total bill amount.**

| Residential Rate Class Consumption Quartiles | Distribution Service Charge | Total Bill |
|---|---|---|
| First Quartile (365kWh/month) | **$22.23** | **$63.35** |
| Second Quartile (580kWh/month) | **$23.71** | **$87.84** |
| Third Quartile (788kWh/month) | **$25.15** | **$111.53** |
| Fourth Quartile (1328kWh/month) | **$28.88** | **$173.14** |

**BOMA-18**

**Reference(s): DSP; Appendix F; Appendix 1.0, Enersource Ratepayer Telephone Survey**

**Please confirm that the more engaged customers, that is the ones which would like more information on the breakdown of the forty-two cent ICM-related rate increase, are less willing to pay higher rates to maintain reliability (thirty-three percent) than the group which does not want more information (less engaged). Confirm similar results with respect to underground cable and overhead power line replacement. Please clarify the tables at the bottom of pp30, 33, and 36.**

**Response:**

Alectra Utilities does not confirm the statement. Customers who are willing to accept the aggregated $0.42 rate increase and those who say they cannot afford to pay more were asked if they would like more information on the specific ICM projects being proposed for 2018. All other respondents were asked about specific projects.

Refer to ICM Assessment Flow Chart (ibid, p28) and Recoded Addressing Capacity Needs (ibid, p30) Exhibit 3, Tab 1, Schedule 1, Attachment 51, for a complete explanation of how respondents were categorized under Maintain, Eventually Decline, Significantly Decline, and Don't know/Refused for the table on page 30, Exhibit 3, Tab 1, Schedule 1, Attachment 51.

Similarly, refer to p31 and p33 for an explanation of the table at the bottom of p33; as well as p34 and p36 for an explanation of the table at the bottom of p36**,** Exhibit 3, Tab 1, Schedule 1, Attachment 51.

**BOMA-19**

**Reference(s): DSP; Appendix F; Appendix 1.0, Enersource Ratepayer Telephone Survey, p33**

**Why is the posited increase ten cents here, down from sixteen cents in the previous table?**

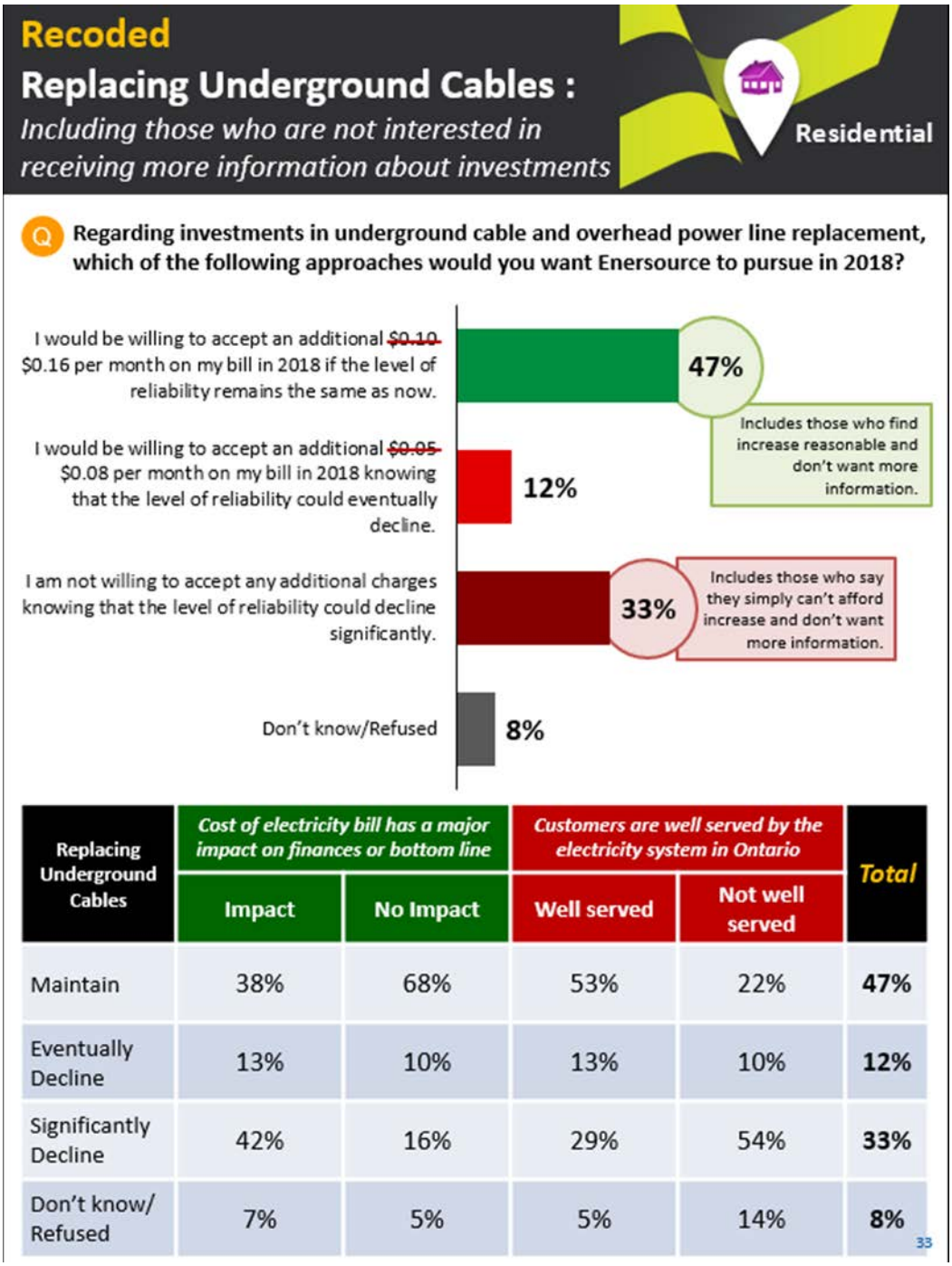
**Response:**

Alectra Utilities identifies that the table contains a typographical error and should read $0.16 and $0.08 under the first two response codes, respectively.

Alectra Utilities identifies that in the online and telephone surveys, customers were presented with the correct scenarios, i.e., $0.16 and $0.08 impact scenarios.

Alectra Utilities has provided a corrected version of the table, below.

Attachment 51, Appendix 1.0, Enersource Telephone Survey report, Page 33




| Replacing Underground Cables | Cost of electricity bill has a major impact on finances or bottom line | | Customers are well served by the electricity system in Ontario | | Total |
|---|---|---|---|---|---|
| | Impact | No Impact | Well served | Not well served | |
| Maintain | 38% | 68% | 53% | 22% | **47%** |
| Eventually Decline | 13% | 10% | 13% | 10% | **12%** |
| Significantly Decline | 42% | 16% | 29% | 54% | **33%** |
| Don't know/ Refused | 7% | 5% | 5% | 14% | **8%** |

33

1

**BOMA-20**

**Reference(s): DSP; Appendix F; Appendix 1.0, Enersource Ratepayer Telephone Survey**

**How are the "totals" column calculated in the tables at the bottom of pp31 and 33?**

**Response:**

Customer preference categories were created based on respondent answers to questions found on p26, 27 and 29 of the Enersource RZ Telephone Survey Report (Attachment 51, Appendix 1.0, Enersource Telephone Survey Report, pages 26, 27, 28)]. Please see Alectra Utilities' response to BOMA-18. Customer preference categories related to specific ICM projects were then cross-tabulated by customer segments. Please see Alectra Utilities' response to BOMA-14, i.e., "Bill Impact on Finances" and "Well Served by System".

**BOMA-21**

**Reference(s): DSP; Appendix F; Appendix 1.0, Enersource Ratepayer Telephone Survey, p39**

**(a) Do you agree that Enersource customers who answer positively to the general question are well-served, or not well-served by the electrical system in Ontario, would not necessarily answer in the same manner if the question used "Enersource", rather than "Ontario"?**

**(b) Why is Ontario used, rather than Enersource in this question?**

**Response:**

a) Customers may answer differently if “Enersource” had been used rather than “Ontario”, as this would be a different question than was asked in Alectra Utilities’ customer engagement.

b) The use of “Ontario” is a standard environmental control question commonly used by LDCs to benchmark general perceptions of the electricity sector in the province. For more information on environmental control questions, see Attachment 51, Customer Engagement Report, p11.

**BOMA-22**

**Reference(s): DSP; Appendix F; Appendix 1.0, Enersource Ratepayer Telephone Survey, p43**

**What step is Enersource taking to respond to requests for clearer bills?**

**Response:**

The Ontario Ministry of Energy ("MOE") has commenced the Redesign Action Plan initiative to redesign the electricity bill. The stated objective of the initiative is to optimize key sections of the bill to enhance the customer experience by:

- Improving accessibility and reducing frustration;
- Providing more useful information;
- Encouraging the adoption of consumer-oriented invoicing processes (e.g., consumer-tested design, mobile-compatible invoices); and
- Promoting a greater understanding of the contents of bills, and energy literacy, across the province.

Alectra Utilities is actively engaged in the MOE's stakeholder sessions. Alectra Utilities understands that the MOE may issue a directive, whether to the Ontario Energy Board ("OEB") or electricity distributors to implement a revised electricity bill format. Alectra Utilities is currently consolidating its Customer Information System ("CIS") across the four predecessor utilities. Once the bill redesign is known and an implementation timeline communicated, Alectra Utilities will work towards the new bill implementation.

**BOMA-23**

**Reference(s): DSP; Appendix F; Appendix 1.0, Enersource Ratepayer Telephone Survey, p52**

**Do you agree that the use of the word "eventually" in this question makes it easier to agree to the option?**

**Response:**

The reference question in this interrogatory for the Enersource RZ Telephone Survey was as follows: *With growth in various parts of Mississauga comes greater demand for electricity. This increased demand for electricity puts increased pressure on the existing electrical infrastructure. **Eventually**, further infrastructure investments will be required to support increased demand for electricity. **[emphasis added]***

*With this in mind, which of the following statements best represents your point of view?*

***[Read and Rotate statements 1 and 2]***

*1* *To help minimize immediate costs to customers, **Enersource** should defer investments in system capacity needs until there is noticable deficiencies in reliability.*

*2* ***Enersource** should proactively invest in system capacity infrastructure to ensure customers in high growth areas do not experience a decrease in reliability, even if this adds a small increase to customer bills.*

*98* *Don't know (**DNR**)*
*99* *Refused (**DNR**)*

Alectra Utilities does not agree. The word "eventually" is necessary in the question to make the statement true: i.e., "eventually" further electrical infrastructure investments will be required to support increased demand for electricity in Mississauga.

**BOMA-24**

**Reference(s): DSP; Appendix F; Appendix 1.0, Enersource Ratepayer Telephone Survey, p53**

**Please confirm that the words "improve reliability" should be replaced by the words "maintain reliability", unless Alectra's is forecasting an increase in reliability for Enersource rate zone customers in 2018. If Alectra is making such a commitment, where is that found in the evidence, and what is the magnitude of the increase (in SAIDI, SAIFI, and CAIDI)?**

**Response:**

The investments Alectra Utilities will be undertaking in the Enersource RZ will 'maintain reliability' at a system wide level, but provide 'improved reliability' for the local area being rebuilt.

**BOMA-25**

**Reference(s): DSP; Appendix F; Appendix 1.0, Enersource Ratepayer Telephone Survey, p38**

**Please provide the average annual kW energy consumption in 2016, 2015, 2014, for each quartile of the small business, residential, and medium business.**

**Response:**

The contact lists provided to Innovative Research Group from Alectra Utilities contained information on all active accounts in service since January 1, 2016 for residential, small commercial (GS < 50 kW), and large commercial (GS > 50 kW) customers. Contained within the customer contact lists was total annual consumption in kWh (from January 1, 2016 to December 31, 2016) for each account.

The tables below provide the average annual kWh consumption in 2016 for each quartile among the ratepayer groups surveyed by telephone in the Enersource RZ. This information is not available for 2014 and 2015, as similar research surveys based on rate class consumption quartiles was not conducted over this timeframe.

**Table 1 – Residential Average Annual Consumption**

| Customer Consumption Metrics | First Quartile (n=128) | Second Quartile (n=125) | Third Quartile (n=125) | Fourth Quartile (n=126) | Total (n=504) |
|---|---|---|---|---|---|
| Average Annual Consumption (kWh) | **4,378** | **6,955** | **9,451** | **15,952** | **9,169** |

**Table 2 – GS<50kW Average Annual Consumption**

| Customer Consumption Metrics | First Quartile (n=50) | Second Quartile (n=50) | Third Quartile (n=50) | Fourth Quartile (n=50) | Total (n=200) |
|---|---|---|---|---|---|
| Average Annual Consumption (kWh) | **6,524** | **16,183** | **34,377** | **85,061** | **35,536** |

**Table 3 - GS>50 kW Average Annual Consumption**

| Customer Consumption Metrics | First Quartile (n=49) | Second Quartile (n=50) | Third Quartile (n=50) | Fourth Quartile (n=51) | Total (n=200) |
|---|---|---|---|---|---|
| Average Annual Consumption (kWh) | **151,066** | **341,783** | **640,938** | **2,910,612** | **972,863** |

**BOMA-26**

**Reference(s): DSP; Appendix F; Appendix 1.0, Enersource Ratepayer Telephone Survey, p65**

**Do you agree that the two headlines on p65 on customer acceptance of increased spending for underground cable refurbishment, which state that a "plurality (32%) agree to spend an extra forty-six cents on their monthly bill to maintain reliability without also indicating that a larger plurality (39%) will not accept any additional charges, even while knowing that the level of reliability could decline significantly", and that a majority would either accept no increase or accept an increase of only half that proposed by the company (39% plus 13% or 52%), are misleading? Please answer fully.**

**Response:**

No, Alectra Utilities does not agree with the question above.

The question on p.65 was asked of small business customer except those who expressly did not want more detail on the ICM projects in question (n=112 of 200). Among this subgroup of small business customers, a plurality (39%) expressed an unwillingness to accept any additional charges to their bill.

**BOMA-27**

**Reference(s): DSP; Appendix F; Appendix 1.0, Enersource Ratepayer Telephone Survey, p59**

**Please confirm that a larger plurality (43%) than the one noted in the headline do not accept the increase of $1.17 per month to finance the requested ICM projects.**

**Response:**

Alectra Utilities does not confirm this statement. The assertion in the question above is incorrect.

One could assert that 14% of small business customers in the Enersource RZ do not accept the ICM related increase of $1.17 as they see it as unreasonable, but not 43%.

**BOMA-28**

**Reference(s): DSP; Appendix F; Appendix 1.0, Enersource Ratepayer Telephone Survey, p68**

**Please confirm that a majority of customers surveyed would not pay more than eighteen cents per month, which is one-half of the amount proposed by Enersource to fix leaking transformers.**

**Response:**

Alectra Utilities does not confirm the statement, above. The assertion in the question above is incorrect. One could assert that 26% would not pay more than $0.18 per month, but not a majority.

**BOMA-29**

**Reference(s): DSP; Appendix F; Appendix 1.0, Enersource Ratepayer Telephone Survey, p73**

**Why, in your view, has such a high percentage of customers not heard of Alectra Utilities?**

**Response:**

Alectra Utilities believes that this is a result of the three-way merger and subsequent acquisition to form Alectra Utilities was only months before the customer consultation and proactive communications initiatives had begun. Further, in this respect, customers started receiving bills from Alectra Utilities and introduction letters to the new utility only weeks earlier.

If this same question were asked of customers today, Alectra Utilities believes awareness levels would be higher.

**BOMA-30**

**Reference(s): DSP; Appendix F; Appendix 1.0, Enersource Ratepayer Telephone Survey, p87**

**(a) Please confirm that the headline "1 in 3 would be willing to pay more in order to maintain current reliability" is misleading, as it does not say how much the one-third would be willing to pay, nor does it say that an equal number of customers would pay only one-third the proposed amount, even knowing that reliability could eventually go down and a larger number (40%) would spend zero, even knowing the level of reliability may decline significantly.**

**(b) Please explain why so many of the headlines, when dealing with cost/willingness to spend systematically highlight positive responses (for example, see pp81 and 65).**

**Response:**

a) Alectra Utilities does not confirm the statement. Alectra Utilities agrees that the headline on p87 should read "***Roughly*** 1-in-3 ***(28%)*** would be willing to pay more in order to maintain current reliability …"

b) Regardless of the reader's interpretation of the data presented on any particular slide, the overall customer engagement research tells a clear story of customer needs and preferences: *The vast majority of Alectra Utilities customers are satisfied with their current level of reliability, and most support some form of investment program (whether that be the proposed amount or a paced approach) that ensures a consistently reliable and modern distribution system.*

**BOMA-31**

**Reference(s): DSP; Appendix F; Appendix 1.0, Enersource Ratepayer Telephone Survey, p92**

**The headline states "ICM Rate Impact; a plurality that proposed increase is reasonable". Please confirm that the headline does not disclose that the plurality is only thirty-seven percent, and a majority (63%) are either unwilling to pay more (29%) or say they would like to hear more about how the money would be invested prior to accepting it.**

**Response:**

Alectra Utilities does not agree with the confirm the statement in the question, above; the assertion in the question is incorrect.

One could assert that 8% of mid-sized business customers in the Enersource RZ do not accept the ICM related increase of $21.76 as they see it as unreasonable.

To sum “those who would like more information” (36%), “those who oppose the rate increase” (8%), and “those who feel they cannot afford a rate increase” (19%) to arrive at a majority of 63% would be incorrect given the different opinions towards ICM investments.

Further, when asked subsequent questions on particular projects, many of the respondents who “would like more information” or “feel they cannot afford a rate increase” in fact supported a variety of the presented investment projects.

**BOMA-32**

**Reference(s): DSP; Appendix F; Appendix 1.0, Enersource Ratepayer Telephone Survey p98**

**What increase was in fact used?**

**Response:**

The GS > 50kW (mid-sized business) customers in the Enersource RZ were presented with a proposed monthly increase of $21.76 in 2018 on the distribution portion of their electricity bills. This represents an incremental increase of 1.8% on the amount remitted to Alectra Utilities in the Enersource RZ and a 0.1% increase on the total electricity bill for the typical mid-sized business customer.

**BOMA-33**

**Reference(s): DSP; Appendix F; Appendix 1.0, Enersource Ratepayer Telephone Survey, p95**

**Please confirm that the headline, in that it states that a plurality (44%) would pay an additional $5.82 to maintain current reliability without also noting that a larger plurality (49%) would either accept only half that proposed monthly increase (17%) or no increase whatsoever (32%) knowing that the level of reliability could decline significantly, is misleading.**

**Response:**

Alectra Utilities does not confirm the statement in the interrogatory, above. The existing heading is accurate. The additional information referred to in the question is clearly provided in the results.

Regardless of the reader's interpretation of the data presented on any particular slide, the overall customer engagement research tells a clear and undeniable story of customer needs and preferences: *The vast majority of Alectra Utilities customers are satisfied with their current level of reliability, and most support some form of investment program (whether that be the proposed amount or a paced approach) that ensures a consistently reliable and modern distribution system.*

**BOMA-34**

**Reference(s): DSP; Appendix F; Appendix 1.0, Enersource Ratepayer Telephone Survey, p101**

**(a) Please confirm that thirty-nine percent would only accept half the proposed investment in transformers ($3.21 or $6.42 per month), while forty-two percent would accept the full amount, yet the headline makes no mention of the initial 50-50 split in customer preferences, thereby rendering it misleading.**

**(b) For each of the proposed increase to rates proposed for leaking transformers, pole replacement, underground transformers, and stations, in which a majority of customers accepted only a lesser (one-half to one-third) of the proposed or refused to accept any increases, what was the increase for that category of customers used in the Enersource 2018 proposal? Was it the proposed amount, or the lesser amount? Please discuss.**

**Response:**

a) No, Alectra Utilities does not believe the existing headline on p101 is misleading as it is both factual and accurate. Please refer to p.102 for the overall mid-size business customers' preference towards the replacement of leaking transformers in the Enersource RZ.

b) As discussed in Exhibit 2, Tab 4, Schedule 11, p.24, Alectra Utilities identified twelve discrete and material capital projects for presentation to customers which totaled approximately $28.6MM for the Enersource Rate Zone. These included the leaking transformer replacement project, subdivision and overhead rebuild projects, substation upgrade projects and a road project. These are presented in Exhibit 2, Tab 4, Schedule 11, Table 137 – Eligible Capital Projects for Customer Consultation Enersource RZ, p. 25. As identified in the Innovative Report, customers were presented with the 2018 bill impacts related to the implementation of the twelve projects identified in Table 137. Based on its feedback from customers, Alectra Utilities revised the 2018 capital forecast and Incremental Capital Module ("ICM") request to remove the Webb Municipal Station substation upgrade project. The ICM Bill Impacts, by customer class, for the remaining eleven proposed projects is provided at Exhibit 2, Tab 4, Schedule 11, Table 148 – ICM Bill Impacts (Total Bill) – Enersource RZ, p.49.

**BOMA-35**

**Reference(s): Ibid, Appendix 3, p8**

**Was the survey done online, in person, or over telephone? Please confirm that there were seven large customers in the consultation.**

**Response:**

The survey was conducted online. A total of seven large customers participated in the consultation from the Enersource RZ.

**BOMA-36**

**Reference(s): Ibid, p10**

**Please explain why the seven day delay in receiving real time internal data for Enersource web portal. Why is there a delay, and when will the delay be reduced to zero?**

**Response:**

Enersource implemented an internal web presentment pilot project in 2015/2016, with an upgrade to the load profile settlement system. The project plan was to develop this system as a web presentment solution for all interval general service customers, however as a result of the merger no further development has been completed as this is not the preferred solution for Alectra. There are currently a small number of customers that have access to this web presentment portal where the process of exporting data to this system is manual and currently completed on a weekly basis, generally every Thursday, and as such real time data can be delayed up to seven days. Customers may request an update for their real time interval data at any time and this will be provided.

Alectra Utilities will have a web presentment solution which provides real time interval data which is anticipated to be available with the consolidation of the PowerStream and Enersource CIS systems in May 2018.

**BOMA-37**

**Reference(s): Ibid, p18**

**If you were to meet the five-year plan request, do you view that as a service paid for by all ratepayers, the large customer class, or by the requesting customer? Please discuss.**

**Response:**

Alectra Utilities declines responding to this question on the basis that the question is not relevant to any issue in the application.

**BOMA-38**

**Reference(s): Ibid, p20**

**The headline states that most large users are willing to pay more for reliability or don't know. Do you agree that the customer responses are that two of seven would pay "a bit more" on distribution rates to maintain the existing level of reliability, one of the seven would pay no more (wants to pay less), and three don't know? Do you agree that the headline, as stated, does not fairly reflect the actual responses?**

**Response:**

Alectra Utilities agrees that the customer responses are:

a) one-in-seven customers would like to pay more if it resulted in improved reliability and quality;

b) two-in-seven would pay "a bit more" on distribution rates to maintain the existing level of reliability;

c) one-in-seven would pay no more (wants to pay less) even if it resulted in lowering the current level of power quality and reliability; and

d) three-in-seven don't know.

The existing headline is accurate.

**BOMA-39**

**Reference(s): Ibid, p21**

**Please confirm that the headline, discussed in paragraph 38, above, would be more accurate if it added the phrase "two of seven would not pay any more, or the full amount requested, to maintain reliability, and".**

**Response:**

Alectra Utilities does not confirm the statement. Adding the suggested phrase to the existing headline would not make it more.

**BOMA-40**

**Reference(s): Ibid, Appendix 4, p3**

**(a) How many of each category of customers answered all of the questions on the portal?**

**(b) Please confirm the number of small businesses in each of the four zones is too small to be statistically significant.**

**Response:**

a) Alectra Utilities had a total of 16,462 or 17,306 residential customers that answered all mandatory online portal questions. A total of 273 out of 289 small business customers answered all mandatory online portal questions.

b) Statistical significance cannot be applied to an online, voluntary survey as it is not a random sample.

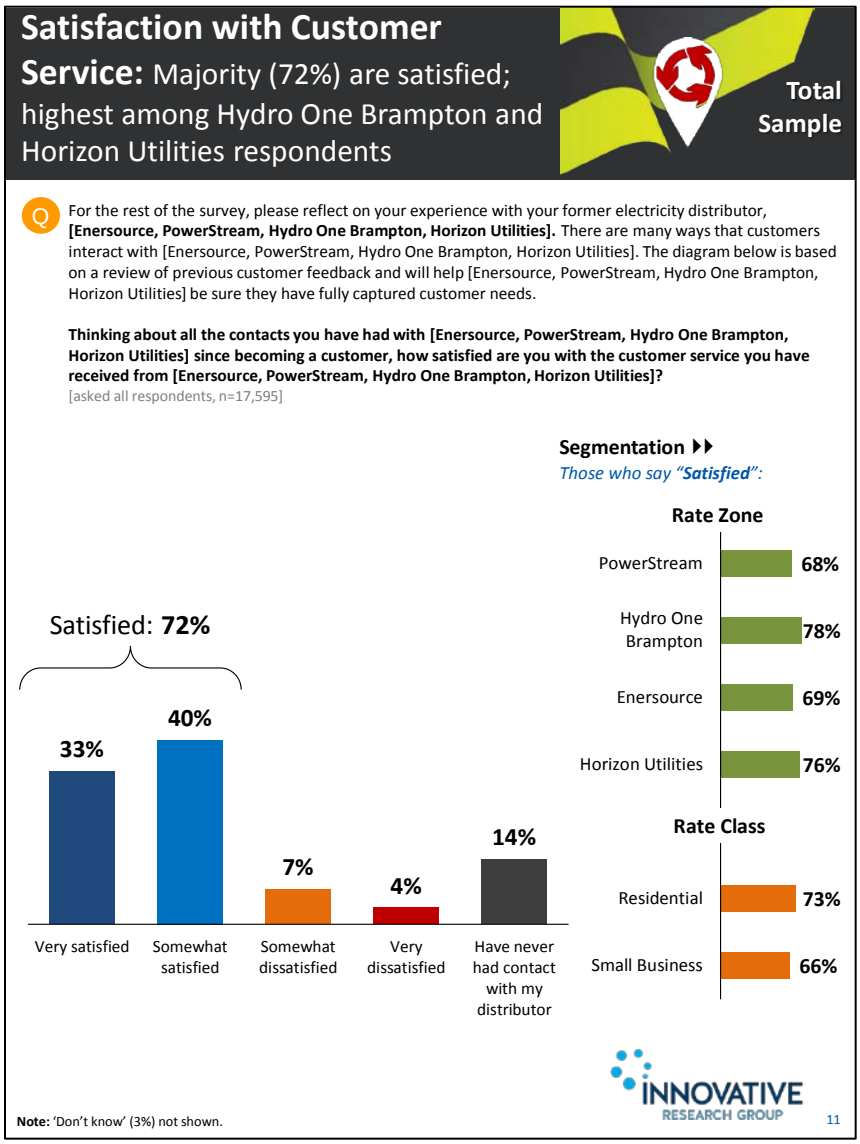
**BOMA-41**

**Reference(s): Ibid, p13**

**Why would only sixty-nine percent of Enersource customers who participated pronounce themselves satisfied with their customer service, while Brampton and Horizon were seventy-eight percent and seventy-six percent, respectively? What lessons are available to Alectra (Enersource) from the two other divisions with significantly higher satisfaction ratings?**

**Response:**

Reference Slide:



The difference in customer satisfaction levels across rate zones is a function of multiple variables. Variables that Alectra Utilities can control, include: customer experience, communications, reliability (SAIDI, SAIFI, CAIDI and power quality) and distribution rates related to each of its four legacy distributors. Variables that Alectra Utilities cannot control include: socio-economic characteristics, demographics, and psychographics of the customers who voluntarily responded to our online survey.

In the representative customer telephone surveys, 79% of residential customers in both the Enersource RZ and PowerStream RZ identified that they are satisfied with the services they receive from Alectra Utilities.

Alectra Utilities is committed to continuous improvement in the services it provides to customers. To help identify areas for service improvements, Alectra Utilities conducts on-going customer engagement, beyond the required rate application customer engagement.

As part of Alectra Utilities' commitment to continuous service improvements, it is in the process of bringing together best practices in customer service from all of its four legacy distributors.

**BOMA-42**

**Reference(s): Ibid, p16**

**Given reasonable distribution rates are a higher priority for customers than ensuring reliable electrical service, by two times (49% vs. 23%), why is Enersource proposing significant rate increases?**

**Response:**

Please see Alectra Utilities' explanation for a proposed rate increase in Attachment 51, p27.

**BOMA-43**

**Reference(s): Ibid, p22**

**Please explain why the headline on restoration times after outages was not divided into very satisfied and somewhat satisfied, rather than single word "satisfied", which in the circumstances is misleading.**

**Response:**

The existing headline is accurate, as it accurately encompasses both respondent groups who expressed satisfaction with restoration times. The additional information, regarding the percentage of “very satisfied” and “somewhat satisfied” respondents, is clearly provided in the results.

**BOMA-44**

**Reference(s): Ibid, p26**

**(a) Fifty-eight percent (Enersource) and fifty-seven percent (PowerStream) average satisfaction rating on customer services is not impressive. What is being done to improve these ratings? Please discuss.**

**(b) Brampton has the best rating on customer service by a significant margin, followed by Horizon. What is Alectra doing to transfer learnings from Brampton to the three other divisions, especially Enersource and PowerStream?**

**Response:**

a) Alectra Utilities is committed to providing its customers with quality customer service that meets their needs. Alectra Utilities is investing in its Customer Information System and Outage Management System, as well as its customer self-serve options, in order to better assist customers.

Within a continuous improvement framework, Alectra Utilities is reviewing current practices and procedures associated with the four legacy LDCs, as it continues to integrate the operations of its four predecessor organizations.

b) Alectra Utilities is committed to continuous improvement and to drawing on the strengths and lessons learned from its four predecessor organizations. Management is reviewing the customer service practices of each of the four predecessor organizations as part of the integration initiative and intends to implement the best practices within Alectra Utilities.

**BOMA-45**

**Reference(s): Ibid, p29**

**What was the cost of PowerStream's proposed system access investment?**

**Response:**

The proposed cost of the system access investment was $11.2MM. Please see Exhibit 3, Tab 1, Schedule 1, Attachment 51, Appendix 5.0, p42.

**BOMA-46**

**Reference(s): Ibid, p30**

**Why would the headline not also include the statement that a larger plurality (40%) would either pay only half the proposed increased amount ($0.06 vs. $0.13) (8%), while thirty-four percent would not accept any increase, even knowing that reliability could decline significantly as a result?**

**Response:**

The existing headline is accurate. The headlines are included in Appendices 1.0 – 4.0, in order to draw the reader's attention to the most salient findings from the data.

Regardless of the reader's interpretation of the data presented on any particular slide, the overall customer engagement research tells a clear and undeniable story of customer needs and preferences: *The vast majority of Alectra Utilities customers are satisfied with their current level of reliability, and most support some form of investment program (whether that be the proposed amount or a paced approach) that ensures a consistently reliable and modern distribution system.*

**BOMA-47**

**Reference(s): Ibid, p31**

**Why does the headline also include the fact that forty-one percent of surveyed customers would pay only half the proposed rate increase, and that seventy-five percent of that forty-one percent would pay no increase even if reliability could decline significantly?**

**Response:**

Alectra Utilities identifies that the interrogatory above is unclear. The question above does not pertain to Appendix 4.0, Online Feedback Portal Feedback, p31 (nor to any other information presented in Appendix 4.0).

**BOMA-48**

**Reference(s): Ibid, p32**

**Why does the headline not also mention that a larger plurality (43% vs. 32%) would either not pay more than half the amount proposed (17%) while thirty-six percent would not be willing to pay any more, knowing that reliability could decline eventually and significantly, respectively?**

**Response:**

The headline would better read on p.32 for online feedback from small businesses in the PowerStream RZ: "*Plurality (36%) of customers not willing to accept any additional changes knowing that the level of reliability could decline significantly*".

The statistically significant telephone survey reveals that a majority of PowerStream RZ small business customers support the proposed investments in all ICM projects.

**BOMA-49**

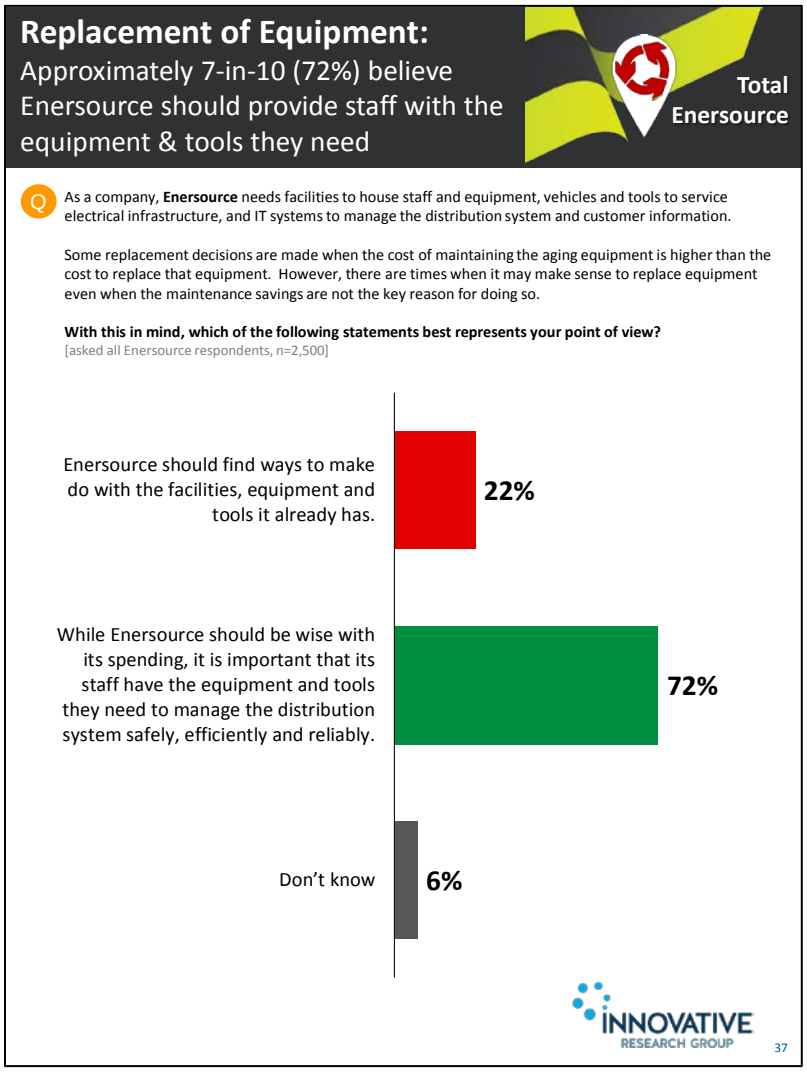
**Reference(s): Ibid, p37**

**Would you agree that this question would be improved if:**
**(a) it noted that the rate increase would be to provide the tools and equipment the staff requires?**
**(b) define what is meant by "wise in its spending" in quantitative terms;**
**(c) pose the two options in less extreme fashion, eg "no new tools" vs. carte blanche for new tools.**

**Please discuss.**

**Response:**

Alectra Utilities provides the Reference Slide:



Response to a) –c):

No, the question would not be improved from its intended purpose with the suggested edits.

The question was designed to assess general preferences related to the trade-offs between investments in general plant and costs to ratepayers. *Do customer believe Alectra should have the tools, equipment, IT systems and facilities it needs to effectively operate the distribution system vs. make do with existing general plant?*

Customers were asked about the cost impact of the DSP investments for the Enersource RZ in aggregate following general trade-off questions.

Based on Innovative Research Group's past experience, customers generally prefer to answer questions related to DSP rate impact in aggregate (dollar amounts) over the period of the investment plan (see ibid, p39 and p40). This form of questioning enables customers to better understand the bottom-line rate impact of a distributor's proposed investment program.

**BOMA-50**

**Reference(s): Ibid, p39**

**Please indicate the increase in residential customer rates per month in each of 2018, 2019, 2020, 2021, and 2022, corresponding to the $3.99 and $1.40 numbers in 2022.**

**Response:**

The increase in residential customer rates per month in each of 2018 through 2022 is provided in Table 1, below. The bill impacts presented in Table 1 incorporate the projected customer rate impact given the varying levels of reliability presented in the Customer Engagement Process. As provided in Exhibit 3, Tab 1, Schedule 1, Attachment 51 – Innovative Customer Engagement Report, Appendix 4.0 – Customer Feedback Portal Online Ratepayer Survey, p.30,

> *"While Enersource proposed a plan that maintains the current level of reliability, as part of its planning process, it has looked at a number of alternative scenarios; one where the level of reliability is maintained; one where the level of reliability eventually declines; and one where no new investments are made and reliability could decline significantly."*

**Table 1 – Residential Customer rates per month 2018-2022**

| Residential | Maintain Reliability | Reliability Declines |
|---|---|---|
| **2018** | $1.12 | $0.27 |
| **2019** | $1.82 | $0.55 |
| **2020** | $2.54 | $0.83 |
| **2021** | $3.26 | $1.11 |
| **2022** | $3.99 | $1.40 |

**BOMA-51**

**Reference(s): Ibid, p40**

**Would not the headline be more accurate if it noted that fifty percent of the respondents agreed to pay no more than half the proposed $11.19 per month in 2022 to ensure current reliability would be maintained, and of that fifty percent, twenty-four percent would be willing to pay no increased rate in 2022 (or presumably, in any intervening year, 2018, 2019, 2020, 2021), even if it meant reliability could eventually decline significantly?**

**Response:**

Alectra Utilities believes that the existing headline is accurate.

Regardless of the reader's interpretation of the data presented on any particular slide, the overall customer engagement research tells a clear and undeniable story of customer needs and preferences: *The vast majority of Alectra Utilities customers are satisfied with their current level of reliability, and most support some form of investment program (whether that be the proposed amount or a paced approach) that ensures a consistently reliable and modern distribution system.*

**BOMA-52**

**Reference(s): Ibid, p38**

**What does Enersource plan to do to disabuse customers of the idea that increasing investments will result in increased reliability, when customers seem to believe that more spending means increases in reliability levels?**

**Response:**

The premise of the question is not a fair extrapolation of the Online Workbook. For example, at Alectra Utilities' Online Feedback Portal Layout which can be found at Attachment 51, Appendix 5.0, page 30, Alectra Utilities has indicated that in the Enersource Rate Zone it has proposed a plan that maintains the current level of reliability.

**BOMA-53**

**Reference(s): Ibid, pp41, 42**

**Why was the nature of the "system service" investments not explained in these questions?**

**Response:**

The nature of “system service” was explained in detail to respondents in the online feedback portal. See Appendix 5.0, Online Feedback Portal Layout, p34, 36 and 38 for the information presented to respondents.

**BOMA-54**

**Reference(s): Enersource DSP, p285**

**Please provide the details of each deferred or cancelled project, which make up the $6.8 million in pacing of the capital investments over the plan period, and why they were chosen for "pacing":**

**(a) as described on this page;**

**(b) on the deferral of the expansion investment related to LRT "deferral and adjusted" (lower 2018 expenditures and higher 2022 expenditures) is as a result of deferral of the LRT project by the relevant agency, for the reason(s). Please explain fully.**

**Response:**

a) Various pacing adjustments were made to planned projects for the years 2017-2022. Some projects were moved out to later years; while some were accelerated to balance the work-load. Please see below for adjustments made:

| BU | Project | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | Total |
|---|---|---|---|---|---|---|---|---|
| C0504 | Webb MS | ($1,775,000) | ($2,525,000) | $2,000,000 | $2,300,000 | | | $0 |
| C0504 | York MS | $1,000,000 | ($1,000,000) | | | | | $0 |
| C0504 | Park Royal | | $1,000,000 | ($1,000,000) | | | | $0 |
| C0504 | Mini Britannia | | | ($2,500,000) | ($2,500,000) | $2,500,000 | $2,500,000 | $0 |
| C0504 | Summerville MS | | | | | $140,000 | ($140,000) | $0 |
| C0504 | Duke MS | | | | | ($3,100,000) | ($2,000,000) | ($5,100,000) |
| C0504 | Shawson MS | | | | | | ($950,000) | ($950,000) |
| C0504 | York MS | | | | | | ($800,000) | ($800,000) |
| **C0504** | **Total** | **($775,000)** | **($2,525,000)** | **($1,500,000)** | **($200,000)** | **($460,000)** | **($1,390,000)** | **($6,850,000)** |
| C0507 | Southdown - South of Royal Windsor | $500,000 | | | | | | $500,000 |
| C0507 | Webb MS - Feeder Egress | ($1,200,000) | ($1,200,000) | $1,200,000 | $1,200,000 | | | $0 |
| C0507 | Stavebank & Port | $300,000 | | | | | | $300,000 |
| C0507 | Derry Road Extension | $200,000 | | | | | | $200,000 |
| C0507 | Hensall Circle Conversion to 13.8KV | $200,000 | | | | | | $200,000 |
| C0507 | Mini Orlando Feeder Egress | $40,000 | | | | | | $40,000 |
| C0507 | Derry - WCB to Argentia | | $1,140,000 | ($1,140,000) | | | | $0 |
| C0507 | Mini BritanniaTS Feeder Egress | | | ($1,200,000) | ($1,200,000) | $1,200,000 | $1,200,000 | $0 |
| C0507 | Centreview - Mavis to Duke | | | $1,200,000 | ($1,200,000) | | | $0 |
| C0507 | Derry - Airport to Goreway | | | | $1,200,000 | ($1,200,000) | | $0 |
| C0507 | Duke MS Feeder Egress | | | | | ($1,200,000) | ($1,200,000) | ($2,400,000) |
| C0507 | Lakeshore - Clarkson to Bexhill | | | | | $1,200,000 | ($1,200,000) | $0 |
| C0507 | New Project - TBD | | | | | | $1,200,000 | $1,200,000 |
| **C0507** | **Total** | **$40,000** | **($60,000)** | **$60,000** | **$0** | **$0** | **$0** | **$40,000** |
| C0532 | LR LRT Construction | | ($4,000,000) | | | | $4,000,000 | $0 |
| C0532 | LR CIAC | | $1,500,000 | | | | ($1,500,000) | $0 |
| **C0532** | **Total** | **$0** | **($2,500,000)** | **$0** | **$0** | **$0** | **$2,500,000** | **$0** |
| **Grand Total** | | **($735,000)** | **($5,085,000)** | **($1,440,000)** | **($200,000)** | **($460,000)** | **$1,110,000** | **($6,810,000)** |

b) The reason for deferral of the $2.5M investment in LRT from 2018 to 2022 is due to a delay in the Design work, which has delayed the project by six months. Construction is anticipated to start in 2018; the project, however, will now be completed in 2022. Six months' worth of investment, amounting to $2.5M, has therefore been deferred to 2022 from 2017.

**BOMA-55**

**Reference(s): Enersource DSP, p285**

**(a) Please explain in more detail the use of CDM in high growth parts of the Mississauga during the DSP planning period.**

**(b) Leaking Transformer – What does the $0.17 monthly increase become if you delay replacement of some of them (2,000 transfer showing "signs of oil leaking")?**

**Response:**

a) Details regarding the CDM initiatives in the Downtown Core are provided in Section 2.3.2.2 of the Alectra Utilities DSP for the Enersource RZ (E3/T1/S1 Pages 222 and 223).

b) During the customer engagement, 38% of customers were willing to accept an additional $0.35 per month on their bill to replace leaking transformers on schedule. 26% of customers were willing to accept an additional $0.17 per month in 2018 to defer costs associated with replacement. The additional $0.17 per month assumes that the project cost of $8.4MM for the Leaking Transformer Replacement Project was reduced by 50%, resulting in the replacement of only a portion of the identified 2000 transformers.

**BOMA-56**

**Reference(s): Enersource DSP, p45, and throughout the Innovative Reports/Appendices**

**What is meant by the oft repeated statement that the level of reliability would eventually decline? What percentage increase in SAIDI or SAIFI is likely, over what period of time?**

**Response:**

Alectra Utilities completed an assessment of the reliability impact for the three scenarios presented in the Customer Engagement for customer input and feedback. The scenario that the level of reliability would eventually decline was assessed under the approach 50% of the proposed ICM projects would be approved. The scenario that the level of reliability would decline significantly was assessed under the approach that none of the ICM projects would be approved. The assessment of the impact was over the five year period 2018-2022.

Table 1 identifies the ranges of reliability declining impacts assessed under each scenario in SAIDI minutes.

**Table 1 – Assessment of Reliability Impact for Scenarios for SAIDI (minutes)**

| Year | Reliability Eventually Declines | Reliability Could Decline Significantly |
|---|---|---|
| 2018 | 0.45 – 1.22 | 1.22 – 1.40 |
| 2019 | 1.22 – 2.35 | 1.40 – 2.82 |
| 2020 | 1.74 – 3.09 | 2.18 – 3.75 |
| 2021 | 2.48 – 4.51 | 2.52 – 5.58 |
| 2022 | 3.50 – 6.06 | 4.13 – 7.55 |

Table 2 identifies the ranges of reliability declining impacts assessed under each scenario in SAIDI % relative to 2016 levels.

**Table 2 – Impact to Reliability in terms of SAIDI % (relative to 2016)**

| Year | Reliability Eventually Declines | Reliability Could Decline Significantly |
|---|---|---|
| 2018 | 0.93% - 2.52% | 2.52% - 2.88% |
| 2019 | 2.52% - 4.84% | 2.88% - 5.80% |
| 2020 | 3.58% - 6.37% | 4.48% - 7.73% |
| 2021 | 5.10% - 9.29% | 5.18% - 11.51% |
| 2022 | 7.22% - 12.50% | 8.51% - 15.57% |

In 2016, the former Enersource Hydro Mississauga did not meet the OEB Scorecard target of 36.6 minutes for the average number of hours that a customer is interrupted (SAIDI). In the 2016 Scorecard Management Discussion and Analysis, Alectra Utilities identified that the target was not achieved due to an increasing number of equipment failures led by cable failures. Alectra Utilities identified that it intends to increase the amount of renewals in the near term to reverse the trend of deteriorating reliability performance. Without the increased funds for renewals, Alectra Utilities predicts that it will continue not achieving the OEB Scorecard SAIDI targets over the assessment period.

**BOMA-57**

**Reference(s): DSP/General**

**What percentage of underground cable in Enersource's service territory are currently installed in ducts?**

**Response:**

Alectra Utilities estimates that 59% of cables in the Enersource Rate Zone ("ERZ") are installed in duct as of December 31, 2015.

**BOMA-58**

**Reference(s): DSP, p8, line 28**

**What is the budget status (actual vs. approved) for each phase of the refurbishment of Martin Avenue pole line?**

**Response:**

The refurbishment of Marin Avenue pole line is not a project in the Alectra Utilities application nor DSP.

**BOMA-59**

**Reference(s): DSP, p44**

**Has Enersource investigated the use of injection to stabilize the performance of underground cables? If not, why not?**

**Response:**

Alectra Utilities Enersource has investigated the use of cable injection as an option for all underground cable rebuild projects in the Enersource RZ. Alectra Utilities has determined that many of the rebuild areas identified in the capital plan are not suited for cable injection since the cables in these respective locations contain solid-type conductors, which cannot be injected. Further, for some of these rebuild projects, the use of cable injection technology is further impeded due to the uncertainty of the large number of splice locations in the area; and high probability of corroded neutrals. Since 95% of cable failures have been unjacketed cable, there is a chance the neutral could be corroded which would result in failure even if the cable is injected. Moreover, since many of these are direct buried cables have previously failed, the splices would have to be replaced to allow the solution to flow through the splice, increasing the cost of injection. The feasibility of cable injection technology is discussed in each of the business cases for the Enersource RZ, provided in Exhibit 3, Tab 1, Schedule 1, Attachment 47 – ICM Business Cases Enersource RZ.

**BOMA-60**

**Reference(s): DSP, p53**

**Please provide information on Electrical Safety Authority annual or biennial audits. Please provide copies or a link where they can be obtained.**

**Response:**

Information regarding a LDCs performance in the annual Electrical Safety Authority ("ESA") audits and periodic Due Diligence Inspections ("DDIs") is measured by Component B: The level of compliance with Regulation 22/04: Electrical Distribution Safety in the Ontario Energy Board's ("OEB") Electricity Scorecard. This metric measures a distributor's level of compliance with Ontario Regulation 22/04 – Electrical Distribution Safety by:

- The ESA's evaluation of the annual compliance audit; and
- The ESA's evaluation of DDIs, Reports of Public Safety Concerns, and Compliance Investigations.

The most recent OEB Scorecard for the Enersource RZ shows that the ESA awarded Enersource a rating of 'Compliant' for 2011 to 2015 inclusive. The 2016 OEB Scorecard for Enersource is published on the OEB's website.

**BOMA-61**

**Reference(s): DSP, p55**

**"Interruption categories such as defective equipment and adverse weather-related outages have been progressively trending upward".**

**Please define defective equipment vs. normal wear and tear. To what extent can the company recover damages, etc. from suppliers of such equipment?**

**Response:**

Defective equipment is defined based on the OEB's reporting cause codes for the various causes of interruption as outlined in the *Electricity Reporting & Record Keep Requirements,* dated May 3, 2016. Cause code 5, Defective Equipment, is defined as "*customer interruptions resulting from distributor equipment failures due to deterioration from age, incorrect maintenance, or imminent failures detected by maintenance".* Normal wear and tear is captured in this definition of defective equipment with reference to "deterioration from age". This definition does not include defective equipment from suppliers.

**BOMA-62**

**Reference(s): DSP, p56 et seq**

**(a) Do Tables 3 through 6 include scheduled outages? What percentage are scheduled? See Table 7. Please provide the Tables 3 through 6 without scheduled outages plan, but including MED and LOS. Please explain, in detail, the contribution of scheduled outages to SAIFI and SAIDI.**

**(b) Do you agree that Table 7 shows improvement in SAIFI over 2014, 2015 and 2016?**

**Response:**

(a) Tables 3 through 6 provided in Exhibit 3, Tab 1, Schedule 1, Attachment 50 – Enersource Rate Zone DSP, p. 55-57, include scheduled outages. Table 1 below, provides the percentage of scheduled outages for SAIDI and SAIFI based on the data provided in Table 3 – Trends in Reliability Indices 2010-2016 (including MED and LOS), of the Enersource Rate Zone DSP.

Table 1 – Percentage of scheduled outages for SAIDI and SAIFI

| KPI | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 |
|---|---|---|---|---|---|---|---|
| % of Scheduled outages for SAIDI | 29.00% | 7.00% | 5.00% | 2.00% | 12.00% | 17.00% | 19.00% |

Tables 3 through 6, provided in the Enersource Rate Zone DSP have been reproduced below to exclude scheduled outages and include Major Event Days ("MED") and Loss of Supply ("LOS").

Table 2 – Trends in Reliability Indices 2010 – 2016 (including MED and LOS, Excluding SCHEDULED Outages)

| KPI | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 |
|---|---|---|---|---|---|---|---|
| SAIDI | 25.04 | 49.76 | 39.81 | 315.33 | 35.61 | 36.22 | 39.45 |
| 3-Yr Average SAIDI | 25.81 | 36.17 | 38.20 | 134.96 | 130.25 | 129.05 | 37.09 |
| SAIFI | 1.21 | 1.96 | 1.71 | 2.67 | 1.11 | 1.60 | 1.08 |
| 3-Yr Average SAIFI | 1.03 | 1.44 | 1.62 | 2.11 | 1.83 | 1.79 | 1.26 |
| CAIDI | 20.73 | 25.43 | 23.32 | 117.90 | 32.09 | 22.64 | 36.49 |
| 3-Yr Average CAIDI | 25.14 | 25.07 | 23.16 | 55.55 | 57.77 | 57.54 | 30.41 |

Table 3 – Trends in Reliability Indices 2010 – 2016 (excluding MED; including LOS; excluding SCHEDULED Outages)

| KPI | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 |
|---|---|---|---|---|---|---|---|
| SAIDI | 25.04 | 49.76 | 39.81 | 31.04 | 26.80 | 36.22 | 39.45 |
| 3-Yr Average SAIDI | 25.81 | 36.17 | 38.20 | 40.20 | 32.55 | 31.35 | 34.16 |
| SAIFI | 1.21 | 1.96 | 1.71 | 1.37 | 0.95 | 1.60 | 1.08 |
| 3-Yr Average SAIFI | 1.03 | 1.44 | 1.62 | 1.68 | 1.34 | 1.30 | 1.21 |
| CAIDI | 20.73 | 25.43 | 23.32 | 22.71 | 28.34 | 22.64 | 36.49 |
| 3-Yr Average CAIDI | 25.14 | 25.07 | 23.16 | 23.82 | 24.79 | 24.57 | 29.16 |

Table 4 – Trends in Reliability Indices 2010 – 2016 (excluding MED; excluding LOS; excluding SCHEDULED Outages)

| KPI | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 |
|---|---|---|---|---|---|---|---|
| SAIDI | 23.14 | 39.94 | 38.61 | 26.21 | 26.71 | 31.18 | 37.29 |
| 3-Yr Average SAIDI | 23.54 | 31.55 | 33.90 | 34.92 | 30.51 | 28.03 | 31.72 |
| SAIFI | 0.97 | 1.53 | 1.34 | 0.86 | 0.94 | 1.42 | 0.98 |
| 3-Yr Average SAIFI | 0.78 | 1.15 | 1.28 | 1.24 | 1.05 | 1.08 | 1.11 |
| CAIDI | 23.46 | 26.18 | 28.75 | 30.36 | 28.40 | 21.90 | 38.18 |
| 3-Yr Average CAIDI | 31.92 | 27.94 | 26.13 | 28.43 | 29.17 | 26.89 | 29.50 |

Table 5 – Trends in Reliability Indices 2010 – 2016 (including MED; excluding LOS; excluding SCHEDULED Outages)

| KPI | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 |
|---|---|---|---|---|---|---|---|
| SAIDI | 23.14 | 39.94 | 38.61 | 84.59 | 35.52 | 31.18 | 37.29 |
| 3-Yr Average SAIDI | 23.54 | 31.55 | 33.90 | 54.38 | 52.91 | 50.43 | 34.66 |
| SAIFI | 0.99 | 1.53 | 1.34 | 1.33 | 1.10 | 1.42 | 0.98 |
| 3-Yr Average SAIFI | 0.78 | 1.15 | 1.28 | 1.40 | 1.26 | 1.29 | 1.17 |
| CAIDI | 23.46 | 26.18 | 28.75 | 63.42 | 32.15 | 21.90 | 38.18 |
| 3-Yr Average CAIDI | 31.92 | 27.94 | 26.13 | 39.45 | 41.44 | 39.16 | 30.75 |

The contribution of scheduled outages to SAIDI and SAIFI over the 2010 – 2016 timeframe is provided in the table below. This is based on the percentage contribution provided in Table 1 above. The increasing trend from 2013 corresponds to the increase in transformer replacements

driven by leaking transformers. Scheduled outages are required when replacing these transformers.

Table 6 – Contribution of scheduled outages to SAIDI and SAIFI 2010-2016

| KPI | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 |
|---|---|---|---|---|---|---|---|
| SAIDI – SCHED | 10.17 | 3.54 | 2.09 | 4.97 | 4.90 | 7.26 | 9.07 |
| SAIFI – SCHED | 0.111 | 0.018 | 0.014 | 0.041 | 0.027 | 0.038 | 0.045 |

(b) Figure 10, provided in the Enersource Rate Zone DSP, p. 59, provides a graph of the trends in SAIFI from 2014 to 2016. As stated on p. 59 of the Enersource Rate Zone DSP, there is a fluctuating but overall rising trend in SAIFI over the 2014-2016 periods. This is mainly attributable to the rising trend in equipment-related failures as well as the number of scheduled outages over those two years.

**BOMA-63**

**Reference(s): DSP, p59**

**Can trend lines in Tables 8, 9, and 10 be drawn back to 2010 to match the tables?**

**Response:**

Alectra Utilities assumes that the reference is to Figures 9, 10 and 11. Alectra Utilities has reproduced Figures 9, 10 and 11 provided in Exhibit 3, Tab 1, Schedule 1, Attachment 50 – Enersource Rate Zone DSP, to include reliability data from 2010 through 2016.

Figure 1 – Trends in SAIDI (2010-2016)

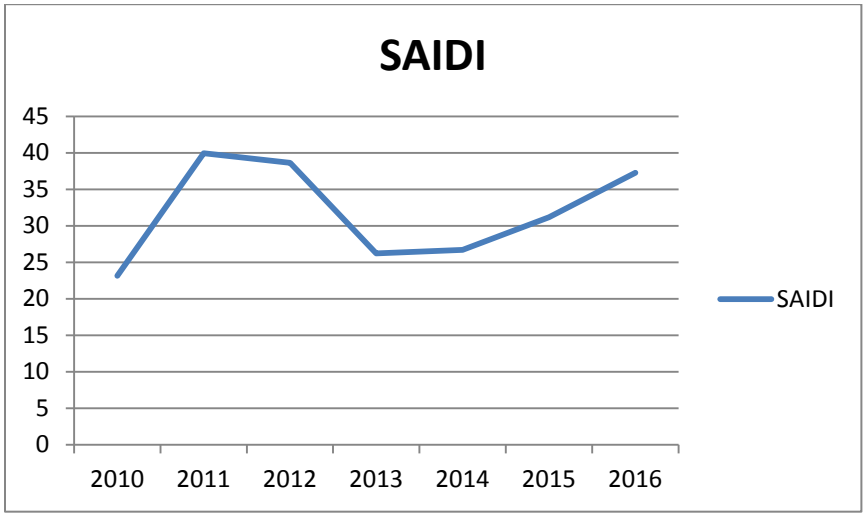


Figure 2 – Trends in SAIFI (2010-2016)

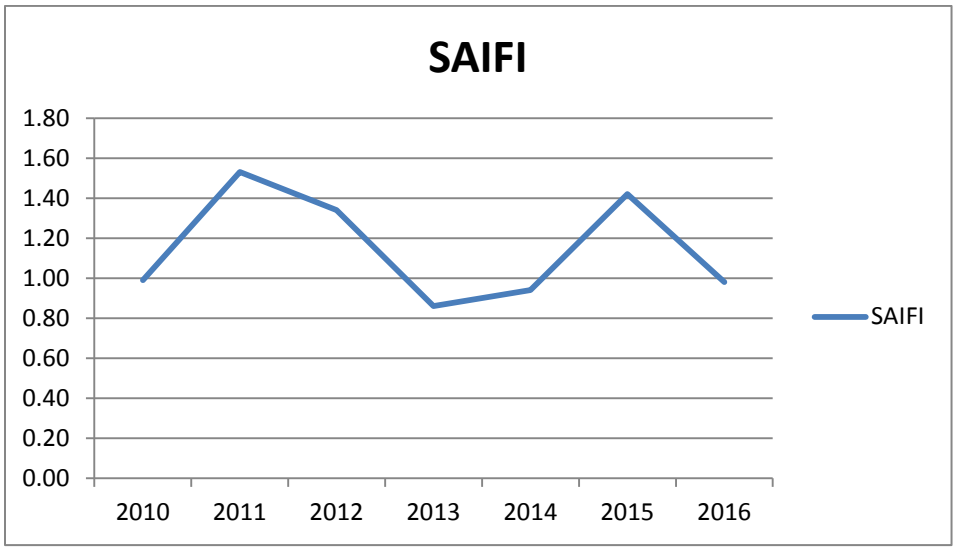
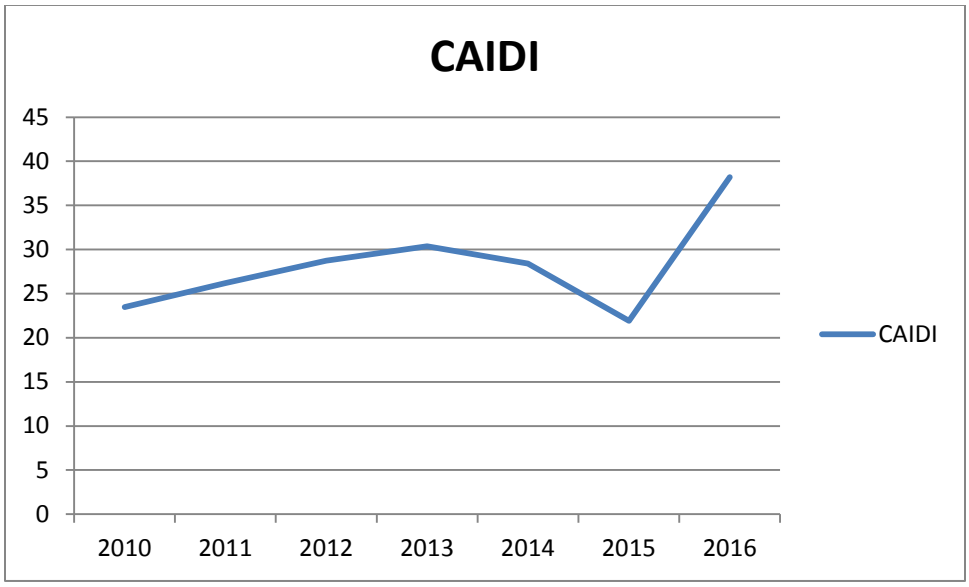



Figure 3 – Trends in CAIFI (2010-2016)



**BOMA-64**

**Reference(s): DSP, pp 58-60**

**(a)**

**(i) Please show table with scheduled outages excluded.**
**(ii) Please quantify how much of the SAIDI and SAIFI readings are due to scheduled outages.**
**(iii) Please provide a table showing the number and time period of scheduled outages from 2010 to 2016 and partial year 2017. Please describe the major categories of scheduled outages, the degree to which they contribute to the outage totals.**
**(iv) Please also show similar schedule for unscheduled outages that cause service interruptions over same period.**
**(v) What projects were deferred as a result of the merger?**

**(b) What percentage (in km) of underground feeders have back-up feeders?**

**Response:**

(ai) Alectra Utilities is assuming the reference is to Table 7. Table 7 excludes scheduled outages.

(aii) Please see Alectra Utilities response to part (ai).

(aiii) Table 1 provides the number and time period of scheduled outages from 2010 to August 2017.

Table 1 – Scheduled outages (2010 – August 2017)

| Scheduled Outage Cause Codes | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | August 2017 | Grand Total |
|---|---|---|---|---|---|---|---|---|---|
| Scheduled: Building/ High Load Move | | | | | | | 1 | | 1 |
| Scheduled: Construction | | | | | 206 | 457 | 678 | 446 | 1787 |
| Scheduled: Forced Switching | | | | | 3 | 11 | 8 | 4 | 26 |
| Scheduled: Maintenance | 1542 | 326 | 243 | 419 | 222 | 214 | 56 | 20 | 3042 |
| Scheduled: Other Sched Outage | | | | | 59 | 6 | | | 65 |
| Scheduled: Scheduled: Open Trans Switch | | | | | 8 | 1 | 2 | | 11 |
| Scheduled: Vegetation Management | | | | | | 4 | 2 | | 6 |
| Grand Total | 1542 | 326 | 243 | 419 | 498 | 693 | 747 | 470 | 4938 |

1 The major categories of scheduled outages are provided in Table 2.

2 Table 2 – Scheduled outage cause codes

| Scheduled Outage Cause Codes | Explanation |
|---|---|
| Scheduled: Building/ High Load Move | Customer driven transportation of very large assets requiring the temporary relocation of plant to allow the asset to travel along municipal roads |
| Scheduled: Construction | These outages are driven by the need for Alectra Utilities construction staff or contractors to perform work safely. i.e. a transformer replacements |
| Scheduled: Forced Switching | These outages pertained to situations were construction staff or contractors requested the feeder be taken offline |
| Scheduled: Maintenance | Prior to 2014 this referred to all scheduled outages, starting in 2014 this only pertained to outages from maintenance related activities where an outage was required. Some situations involve dry ice cleaning, on repairing connections on a transformer. |
| Scheduled: Other Sched Outage | These refer to outages that do not fall into any of the other categories. |
| Scheduled: Scheduled: Open Trans Switch | These refer to outages where a transformer switch is required to be opened to provide isolation for customer contractors |
| Scheduled: Vegetation Management | These refer to outages required to provide a safe work zone for tree trimming contractors to perform work. |

3 Table 3 provides the percentage contribution of scheduled outages to the outage total

4 Table 3 – Percentage contribution of scheduled outages by cause code

| Scheduled Outage Cause Codes | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | Grand Total |
|---|---|---|---|---|---|---|---|---|---|
| Scheduled: Building/ High Load Move | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Scheduled: Construction | 0% | 0% | 0% | 0% | 41% | 66% | 91% | 95% | 36% |
| Scheduled: Forced Switching | 0% | 0% | 0% | 0% | 1% | 2% | 1% | 1% | 1% |
| Scheduled: Maintenance | 100% | 100% | 100% | 100% | 45% | 31% | 7% | 4% | 62% |
| Scheduled: Other Sched Outage | 0% | 0% | 0% | 0% | 12% | 1% | 0% | 0% | 1% |
| Scheduled: Scheduled: Open Trans Switch | 0% | 0% | 0% | 0% | 2% | 0% | 0% | 0% | 0% |
| Scheduled: Vegetation Management | 0% | 0% | 0% | 0% | 0% | 1% | 0% | 0% | 0% |
| Grand Total | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% |

(aiv) Table 4 provides the breakdown by cause code for unscheduled outages that causel service interruptions from 2010 to August 2017.

Table 4 – Unscheduled outages by cause code

| Non-Scheduled Outage Cause Code | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | Grand Total |
|---|---|---|---|---|---|---|---|---|---|
| A: Default | 1 | | | | | | | | 1 |
| A: Unknown | 38 | 49 | 33 | 26 | 37 | 35 | 44 | 19 | 281 |
| Environment: Contamination (Dirt, other) | | | | | | 2 | | 1 | 3 |
| Environment: Contamination (Salt) | | | | | | 2 | | | 2 |
| Environment: Fire | | | | | 1 | | 1 | 6 | 8 |
| Environment: Flood | | | | | | 1 | | 2 | 3 |
| Environment: Other Adverse Environment | 1 | 5 | | 1 | | | | | 7 |
| Equipment: Cable | 153 | 199 | 190 | 189 | 147 | 227 | 232 | 158 | 1495 |
| Equipment: Connections | 5 | 8 | 12 | 8 | 9 | 14 | 4 | 3 | 63 |
| Equipment: Cut Out | 9 | 33 | 21 | 25 | 33 | 47 | 28 | 11 | 207 |
| Equipment: Elbow/Termination | 17 | 10 | 9 | 16 | 13 | 35 | 27 | 11 | 138 |
| Equipment: Fuse | 23 | 15 | 19 | 13 | 8 | 11 | 4 | 1 | 94 |
| Equipment: Insulator | 4 | 7 | 6 | 9 | 11 | 11 | 8 | | 56 |
| Equipment: Lightning Arrester | 2 | 1 | 5 | 4 | 7 | 4 | 2 | | 25 |
| Equipment: Load Centre | 8 | 13 | 5 | 10 | 23 | 10 | 7 | 1 | 77 |
| Equipment: Meter | 1 | | | 1 | | | | | 2 |
| Equipment: Meter Base | 2 | 1 | | | | | | 1 | 4 |
| Equipment: Neutral | | | 2 | 1 | | 1 | | | 4 |
| Equipment: O/H Hardware (including Pole) | 10 | 14 | 19 | 12 | 11 | 16 | 6 | 5 | 93 |
| Equipment: Others | 17 | 19 | 2 | 4 | 2 | | 1 | 1 | 46 |
| Equipment: Secondary Bus | 3 | 3 | 3 | 4 | 6 | 1 | 2 | 2 | 24 |
| Equipment: Secondary Connections | 2 | 1 | 5 | 6 | 4 | 1 | 3 | 2 | 24 |
| Equipment: Secondary Meter | 1 | 1 | | | | | | | 2 |
| Equipment: Secondary Meter Base | | 2 | | 1 | 1 | | | | 4 |
| Equipment: Secondary Neutral | | 1 | | | | | 1 | | 2 |
| Equipment: Secondary Others | 3 | 2 | 4 | 1 | 1 | 1 | 2 | | 14 |
| Equipment: Secondary U/G Burn Off | 2 | 5 | 1 | | 1 | 5 | 1 | 3 | 18 |
| Equipment: Splice | 6 | 2 | 12 | 7 | 13 | 3 | 1 | 2 | 46 |
| Equipment: Substation | | 3 | 7 | 1 | 4 | 2 | | 1 | 18 |
| Equipment: Switch | 6 | 7 | 9 | 8 | 7 | 6 | 5 | 7 | 55 |
| Equipment: Transformer | 46 | 38 | 67 | 89 | 64 | 55 | 59 | 43 | 461 |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Foreign: Agricultural Equipment | | | | | | 1 | | | 1 |
| Foreign: Crane | | | | | 3 | 1 | | | 4 |
| Foreign: Customer Equipment | 12 | 12 | 7 | 6 | 12 | 8 | 10 | 12 | 79 |
| Foreign: Customer-Cut Trees | | | | | | 1 | | | 1 |
| Foreign: Dig-In | 9 | 17 | 14 | 6 | 14 | 13 | 20 | 12 | 105 |
| Foreign: Foreign Objects | | | | | 3 | 2 | 4 | 6 | 15 |
| Foreign: Other foreign Interference | 6 | 15 | 4 | 11 | 4 | | 5 | | 45 |
| Foreign: Other Utilities | 2 | 4 | | 4 | 3 | 6 | 6 | 1 | 26 |
| Foreign: Vehicle | 17 | 22 | 28 | 29 | 37 | 24 | 26 | 14 | 197 |
| Foreign: Wildlife (Bird/Animal) | 118 | 159 | 140 | 117 | 173 | 196 | 143 | 92 | 1138 |
| Human: Commissioning Error | | | | | | | | 1 | 1 |
| Human: Improper Const./installation | | | | | 1 | | 1 | | 2 |
| Human: Improper Design | | | | | | 4 | | 2 | 6 |
| Human: Improper Equip./Tool/ Maintenance | | | | | 1 | | 1 | | 2 |
| Human: Other Human Element | 5 | 6 | 3 | 4 | 1 | 2 | 1 | | 22 |
| Human: Protection Setting | | | | | 1 | | | | 1 |
| Human: Switching Error | | | | | 2 | 1 | 1 | | 4 |
| Lightning: Lightning | 6 | 11 | 8 | 9 | 5 | 3 | 10 | 3 | 55 |
| Loss of Supply: Other Loss of Supply | 15 | 47 | 15 | 100 | 8 | 7 | 18 | 4 | 214 |
| Loss of Supply: Transmission Inadvertent | | | | | 1 | 11 | 1 | 4 | 17 |
| Tree: Broken Branch | | | | | 16 | 2 | 4 | 7 | 29 |
| Tree: Falling Tree | | | | | 4 | 6 | 5 | 2 | 17 |
| Tree: Other Vegetation | 39 | 42 | 32 | 49 | 4 | 1 | 2 | 1 | 170 |
| Tree: Tree Growth/ Untrimmed Tree | | | | | 10 | 10 | 5 | 4 | 29 |
| Weather: Extreme Wind | | | | | 48 | 11 | 17 | 5 | 81 |
| Weather: Freezing Rain | | | | | | 41 | | 1 | 42 |
| Weather: Other Adverse Weather | 41 | 17 | 36 | 151 | 2 | 6 | 2 | | 255 |
| Weather: Wet Snow | | | | | 1 | | | 1 | 2 |
| X: CR Condition | | 2 | | | | | | | 2 |
| X: Underground Cable Fault Deficiency | | 2 | | | | | | | 2 |
| Grand Total | 630 | 795 | 718 | 922 | 757 | 847 | 720 | 452 | 5841 |

1 Table 5 provides the percentage contribution of scheduled outages to the outage total.

| Table 5 - Percentage contribution of scheduled outages by cause | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | Grand Total |
|---|---|---|---|---|---|---|---|---|---|

| code Non Scheduled Outage Cause Code | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| A: Default | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| A: Unknown | 6% | 6% | 5% | 3% | 5% | 4% | 6% | 4% | 5% |
| Environment: Contamination (Dirt, other) | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Environment: Contamination (Salt) | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Environment: Fire | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 1% | 0% |
| Environment: Flood | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Environment: Other Adverse Environment | 0% | 1% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Equipment: Cable | 24% | 25% | 26% | 20% | 19% | 27% | 32% | 35% | 26% |
| Equipment: Connections | 1% | 1% | 2% | 1% | 1% | 2% | 1% | 1% | 1% |
| Equipment: Cut Out | 1% | 4% | 3% | 3% | 4% | 6% | 4% | 2% | 4% |
| Equipment: Elbow/Termination | 3% | 1% | 1% | 2% | 2% | 4% | 4% | 2% | 2% |
| Equipment: Fuse | 4% | 2% | 3% | 1% | 1% | 1% | 1% | 0% | 2% |
| Equipment: Insulator | 1% | 1% | 1% | 1% | 1% | 1% | 1% | 0% | 1% |
| Equipment: Lightning Arrester | 0% | 0% | 1% | 0% | 1% | 0% | 0% | 0% | 0% |
| Equipment: Load Centre | 1% | 2% | 1% | 1% | 3% | 1% | 1% | 0% | 1% |
| Equipment: Meter | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Equipment: Meter Base | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Equipment: Neutral | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Equipment: O/H Hardware (including Pole) | 2% | 2% | 3% | 1% | 1% | 2% | 1% | 1% | 2% |
| Equipment: Others | 3% | 2% | 0% | 0% | 0% | 0% | 0% | 0% | 1% |
| Equipment: Secondary Bus | 0% | 0% | 0% | 0% | 1% | 0% | 0% | 0% | 0% |
| Equipment: Secondary Connections | 0% | 0% | 1% | 1% | 1% | 0% | 0% | 0% | 0% |
| Equipment: Secondary Meter | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Equipment: Secondary Meter Base | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Equipment: Secondary Neutral | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Equipment: Secondary Others | 0% | 0% | 1% | 0% | 0% | 0% | 0% | 0% | 0% |
| Equipment: Secondary U/G Burn Off | 0% | 1% | 0% | 0% | 0% | 1% | 0% | 1% | 0% |
| Equipment: Splice | 1% | 0% | 2% | 1% | 2% | 0% | 0% | 0% | 1% |
| Equipment: Substation | 0% | 0% | 1% | 0% | 1% | 0% | 0% | 0% | 0% |
| Equipment: Switch | 1% | 1% | 1% | 1% | 1% | 1% | 1% | 2% | 1% |
| Equipment: Transformer | 7% | 5% | 9% | 10% | 8% | 6% | 8% | 10% | 8% |
| Foreign: Agricultural Equipment | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Foreign: Crane | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Foreign: Customer Equipment | 2% | 2% | 1% | 1% | 2% | 1% | 1% | 3% | 1% |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Foreign: Customer-Cut Trees | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Foreign: Dig-In | 1% | 2% | 2% | 1% | 2% | 2% | 3% | 3% | 2% |
| Foreign: Foreign Objects | 0% | 0% | 0% | 0% | 0% | 0% | 1% | 1% | 0% |
| Foreign: Other foreign Interference | 1% | 2% | 1% | 1% | 1% | 0% | 1% | 0% | 1% |
| Foreign: Other Utilities | 0% | 1% | 0% | 0% | 0% | 1% | 1% | 0% | 0% |
| Foreign: Vehicle | 3% | 3% | 4% | 3% | 5% | 3% | 4% | 3% | 3% |
| Foreign: Wildlife (Bird/Animal) | 19% | 20% | 19% | 13% | 23% | 23% | 20% | 20% | 19% |
| Human: Commissioning Error | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Human: Improper Const./installation | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Human: Improper Design | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Human: Improper Equip./Tool/ Maintenance | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Human: Other Human Element | 1% | 1% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Human: Protection Setting | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Human: Switching Error | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Lightning: Lightning | 1% | 1% | 1% | 1% | 1% | 0% | 1% | 1% | 1% |
| Loss of Supply: Other Loss of Supply | 2% | 6% | 2% | 11% | 1% | 1% | 3% | 1% | 4% |
| Loss of Supply: Transmission Inadvertent | 0% | 0% | 0% | 0% | 0% | 1% | 0% | 1% | 0% |
| Tree: Broken Branch | 0% | 0% | 0% | 0% | 2% | 0% | 1% | 2% | 0% |
| Tree: Falling Tree | 0% | 0% | 0% | 0% | 1% | 1% | 1% | 0% | 0% |
| Tree: Other Vegetation | 6% | 5% | 4% | 5% | 1% | 0% | 0% | 0% | 3% |
| Tree: Tree Growth/ Untrimmed Tree | 0% | 0% | 0% | 0% | 1% | 1% | 1% | 1% | 0% |
| Weather: Extreme Wind | 0% | 0% | 0% | 0% | 6% | 1% | 2% | 1% | 1% |
| Weather: Freezing Rain | 0% | 0% | 0% | 0% | 0% | 5% | 0% | 0% | 1% |
| Weather: Other Adverse Weather | 7% | 2% | 5% | 16% | 0% | 1% | 0% | 0% | 4% |
| Weather: Wet Snow | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| X: CR Condition | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| X: Underground Cable Fault Deficiency | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Grand Total | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% |

(av) Certain General Plant investments that were planned by the former Enersource as a stand-alone utility will instead be evaluated, prioritized, and executed by Alectra Utilities as a consolidated entity to maximize efficiency gains and value creation. As a result, these investments are no longer specific to the Enersource Rate Zone and therefore have been

excluded from this Enersource RZ DSP. Instead, these investments will form part of Alectra Utilities' DSP that will cover all four rate zones.

b) 100% of underground feeders in the Enersource Rate Zone have an alternate supply.

**BOMA-65**

**Reference(s): DSP, p61**

**Were projects selectively deferred or were they not done because people didn't have the time to do them? Please provide particulars leading to the "underspends".**

**Response:**

The projects were selectively deferred. Details pertaining to the deferrals were addressed in Alectra Utilities response to ERZ-Staff-52.

**BOMA-66**

**Reference(s): DSP, p62**

**Are those costs OM&A costs? Were they capitalized?**

**Response:**

The costs included in the calculation of Per-Unit Cost are based on the installation of capital assets therefore they are not OM&A costs and are capitalized as part of the applicable projects.

**BOMA-67**

**Reference(s): DSP, p64**

**Why were there large increases in scheduled outages in 2015 and 2016, up twenty percent, and fifteen percent, respectively?**

**Response:**

Due to switchgear and cable failures, along with a significant amount of leaking transformers, Alectra Utilities' predecessor, Enersource, executed new system renewal projects, as well as increased spending on system renewal activities to address these three issues in 2015. The replacement of these assets required a planned scheduled outage. The number of scheduled outages increased from 498 in 2014 to 693 in 2015 and 747 in 2016. This resulted in an increase in customer minutes in 2015 and 2016.

**BOMA-68**

**Reference(s): DSP, p66, Table 9**

**What accounts for the decrease in customer interruption minutes driven by defective overhead equipment? Please discuss.**

**Response:**

Please see Alectra Utilities response to ERZ-Staff 54 b(i).

**BOMA-69**

**Reference(s): DSP, p68**

**Please define "sustained interruptions" (Table 10). Please explain why the largest single component, and approximately fifty percent of sustained customer interruptions in 2016, is due to scheduled outages. What is that figure in each year from 2010 to 2016? What is forecast for the next three to four years?**

**Response:**

i) Alectra Utilities defines a sustained outage in the Enersource Rate Zone as an outage that lasts longer than 1 minute.

ii) Please see Alectra Utilities' response to BOMA-67.

iii) Please see Alectra Utilities' response to BOMA-64 (aiii).

iv) Please see Alectra Utilities' response to BOMA-81 (biii).

**BOMA-70**

**Reference(s): DSP, p72**

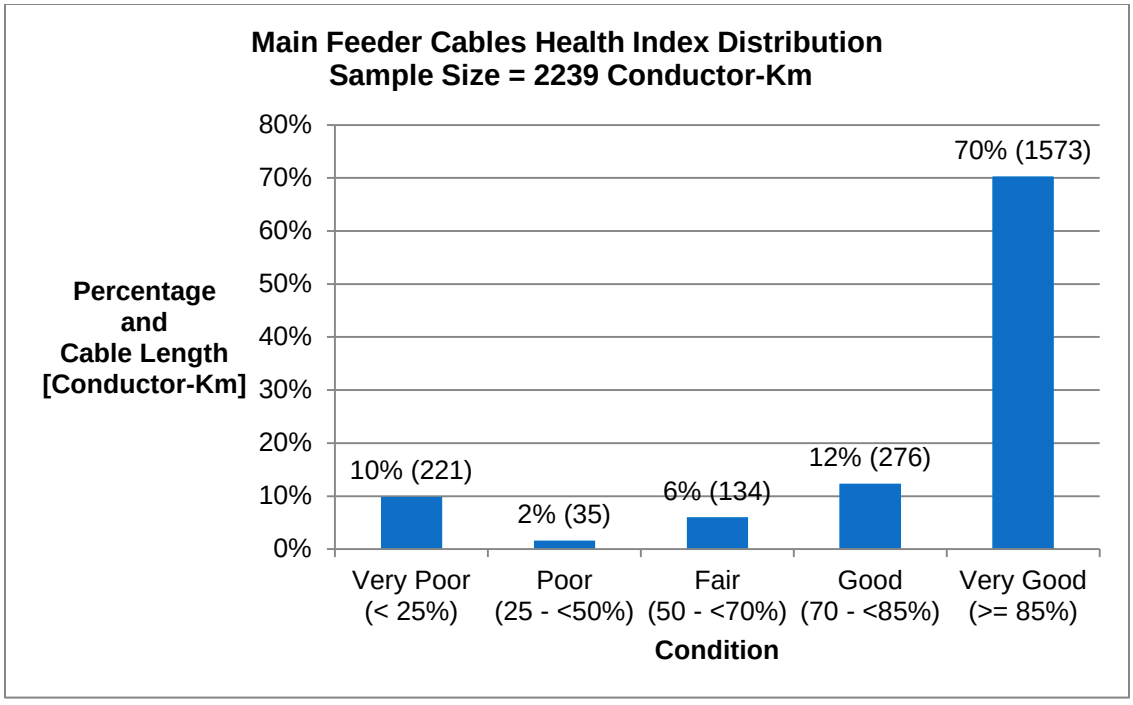
**Please confirm that eighty-five percent of underground main feeders are judged to be in very good, good, or fair condition, and eighty percent of distribution feeders are judged to be in very good, good, or fair condition. Please advise how many underground feeder lengths that are in very good; good; fair; conditions are being replaced as a result of the zonal approach. What alternatives exist? Please discuss.**

**Response:**

There is no reference to this material quoted on page 72 of the Enersource Rate Zone DSP. Generally, cable lengths with very good, good or fair Health Index values are not being replaced.

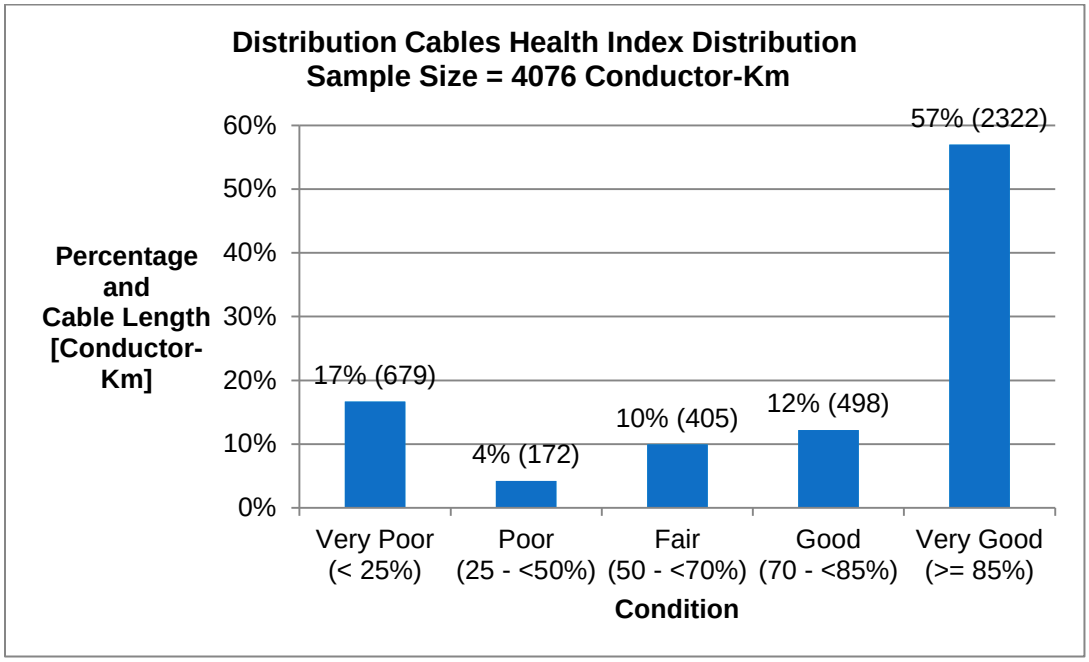
Feeder cable health index distributions are provided in Figure 63 of the Enersource Rate Zone DSP, also shown below as Figure 1.

Figure 1 – Main Feeder Cables Health Index Distribution




Distribution cable health index distributions are provided in Figure 64 of the Enersource Rate Zone DSP, also shown below as Figure 2.

Figure 2 – Distribution Cables Health Index Distribution



**BOMA-71**

**Reference(s): DSP**

**(a) How many distribution transformers have been identified as:**
**(i) leaking oil and have PCBs over threshold;**
**(ii) leaking oil, but no PCBs;**
**(iii) have PCBs over threshold, but are not leaking oil.**

**(b) How many of each category of transformer have been replaced?**

**(c) By what date must the remaining 2,200 transformers be replaced:**
**(i) under provincial law;**
**(ii) under federal law.**

**(d) What does GIS do to identify assets that need to be replaced? How was this done before GIS was used? What has changed under GIS?**

**Response:**

a) (i) Alectra Utilities has identified 20 distribution transformers that are leaking oil and have PCBs over the threshold.
(ii) Alectra Utilities has identified 2054 distribution transformers that are leaking oil, but have no PCBs.
(iii) Alectra Utilities has identified 170 distribution transformers that have PCBs over the threshold, but are not leaking oil.

b) In reference to part a), in 2016 the following number of transformers have been replaced:
(i) leaking oil and have PCBs over threshold - 3
(ii) leaking oil, but no PCBs - 281
(iii) have PCBs over threshold, but are not leaking oil – 16

c) (i) There is no provincial PCB regulation.
(ii) The federal PCB reglation provides that only transformers containing >50 ppm of PCB must be replaced by Dec 31, 2025

d) Geographic Information System (“GIS”) is a geospatial asset database, which has been in use for over ten years. It provides information regarding asset quantity and location, as well

as condition data for distribution assets, which is captured via annual inspections. GIS facilitates overlay of condition parameters which can highlight multiple asset performance issues in a given area. Prior to GIS much of this activity was performed in a manual format using paper maps and excel files.

**BOMA-72**

**Reference(s): DSP, p80**

**Given that Alectra has stated that it wishes to rationalize general plant investments, will there be any investments in General Plant for 2018? What are they, in detail? Why are they going ahead before their evaluation, prioritization, and execution by Alectra Utilities, as part of Alectra's proposed 2019 DSP?**

**Response:**

Yes, the investments made in 2018 have been identified in the 2018 General Plant budget. Alectra Utilities 2018 General Plant Budget is provided in Section 3.5.2.4 of the Enersource Rate Zone DSP (p. 387-394). Alectra Utilities is proceeding with these investments as they are required to manage and maintain separate legacy IT environments until integration efforts are complete. Alectra Utilities is planning to rationalize these investments for 2019 and beyond and create an Alectra Utilities General Plant budget.

**BOMA-73**

**Reference(s): DSP, p82**

**Please provide more detail on these "supplemental quantitative and qualitative analyses". Is the replacement decision made on the basis of age alone, or age and conditions, as determined by the H1 index?**

**Response:**

The supplemental quantitative and qualitative analyses includes identifying assets with a poor or very poor Health Index ("HI") in the Geographical Information System ("GIS"). Alectra Utilities uses an overlay feature in the GIS to identify sections of underground cables that have experienced multiple cable faults (outage information tracked in the Outage Management System), contain transformers that have shown signs of leaking (tracked through inspection records in GIS) and are located in customers' back yards. This initial overlay allows Alectra Utilities to provide high-level identification of trouble areas, which are then further refined by reviewing the areas in more granularity. For overhead projects, a similar overlay methodology is used. This methodology overlays pole condition, inspection results (i.e. visual inspection, resistograph drill results), and specific make of accessory hardware (e.g. porcelain insulator, open-bus secondaries, vintage cross arms) to identify trouble areas. For both overhead and underground project identification, the overlay methodology allows Alectra Utilities to identify areas where multiple asset issues and risks can be identified and ensure that asset renewal investment funds are allocated in the worst performing areas and economies of scale are achieved.

**BOMA-74**

**Reference(s): DSP, p88**

**(a) What percentage of overhead motorized switches and pole mounted switches do the 127 and 133 represent? Please discuss.**

**(b) Please provide copies of the ACA Reports from 2011 to 2016, inclusive.**

**Response:**

a) The reference on page 88 refers to scada controlled pole mounted and pad mounted switches. 127 motorized pole mounted switches represent 4.8 % of the total overhead switch population including load break and non-load break switches. 139 motorized pad mounted switches represent 17 % of the total pad mounted switch population.

b) Please see Alectra Utilities response to BOMA-74 b).

**BOMA-75**

**Reference(s): DSP, p90**

**"Underground cables are one of the major distribution assets with a poor or very poor H1".**

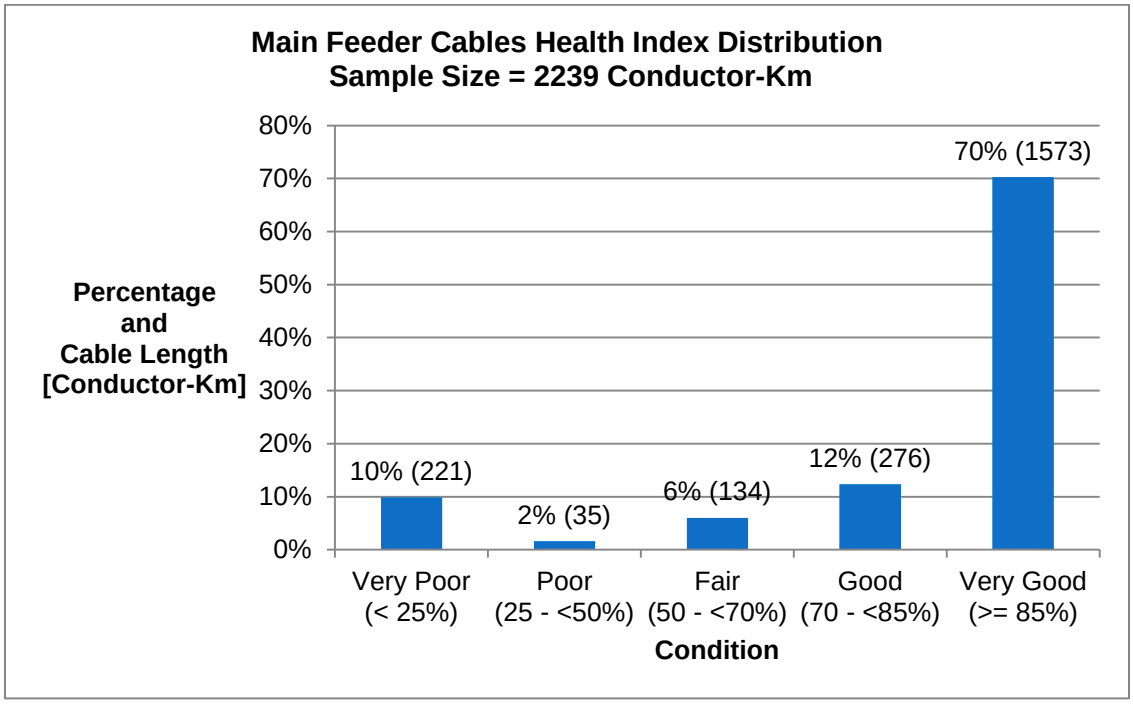
**Please confirm that eighty-five percent and eighty percent, respectively, of underground main feeders and secondary feeders are in very good, good, or fair condition.**

**Response:**

Underground cable assets include feeder class and distribution class.

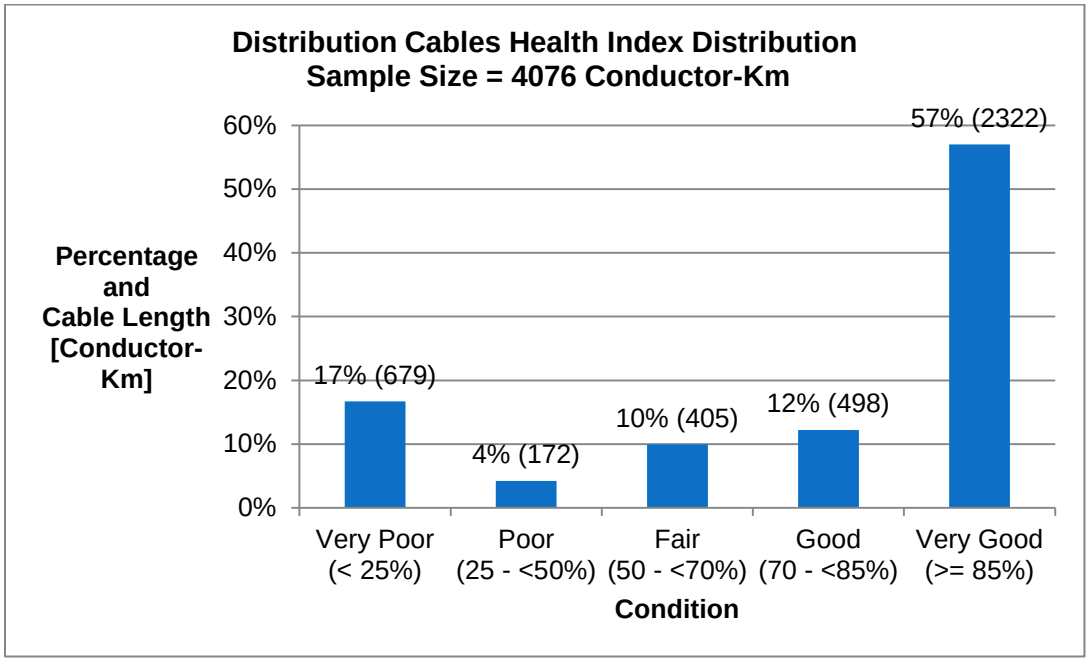
Feeder cable health index distributions are provided in Figure 63 of the Enersource Rate Zone DSP, also shown below as Figure 1.

Figure 1 – Main Feeder Cables Health Index Distribution




Distribution cable health index distributions are provided in Figure 64 of the Enersource Rate Zone DSP, also shown below as Figure 2.

Figure 2 – Distribution Cables Health Index Distribution



**BOMA-76**

**Reference(s): DSP, p91, Table 12**

**(a) How many air-insulated switches does Enersource have? Are all forty switchgears to be replaced air-driven?**

**(b) How many air-insulated switchgears have been replaced in each of the last five years?**

**(c) What has been air-insulated switchgear failure rate in each of the last five years?**

**(d) How many of the switchgears replaced in the last five years and to be replaced in 2018, are in poor or very poor condition, or were in poor or very poor condition in the year in which they were replaced?**

**(e) What is the age of each of the thirty-three switchgears that will be replaced in 2018? What is the expected life for each of them?**

**(f) Please distinguish between underground rebuilds and replacements, and explain why directional drilling is used only for replacement with no "rebuild" component.**

**Response:**

a) Alectra Utilities has 587 air-insulated switchgears in the Enersource Rate Zone. (Overhead air switches not included in this count). The Pad Mounted Switchgear (PMH) Replacement Yearly Program Business Case in Appendix E of the Enersource Rate Zone DSP identifies 40 units that are planned for replacement, of which 15 units are planned for proactive replacement and 25 units are allocated to reactive failures based on updated inspection.

b) Table 1 below provides the number of air-insulated switchgears replaced in the last five years:

Table 1 – Air-insulated switchgear replacement (2012-2016)

| Year | 2012 | 2013 | 2014 | 2015 | 2016 |
|---|---|---|---|---|---|
| Replacements | 15 | 44 | 32 | 46 | 55 |

c) Table 2 below provides the number of failed air-insulated switchgears in the last five years.

Table 2 – Air-insulated switchgear failure rate (2012-2016)

| Year | 2012 | 2013 | 2014 | 2015 | 2016 |
|---|---|---|---|---|---|
| Air-Insulated Switchgear Failures | 10 | 14 | 19 | 11 | 11 |

d) Table 3 below provides the number of switchgears replaced in the last 5 years and to be replaced in 2018 in poor or very poor condition based on the ACA.

Table 3 – Switchgears replacement/planned replacement (2011-2018)

| Year | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|---|---|---|
| Very Poor or Poor condition | 1 | 4 | 21 | 18 | 41 | 63 | 43 | 8 |

Alectra Utilities notes that updated information based on inspection or maintenance which would alter an ACA score to poor or very poor may not be reflected in that years ACA report based on timing of acquiring the data.

e) Table 4 provides the age of the 22 switchgear units planned for proactive replacement.

| Units | Age |
|---|---|
| SG1143 | 28 |
| SG1192 | 26 |
| SG1194 | 18 |
| SG1292 | 31 |
| SG1380 | 28 |
| SG1251 | 27 |
| SG1209 | 31 |
| SG1136 | 14 |
| SG1364 | 18 |
| SG1509 | 18 |
| SG1510 | 17 |
| SG1512 | 16 |
| SG1521 | 23 |
| SG1594 | 28 |
| SG1709 | 17 |
| SG1761 | 15 |
| SG1777 | 22 |
| SG1030 | 22 |
| SG1110 | 27 |
| SG1268 | 23 |
| SG1508 | 28 |
| SG1782 | 27 |

f) Underground replacements are specific to cables that have had more than 3 failures, with no other cables in the vicinity having a similar level of faults. In these cases, a directional bore is used to replace the single cable. Underground rebuilds involve areas with multiple cables in proximity having several cable failures.

**BOMA-77**

**Reference(s): DSP, p95**

**Does Alectra plan to have one IT asset management plan, and one IT system for each of its four divisions or have one IT asset management program with one IT system? If not, how does Alectra achieve compatibility for formulating, assessing, tracking and reporting asset management across its four divisions? Please discuss fully.**

**Response:**

Alectra Utilities plans on having one IT asset management plan and one IT system for Alectra Utilities' IT assets.

**BOMA-78**

**Reference(s): DSP, p98**

**(a) Please discuss the changes in ways in which customers engage with their utility in the last few years. Please discuss each change separately and for each change, outline the implication for the utilities' IT program/services.**

**(b) How many spare transformers of each type does Enersource maintain? What is the current book value, and forecast 2018 depreciation? Has Enersource considered reducing the number and configuration of spares in light of the merger?**

**Response:**

a) Over the past several years customers have come to expect their utility to provide access to customer information 24 hours a day, seven days a week. This information can consist of anything from customer billing information, Time of Use consumption, outage notifications, on line web forms etc.

Customers expect to be able to call in after hours to their utility and have access to their latest balance, their last amount due, last bill payment due date, or determine when their next bill is due etc. IT systems must be accommodate and process these requests instantaneously. Alectra Utilities is responding to its customer's expectation through it telephony and voice services which are integrated with the Customer Information System. These requests require that the utilities Interactive Voice Response ("IVR") systems be integrated with the CIS systems to allow the customers to extract this data in real time.

Access to outage information has also become of importance to customers. Most utilities now display customer outage maps on their website. Information is fed directly from the company's Outage Management System ("OMS") system and is displayed in real time on the web site identifying the areas impacted by outages. Estimated restoration times are also displayed to advise customers as to when they can expect power restored. These maps require the integration of several systems in real time in order to keep the outage information current and accurate.

Customers have the ability to download Time of Use information directly from the Utilities website. This information provides customers with hourly consumption data and can help them to better manage their electricity costs. This information can be viewed in various user friendly graphics. All of these customer centric options require the integration of several

different IT systems to be able to supply the customer with the information that they have requested.

b) Alectra Utilities has 9 spare power distribution transformers in the Enersource Rate Zone. Table 1 lists the transformers with attributes including the present book value and forecast 2018 depreciation value. As of December 2016, the total book value of the spare power transformers is $1.07MM with a forecasted 2018 depreciation of $0.043MM. Alectra Utilities is in the process of phasing out two configurations in the Enersource Rate Zone, reducing the number of spares from 9 to 6 transformers. Any further reduction of emergency inventory assets is dependent on the future progress of material standardization, harmonization of operational contingency plans and as well as consolidation of asset condition assessment and risk management practices at Alectra Utilities.

*Table 1: List of Spare Power Transformers with Book & Depreciation Forecast Values in the Enersource Rate Zone*

| Spare Transformer | Capacity (MVA) | Primary Voltage/ Secondary Voltage | Present Book Value ($) | Forecast 2018 Depreciation ($) |
|---|---|---|---|---|
| AQUITAINE_7 | 3/4 | 27.6kV/4.16kV | $58,571 | -$1,748 |
| REXDALE | 20/26/33 | 44kV/13.8kV | $120,138 | -$5,860 |
| AQUITAINE _6 | 5/6.6 | 27.6kV/4.16kV | $23,241 | -$2,021 |
| AQUITAINE _5 | 20/26.6/33.3 | 44kV/13.8kV | $185,177 | -$13,717 |
| WINSTON | 20/26.6/33.3 | 44kV/13.8kV | $657,879 | -$18,024 |
| AQUITAINE _1 | 10/13.3/16.6 | 44kV/13.8kV | $0 | $0 |
| AQUITAINE _2 | 1/1.125 | 27.6kV/347/240V | $0 | $0 |
| AQUITAINE _3 | 10/13.3/16.6 | 44kV/13.8kV | $0 | $0 |
| AQUITAINE _4 | 5/6.67 | 27.6kV/4.16kV | $23,241 | -$2,021 |
| | | **Total** | **$1,068,245** | **-$43,392** |

**BOMA-79**

**Reference(s): DSP, p103**

**"The OEB requires that every LDC maintains reliability performance within its own historical three-year range."**

**Aside from the OEB's rather forgiving standard, why does Alectra not try to improve reliability? Please provide a copy of the CEA's Electric Power System Reliability Assessment Program.**

**Response:**

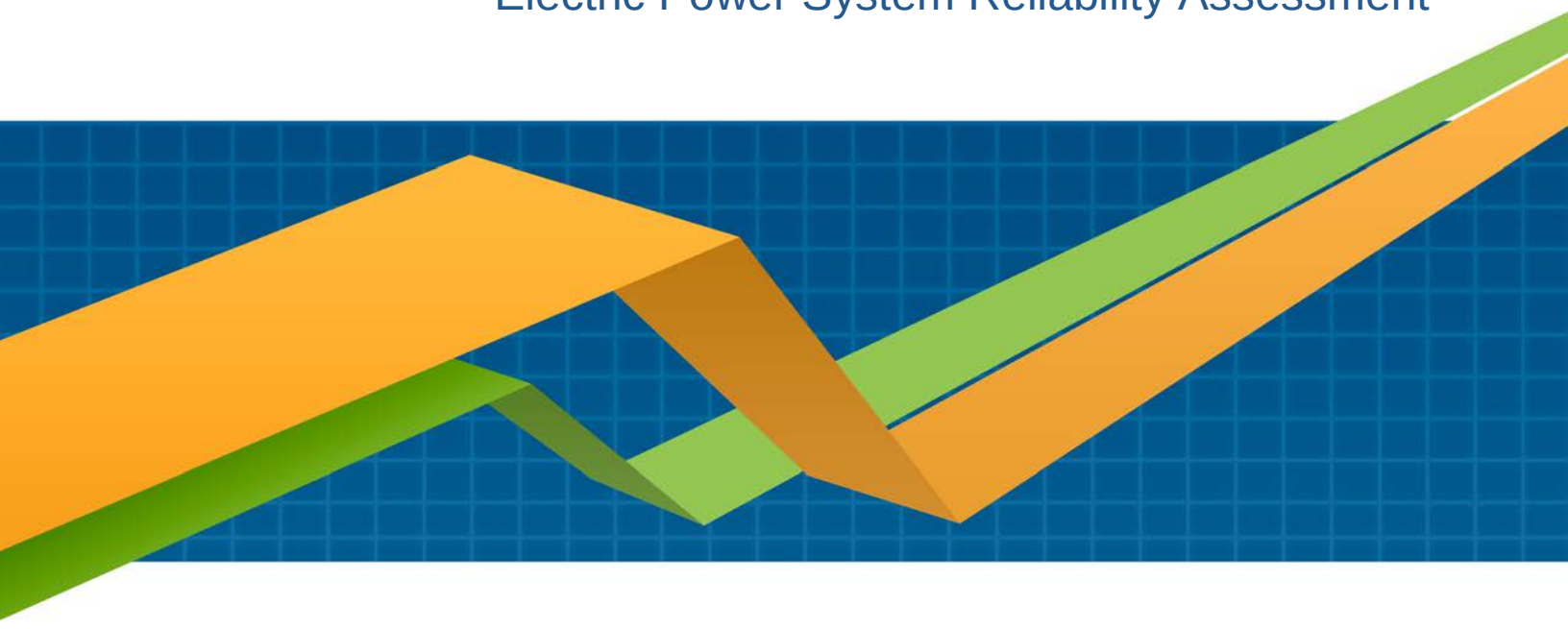
Alectra Utilities has internal metrics for reliability which exceed the Ontario Energy Board's ("OEB") target. Alectra Utilities has provided BOMA-79_Attach 1_ CEA Electric Power System Reliability Assessment for 2016.

Analytics | Analyse

# 2016

# Service Continuity Data on Distribution System Performance in Electrical Utilities

## Electric Power System Reliability Assessment



www.electricity.ca

Canadian Electricity Association | Association canadienne de l'électricité

Acknowledgements

The Canadian Electricity Association gratefully acknowledges the support of the participant utilities whose data was used in the preparation of this report. We also wish to thank the Service Continuity Committee (SCC) for their support and guidance throughout the year.

Participation

If your utility is interested in participating in the Service Continuity Committee, please contact CEA at the contact information shown below.

## Version Control

Document release date: June 5, 2017

This document supersedes all earlier versions.

This document is considered: FINAL

**Canadian Electricity Association**
Contact: Daniel Gent
gent@electricity.ca
www.electricity.ca

Copyright © Canadian Electricity Association. All rights reserved.

## INTRODUCTION

This report presents the results of the fifty-fourth consecutive survey of the performance of the Distribution Systems in electrical utilities. The report, prepared by the Canadian Electricity Association (CEA), presents a statistical summary of the Distribution Systems Performance for the year 2016 and compares it to 2015, as well as to the 2012-2016 five-year average.

The report presents some industry standard metrics for the Electricity Distribution including:

- System Average Interruption Frequency Index (SAIFI)
- System Average Interruption Duration Index (SAIDI)
- Customer Average Interruption Duration Index (CAIDI)
- Index of Reliability (IOR)
- Customer Interruptions per Kilometre (CIKM)
- Customer Hours per Kilometre (CHIKM)

By using the above metrics in combination with the cause of an electricity interruption, utility companies can

- set targets for improvement
- develop programs in support of their improvement targets
- make design/build decisions that try to mitigate interruption causes

Major Event Days (MEDs) are included in all statistics within this report. Major Event Days -- also referred to as Most Prominent Events -- events that exceed reasonable design and or operational limits of the electric power system.

National significant events (or catastrophic events) are a subset of MEDs. These are generally events that are larger than most MEDs, are outside the control of the utility, and have an impact on the national composite statistics. These are evaluated on a case-by-case basis by the Service Continuity Committee.

Members of the Service Continuity Committee and participants in the Service Continuity program follow a systematic procedure for collecting and analyzing data with regard to the Distribution System Performance according to definitions set by the Committee. This procedure follows the guidelines set out by CEA's Electric Power System Reliability Assessment program (EPSRA) which governs system continuity statistics for the entire electricity system. This includes the statistics captured in this report for the Distribution system and also statistics captured in the Bulk Electric System (BES) for service interruptions within the Transmission system. The EPSRA program is governed by the Consultative Committee on Outage Statistics (CCOS). The CCOS Committee was chaired until early 2010 by Dr. Roy Billinton of the University of Saskatchewan, a world renowned expert in the field of Electricity Equipment and Systems Reliability. The mission and vision of the Service Continuity Committee is below:

**Mission:**
Provide a mechanism to collect, analyze and report system distribution outage data, processes and functions in order to encourage members to gain and share insights and benefits through a community of practice.

**Vision:**
To be recognized as a trusted forum in distribution reliability practices through shared experiences and data analysis.

**Objectives:**

- Act as governing body that will oversee changes and enhancements of the database application and the data itself, while ensuring a high level of data quality/integrity.
- Act as distribution experts under the auspices of the CEA Analytics department and collaborate with the other Consultative Committee on Outage Statistics (CCOS) committees to share and present an overall view of Canadian electricity reliability.
- Actively perform/seek new research/analysis that will provide insight into enhancing distribution reliability.

- Add value to SCC members by providing a confidential forum for distribution system personnel to identify, develop and monitor the relevancy of distribution performance reliability measures, through shared practices, lessons learned and data analysis.
- Facilitate development of inter-utility networking for distribution system reliability.
- Maintain, update and provide guidance on common definitions and terms used in service continuity performance measurements, consistent with Canadian and International utility practices.
- Coordinate research efforts with other CEA groups as required.
- Be recognized nationally and internationally as a credible and trusted source for reliability information.

The membership of SCC includes one member of each of the participating CEA Corporate member utilities. It is chaired by Riaz Shaikh of PowerStream. The Vice-Chair is Betsy Matamoros of Fortis BC.

**ACKNOWLEDGEMENT**

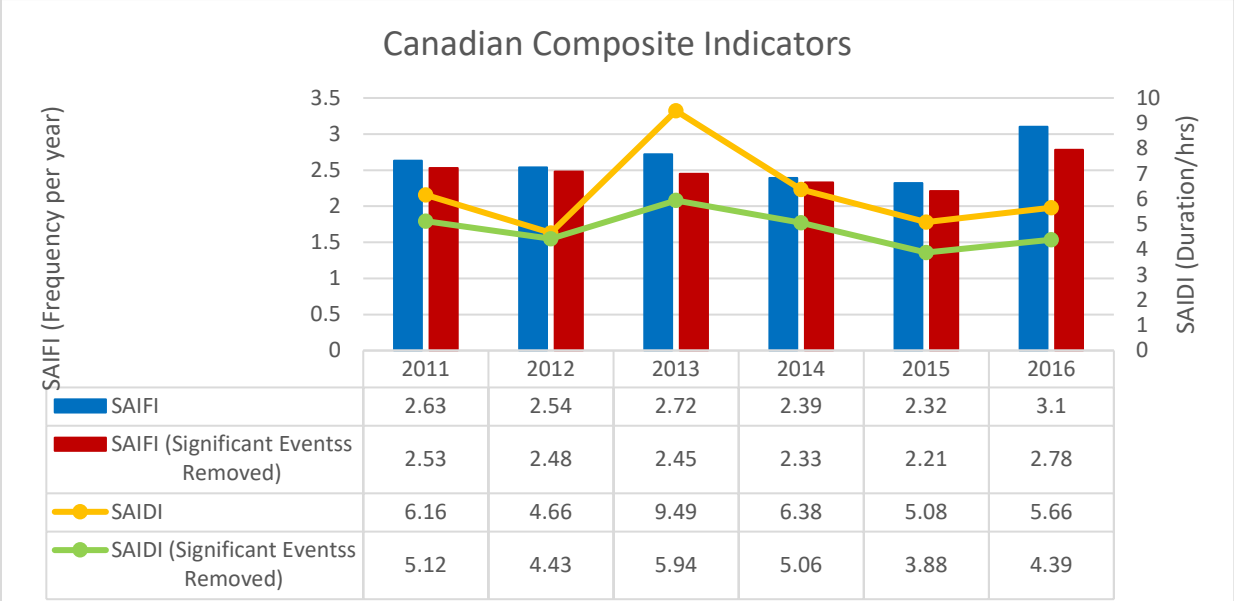
We wish to thank the utilities that have contributed data for this report. They are:

ATCO Electric
Barbados Light & Power Company
BC Hydro
Caribbean Utilities
City of Lethbridge
City of Medicine Hat
City of Red Deer
City of Summerside
Dominica Electricity Services Ltd.
Enersource Hydro Mississauga
ENMAX Power Co.
EPCOR
Fortis Alberta
Fortis BC
Grand Bahama Power Company
Horizon Utilities
Hydro One
Hydro One Brampton
Hydro Ottawa
Hydro Québec
London Hydro
Manitoba Hydro
Maritime Electric Co. Ltd.
New Brunswick Power
Newfoundland and Labrador Hydro
Newfoundland Power
Newmarket-Tay Power Distribution Ltd.
Northland Utilities
Northwest Territories Power Corp.
Nova Scotia Power
Oakville Hydro
Oshawa PUC Networks
PowerStream Inc.
Qulliq Energy Corporation
Saint John Energy
Saskatoon Light & Power
SaskPower
St. Lucia Electricity Services
St. Thomas Energy
Toronto Hydro
Utilities Kingston
Veridian Connections
Waterloo North Hydro
Yukon Electrical Co. Ltd.
Yukon Energy

# Executive Summary

## Service Continuity Committee (SCC) 2016 System Performance Report

### Overview




| | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 |
|---|---|---|---|---|---|---|
| SAIFI | 2.63 | 2.54 | 2.72 | 2.39 | 2.32 | 3.1 |
| SAIFI (Significant Eventss Removed) | 2.53 | 2.48 | 2.45 | 2.33 | 2.21 | 2.78 |
| SAIDI | 6.16 | 4.66 | 9.49 | 6.38 | 5.08 | 5.66 |
| SAIDI (Significant Eventss Removed) | 5.12 | 4.43 | 5.94 | 5.06 | 3.88 | 4.39 |

**Highlights (all events):**

- Tree Contacts contributed to 2 hours of the 5.66 SAIDI hours, they remain the largest contributor to SAIDI, the number of tree contacts has increased from 14% (2015) to 16% (2016) of interruptions or almost 10,000 interruptions, and 9,000,000 customer hours.
- Equipment Failure contributed to 0.85 hours of the 5.66 SAIDI hours, the 2nd largest contributor to SAIDI. Even though the SAIDI value was flat the number of interruptions due to equipment failures decreased slightly to 18.5% from 20% in 2015.
- The third largest contributor to SAIDI was Loss of Supply, contributing 0.57 hrs. This was a slight increase in interruptions from 2.6% to 2.9% (2016), however was a large increase in customer hours by almost 600,000 hours.

**All Recorded Interruptions Summary**

| Interruptions | Customer Interruptions | Customer Hours of Interruptions | SAIFI | SAIDI |
|---|---|---|---|---|
| 292,906 | 44,929,125 | 82,127,861 | 3.10 | 5.66 |

**Significant Events (SE) are those major events that the committee has deemed completely outside the control of the utility, and significantly impact the Canadian Index.**

| Interruptions | Customer Interruptions | Customer Hours of Interruption | Contribution to Composite SAIFI | Contribution to Composite SAIDI |
|---|---|---|---|---|
| 11,367 | 4,558,770 | 18,270,708 | 0.32 | 1.27 |

- Events classified as Significant Events, included two separate ice-storms, a lightning storm and the Fort McMurray fires. They represent 22% of the total hours of outages from 2016.

## TABLE OF CONTENTS


PAGE

1.0 **DEFINITIONS** ..... 1

1.1 Definition of Terms ..... 2
1.2 Classification of Interruptions by Cause ..... 4

2.0 **PERFORMANCE OF UTILITIES** ..... 5

2.1 Comparison of 2016 Canadian System Indices to 2015 ..... 6
2.2 Comparison of 2016 International System Indices to 2015 ..... 6
2.3 General Statistics Summary ..... 7
Graph 2-1 Systems Indices for 2011-2016 Canadian Data ..... 8
Graph 2-2 Causes of Interruptions for 2012-2016 Canadian Data ..... 9
Graph 2-3 Contribution to SAIFI by Cause for 2012-2016 Canadian Data ..... 10
Graph 2-4 Contribution to SAIDI by Cause for 2012-2016 Canadian Data ..... 11
Graph 2-5 Contribution to CAIDI by Cause for 2012-2016 Canadian Data ..... 12
Graph 2-6 Contribution to CHIKM by Cause for 2012-2016 Canadian Data ..... 13
Graph 2-7 Contribution to CIKM by Cause for 2012-2016 Canadian Data ..... 14
Graph 2-8 Normal Distribution SAIDI and SAIFI ..... 15

3.0 **TABULATION AND ANALYSIS OF SERVICE INTERRUPTION DATA** ..... 16

Table 3-1 Summary of Interruption Data for the Years 2011 to 2016 ..... 17
Table 3-2 System Causes of Service Interruption for Year 2016 – Canadian ..... 18
Table 3-2a System Causes of Service Interruption for Year 2016 – International ..... 19

4.0 **SUMMARY** ..... 20

4.1 Major Event and Significant Event Summary - Canadian ..... 21
4.2 Major Event and Significant Event Summary – International ..... 22

5.0 **SYSTEM CAUSES OF SERVICE OUTAGES BASED ON CUSTOMER DATA** ..... 24

Graph 5-1 Contributions to SAIFI for 2016 - Canadian ..... 25
Graph 5-1a Contributions to SAIFI for 2016 - International ..... 26
Graph 5-2 Contributions to SAIDI for 2016 - Canadian ..... 27
Graph 5-2a Contributions to SAIDI for 2016 - International ..... 28
Graph 5-3 Contributions to CAIDI for 2016 - Canadian ..... 29
Graph 5-3a Contributions to CAIDI for 2016 - International ..... 30
Graph 5-4 Contributions to CHIKM for 2016 – Canadian ..... 31
Graph 5-4a Contributions to CHIKM for 2016 – International ..... 32
Graph 5-5 Contributions to CIKM for 2016 – Canadian ..... 33
Graph 5-5a Contributions to CIKM for 2016 – International ..... 34
Graph 5-6 Summary of Causes for All Interruptions for 2016 Canadian Data ..... 35
Graph 5-6a Summary of Causes for All Interruptions for 2016 International Data ..... 36

6.0 **TABULATION OF SERVICE INTERRUPTION DATA FOR REGION 1 (URBAN UTILITIES)** ..... 39

6.0 List of Region 1 Utilities ..... 40
Table 6-1 Region 1 Summary of Interruption Data for 2011-2016 ..... 41
Table 6-2 Region 1 System Causes of Service Interruption for 2016 ..... 42
Graph 6-1 Region 1 SAIDI Excluding MPEs ..... 43
Graph 6-2 Region 1 SAIDI Excluding Significant Events ..... 43
Graph 6-3 Region 1 SAIDI Including All Events ..... 44
Graph 6-4 Region 1 CAIDI Excluding MPEs ..... 44
Graph 6-5 Region 1 CAIDI Excluding Significant Events ..... 45
Graph 6-6 Region 1 CAIDI Including All Events ..... 45
Graph 6-7 Region 1 Customer Hours per KM Excluding MPEs ..... 46
Graph 6-8 Region 1 Customer Hours per KM Excluding Significant Events ..... 46
Graph 6-9 Region 1 Customer Hours per KM Including All Events ..... 47
Graph 6-10 Region 1 Customer Interruptions per KM Excluding MPEs ..... 47
Graph 6-11 Region 1 Customer Interruptions per KM Excluding Significant Events ..... 48
Graph 6-12 Region 1 Customer Interruptions per KM Including All Evens ..... 48
Graph 6-13 Region 1 SAIFI Excluding MPEs ..... 49
Graph 6-14 Region 1 SAIFI Excluding Significant Events ..... 49
Graph 6-15 Region 1 SAIFI Including All Events ..... 50

7.0 **TABULATION OF SERVICE INTERRUPTION FOR REGION 2 (URBAN/RURAL UTILITIES)** ..... 51

7.0 List of Region 2 Utilities ..... 52
Table 7-1 Region 2 Summary of Interruption Data for 2011-2016 ..... 53
Table 7-2 Region 2 System Causes of Service Interruption for 2016 ..... 54
Graph 7-1 Region 2 SAIDI Excluding MPEs ..... 55
Graph 7-2 Region 2 SAIDI Excluding Significant Events ..... 55
Graph 7-3 Region 2 SAIDI Including All Events ..... 56
Graph 7-4 Region 2 CAIDI Excluding MPEs ..... 56
Graph 7-5 Region 2 CAIDI Excluding Significant Events ..... 57
Graph 7-6 Region 2 CAIDI Including All Events ..... 57
Graph 7-7 Region 2 Customer Hours per KM Excluding MPEs ..... 58
Graph 7-8 Region 2 Customer Hours per KM Excluding Significant Events ..... 58
Graph 7-9 Region 2 Customer Hours per KM Including All Events ..... 59
Graph 7-10 Region 2 Customer Interruptions per KM Excluding MPEs ..... 59
Graph 7-11 Region 2 Customer Interruptions per KM Excluding Significant Events ..... 60
Graph 7-12 Region 2 Customer Interruptions per KM Including All Evens ..... 60
Graph 7-13 Region 2 SAIFI Excluding MPEs ..... 61
Graph 7-14 Region 2 SAIFI Excluding Significant Events ..... 61
Graph 7-15 Region 2 SAIFI Including All Events ..... 62

8.0 **SYSTEM INDICES BY REGIONS** ..... 63

Graph 8-1 System Indices for Region 1, Region 2 and Total Regions for 2016 Data ..... 64

# 1.0 DEFINITIONS

## 1.0 DEFINITIONS

### 1.1 DEFINITION OF TERMS

**DISTRIBUTION SYSTEM**

A Distribution System is that portion of an electric power system which links the Bulk Electricity System (BES) or sources with the customer's facilities.

Subtransmission lines, distribution substations, primary feeders, distribution transformers, secondaries and customers' services all form different parts of what can generally be called Distribution Systems. The Delivery Point (DP) is the delineation point between the BES and the Distribution System. It is the low voltage busbar of the step down transformer station, whereby the transformer busbar is considered part of the BES System. At the transformer station the voltage is stepped down from a transmission voltage, which may cover a range of 60-750kV to a distribution voltage of under 60kV.

Where the reporting company does not own the equipment up to the Delivery Point as defined above, the delineation point shall be at the point of ownership.

**CUSTOMERS**

The average number of customers served in the region during the reporting period. This means the number of customer services fed at secondary, primary and subtransmission voltages. A customer is defined as a metered service. Municipal utilities buying power from Provincial utilities should not be reported as customers by the Provincial utility.

**INTERRUPTION**

An *interruption* is the loss of service to one or more customers and is the result of one or more component outages. A *momentary interruption* is defined as an interruption with a duration of less than one (1) minute. These are interruptions generally restored by automatic reclosure facilities, which are of a very short duration (on the order of a few seconds).

**INTERRUPTION-DURATION**

This is the period from the initiation of an interruption to a customer until service has been restored to that customer.

**INTERRUPTION START TIME**

An interruption is deemed to have occurred when the utility supplying power is made aware that a customer is without power. This is either the time the customer calls in or the time remote monitoring devices indicate a power interruption. It may be for either a full or part power interruption.

**INTERRUPTION END TIME**

An interruption is deemed to have ended when the utility supplying power is made aware that a customer's power has been restored. This is either the time the restoring crew reports the restoration is complete or the time remote monitoring devices indicate a power has been restored.

**CUSTOMER-HOURS OF INTERRUPTION**

This is the product of the customer services interrupted by the period of interruption.

**CUSTOMER-INTERRUPTIONS**

This is the sum of products of the customer services interrupted by the number of interruptions that affect those customer services.

**SYSTEM AVERAGE INTERRUPTION FREQUENCY INDEX (SAIFI)**

This index is defined as the average number of interruptions per customer served per year.

$$\textbf{SAIFI} = \frac{\text{Total Customer-Interruptions}}{\text{Total Customers Served}}$$

**SYSTEM AVERAGE INTERRUPTION FREQUENCY INDEX (MOMENTARY) SAIFI (MI)**

This index is defined as the average number of interruptions per customer served per year for momentary interruptions (interruptions of a duration less than 1 minute).

$$\textbf{SAIFI (MI)} = \frac{\text{Total Momentary Customer-Interruptions}}{\text{Total Customers Served (in area where momentary interruptions are monitored)}}$$

**SYSTEM AVERAGE INTERRUPTION DURATION INDEX (SAIDI)**

This index is defined as the system average interruption duration for customers served per year.

$$\textbf{SAIDI} = \frac{\text{Total Customer-Hours of Interruptions}}{\text{Total Customers Served}}$$

**CUSTOMER AVERAGE INTERRUPTION DURATION INDEX (CAIDI)**

This index is defined as the customer average interruption duration for customers interrupted during a year.

$$\textbf{CAIDI} = \frac{\text{Total Customer-Hours of Interruptions}}{\text{Total Customer Interruptions}}$$

**CUSTOMER INTERRUPTIONS PER KM**

$$\textbf{Customer Interruptions per KM} = \frac{\text{Customer Interruptions}}{\text{Circuit Km}}$$

**CUSTOMER HOURS PER KM**

$$\textbf{Customer Hours per KM} = \frac{\text{Customer Hours}}{\text{Circuit Km}}$$

**INDEX OF RELIABILITY**

The per unit of annual customer-hours that service is available.

$$\textbf{Index of Reliability} = \frac{\text{8,760 hours/year - SAIDI}}{\text{8,760 hours/year}}$$

## 1.2 CLASSIFICATION OF INTERRUPTIONS BY CAUSE

A customer interruption has been defined in terms of primary cause of the interruption. These causes have been assigned the following codes:

**0 -** ***Unknown/Other***

Customer interruptions with no apparent cause or reason which could have contributed to the outage.

**1 -** ***Scheduled Outage***

Customer interruptions due to the disconnection at a selected time for the purpose of construction or preventive maintenance.

**2 -** ***Loss of Supply***

Customer interruptions due to problems in the bulk electricity supply system such as underfrequency load shedding, transmission system transients, or system frequency excursions. During a rotating load shedding cycle, the duration is the total outage time until normal operating conditions resume, while the number of customers affected is the average number of customers interrupted per rotating cycle.

**3 -** ***Tree Contacts***

Customer interruptions caused by faults due to trees or tree limbs contacting energized circuits.

**4 -** ***Lightning***

Customer interruptions due to lightning striking the Distribution System, resulting in an insulation breakdown and/or flashovers.

**5 -** ***Equipment Failure***

Customer interruptions resulting from equipment failures due to deterioration from age, incorrect maintenance, or imminent failures detected by maintenance.

**6 -** ***Adverse Weather***

Customer interruptions resulting from rain, ice storms, snow, winds, extreme ambient temperatures, freezing fog, or frost and other extreme conditions.

**7 -** ***Adverse Environment***

Customer interruptions due to equipment being subjected to abnormal environment such as salt spray, industrial contamination, humidity, corrosion, vibration, fire or flooding.

**8 -** ***Human Element***

Customer interruptions due to the interface of the utility staff with the system such as incorrect records, incorrect use of equipment, incorrect construction or installation, incorrect protection settings, switching errors, commissioning errors, deliberate damage, or sabotage.

**9 -** ***Foreign Interference***

Customer interruptions beyond the control of the utility such as birds, animals, vehicles, dig-ins, vandalism, sabotage and foreign objects.

# 2.0 PERFORMANCE OF UTILITIES

## 2.0 PERFORMANCE OF UTILITIES

### 2.1 COMPARISON OF 2016 CANADIAN SYSTEM INDICES TO 2015

| | |
|---|---|
| **SAIFI** | The average number of interruptions per customer per year was 3.10, which represents an increase of 33.4% over the 2015 figure of 2.32. |
| **SAIDI** | The system average interruption duration for customers served was 5.66 hours per year, which represents an increase of 11.5% over the 2015 figure of 5.08 hours. |
| **CAIDI** | The average customer interruption duration per interruption was 1.83 hours, which represents a decrease of 16.4% over the 2015 figure of 2.19 hours. |
| **Index of Reliability** | or the per unit annual customer hours that service is available was 0.999354, as compared to 0.999420 in 2015. |
| **CHIKM** | The average customer hour interruptions per KM was 100.50, which represents an increase of 12.7% over the 2015 figure of 89.14. |
| **CIKM** | The average customer interruptions per KM was 54.98, which represents an increase of 34.9% over the 2015 figure of 40.75. |

### 2.2 COMPARISON OF 2016 INTERNATIONAL SYSTEM INDICES TO 2015

| | |
|---|---|
| **SAIFI** | The average number of interruptions per customer per year was 8.22, which represents an increase of 36.54% over the 2015 value of 6.02. |
| **SAIDI** | The system average of interruption duration for customers served was 15.28 hours per year, which represents an increase of 91.48% over the 2015 value of 7.98. |
| **CAIDI** | The average customer interruption duration per interruption was 1.86 which represents an increase of 40.91% over the 2015 value of 1.32. |
| **Index of Reliability** | The Index of Reliability was 0.998256, as compared to 0.999090 in 2015. |
| **CHIKM** | The average customer hour interruptions per KM was 423.5, which represents an increase of 39.87% over the 2015 value of 302.79. |
| **CIKM** | The average customer interruptions per KM was 227.70, which represents a decrease of 0.47% over the 2015 value of 228.78. |

## 2.3 General Statistics Summary:

**Canadian Utilities:**

| | 2016 | 2015 |
|---|---|---|
| *Total Customers:* | 14,509,663 | 14,329,556 |
| *Total Distribution System Peak (KW):* | 77,578,797 | 89,056,407 |
| *Average Distribution System Peak (KW):* | 1,891,1657 | 2,283,498 |
| *Total Area Served (SQ.KM):* | 5,863,913 | 5,863,146 |
| *Total Distribution Circuit (KM) Overhead:* | 668,582 | 667,728 |
| *Total Distribution Circuit (KM) Underground:* | 148,579 | 149,025 |
| *Total Distribution Circuit (KM) Both:* | 817,161 | 816,753 |

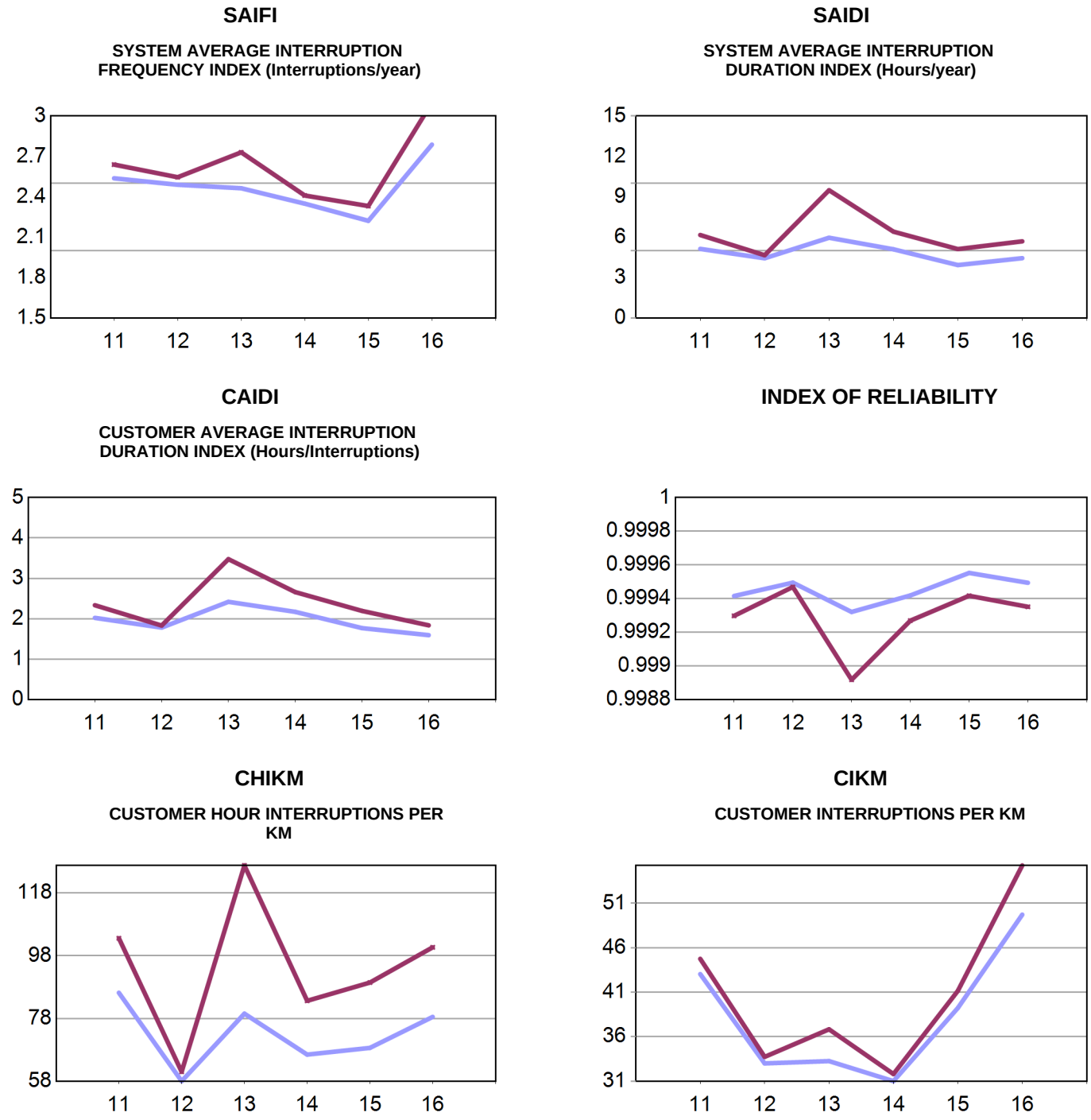
**International Utilities:**

| | 2016 | 2015 |
|---|---|---|
| *Total Customers:* | 276,529 | 361,737 |
| *Total Distribution System Peak (KW):* | 278,510 | 2,097,169 |
| *Average Distribution System Peak (KW):* | 564.2 | 349,528 |
| *Total Area Served (SQ.KM):* | 2,821 | 3,771 |
| *Total Distribution Circuit (KM) Overhead:* | 9127 | 4,721 |
| *Total Distribution Circuit (KM) Underground:* | 858 | 4,806 |
| *Total Distribution Circuit (KM) Both:* | 9985 | 9,527 |

**Combined:**

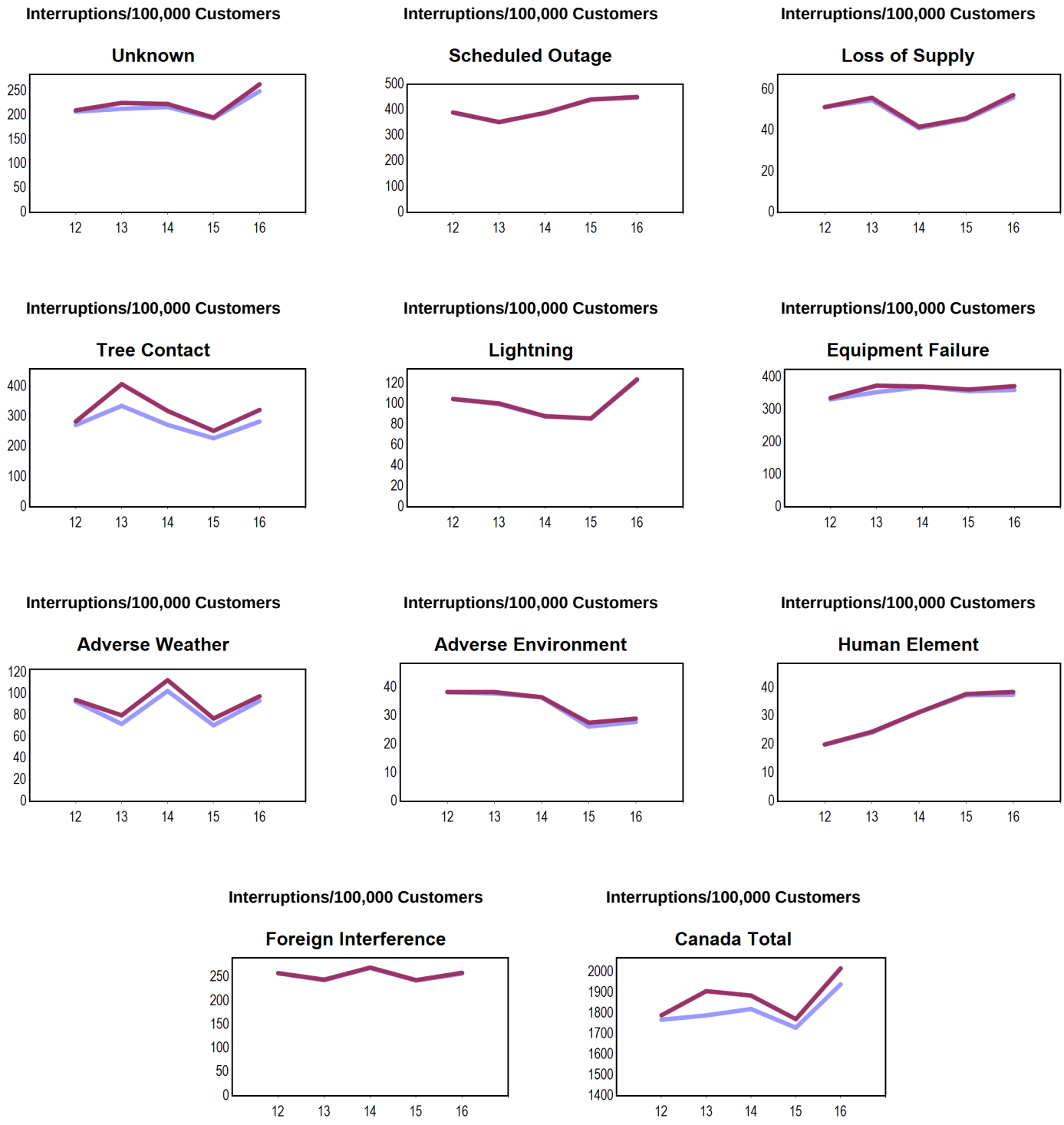
| | 2016 | 2015 |
|---|---|---|
| *Total Customers:* | 14,786,192 | 14,691,293 |
| *Total Distribution System Peak (KW):* | 77,854,332 | 91,153,576 |
| *Average Distribution System Peak (KW):* | 1,692,550 | 2,025,635 |
| *Total Area Served (SQ.KM):* | 5,866,734 | 5,866,917 |
| *Total Distribution Circuit (KM) Overhead:* | 677,709 | 672,449 |
| *Total Distribution Circuit (KM) Underground:* | 6,544,443 | 153,831 |
| *Total Distribution Circuit (KM) Both:* | 827,146 | 826,280 |

The annual variations in the service indices for Canadian data for the period 2011 to 2016 are shown below in Graph 2.1.



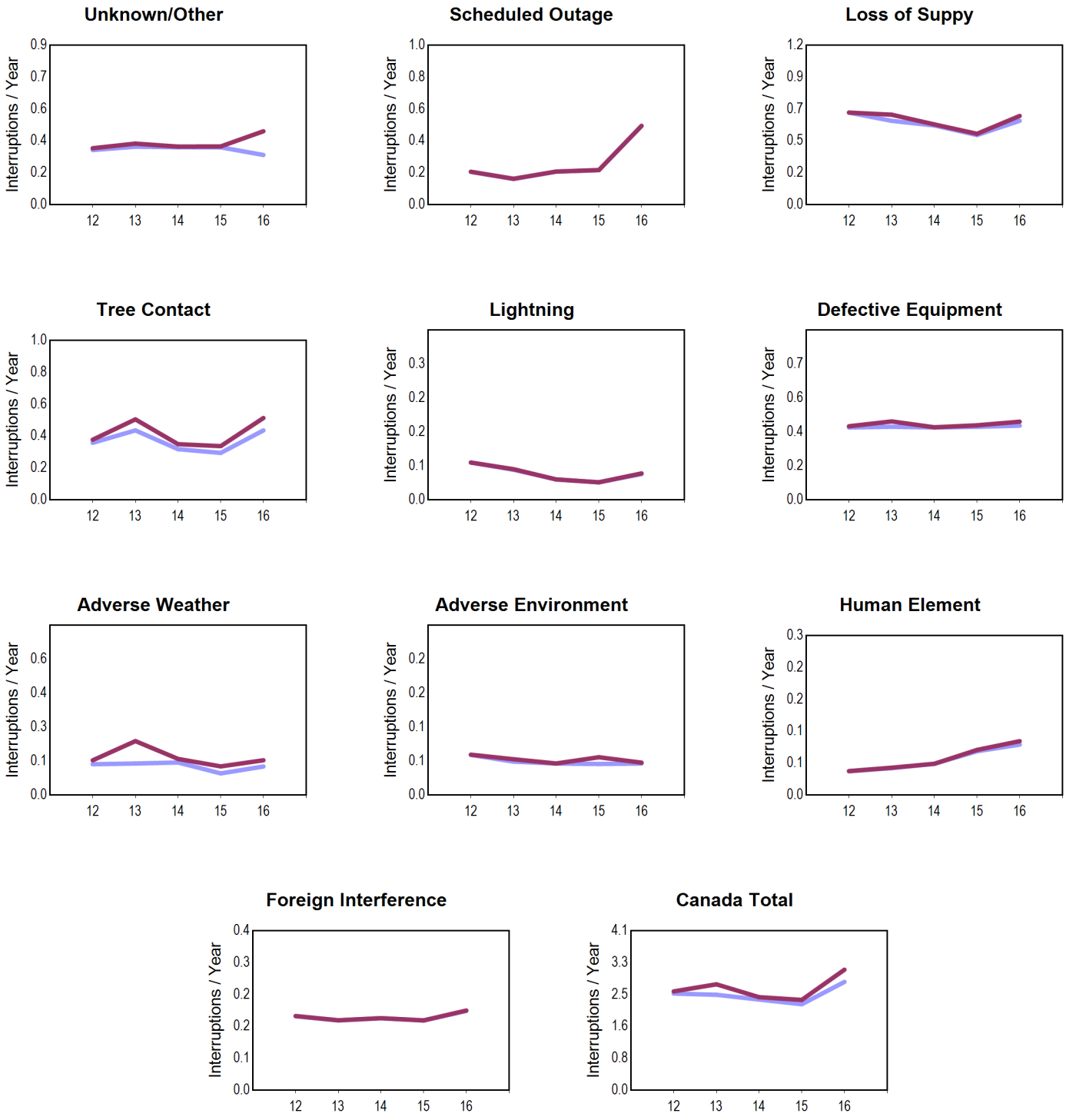

Note: ——— denotes the exclusion of Significant Event data.

***Graph 2-1 System Indices of SAIFI, SAIDI, CAIDI & IOR for 2011-2016 Canadian Data***



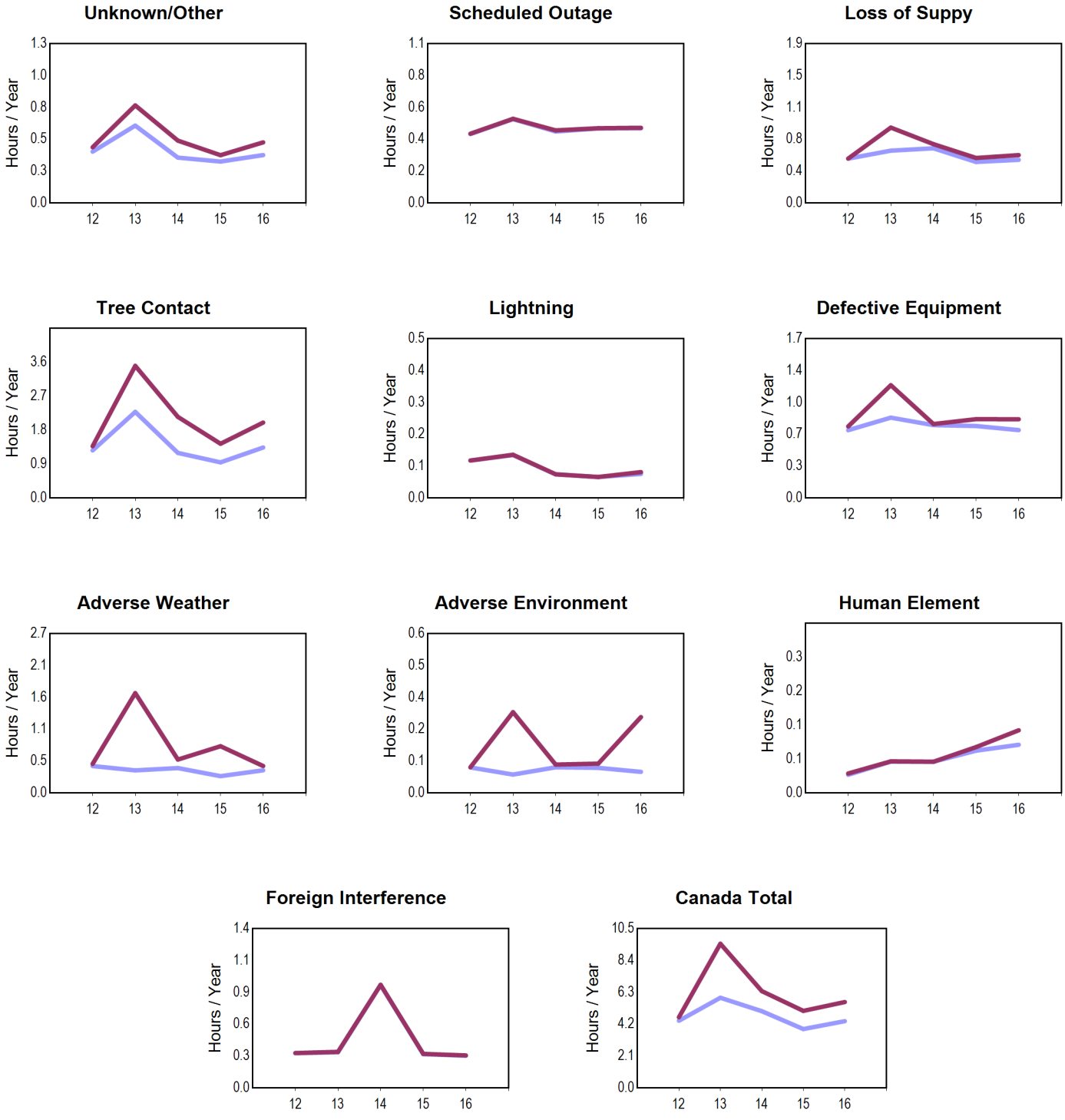

Note: ——— denotes the exclusion of Significant Event data.

***Graph 2-2 Causes of Interruptions for 2012-2016 Canadian Data - normalized to 100,000 customers***



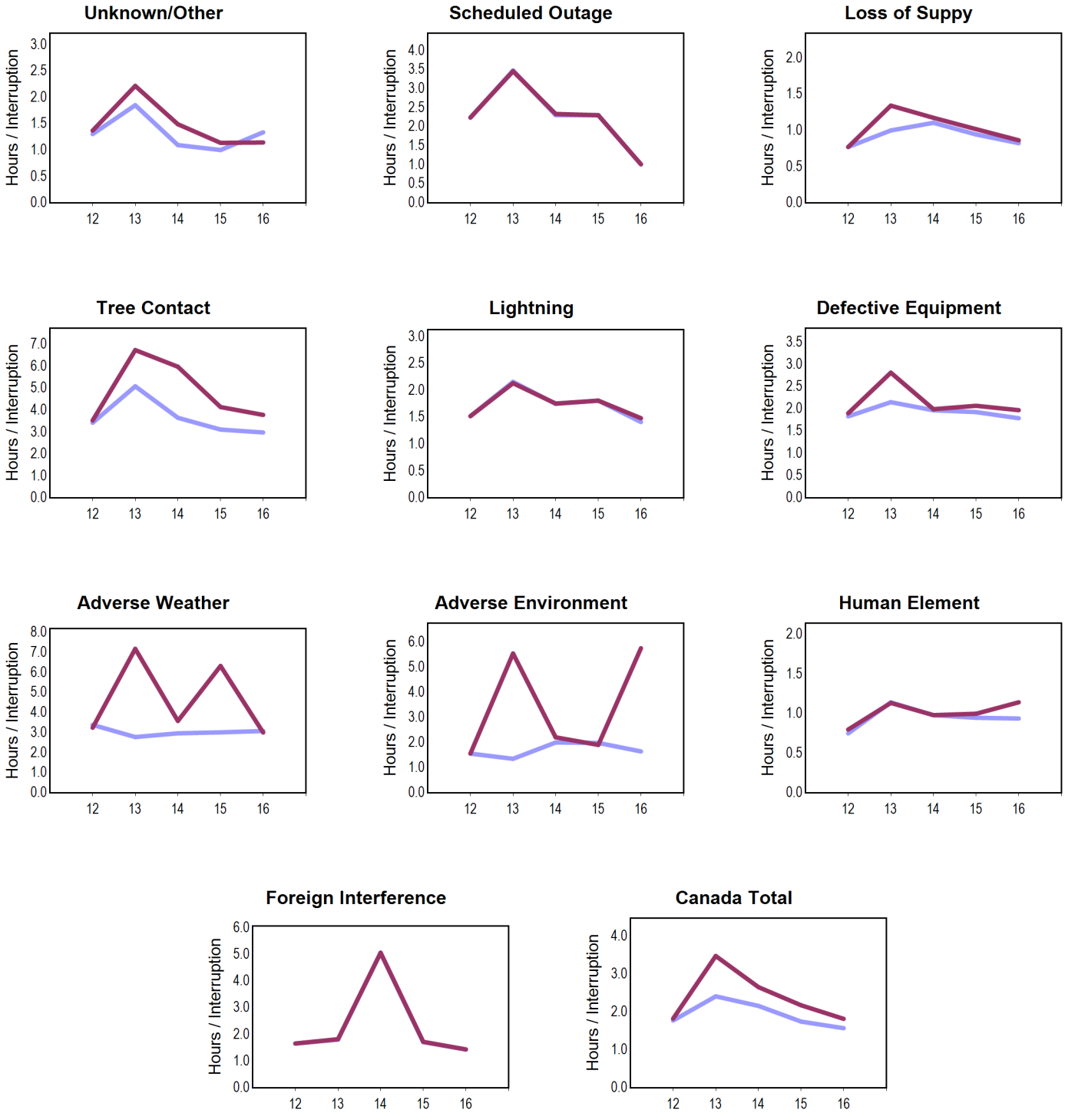

Note: ——— denotes the exclusion of Significant Event data.

***Graph 2-3 Contribution to SAIFI by Cause for 2012-2016 Canadian Data***



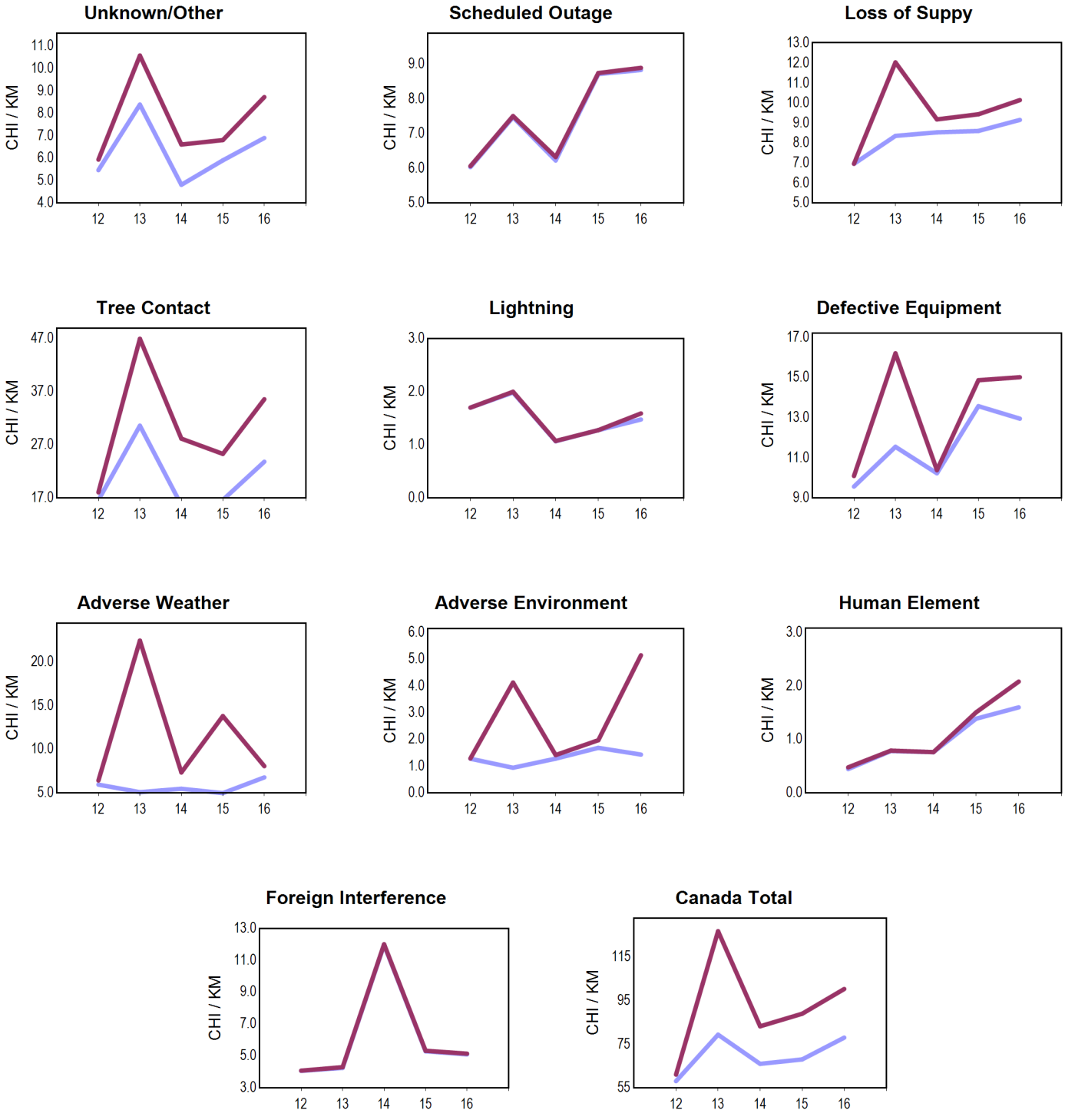

Note: ——— denotes the exclusion of Significant Event data.

***Graph 2-4 Contribution to SAIDI by Cause for 2012-2016 Canadian Data***



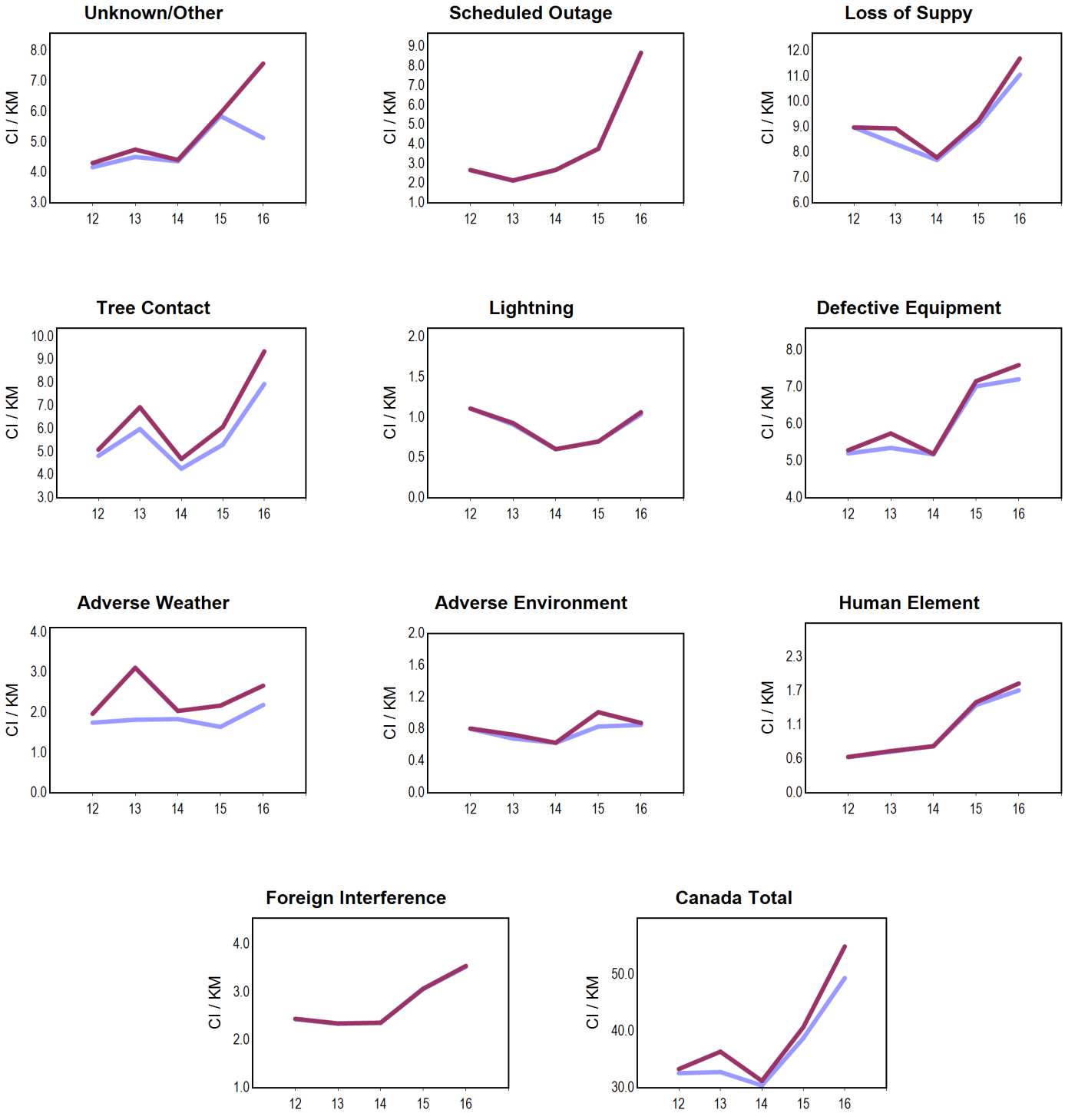

Note: ——— denotes the exclusion of Significant Event data.

***Graph 2-5 Contribution to CAIDI by Cause for 2012-2016 Canadian Data***



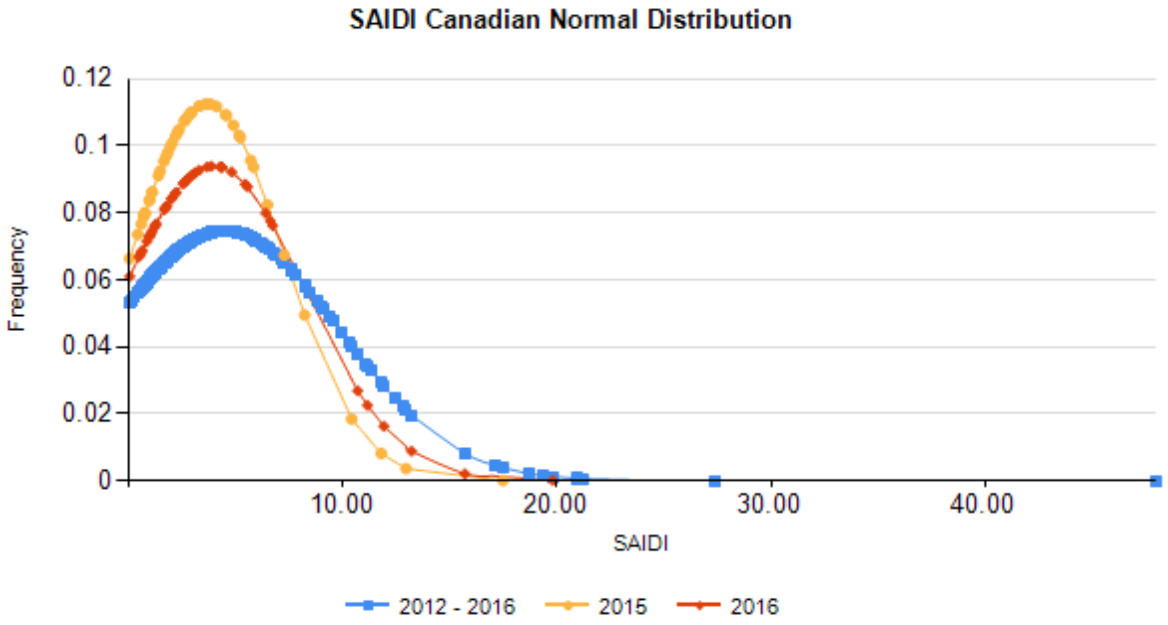

Note: ——— denotes the exclusion of Significant Event data.

***Graph 2-6 Contribution to CHIKM by Cause for 2012-2016 Canadian Data***



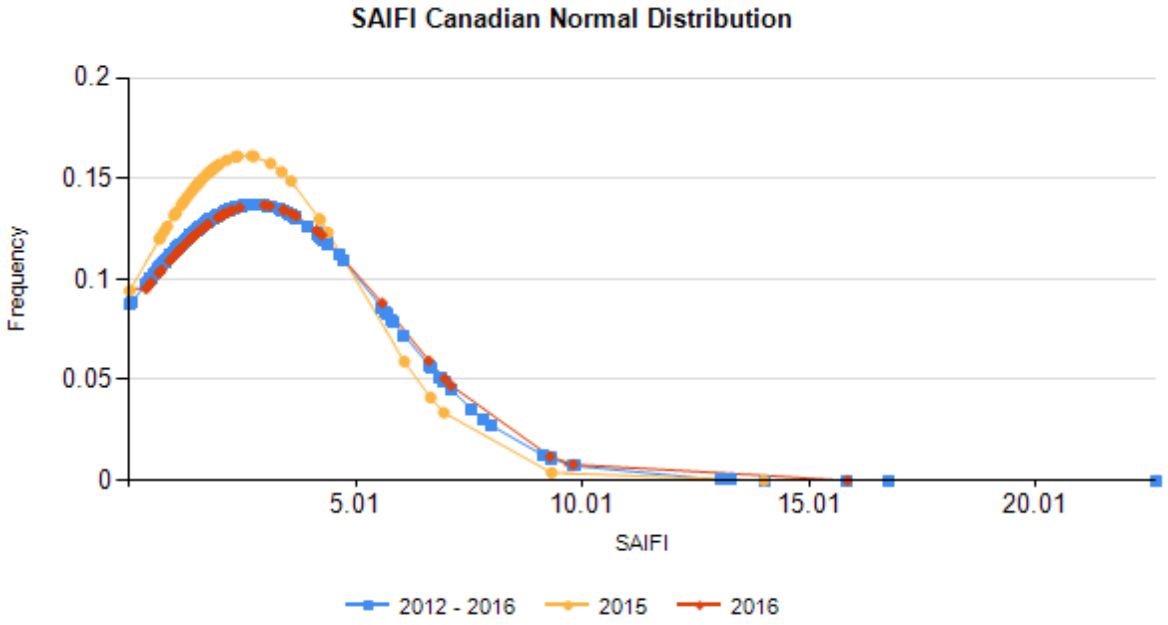

Note: —— denotes the exclusion of Significant Event data.

***Graph 2-7 Contribution to CIKM by Cause for 2012-2016 Canadian Data***




2016 SAIDI normal distribution confidence level: 95% 3.95 +/- 1.03

2016 SAIDI Standard Error 0.57




2016 SAIFI normal distribution confidence level: 95% 2.86 +/- 0.71

2016 SAIFI Standard Error 0.41

# 3.0 TABULATION AND ANALYSIS OF SERVICE INTERRUPTION DATA

**TABLE 3-1**

**SUMMARY OF INTERRUPTION DATA**

**(Including Derivation of Index of Reliability)**

**FOR YEARS 2011 - 2016**

*THE "INDEX OF RELIABILITY" IS A MEASURE OF SERVICE RELIABILITY.*
*IT EQUALS THE PER UNIT ANNUAL CUSTOMER-HOURS THAT SERVICE IS AVAILABLE.*

**CANADIAN UTILITIES IN 2016**

| YEAR | NUMBER OF CUSTOMERS SERVED | NUMBER OF INTERRUPTIONS | TOTAL CUSTOMER INTERRUPTIONS | (A) TOTAL INTERRUPTED CUST. HOURS | (B) TOTAL AVAILABLE CUST. HOURS | (C) INDEX OF RELIABILITY |
|---|---|---|---|---|---|---|
| 2011 | 13,166,791 | 247,330 | 34,640,048 | 81,099,286 | 115,341,089,160 | 0.999297 |
| 2011** | 13,166,791 | 238,144 | 33,292,588 | 67,434,099 | 115,341,089,160 | 0.999415 |
| 2012 | 13,404,198 | 240,053 | 34,048,735 | 62,443,872 | 117,420,774,480 | 0.999468 |
| 2012** | 13,404,198 | 237,178 | 33,295,600 | 59,383,340 | 117,420,774,480 | 0.999494 |
| 2013 | 13,737,830 | 262,160 | 37,393,115 | 130,409,957 | 120,343,390,800 | 0.998916 |
| 2013** | 13,737,830 | 245,962 | 33,704,732 | 81,641,090 | 120,343,390,800 | 0.999322 |
| 2014 | 13,972,670 | 263,607 | 33,413,324 | 89,095,948 | 122,400,589,200 | 0.999272 |
| 2014** | 13,972,670 | 254,488 | 32,560,856 | 70,666,529 | 122,400,589,200 | 0.999423 |
| 2015 | 14,321,390 | 253,821 | 33,247,310 | 72,732,010 | 125,455,376,400 | 0.999420 |
| 2015** | 14,321,390 | 247,863 | 31,665,128 | 55,618,878 | 125,455,376,400 | 0.999557 |
| 2016 | 14,509,663 | 292,906 | 44,929,125 | 82,127,861 | 127,104,647,880 | 0.999354 |
| 2016** | 14,509,663 | 281,539 | 40,370,352 | 63,857,155 | 127,104,647,880 | 0.999498 |

*** Excludes Significant Events*

**INTERNATIONAL UTILITIES IN 2016**

| | | | | | | |
|---|---|---|---|---|---|---|
| 2011 | 160,859 | 6,898 | 919,580 | 737,138 | 1,409,124,840 | 0.999477 |
| 2012 | 106,299 | 2,924 | 718,946 | 751,786 | 931,179,240 | 0.999193 |
| 2013 | 585,553 | 16,734 | 3,083,530 | 3,743,124 | 5,129,444,280 | 0.999270 |
| 2014 | 787,143 | 19,769 | 6,597,349 | 5,656,404 | 6,895,372,680 | 0.999180 |
| 2015 | 361,737 | 2,420 | 2,178,927 | 2,884,883 | 3,168,816,120 | 0.999090 |
| 2016 | 276,529 | 2,447 | 2,273,771 | 4,224,430 | 2,422,394,040 | 0.998256 |
| 2016** | 276,529 | 2,418 | 2,154,361 | 2,481,424 | 2,422,394,040 | 0.998976 |

**(A) = SUMMATION OF THE NUMBER OF CUSTOMERS x RESTORATION TIME IN HOURS OF EACH INTERRUPTION**

**(B) = TWELVE MONTH AVERAGE NUMBER OF CUSTOMERS x 8,760 HOURS (ONE YEAR)**

**(C) = INDEX OF RELIABILITY: 1 - (A)/(B)**

## TABLE 3-2

## SYSTEM CAUSES OF SERVICE INTERRUPTION

## FOR YEAR 2016

*Canadian*

**14,509,663 CUSTOMERS IN 2016**
**14,321,390 CUSTOMERS IN 2015**

| PRIMARY CAUSE | NUMBER OF INTERRUPTIONS | | CUSTOMER INTERRUPTIONS | | CUSTOMER HOUR INTERRUPTIONS | | SAIFI | SAIDI | CAIDI | CHIKM | CIKM |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | NUMBER | % | NUMBER | % | NUMBER | % | | (HRS) | (HRS) | | |
| **Unknown/Other** | | | | | | | | | | | |
| 2016 | 38,384 | 13.1 | 6,202,046 | 13.8 | 7,140,281 | 8.7 | 0.43 | 0.49 | 1.15 | 8.74 | 7.59 |
| 2015 | 28,048 | 11.1 | 4,861,498 | 14.6 | 5,561,781 | 7.6 | 0.34 | 0.39 | 1.14 | 6.82 | 5.96 |
| 5 YEAR AVERAGE | 31,407 | 12.0 | 5,017,274 | 13.7 | 7,342,642 | 8.4 | 0.36 | 0.52 | 1.46 | 7.73 | 5.28 |
| **Scheduled Outage** | | | | | | | | | | | |
| 2016 | 65,477 | 22.4 | 7,108,581 | 15.8 | 7,274,051 | 8.9 | 0.49 | 0.50 | 1.02 | 8.90 | 8.70 |
| 2015 | 63,241 | 24.9 | 3,088,320 | 9.3 | 7,140,992 | 9.8 | 0.22 | 0.50 | 2.31 | 8.75 | 3.79 |
| 5 YEAR AVERAGE | 56,805 | 21.6 | 3,611,215 | 9.9 | 7,016,796 | 8.0 | 0.26 | 0.50 | 1.94 | 7.39 | 3.80 |
| **Loss of Supply** | | | | | | | | | | | |
| 2016 | 8,350 | 2.9 | 9,569,504 | 21.3 | 8,303,407 | 10.1 | 0.66 | 0.57 | 0.87 | 10.16 | 11.71 |
| 2015 | 6,610 | 2.6 | 7,547,355 | 22.7 | 7,710,151 | 10.6 | 0.53 | 0.54 | 1.02 | 9.45 | 9.25 |
| 5 YEAR AVERAGE | 7,093 | 2.7 | 8,763,332 | 23.9 | 9,063,751 | 10.4 | 0.63 | 0.65 | 1.03 | 9.54 | 9.23 |
| **Tree Contacts** | | | | | | | | | | | |
| 2016 | 46,867 | 16.0 | 7,659,748 | 17.0 | 29,091,503 | 35.4 | 0.53 | 2.00 | 3.80 | 35.60 | 9.37 |
| 2015 | 36,277 | 14.3 | 4,968,953 | 14.9 | 20,659,014 | 28.4 | 0.35 | 1.44 | 4.16 | 25.32 | 6.09 |
| 5 YEAR AVERAGE | 44,423 | 16.9 | 5,998,854 | 16.4 | 29,310,743 | 33.6 | 0.43 | 2.10 | 4.89 | 30.86 | 6.32 |
| **Lightning** | | | | | | | | | | | |
| 2016 | 18,014 | 6.2 | 873,627 | 1.9 | 1,301,101 | 1.6 | 0.06 | 0.09 | 1.49 | 1.59 | 1.07 |
| 2015 | 12,332 | 4.9 | 574,224 | 1.7 | 1,043,276 | 1.4 | 0.04 | 0.07 | 1.82 | 1.28 | 0.70 |
| 5 YEAR AVERAGE | 14,119 | 5.4 | 839,107 | 2.3 | 1,456,574 | 1.7 | 0.06 | 0.10 | 1.74 | 1.53 | 0.88 |
| **Defective Equipment** | | | | | | | | | | | |
| 2016 | 54,103 | 18.5 | 6,212,250 | 13.8 | 12,280,405 | 15.0 | 0.43 | 0.85 | 1.98 | 15.03 | 7.60 |
| 2015 | 51,904 | 20.4 | 5,848,664 | 17.6 | 12,138,735 | 16.7 | 0.41 | 0.85 | 2.08 | 14.88 | 7.17 |
| 5 YEAR AVERAGE | 50,896 | 19.4 | 5,785,496 | 15.8 | 12,497,304 | 14.3 | 0.41 | 0.89 | 2.16 | 13.16 | 6.09 |
| **Adverse Weather** | | | | | | | | | | | |
| 2016 | 14,221 | 4.9 | 2,186,308 | 4.9 | 6,606,817 | 8.0 | 0.15 | 0.46 | 3.02 | 8.09 | 2.68 |
| 2015 | 11,063 | 4.4 | 1,778,234 | 5.3 | 11,274,665 | 15.5 | 0.12 | 0.79 | 6.34 | 13.82 | 2.18 |
| 5 YEAR AVERAGE | 12,956 | 4.9 | 2,274,490 | 6.2 | 11,076,588 | 12.7 | 0.16 | 0.79 | 4.87 | 11.66 | 2.39 |
| **Adverse Environment** | | | | | | | | | | | |
| 2016 | 4,226 | 1.4 | 729,476 | 1.6 | 4,212,058 | 5.1 | 0.05 | 0.29 | 5.77 | 5.15 | 0.89 |
| 2015 | 3,965 | 1.6 | 839,606 | 2.5 | 1,613,736 | 2.2 | 0.06 | 0.11 | 1.92 | 1.98 | 1.03 |
| 5 YEAR AVERAGE | 4,753 | 1.8 | 770,949 | 2.1 | 2,582,899 | 3.0 | 0.06 | 0.18 | 3.35 | 2.72 | 0.81 |
| **Human Element** | | | | | | | | | | | |
| 2016 | 5,594 | 1.9 | 1,484,051 | 3.3 | 1,702,980 | 2.1 | 0.10 | 0.12 | 1.15 | 2.08 | 1.82 |
| 2015 | 5,417 | 2.1 | 1,227,977 | 3.7 | 1,231,523 | 1.7 | 0.09 | 0.09 | 1.00 | 1.51 | 1.51 |
| 5 YEAR AVERAGE | 4,291 | 1.6 | 974,109 | 2.7 | 1,012,029 | 1.2 | 0.07 | 0.07 | 1.04 | 1.07 | 1.03 |
| **Foreign Interference** | | | | | | | | | | | |
| 2016 | 37,670 | 12.9 | 2,903,534 | 6.5 | 4,215,258 | 5.1 | 0.20 | 0.29 | 1.45 | 5.16 | 3.55 |
| 2015 | 34,964 | 13.8 | 2,512,479 | 7.6 | 4,358,139 | 6.0 | 0.18 | 0.30 | 1.73 | 5.34 | 3.08 |
| 5 YEAR AVERAGE | 35,766 | 13.6 | 2,571,497 | 7.0 | 6,002,603 | 6.9 | 0.18 | 0.43 | 2.33 | 6.32 | 2.71 |
| **Total** | | | | | | | | | | | |
| 2016 | 292,906 | 100.0 | 44,929,125 | 100.0 | 82,127,861 | 100.0 | 3.10 | 5.66 | 1.83 | 100.50 | 54.98 |
| 2015 | 253,821 | 100.0 | 33,247,310 | 100.0 | 72,732,010 | 100.0 | 2.32 | 5.08 | 2.19 | 89.14 | 40.75 |
| 5 YEAR AVERAGE | 262,509 | 100.0 | 36,606,322 | 100.0 | 87,361,930 | 100.0 | 2.62 | 6.24 | 2.39 | 91.98 | 38.54 |

## TABLE 3-2A

## SYSTEM CAUSES OF SERVICE INTERRUPTION

## FOR YEAR 2016

***International***

**276,529 CUSTOMERS IN 2016**
**361,737 CUSTOMERS IN 2015**

| PRIMARY CAUSE | NUMBER OF INTERRUPTIONS | | CUSTOMER INTERRUPTIONS | | CUSTOMER HOUR INTERRUPTIONS | | SAIFI | SAIDI | CAIDI | CHIKM | CIKM |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | NUMBER | % | NUMBER | % | NUMBER | % | | (HRS) | (HRS) | | |
| **Unknown/Other** | | | | | | | | | | | |
| 2016 | 335 | 13.7 | 225,223 | 9.9 | 219,475 | 5.2 | 0.81 | 0.79 | 0.97 | 21.98 | 22.55 |
| 2015 | 342 | 14.1 | 183,628 | 8.4 | 184,345 | 6.4 | 0.51 | 0.51 | 1.00 | 19.35 | 19.27 |
| 5 YEAR AVERAGE | 1,416 | 16.0 | 594,982 | 20.0 | 365,980 | 10.6 | 1.41 | 0.86 | 0.62 | 35.03 | 56.95 |
| **Scheduled Outage** | | | | | | | | | | | |
| 2016 | 536 | 21.9 | 95,458 | 4.2 | 327,158 | 7.7 | 0.35 | 1.18 | 3.43 | 32.76 | 9.56 |
| 2015 | 815 | 33.7 | 81,637 | 3.7 | 291,241 | 10.1 | 0.23 | 0.81 | 3.57 | 30.57 | 8.57 |
| 5 YEAR AVERAGE | 1,070 | 12.1 | 155,664 | 5.2 | 557,275 | 16.1 | 0.37 | 1.32 | 3.58 | 53.34 | 14.90 |
| **Loss of Supply** | | | | | | | | | | | |
| 2016 | 419 | 17.1 | 972,888 | 42.8 | 978,855 | 23.2 | 3.52 | 3.54 | 1.01 | 98.02 | 97.43 |
| 2015 | 286 | 11.8 | 770,353 | 35.4 | 441,691 | 15.3 | 2.13 | 1.22 | 0.57 | 46.36 | 80.85 |
| 5 YEAR AVERAGE | 1,306 | 14.7 | 778,382 | 26.2 | 381,482 | 11.1 | 1.84 | 0.90 | 0.49 | 36.51 | 74.50 |
| **Tree Contacts** | | | | | | | | | | | |
| 2016 | 169 | 6.9 | 136,202 | 6.0 | 149,342 | 3.5 | 0.49 | 0.54 | 1.10 | 14.96 | 13.64 |
| 2015 | 130 | 5.4 | 128,272 | 5.9 | 95,156 | 3.3 | 0.35 | 0.26 | 0.74 | 9.99 | 13.46 |
| 5 YEAR AVERAGE | 1,255 | 14.2 | 215,118 | 7.2 | 287,985 | 8.3 | 0.51 | 0.68 | 1.34 | 27.56 | 20.59 |
| **Lightning** | | | | | | | | | | | |
| 2016 | 118 | 4.8 | 68,343 | 3.0 | 53,639 | 1.3 | 0.25 | 0.19 | 0.78 | 5.37 | 6.84 |
| 2015 | 41 | 1.7 | 34,481 | 1.6 | 20,640 | 0.7 | 0.10 | 0.06 | 0.60 | 2.17 | 3.62 |
| 5 YEAR AVERAGE | 141 | 1.6 | 111,963 | 3.8 | 88,794 | 2.6 | 0.26 | 0.21 | 0.79 | 8.50 | 10.72 |
| **Defective Equipment** | | | | | | | | | | | |
| 2016 | 520 | 21.3 | 374,131 | 16.5 | 467,678 | 11.1 | 1.35 | 1.69 | 1.25 | 46.83 | 37.47 |
| 2015 | 503 | 20.8 | 530,008 | 24.3 | 681,046 | 23.6 | 1.47 | 1.88 | 1.28 | 71.48 | 55.63 |
| 5 YEAR AVERAGE | 1,910 | 21.6 | 581,929 | 19.6 | 729,566 | 21.1 | 1.37 | 1.72 | 1.25 | 69.83 | 55.70 |
| **Adverse Weather** | | | | | | | | | | | |
| 2016 | 90 | 3.7 | 155,310 | 6.8 | 1,772,125 | 41.9 | 0.56 | 6.41 | 11.41 | 177.46 | 15.55 |
| 2015 | 44 | 1.8 | 63,870 | 2.9 | 793,727 | 27.5 | 0.18 | 2.19 | 12.43 | 83.30 | 6.70 |
| 5 YEAR AVERAGE | 81 | 0.9 | 89,405 | 3.0 | 573,852 | 16.6 | 0.21 | 1.36 | 6.42 | 54.92 | 8.56 |
| **Adverse Environment** | | | | | | | | | | | |
| 2016 | 44 | 1.8 | 22,840 | 1.0 | 40,397 | 1.0 | 0.08 | 0.15 | 1.77 | 4.05 | 2.29 |
| 2015 | 36 | 1.5 | 32,472 | 1.5 | 38,341 | 1.3 | 0.09 | 0.11 | 1.18 | 4.02 | 3.41 |
| 5 YEAR AVERAGE | 612 | 6.9 | 72,717 | 2.4 | 83,911 | 2.4 | 0.17 | 0.20 | 1.15 | 8.03 | 6.96 |
| **Human Element** | | | | | | | | | | | |
| 2016 | 46 | 1.9 | 44,963 | 2.0 | 28,402 | 0.7 | 0.16 | 0.10 | 0.63 | 2.84 | 4.50 |
| 2015 | 65 | 2.7 | 113,108 | 5.2 | 107,153 | 3.7 | 0.31 | 0.30 | 0.95 | 11.25 | 11.87 |
| 5 YEAR AVERAGE | 132 | 1.5 | 91,900 | 3.1 | 64,670 | 1.9 | 0.22 | 0.15 | 0.70 | 6.19 | 8.80 |
| **Foreign Interference** | | | | | | | | | | | |
| 2016 | 170 | 6.9 | 178,413 | 7.8 | 187,359 | 4.4 | 0.65 | 0.68 | 1.05 | 18.76 | 17.87 |
| 2015 | 158 | 6.5 | 241,098 | 11.1 | 231,543 | 8.0 | 0.67 | 0.64 | 0.96 | 24.30 | 25.30 |
| 5 YEAR AVERAGE | 937 | 10.6 | 278,445 | 9.4 | 318,612 | 9.2 | 0.66 | 0.75 | 1.14 | 30.50 | 26.65 |
| **Total** | | | | | | | | | | | |
| 2016 | 2,447 | 100.0 | 2,273,771 | 100.0 | 4,224,430 | 100.0 | 8.22 | 15.28 | 1.86 | 423.04 | 227.70 |
| 2015 | 2,420 | 100.0 | 2,178,927 | 100.0 | 2,884,883 | 100.0 | 6.02 | 7.98 | 1.32 | 302.78 | 228.69 |
| 5 YEAR AVERAGE | 8,859 | 100.0 | 2,970,505 | 100.0 | 3,452,125 | 100.0 | 7.01 | 8.15 | 1.16 | 330.41 | 284.31 |

# 4.0 SUMMARY

## 4.0 SUMMARY

- For the 2016 reporting year, based on data for 14.5 million customers in Canada and 0.3 million international customers, the system indices are the following:

| ***Canadian*** | | ***Excluding SE**** | ***International*** | | ***Excluding SE**** |
|---|---|---|---|---|---|
| SAIFI | 3.10 | 2.77 | SAIFI | 8.22 | 7.79 |
| SAIDI | 5.66 | 4.28 | SAIDI | 15.28 | 8.98 |
| CAIDI | 1.83 | 1.54 | CAIDI | 1.86 | 1.15 |
| IOR | 0.999354 | 0.999511 | IOR | 0.998256 | 0.998975 |
| CHIKM | 100.50 | 76.01 | CHIKM | 423.05 | 248.52 |
| CIKM | 54.98 | 49.26 | CIKM | 227.70 | 215.76 |

**SE - Significant Events*

***Canadian Statistics***

- The number of customers as compared to last year has remained relatively stable with a slight increase of 1.3%.
- Compared to the previous year, the total interrupted customer-hours increased by 11.4 %. (Derived from Table 3-1).
- The number of interruptions increased by 13.3 %. (Table 3-1).
- The total customer interruptions increased by 26.0 %. (Table 3-1).
- The customer average interruption duration index or the average restoration time for affected customers was 1.83 hours, compared to 2.19 hours for 2015. (Table 3-2).

- The five major causes of service interruption of utilities are: (Derived from table 3-2)

***Canadian:***

- Scheduled Outage 22.35%
- Defective Equipment 18.47%
- Tree Contacts 16.0%
- Unknown/Other 13.1%
- Foreign Interference 12.86%

***International:***

- Scheduled Outage 21.9%
- Defective Equipment 21.25%
- Loss of Supply 17.12%
- Unknown/Other 13.69%
- Foreign Interference 6.95%

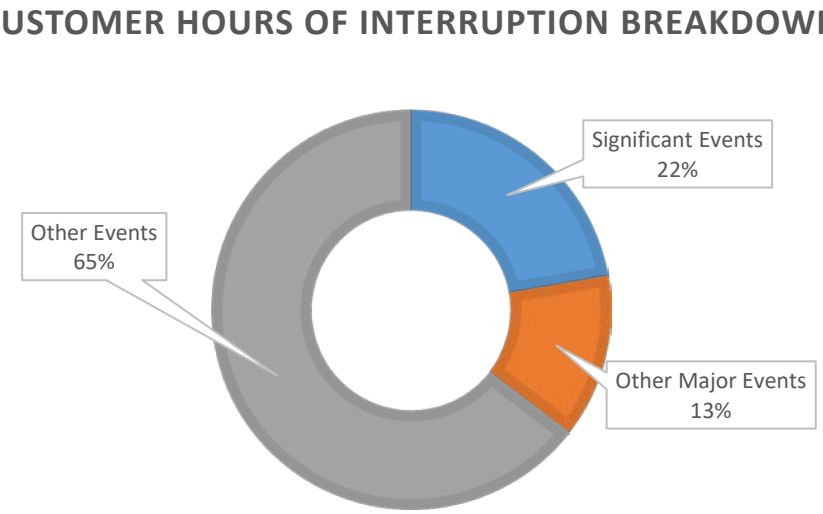
## Section 4.1 Major Event and Significant Event Summary

For the year 2016, Canadian Utilities identified Major Event Days.

| All Recorded Major Events | | | | | |
|---|---|---|---|---|---|
| Year | Interruptions | Customer Interruptions | Customer Hours of Interruptions | Contribution to Composite SAIFI | Contribution to Composite SAIDI |
| 2016 | 20,674 | 6,545,906 | 29,138,473 | 0.45 | 2.02 |
| 2015 | 13,059 | 3,737,677 | 26,234,850 | 0.26 | 1.83 |

Significant Events were determined from the recorded major event days. In 2016, those events are the following:

| Significant Event Statistics | | | | | |
|---|---|---|---|---|---|
| Event | Interruptions | Customer Interruptions | Customer Hours of Interruption | Contribution to Composite SAIFI | Contribution to Composite SAIDI |
| **Ontario Ice Storm** | 3,148 | 598,963 | 5,724,264 | 0.04 | 0.40 |
| **Multi-Province Ice Storm** | 4,216 | 1,976,383 | 5,528,213 | 0.14 | 0.38 |
| **Quebec Lightning Storm** | 3,134 | 1,947,923 | 3,941,115 | 0.13 | 0.27 |
| **Fort McMurray Fires** | 869 | 35,501 | 3,077,116 | 0.00 | 0.21 |



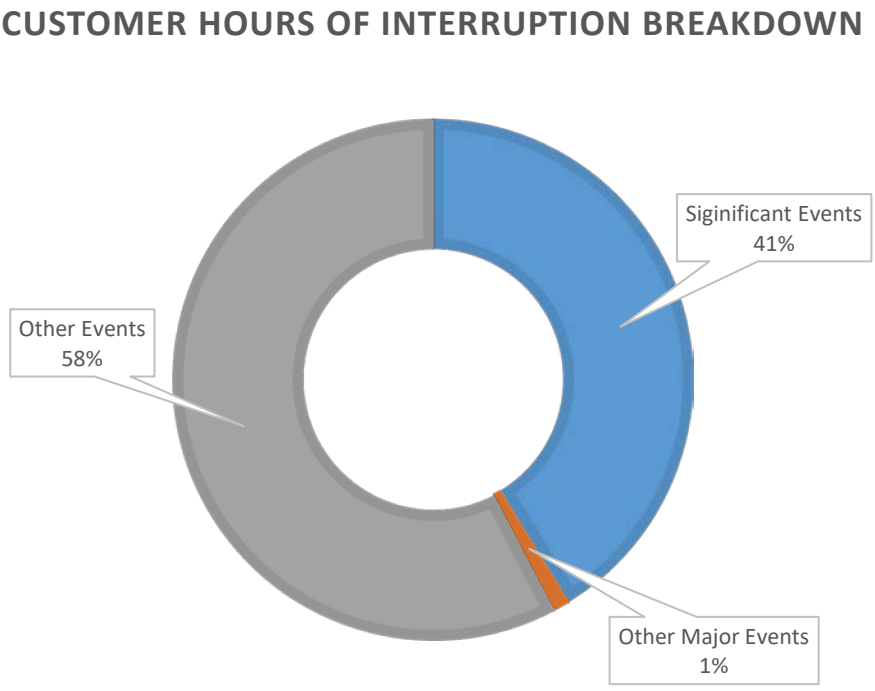
## Section 4.2 International Major Event and Significant Event Summary

For the year 2016, International Utilities identified Major Event Days.

| All Recorded Major Events | | | | | |
|---|---|---|---|---|---|
| Year | Interruptions | Customer Interruptions | Customer Hours of Interruptions | Contribution to Composite SAIFI | Contribution to Composite SAIDI |
| 2016 | 48 | 318,301 | 1,786,808 | 1.15 | 6.46 |

Significant Events were determined from the recorded major event days. In 2016, those events are the following:

| Significant Event Statistics | | | | | |
|---|---|---|---|---|---|
| Event | Interruptions | Customer Interruptions | Customer Hours of Interruption | Contribution to Composite SAIFI | Contribution to Composite SAIDI |
| **Hurricane Matthew** | 29 | 119,410 | 1,743,006 | 0.43 | 6.3 |



# 5.0 SYSTEM CAUSES OF SERVICE OUTAGE

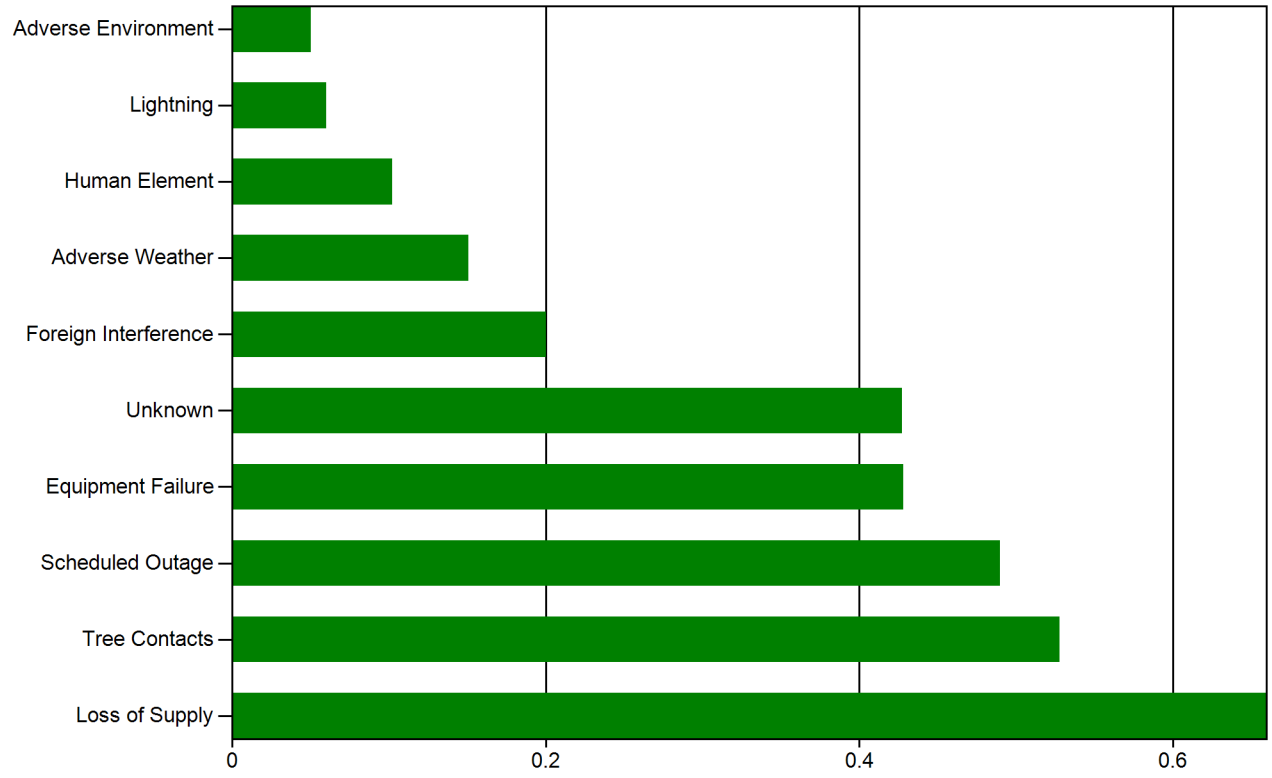
## 5.0 SYSTEM CAUSES OF SERVICE OUTAGE

**SAIFI**

Graphs 5-1 and 5-1a indicate the contributions to SAIFI for each of the ten cause groups for the Canadian and International participants. The causes are listed, along with a third column which contains the percentage of interruptions attributed to each cause.

***Canadian***

| | *SAIFI* | *% Interruptions* |
|---|---|---|
| Adverse Environment | 0.05 | 1.4 |
| Lightning | 0.06 | 6.2 |
| Human Element | 0.10 | 1.9 |
| Adverse Weather | 0.15 | 4.9 |
| Foreign Interference | 0.20 | 12.9 |
| Unknown | 0.43 | 13.1 |
| Equipment Failure | 0.43 | 18.5 |
| Scheduled Outage | 0.49 | 22.4 |
| Tree Contacts | 0.53 | 16.0 |
| Loss of Supply | 0.66 | 2.9 |

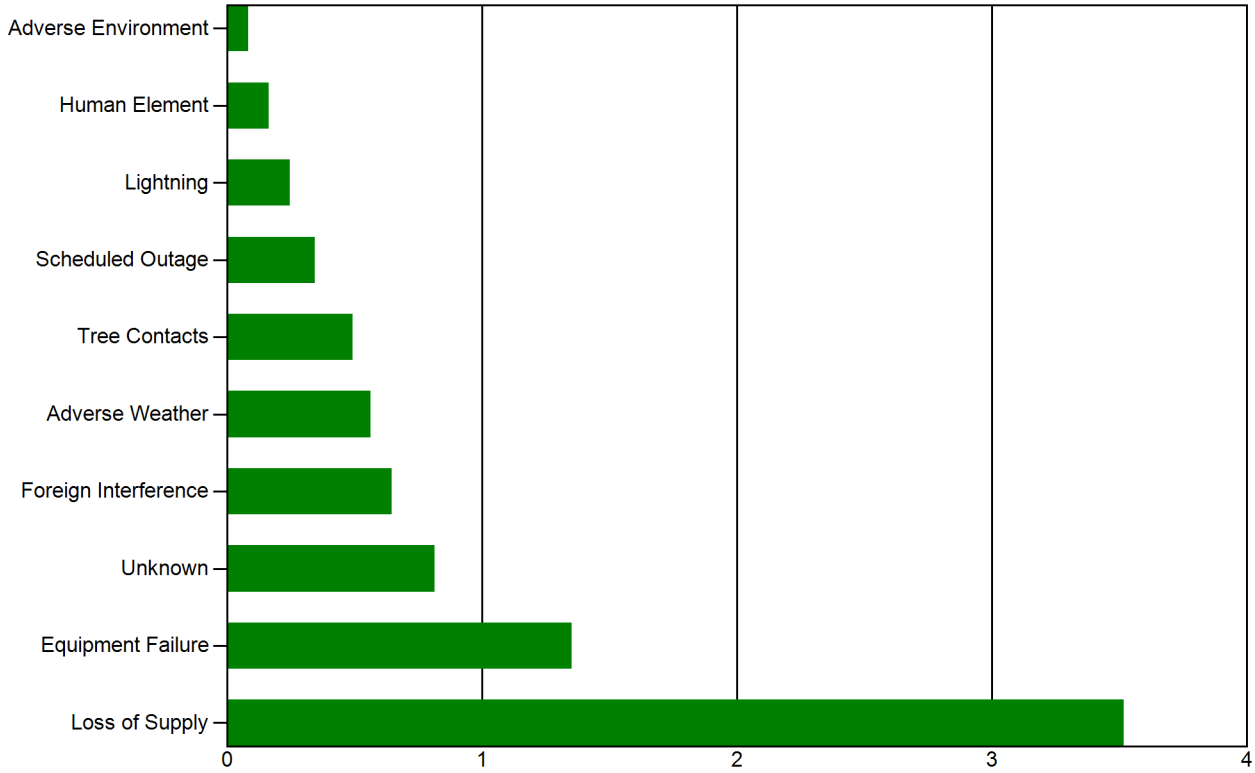



**TOTAL SAIFI = 3.10**

***Graph 5-1 Contributions to SAIFI for 2016***

***International***

| | *SAIFI* | *% Interruptions* |
|---|---|---|
| Adverse Environment | 0.08 | 1.8 |
| Human Element | 0.16 | 1.9 |
| Lightning | 0.25 | 4.8 |
| Scheduled Outage | 0.35 | 21.9 |
| Tree Contacts | 0.49 | 6.9 |
| Adverse Weather | 0.56 | 3.7 |
| Foreign Interference | 0.65 | 6.9 |
| Unknown | 0.81 | 13.7 |
| Equipment Failure | 1.35 | 21.3 |
| Loss of Supply | 3.52 | 17.1 |




**TOTAL SAIFI = 8.22**

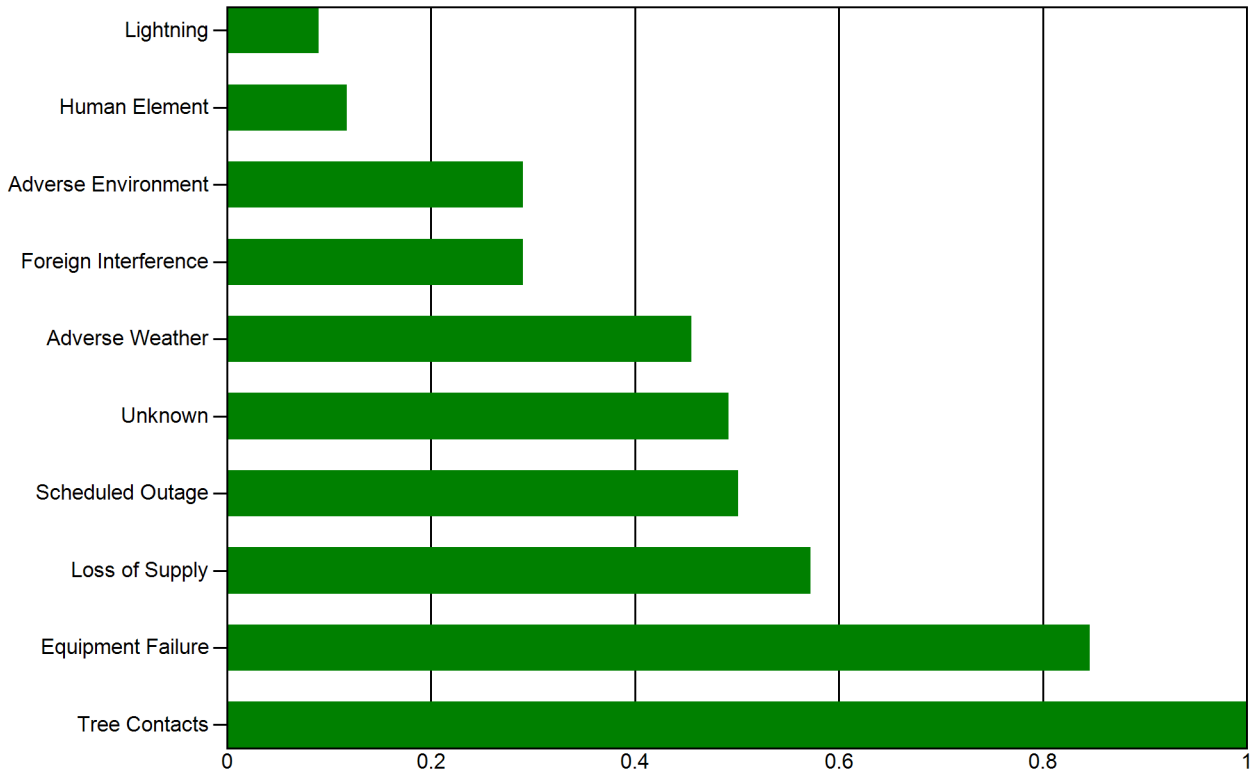
***Graph 5-1a Contributions to SAIFI for 2016***

## SAIDI

Graphs 5-2 and 5-2a indicate the contributions to SAIDI for each of the ten cause groups for the Canadian and International participants. The causes are listed, along with a third column which contains the percentage of customer interruptions attributed to each cause.

### *Canadian*

| | *SAIDI* | *% Customer Interruptions* |
|---|---|---|
| Lightning | 0.09 | 1.9 |
| Human Element | 0.12 | 3.3 |
| Adverse Environment | 0.29 | 1.6 |
| Foreign Interference | 0.29 | 6.5 |
| Adverse Weather | 0.46 | 4.9 |
| Unknown | 0.49 | 13.8 |
| Scheduled Outage | 0.50 | 15.8 |
| Loss of Supply | 0.57 | 21.3 |
| Equipment Failure | 0.85 | 13.8 |
| Tree Contacts | 2.00 | 17.0 |

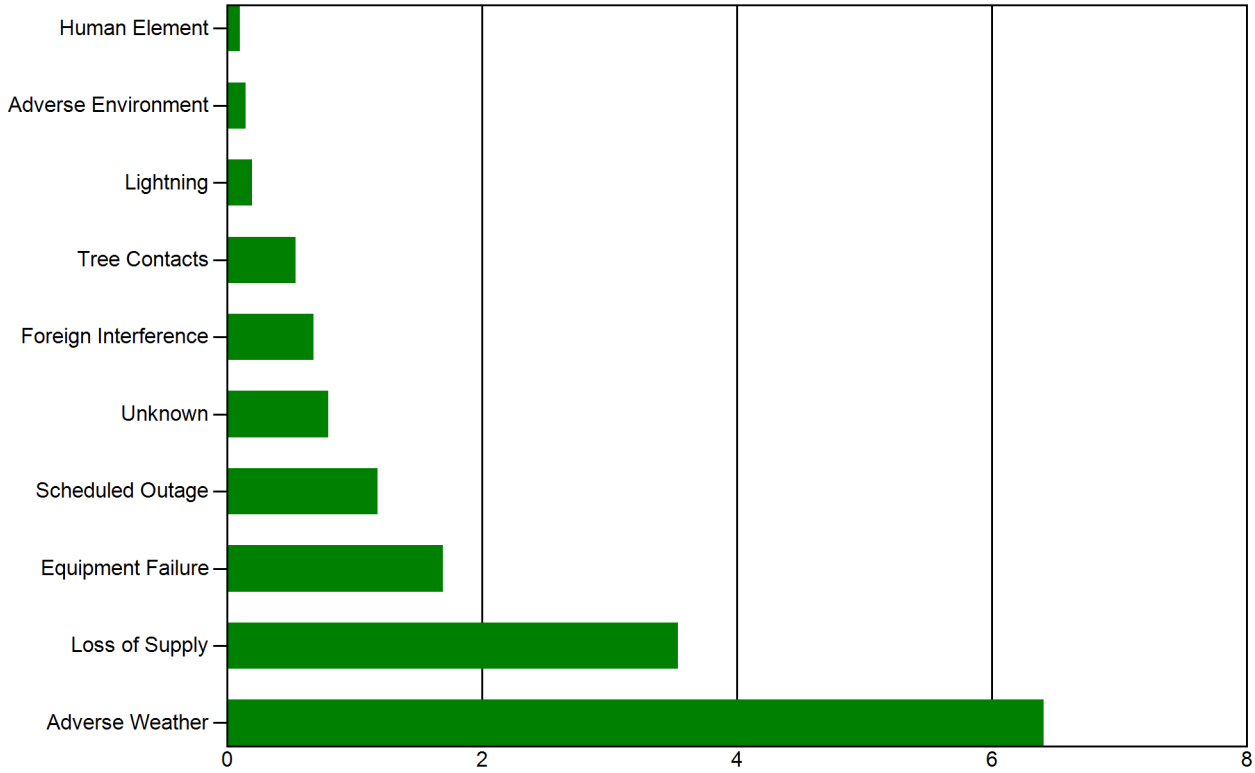



**TOTAL SAIDI = 5.66**

***Graph 5-2 Contributions to SAIDI for 2016***

***International***

| | *SAIDI* | *% Customer Interruptions* |
|---|---|---|
| Human Element | 0.10 | 2.0 |
| Adverse Environment | 0.15 | 1.0 |
| Lightning | 0.19 | 3.0 |
| Tree Contacts | 0.54 | 6.0 |
| Foreign Interference | 0.68 | 7.8 |
| Unknown | 0.79 | 9.9 |
| Scheduled Outage | 1.18 | 4.2 |
| Equipment Failure | 1.69 | 16.5 |
| Loss of Supply | 3.54 | 42.8 |
| Adverse Weather | 6.41 | 6.8 |




**TOTAL SAIDI = 15.28**

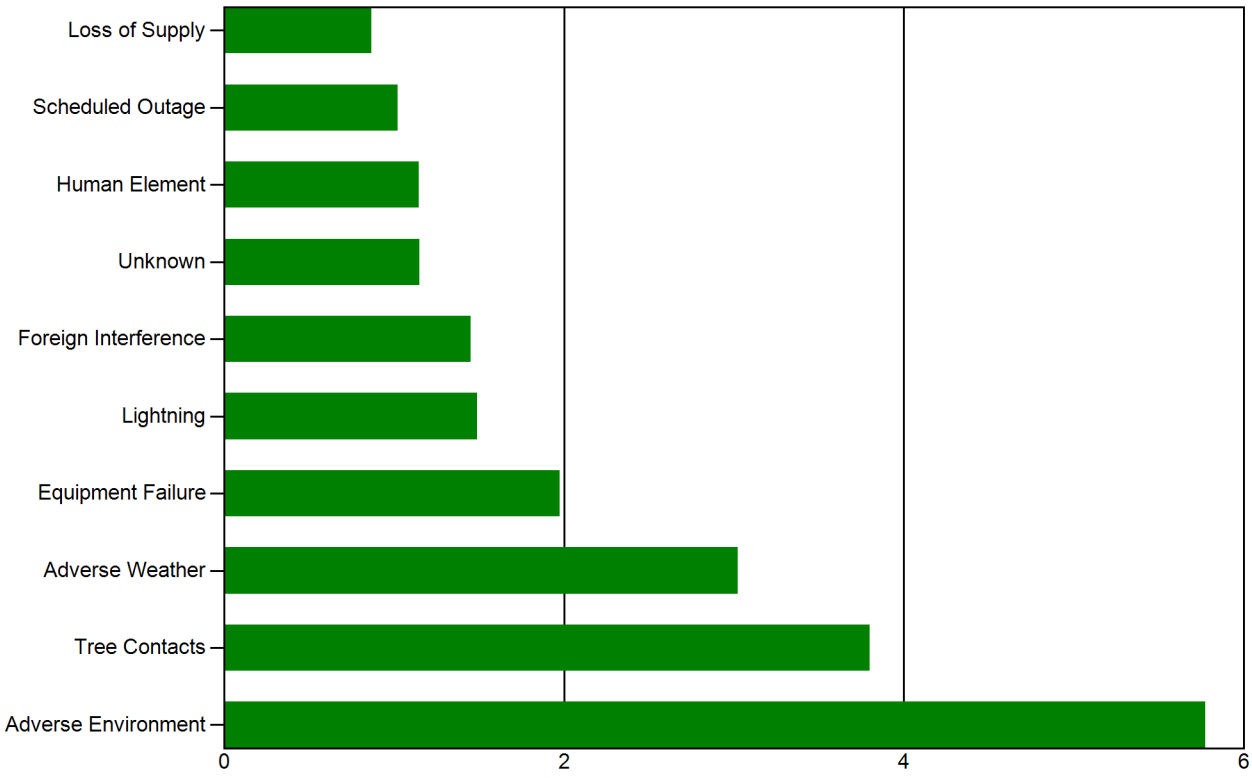
***Graph 5-2a Contributions to SAIDI for 2016***

## CAIDI

Graphs 5-3 and 5-3a indicate the contributions to CAIDI for each of the ten cause groups for the Canadian and International participants. The causes are listed, along with a third column which contains the percentage of customer hours of interruption attributed to each cause.

### *Canadian*

| | *CAIDI* | *% Customer-hrs Interruptions* |
|---|---|---|
| Loss of Supply | 0.87 | 10.1 |
| Scheduled Outage | 1.02 | 8.9 |
| Human Element | 1.15 | 2.1 |
| Unknown | 1.15 | 8.7 |
| Foreign Interference | 1.45 | 5.1 |
| Lightning | 1.49 | 1.6 |
| Equipment Failure | 1.98 | 15.0 |
| Adverse Weather | 3.02 | 8.0 |
| Tree Contacts | 3.80 | 35.4 |
| Adverse Environment | 5.77 | 5.1 |

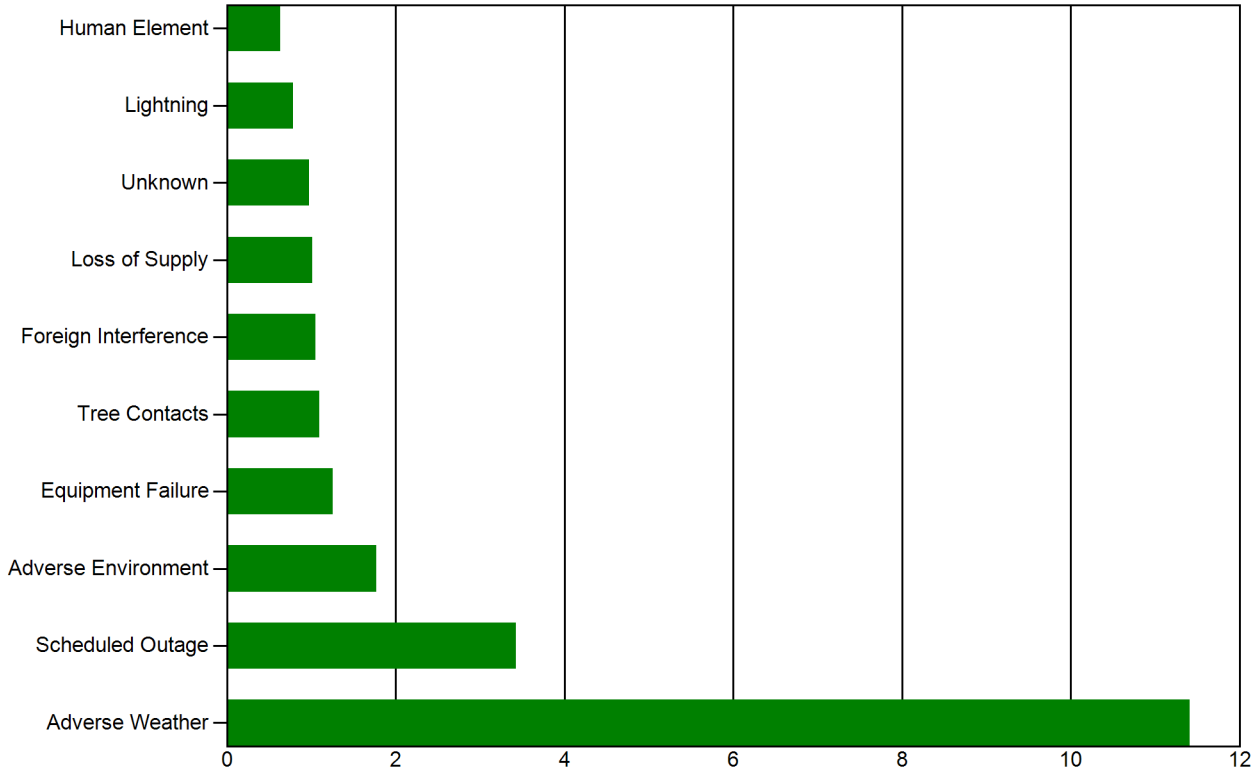



**TOTAL CAIDI = 1.83**

***Graph 5-3 Contributions to CAIDI for 2016***

***International***

| | *CAIDI* | *% Customer-hrs Interruptions* |
|---|---|---|
| Human Element | 0.63 | 0.7 |
| Lightning | 0.78 | 1.3 |
| Unknown | 0.97 | 5.2 |
| Loss of Supply | 1.01 | 23.2 |
| Foreign Interference | 1.05 | 4.4 |
| Tree Contacts | 1.10 | 3.5 |
| Equipment Failure | 1.25 | 11.1 |
| Adverse Environment | 1.77 | 1.0 |
| Scheduled Outage | 3.43 | 7.7 |
| Adverse Weather | 11.41 | 41.9 |




**TOTAL CAIDI = 1.86**

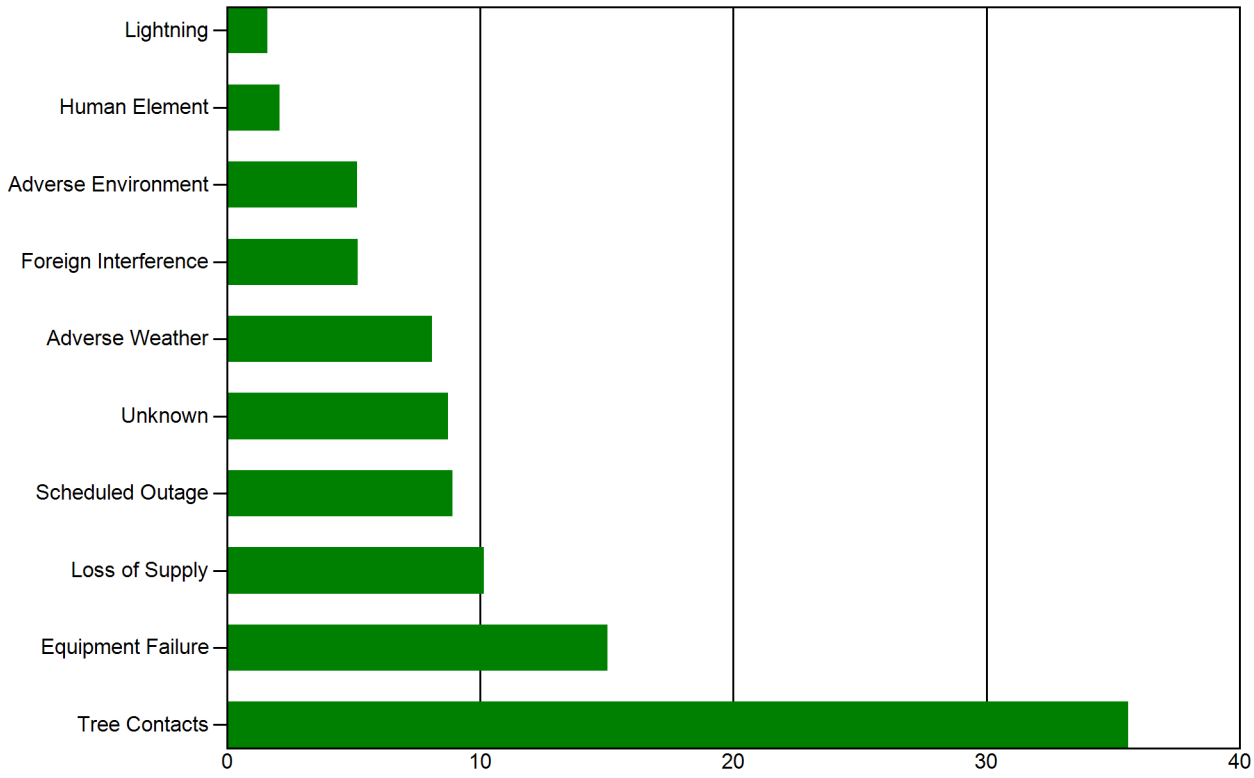
***Graph 5-3a Contributions to CAIDI for 2016***

## CHIKM

Graphs 5-4 and 5-4a indicate the contributions to CHIKM for each of the ten cause groups for the Canadian and International participants. The causes are listed, along with a third column which contains the percentage of customer hours of interruption per circuit km attributed to each cause.

### *Canadian*

| | *CHIKM* | *% Customer-hrs Interruptions* |
|---|---|---|
| Lightning | 1.59 | 1.6 |
| Human Element | 2.08 | 2.1 |
| Adverse Environment | 5.15 | 5.1 |
| Foreign Interference | 5.16 | 5.1 |
| Adverse Weather | 8.09 | 8.0 |
| Unknown | 8.74 | 8.7 |
| Scheduled Outage | 8.90 | 8.9 |
| Loss of Supply | 10.16 | 10.1 |
| Equipment Failure | 15.03 | 15.0 |
| Tree Contacts | 35.60 | 35.4 |

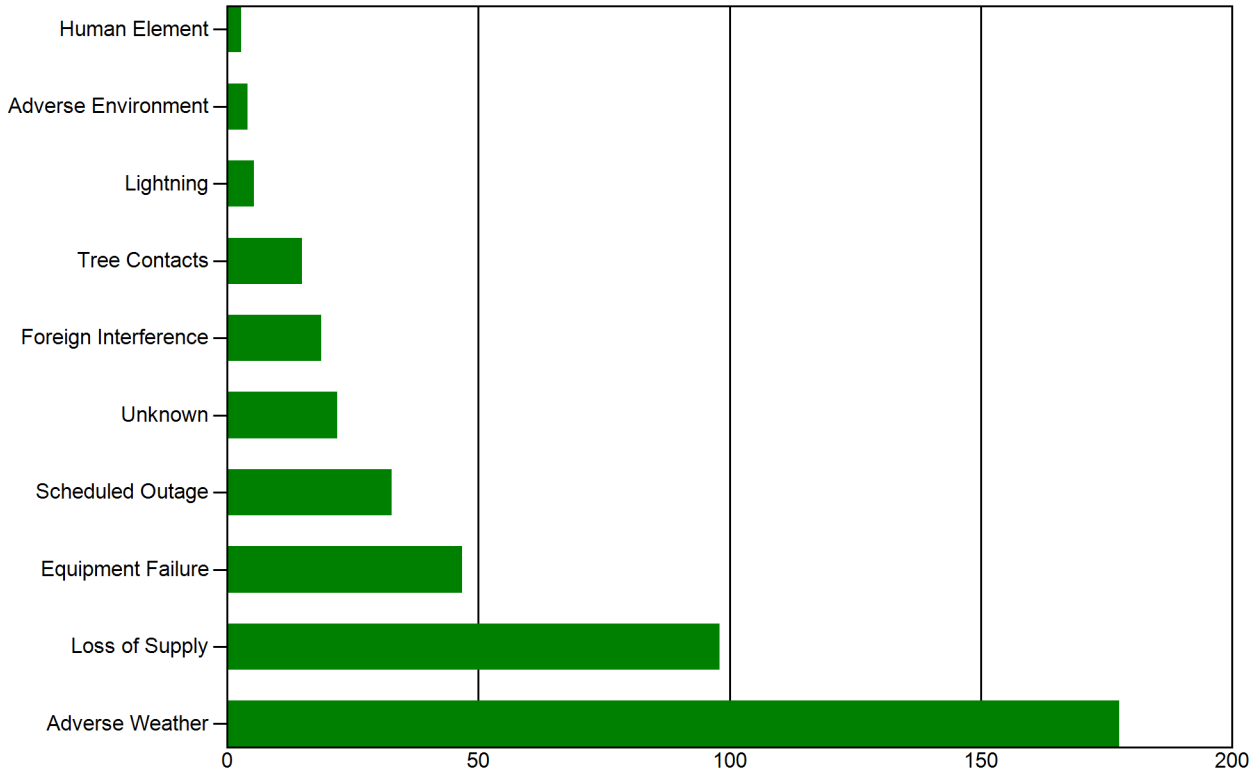



**TOTAL CHIKM = 100.50**

***Graph 5-4 Contributions to CHIKM for 2016***

***International***

| | *CHIKM* | *% Customer-hrs Interruptions* |
|---|---|---|
| Human Element | 2.84 | 0.7 |
| Adverse Environment | 4.05 | 1.0 |
| Lightning | 5.37 | 1.3 |
| Tree Contacts | 14.96 | 3.5 |
| Foreign Interference | 18.76 | 4.4 |
| Unknown | 21.98 | 5.2 |
| Scheduled Outage | 32.76 | 7.7 |
| Equipment Failure | 46.83 | 11.1 |
| Loss of Supply | 98.03 | 23.2 |
| Adverse Weather | 177.47 | 41.9 |




**TOTAL CHIKM = 423.05**

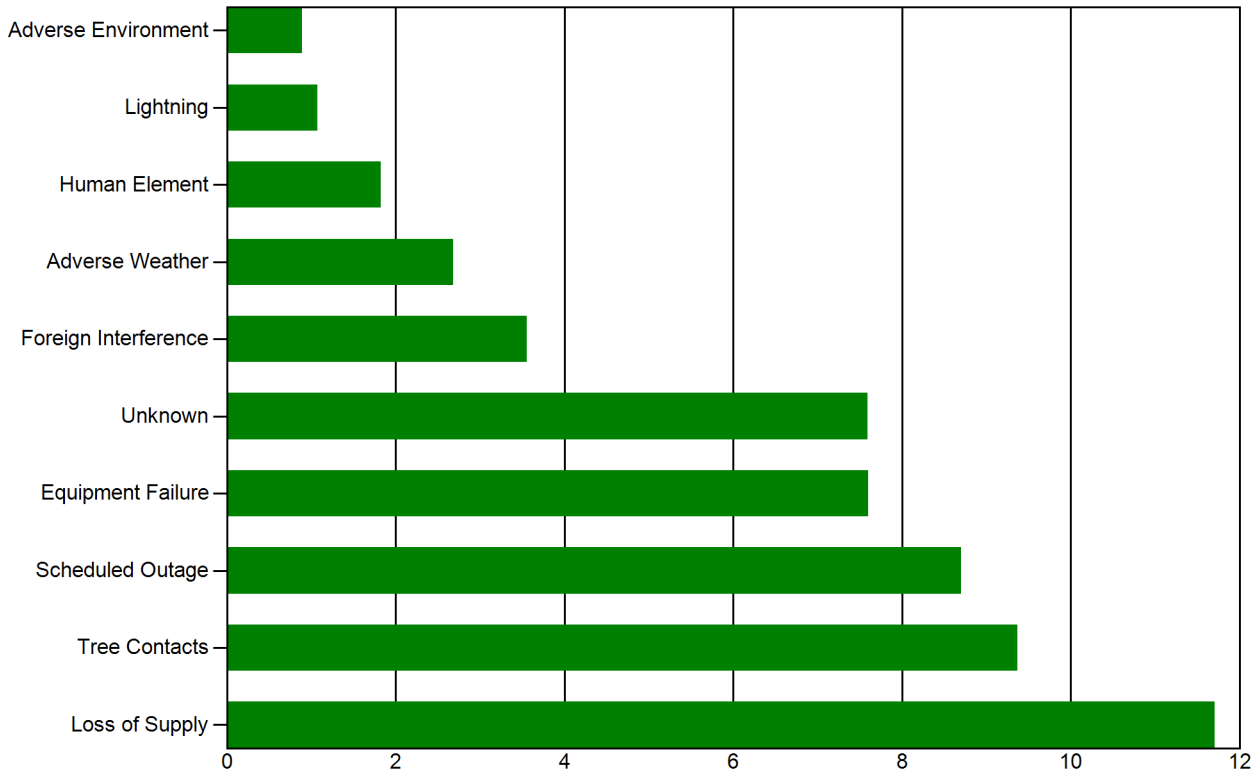
***Graph 5-4a Contributions to CHIKM for 2016***

## CIKM

Graphs 5-5 and 5-5a indicate the contributions to CIKM for each of the ten cause groups for the Canadian and International participants. The causes are listed, along with a third column which contains the percentage of customer interruption per circuit km attributed to each cause.

### *Canadian*

| | *CIKM* | *% Customer Interruptions* |
|---|---|---|
| Adverse Environment | 0.89 | 1.6 |
| Lightning | 1.07 | 1.9 |
| Human Element | 1.82 | 3.3 |
| Adverse Weather | 2.68 | 4.9 |
| Foreign Interference | 3.55 | 6.5 |
| Unknown | 7.59 | 13.8 |
| Equipment Failure | 7.60 | 13.8 |
| Scheduled Outage | 8.70 | 15.8 |
| Tree Contacts | 9.37 | 17.0 |
| Loss of Supply | 11.71 | 21.3 |

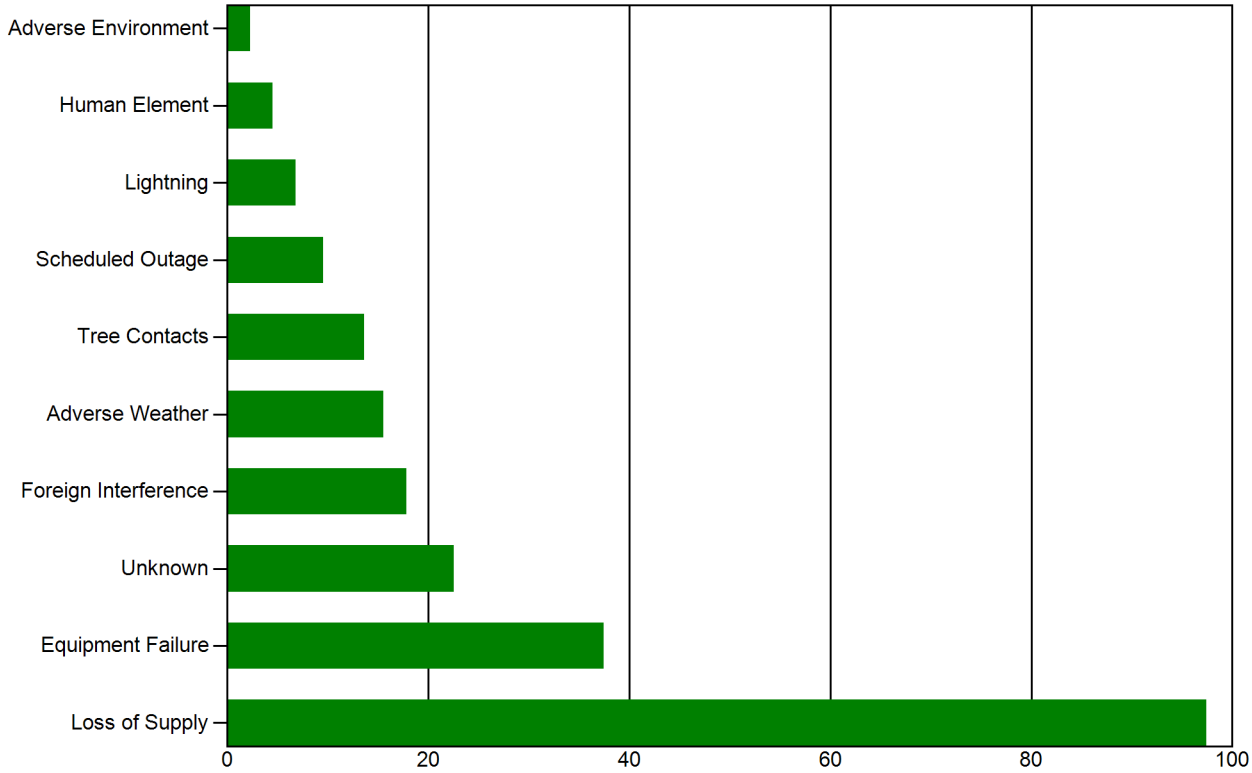



**TOTAL CIKM = 54.98**

***Graph 5-5 Contributions to CIKM for 2016***

***International***

| | *CIKM* | *% Customer Interruptions* |
|---|---|---|
| Adverse Environment | 2.29 | 1.0 |
| Human Element | 4.50 | 2.0 |
| Lightning | 6.84 | 3.0 |
| Scheduled Outage | 9.56 | 4.2 |
| Tree Contacts | 13.64 | 6.0 |
| Adverse Weather | 15.55 | 6.8 |
| Foreign Interference | 17.87 | 7.8 |
| Unknown | 22.55 | 9.9 |
| Equipment Failure | 37.47 | 16.5 |
| Loss of Supply | 97.43 | 42.8 |

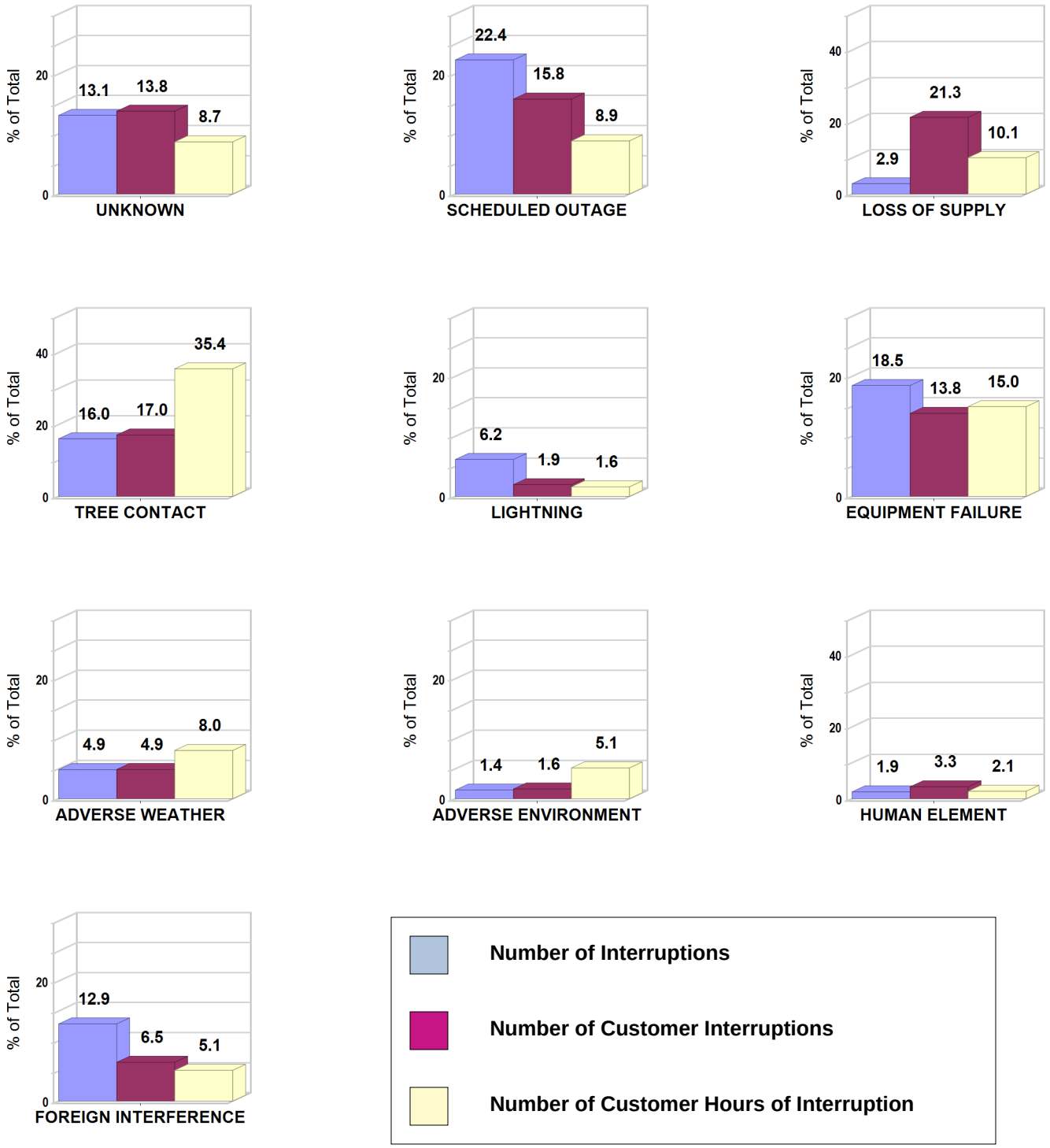



**TOTAL CIKM = 227.70**

***Graph 5-5a Contributions to CIKM for 2016***

Graph 5-6 is a comparison between the effect of each cause of interruption and the percentage of Interruptions, Customer Interruptions and Customer Hours of Interruptions for Canadian participants.

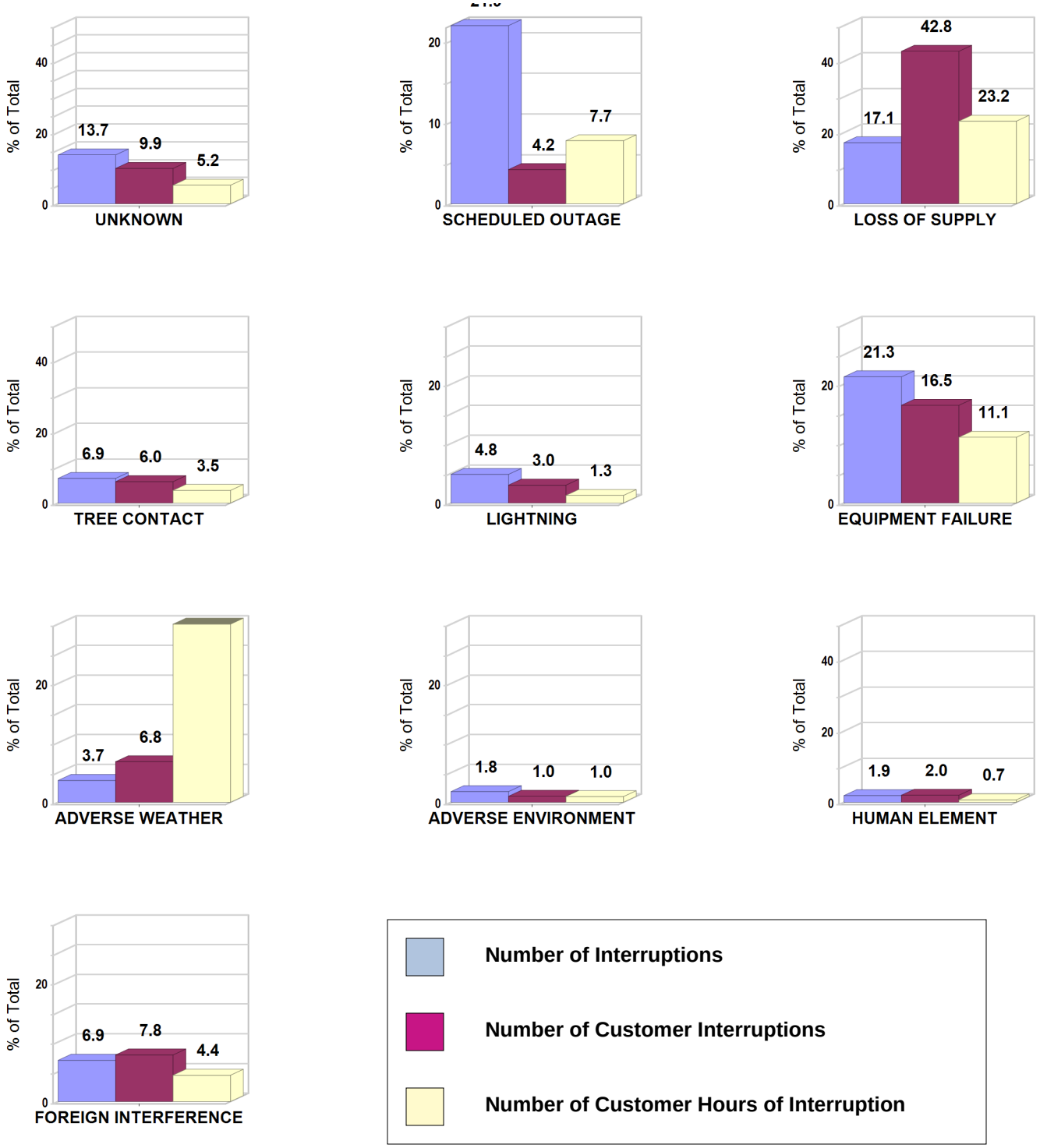
***Canadian***




***Graph 5-6 Causes of Interruptions, Customer Interruptions and Customer Hours of Interruption for 2016 Canadian Data.***

The following graphs show the comparison between the effect of each cause of interruption and the percentage of Interruptions, Customer Interruptions and Customer Hours of Interruption.

***International***




***Graph 5-6a Causes of Interruptions, Customer Interruptions and Customer Hours of Interruption for 2016 International Data.***

The major causes of all interruptions, as compared to 2015 are:

***Canadian***

| **Unknown** | **2016** | **2015** |
|---|---|---|
| Interruptions | 13.1% | 11.05% |
| Customer Interruptions | 13.8% | 14.62% |
| Customer Hours of Interruption | 8.69% | 7.65% |

| **Scheduled Outage** | **2016** | **2015** |
|---|---|---|
| Interruptions | 22.35% | 24.92% |
| Customer Interruptions | 15.82% | 9.29% |
| Customer Hours of Interruption | 8.86% | 9.82% |

| **Loss of Supply** | **2016** | **2015** |
|---|---|---|
| Interruptions | 2.85% | 2.6% |
| Customer Interruptions | 21.3% | 22.7% |
| Customer Hours of Interruption | 10.11% | 10.6% |

| **Tree Contacts** | **2016** | **2015** |
|---|---|---|
| Interruptions | 16.0% | 14.29% |
| Customer Interruptions | 17.05% | 14.95% |
| Customer Hours of Interruption | 35.42% | 28.4% |

| **Lightning** | **2016** | **2015** |
|---|---|---|
| Interruptions | 6.15% | 4.86% |
| Customer Interruptions | 1.94% | 1.73% |
| Customer Hours of Interruption | 1.58% | 1.43% |

| **Equipment Failure** | **2016** | **2015** |
|---|---|---|
| Interruptions | 18.47% | 20.45% |
| Customer Interruptions | 13.83% | 17.59% |
| Customer Hours of Interruption | 14.95% | 16.69% |

| **Adverse Weather** | **2016** | **2015** |
|---|---|---|
| Interruptions | 4.86% | 4.36% |
| Customer Interruptions | 4.87% | 5.35% |
| Customer Hours of Interruption | 8.04% | 15.5% |

| **Adverse Environment** | **2016** | **2015** |
|---|---|---|
| Interruptions | 1.44% | 1.56% |
| Customer Interruptions | 1.62% | 2.53% |
| Customer Hours of Interruption | 5.13% | 2.22% |

| **Human Element** | **2016** | **2015** |
|---|---|---|
| Interruptions | 1.91% | 2.13% |
| Customer Interruptions | 3.3% | 3.69% |
| Customer Hours of Interruption | 2.07% | 1.69% |

| **Foreign Interference** | **2016** | **2015** |
|---|---|---|
| Interruptions | 12.86% | 13.78% |
| Customer Interruptions | 6.46% | 7.56% |
| Customer Hours of Interruption | 5.13% | 5.99% |

The major causes of all interruptions, as compared to 2015 are:

***International Participants***

| **Unknown** | **2016** | **2015** |
|---|---|---|
| Interruptions | 13.69% | 14.13% |
| Customer Interruptions | 9.91% | 8.43% |
| Customer Hours of Interruption | 5.2% | 6.39% |

| **Scheduled Outage** | **2016** | **2015** |
|---|---|---|
| Interruptions | 21.9% | 33.68% |
| Customer Interruptions | 4.2% | 3.75% |
| Customer Hours of Interruption | 7.74% | 10.1% |

| **Loss of Supply** | **2016** | **2015** |
|---|---|---|
| Interruptions | 17.12% | 11.82% |
| Customer Interruptions | 42.79% | 35.35% |
| Customer Hours of Interruption | 23.17% | 15.31% |

| **Tree Contacts** | **2016** | **2015** |
|---|---|---|
| Interruptions | 6.91% | 5.37% |
| Customer Interruptions | 5.99% | 5.89% |
| Customer Hours of Interruption | 3.54% | 3.3% |

| **Lightning** | **2016** | **2015** |
|---|---|---|
| Interruptions | 4.82% | 1.69% |
| Customer Interruptions | 3.01% | 1.58% |
| Customer Hours of Interruption | 1.27% | 0.72% |

| **Equipment Failure** | **2016** | **2015** |
|---|---|---|
| Interruptions | 21.25% | 20.79% |
| Customer Interruptions | 16.45% | 24.32% |
| Customer Hours of Interruption | 11.07% | 23.61% |

| **Adverse Weather** | **2016** | **2015** |
|---|---|---|
| Interruptions | 3.68% | 1.82% |
| Customer Interruptions | 6.83% | 2.93% |
| Customer Hours of Interruption | 41.95% | 27.51% |

| **Adverse Environment** | **2016** | **2015** |
|---|---|---|
| Interruptions | 1.8% | 1.49% |
| Customer Interruptions | 1.0% | 1.49% |
| Customer Hours of Interruption | 0.96% | 1.33% |

| **Human Element** | **2016** | **2015** |
|---|---|---|
| Interruptions | 1.88% | 2.69% |
| Customer Interruptions | 1.98% | 5.19% |
| Customer Hours of Interruption | 0.67% | 3.71% |

| **Foreign Interference** | **2016** | **2015** |
|---|---|---|
| Interruptions | 6.95% | 6.53% |
| Customer Interruptions | 7.85% | 11.06% |
| Customer Hours of Interruption | 4.44% | 8.03% |

# 6.0 TABULATION OF SERVICE INTERRUPTION DATA FOR REGION 1 (URBAN UTILITIES)

## 6.0 Region 1 (Urban Utilities)

City of Lethbridge

City of Medicine Hat

City of Red Deer

Enersource Hydro Mississauga

ENMAX Power Corporation

EPCOR

Horizon Utilities

Hydro One Brampton

Hydro Ottawa

Kingston Utilities

London Hydro

Oakville Hydro Electricity Distribution

Oshawa Power and Utilities Corporation

PowerStream Inc.

Saint John Energy

Saskatoon Light & Power

St. Thomas Energy

Summerside Electric

Toronto Hydro

* B.C. Hydro - Vancouver/Burnaby District
* B.C. Hydro - Victoria District
* Hydro One - Combined Urban Areas
* Hydro-Québec - Montréal Métropolitain
* Hydro-Québec - Québec Métropolitain
* Manitoba Hydro - Winnipeg
* Maritime Electric Company - Charlottetown
* NSPI - Halifax Urban
* NSPI - Provincial Urban Areas (excl. Halifax)

**TABLE 6-1 (REGION 1)**

**SUMMARY OF INTERRUPTION DATA**

**(Including Derivation of Index of Reliability)**

**FOR YEARS 2011 - 2016**

*THE "INDEX OF RELIABILITY" IS A MEASURE OF SERVICE RELIABILITY.*
*IT EQUALS THE PER UNIT ANNUAL CUSTOMER-HOURS THAT SERVICE IS AVAILABLE.*

**CANADIAN UTILITIES IN 2016**

| YEAR | NUMBER OF CUSTOMERS SERVED | NUMBER OF INTERRUPTIONS | TOTAL CUSTOMER INTERRUPTIONS | (A) TOTAL INTERRUPTED CUST. HOURS | (B) TOTAL AVAILABLE CUST. HOURS | (C) INDEX OF RELIABILITY |
|---|---|---|---|---|---|---|
| 2011 | 4,098,135 | 18,993 | 5,586,221 | 6,692,238 | 35,899,658,220 | 0.999814 |
| 2011** | 4,098,135 | 18,613 | 5,455,638 | 6,111,107 | 35,899,658,220 | 0.999830 |
| 2012 | 5,456,973 | 32,019 | 10,133,340 | 10,742,967 | 47,803,083,480 | 0.999775 |
| 2012** | 5,456,973 | 31,785 | 9,883,968 | 10,276,493 | 47,803,083,480 | 0.999785 |
| 2013 | 5,294,438 | 30,971 | 10,861,180 | 34,543,885 | 46,379,276,880 | 0.999255 |
| 2013** | 5,294,438 | 29,675 | 9,000,376 | 13,085,169 | 46,379,276,880 | 0.999718 |
| 2014 | 5,749,832 | 32,921 | 8,946,377 | 12,144,299 | 50,368,528,320 | 0.999759 |
| 2014** | 5,749,832 | 32,897 | 8,943,455 | 12,134,863 | 50,368,528,320 | 0.999759 |
| 2015 | 6,043,428 | 30,873 | 8,553,674 | 13,461,099 | 52,940,429,280 | 0.999746 |
| 2015** | 6,043,428 | 30,782 | 8,497,281 | 13,273,977 | 52,940,429,280 | 0.999749 |
| 2016 | 6,120,813 | 35,261 | 11,565,480 | 13,042,638 | 53,618,321,880 | 0.999757 |
| 2016** | 6,120,813 | 35,175 | 11,387,970 | 12,339,212 | 53,618,321,880 | 0.999770 |

*** Excludes Significant Events*

**INTERNATIONAL UTILITIES IN 2016**

| | | | | | | |
|---|---|---|---|---|---|---|
| 2011 | 38,810 | 4,072 | 80,502 | 31,024 | 339,975,600 | 0.999909 |
| 2012 | 45,107 | 2,353 | 78,232 | 28,074 | 395,137,320 | 0.999929 |
| 2013 | 52,628 | 2,916 | 170,511 | 145,780 | 461,021,280 | 0.999684 |
| 2014 | 69,514 | 2,278 | 114,597 | 53,559 | 608,942,640 | 0.999912 |
| 2015 | 88,117 | 619 | 89,498 | 52,853 | 771,904,920 | 0.999932 |

**(A) = SUMMATION OF THE NUMBER OF CUSTOMERS x RESTORATION TIME IN HOURS OF EACH INTERRUPTION**

**(B) = TWELVE MONTH AVERAGE NUMBER OF CUSTOMERS x 8,760 HOURS (ONE YEAR)**

**(C) = INDEX OF RELIABILITY: 1 - (A)/(B)**

**TABLE 6-2 (REGION 1)**

**SYSTEM CAUSES OF SERVICE INTERRUPTIONS**

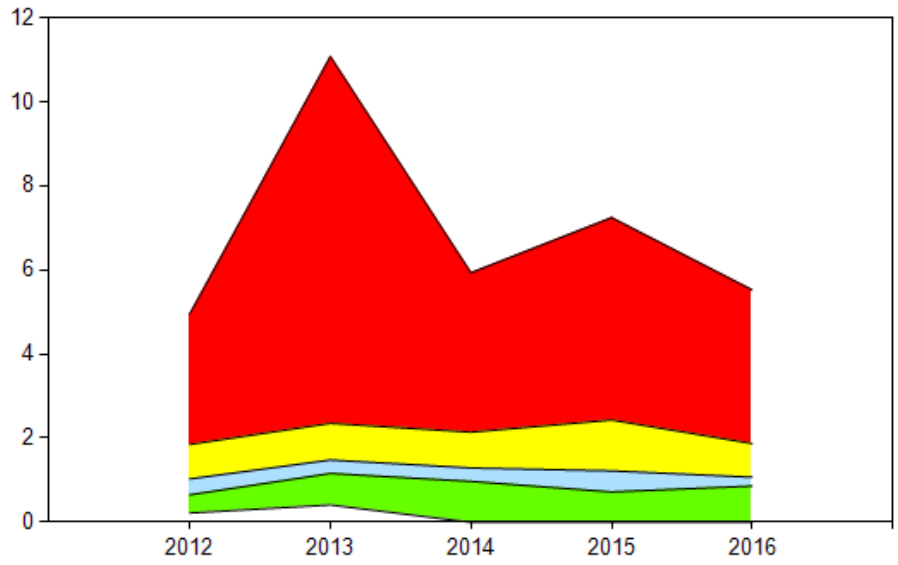
**FOR YEAR 2016**

***Canadian***

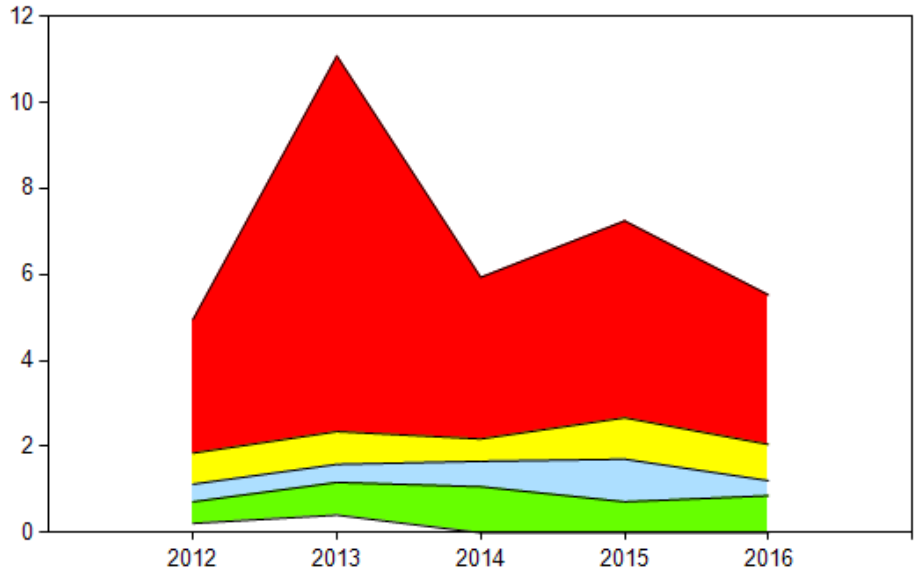
**6,113,953 CUSTOMERS IN 2016**
**6,043,428 CUSTOMERS IN 2015**

| PRIMARY CAUSE | NUMBER OF INTERRUPTIONS | | CUSTOMER INTERRUPTIONS | | CUSTOMER HOUR INTERRUPTIONS | | SAIFI | SAIDI | CAIDI | CHIKM | CIKM |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | NUMBER | % | NUMBER | % | NUMBER | % | | (HRS) | (HRS) | | |
| **Unknown/Other** | | | | | | | | | | | |
| 2016 | 3,024 | 8.6 | 2,870,533 | 24.9 | 1,178,274 | 9.0 | 0.47 | 0.19 | 0.41 | 137.00 | 122.00 |
| 2015 | 2,350 | 7.6 | 906,751 | 10.6 | 920,543 | 6.8 | 0.15 | 0.15 | 1.02 | 138.00 | 88.00 |
| 5 YEAR AVERAGE | 2,694 | 8.3 | 1,633,732 | 16.3 | 963,936 | 5.7 | 0.29 | 0.17 | 0.59 | 183.00 | 106.00 |
| **Scheduled Outage** | | | | | | | | | | | |
| 2016 | 14,540 | 41.3 | 712,532 | 6.2 | 1,660,256 | 12.7 | 0.12 | 0.27 | 2.33 | 137.00 | 122.00 |
| 2015 | 11,290 | 36.6 | 565,674 | 6.6 | 1,600,103 | 11.9 | 0.09 | 0.26 | 2.83 | 138.00 | 88.00 |
| 5 YEAR AVERAGE | 11,793 | 36.4 | 599,973 | 6.0 | 1,569,032 | 9.3 | 0.10 | 0.27 | 2.62 | 183.00 | 106.00 |
| **Loss of Supply** | | | | | | | | | | | |
| 2016 | 1,010 | 2.9 | 2,060,749 | 17.8 | 1,652,457 | 12.7 | 0.34 | 0.27 | 0.80 | 137.00 | 122.00 |
| 2015 | 776 | 2.5 | 1,553,620 | 18.2 | 1,226,682 | 9.1 | 0.26 | 0.20 | 0.79 | 138.00 | 88.00 |
| 5 YEAR AVERAGE | 946 | 2.9 | 1,904,619 | 19.0 | 1,897,283 | 11.3 | 0.33 | 0.33 | 1.00 | 183.00 | 106.00 |
| **Tree Contacts** | | | | | | | | | | | |
| 2016 | 2,725 | 7.7 | 1,198,611 | 10.4 | 2,791,840 | 21.4 | 0.20 | 0.46 | 2.33 | 137.00 | 122.00 |
| 2015 | 2,119 | 6.9 | 763,356 | 8.9 | 1,914,013 | 14.2 | 0.13 | 0.32 | 2.51 | 138.00 | 88.00 |
| 5 YEAR AVERAGE | 2,551 | 7.9 | 912,378 | 9.1 | 2,513,492 | 15.0 | 0.16 | 0.44 | 2.75 | 183.00 | 106.00 |
| **Lightning** | | | | | | | | | | | |
| 2016 | 431 | 1.2 | 201,346 | 1.7 | 276,504 | 2.1 | 0.03 | 0.05 | 1.37 | 137.00 | 122.00 |
| 2015 | 396 | 1.3 | 199,530 | 2.3 | 177,100 | 1.3 | 0.03 | 0.03 | 0.89 | 138.00 | 88.00 |
| 5 YEAR AVERAGE | 452 | 1.4 | 270,850 | 2.7 | 253,334 | 1.5 | 0.05 | 0.04 | 0.94 | 183.00 | 106.00 |
| **Defective Equipment** | | | | | | | | | | | |
| 2016 | 7,316 | 20.8 | 2,149,569 | 18.6 | 2,716,383 | 20.9 | 0.35 | 0.44 | 1.26 | 137.00 | 122.00 |
| 2015 | 7,478 | 24.2 | 2,062,032 | 24.1 | 2,679,702 | 19.9 | 0.34 | 0.44 | 1.30 | 138.00 | 88.00 |
| 5 YEAR AVERAGE | 7,352 | 22.7 | 2,086,574 | 20.8 | 2,679,201 | 16.0 | 0.36 | 0.47 | 1.28 | 183.00 | 106.00 |
| **Adverse Weather** | | | | | | | | | | | |
| 2016 | 742 | 2.1 | 567,279 | 4.9 | 969,112 | 7.4 | 0.09 | 0.16 | 1.71 | 137.00 | 122.00 |
| 2015 | 1,016 | 3.3 | 596,410 | 7.0 | 2,784,511 | 20.7 | 0.10 | 0.46 | 4.67 | 138.00 | 88.00 |
| 5 YEAR AVERAGE | 1,230 | 3.8 | 939,568 | 9.4 | 4,681,026 | 27.9 | 0.16 | 0.82 | 4.98 | 183.00 | 106.00 |
| **Adverse Environment** | | | | | | | | | | | |
| 2016 | 714 | 2.0 | 395,741 | 3.4 | 483,489 | 3.7 | 0.06 | 0.08 | 1.22 | 137.00 | 122.00 |
| 2015 | 766 | 2.5 | 559,354 | 6.5 | 876,907 | 6.5 | 0.09 | 0.15 | 1.57 | 138.00 | 88.00 |
| 5 YEAR AVERAGE | 970 | 3.0 | 455,257 | 4.5 | 1,144,963 | 6.8 | 0.08 | 0.20 | 2.51 | 183.00 | 106.00 |
| **Human Element** | | | | | | | | | | | |
| 2016 | 674 | 1.9 | 531,593 | 4.6 | 452,978 | 3.5 | 0.09 | 0.07 | 0.85 | 137.00 | 122.00 |
| 2015 | 685 | 2.2 | 552,431 | 6.5 | 511,807 | 3.8 | 0.09 | 0.08 | 0.93 | 138.00 | 88.00 |
| 5 YEAR AVERAGE | 531 | 1.6 | 386,428 | 3.9 | 289,538 | 1.7 | 0.07 | 0.05 | 0.75 | 183.00 | 106.00 |
| **Foreign Interference** | | | | | | | | | | | |
| 2016 | 4,030 | 11.4 | 863,059 | 7.5 | 846,826 | 6.5 | 0.14 | 0.14 | 0.98 | 137.00 | 122.00 |
| 2015 | 3,997 | 12.9 | 794,516 | 9.3 | 769,733 | 5.7 | 0.13 | 0.13 | 0.97 | 138.00 | 88.00 |
| 5 YEAR AVERAGE | 3,879 | 12.0 | 819,739 | 8.2 | 792,269 | 4.7 | 0.14 | 0.14 | 0.97 | 183.00 | 106.00 |
| **Total** | | | | | | | | | | | |
| 2016 | 35,206 | 100.0 | 11,551,012 | 100.0 | 13,028,119 | 100.0 | 1.89 | 2.13 | 1.13 | 137.00 | 122.00 |
| 2015 | 30,873 | 100.0 | 8,553,674 | 100.0 | 13,461,099 | 100.0 | 1.42 | 2.23 | 1.57 | 138.00 | 88.00 |
| 5 YEAR AVERAGE | 32,398 | 100.0 | 10,009,117 | 100.0 | 16,784,074 | 100.0 | 1.75 | 2.93 | 1.68 | 183.00 | 106.00 |

Note: Quartiles include Canadian and International Utilities

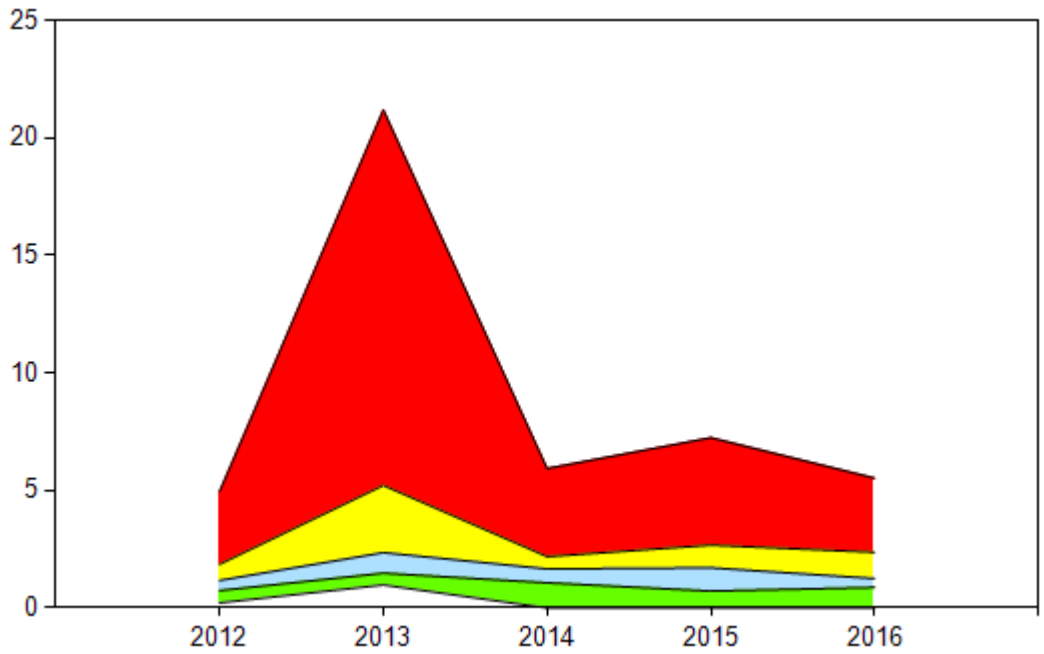



**Graph 6-1: Region 1 SAIDI, Excluding MPEs**

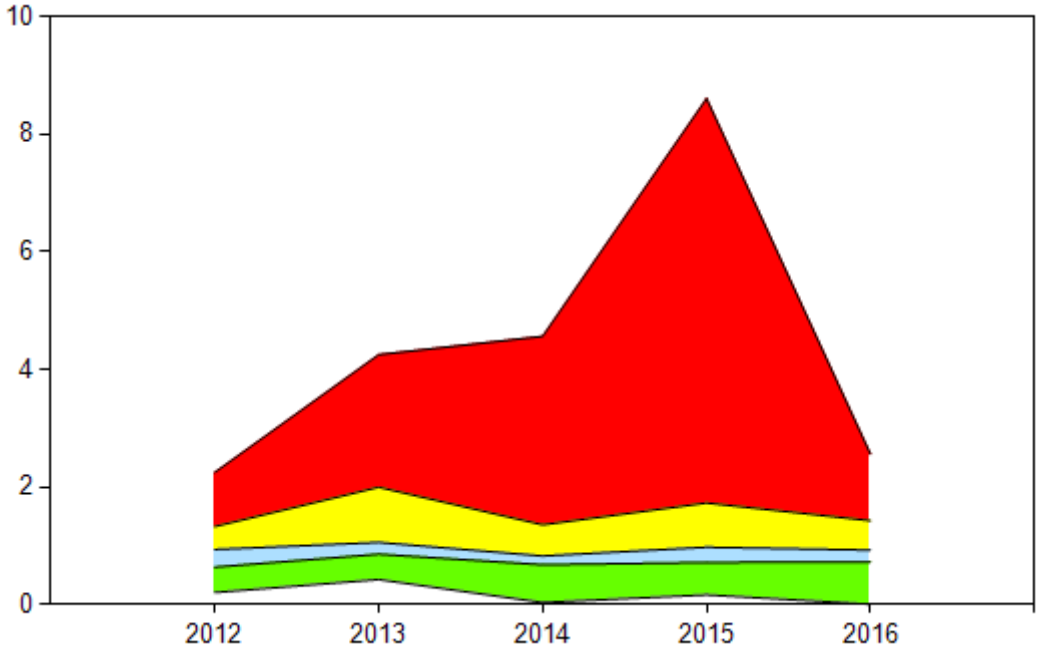



**Graph 6-2: Region 1 SAIDI, Excluding Significant Events**

Note: Quartiles include Canadian and International Utilities

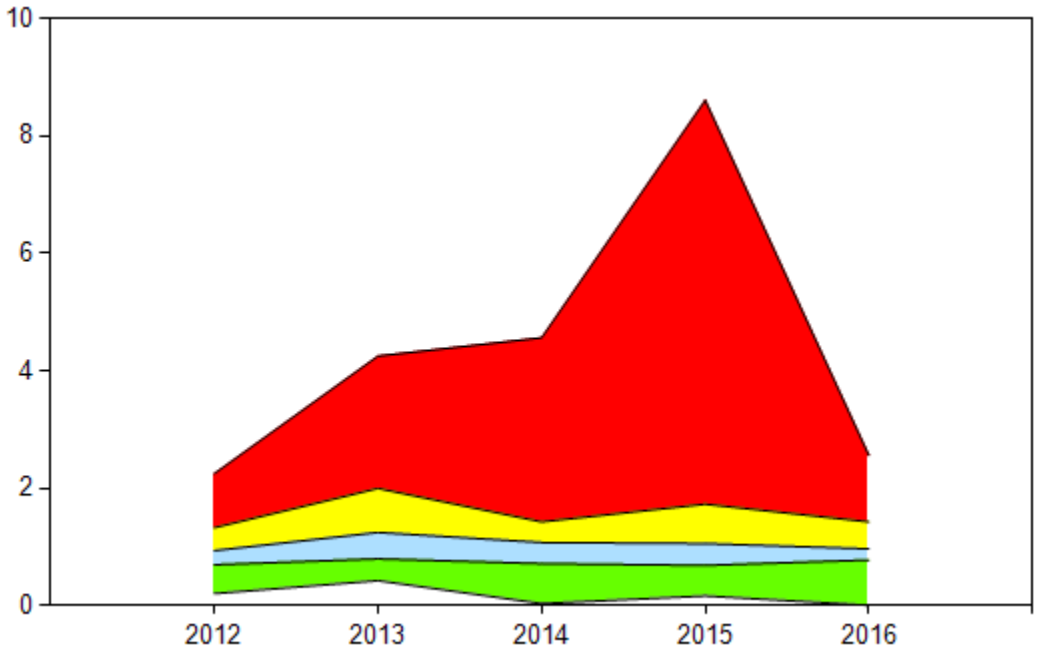



**Graph 6-3: Region 1 SAIDI, Including All Events**

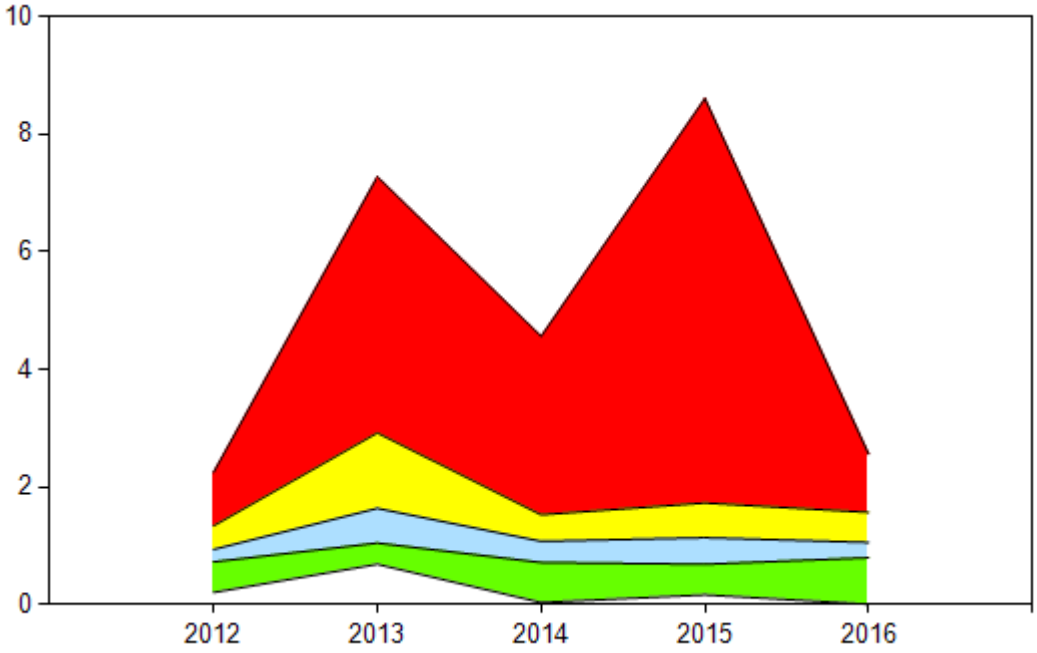



**Graph 6-4: Region 1 CAIDI, Excluding MPEs**

Note: Quartiles include Canadian and International Utilities

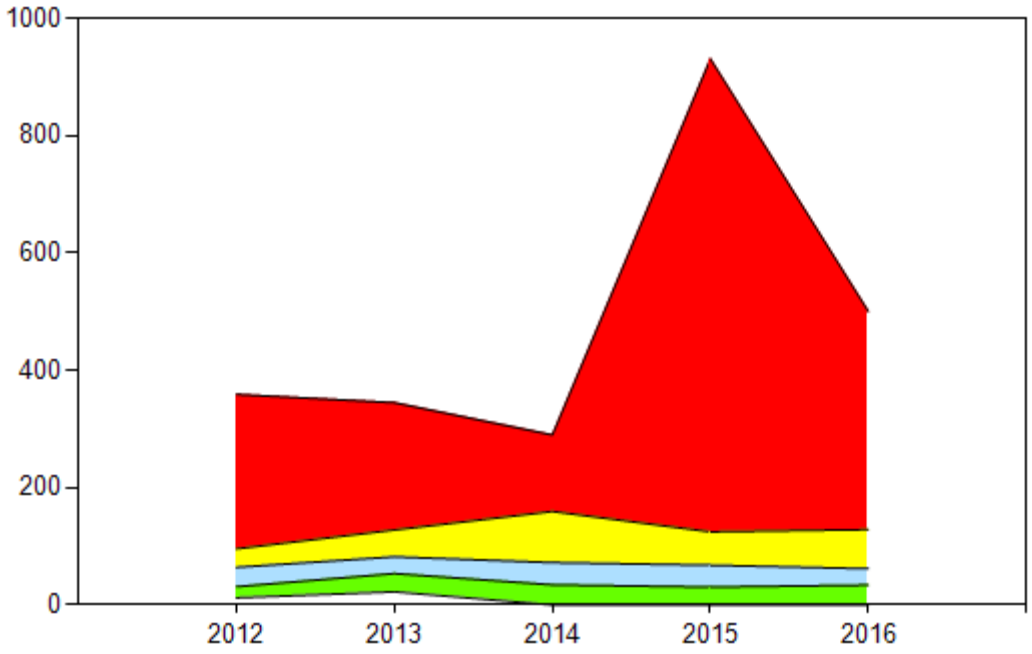



**Graph 6-5: Region 1 CAIDI, Excluding Significant Events**

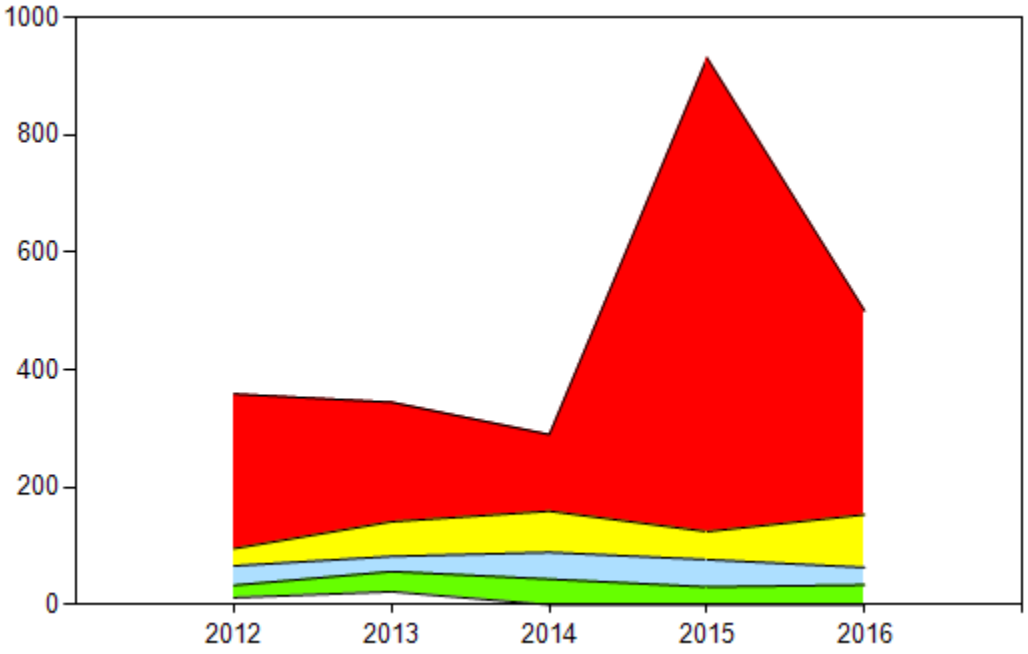



**Graph 6-6: Region 1 CAIDI, Including All Events**

Note: Quartiles include Canadian and International Utilities

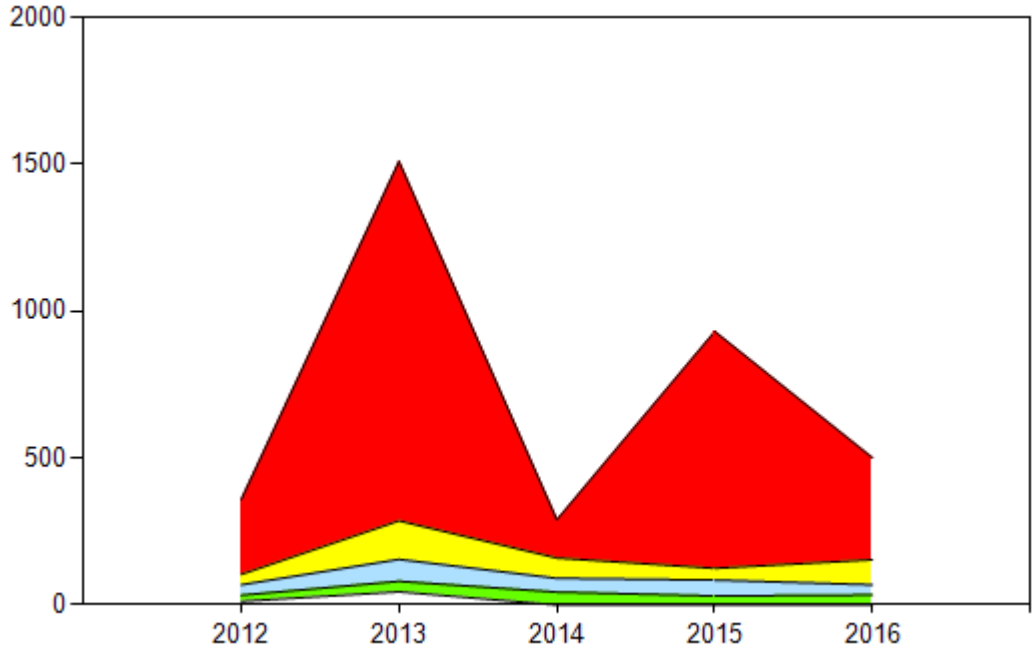



**Graph 6-7: Region 1 CHIKM, Excluding MPEs**

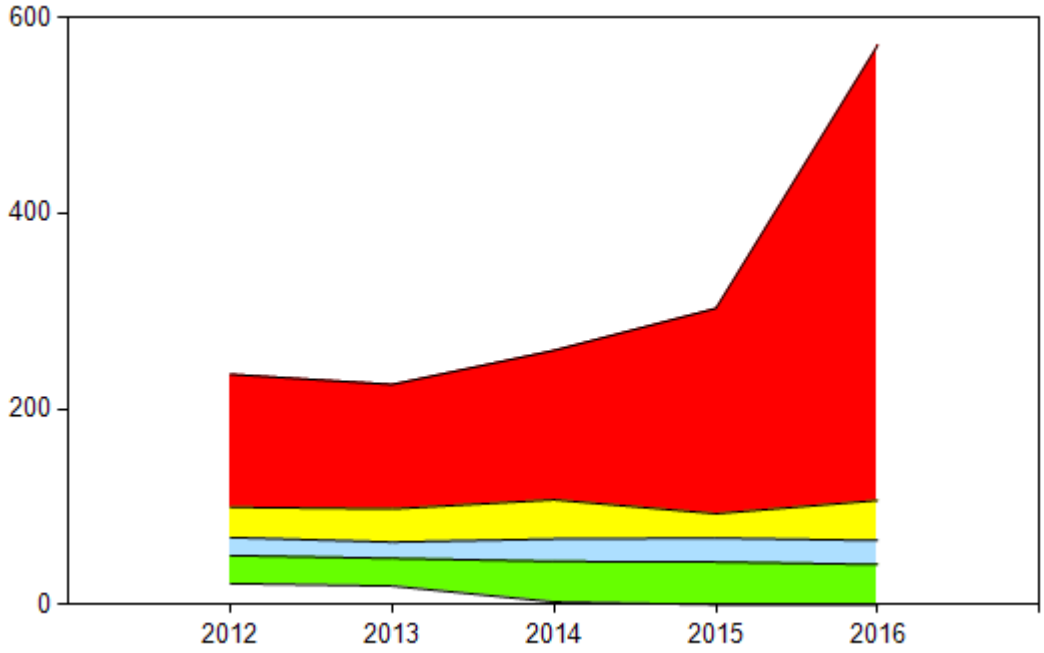



**Graph 6-8: Region 1 CHIKM, Excluding Significant Events**

Note: Quartiles include Canadian and International Utilities

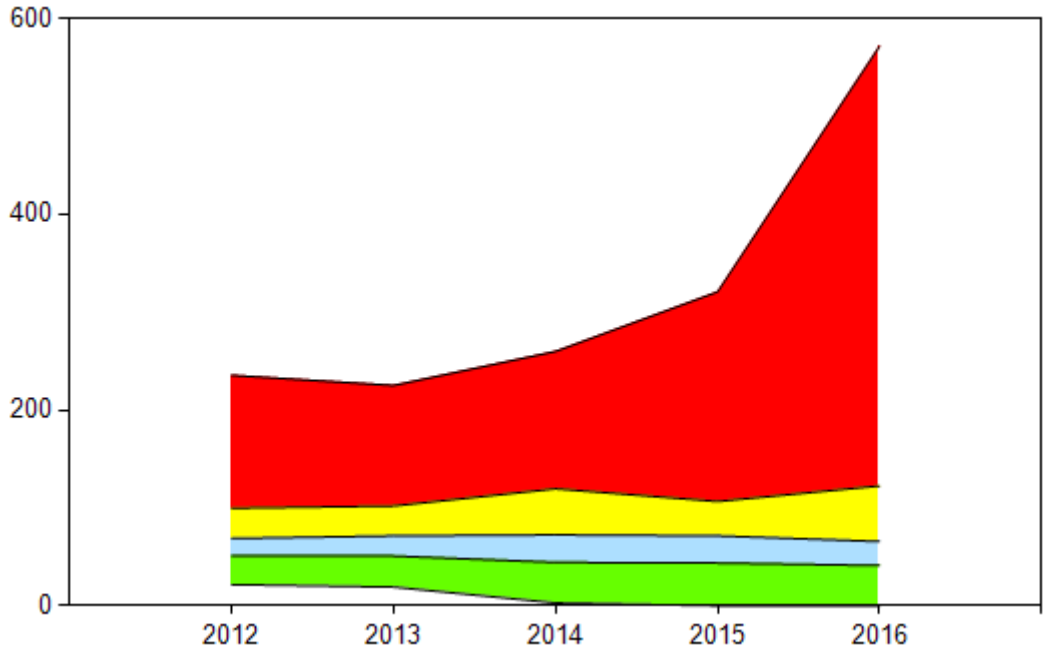



**Graph 6-9: Region 1 CHIKM, Including All Events**

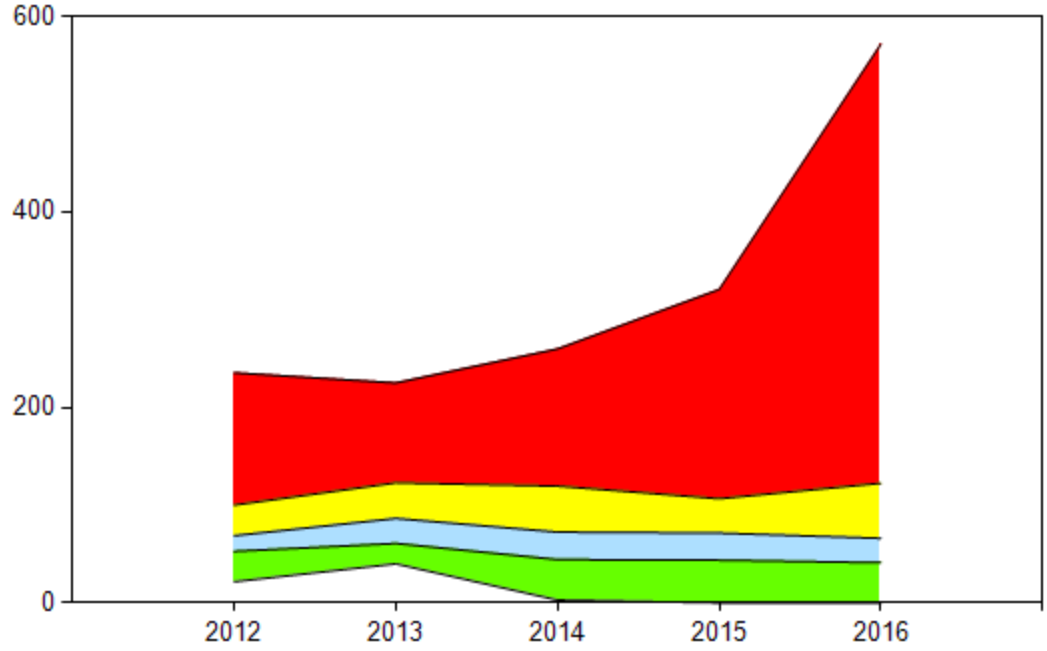



**Graph 6-10: Region 1 CIKM, Excluding MPEs**

Note: Quartiles include Canadian and International Utilities

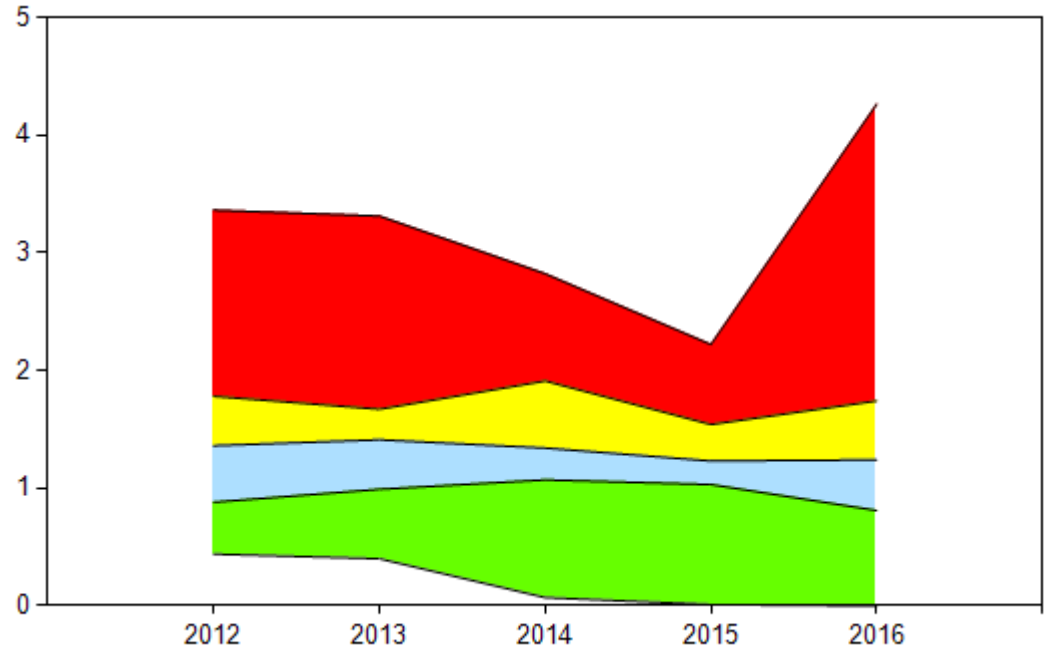



**Graph 6-11: Region 1 CIKM, Excluding Significant Events**

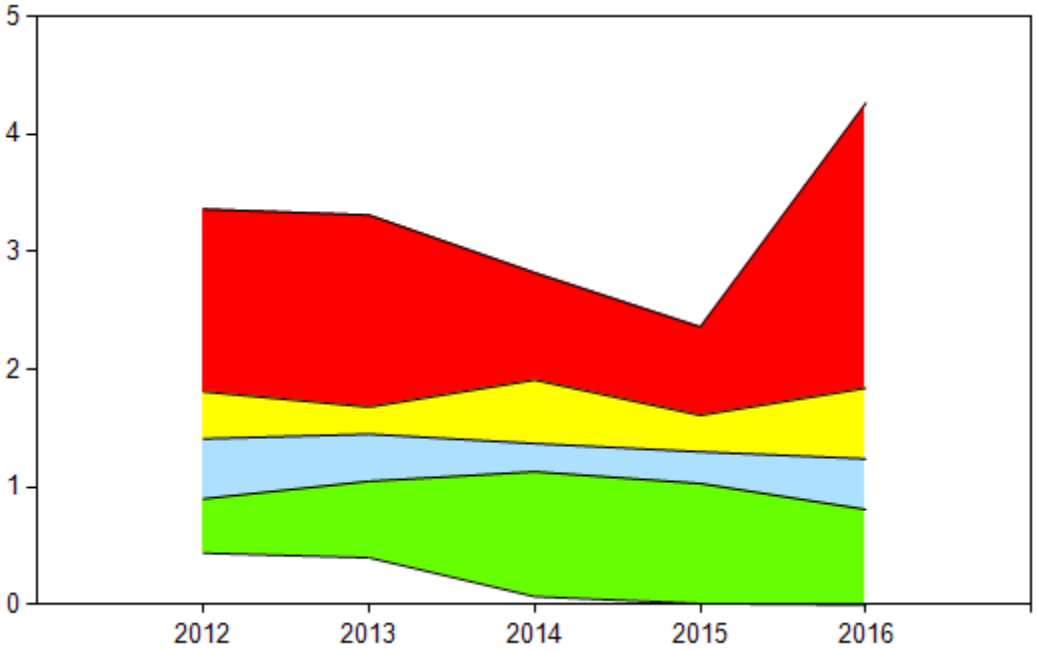



**Graph 6-12: Region 1 CIKM, Including All Events**

Note: Quartiles include Canadian and International Utilities

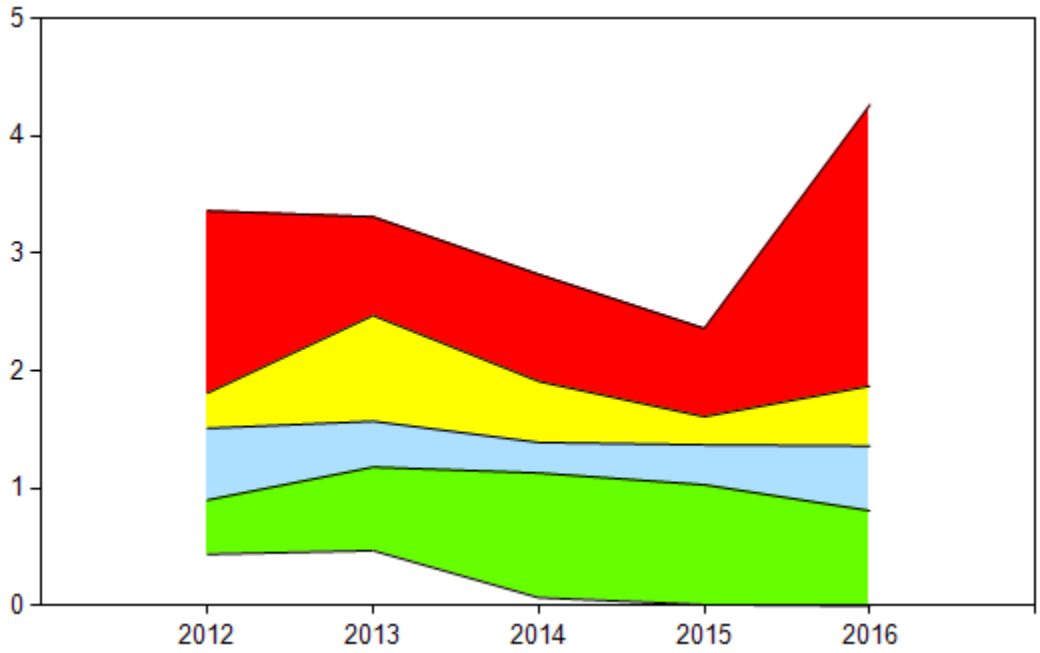



**Graph 6-13: Region 1 SAIFI, Excluding MPEs**




**Graph 6-14: Region 1 SAIFI, Excluding Significant Events**

Note: Quartiles include Canadian and International Utilities




**Graph 6-15: Region 1 SAIFI, Including All Events**

# 7.0 TABULATION OF
# SERVICE INTERRUPTION DATA
# FOR
# REGION 2 (URBAN/RURAL UTILITIES)

## 7.0 Region 2 (Urban / Rural Utilities)

ATCO Electric

B.C. Hydro

Barbados Light & Power Company

Caribbean Utilities

Dominica Electricity Services Ltd.

FortisAlberta

FortisBC

Grand Bahama Power Company

Hydro One

Hydro-Québec

Manitoba Hydro

Maritime Electric Company

New Brunswick Power

Newfoundland & Labrador Hydro

Newfoundland Power

Newmarket-Tay Power Distribution Ltd.

Northland Utilities (NWT)

Northland Utilities (Yellowknife)

Northwest Territories Power Corporation

Nova Scotia Power Inc.

Qulliq Energy Corporation

SaskPower

St. Lucia Electricity Services

Veridian Connections

Waterloo North Hydro Inc.

Yukon Electrical Co. Ltd.

Yukon Energy

**TABLE 7-1 (REGION 2)**

**SUMMARY OF INTERRUPTION DATA**

**(Including Derivation of Index of Reliability)**

**FOR YEARS 2011 - 2016**

*THE "INDEX OF RELIABILITY" IS A MEASURE OF SERVICE RELIABILITY.*
*IT EQUALS THE PER UNIT ANNUAL CUSTOMER-HOURS THAT SERVICE IS AVAILABLE.*

**CANADIAN UTILITIES IN 2016**

| YEAR | NUMBER OF CUSTOMERS SERVED | NUMBER OF INTERRUPTIONS | TOTAL CUSTOMER INTERRUPTIONS | (A) TOTAL INTERRUPTED CUST. HOURS | (B) TOTAL AVAILABLE CUST. HOURS | (C) INDEX OF RELIABILITY |
|---|---|---|---|---|---|---|
| 2011 | 10,326,243 | 236,958 | 30,682,291 | 77,424,503 | 90,457,888,680 | 0.999144 |
| 2011** | 10,326,243 | 227,883 | 29,414,607 | 64,028,521 | 90,457,888,680 | 0.999292 |
| 2012 | 10,520,087 | 228,415 | 29,813,908 | 59,041,000 | 92,155,962,120 | 0.999359 |
| 2012** | 10,520,087 | 225,728 | 29,305,502 | 56,421,959 | 92,155,962,120 | 0.999388 |
| 2013 | 10,660,339 | 248,987 | 31,338,135 | 104,740,011 | 93,384,569,640 | 0.998878 |
| 2013** | 10,660,339 | 234,085 | 29,510,555 | 77,429,859 | 93,384,569,640 | 0.999171 |
| 2014 | 10,800,893 | 249,987 | 28,793,848 | 84,390,893 | 94,615,822,680 | 0.999108 |
| 2014** | 10,800,893 | 240,892 | 27,944,301 | 65,970,910 | 94,615,822,680 | 0.999303 |
| 2015 | 10,930,018 | 240,716 | 28,646,113 | 68,474,108 | 95,746,957,680 | 0.999285 |
| 2015** | 10,930,018 | 234,785 | 27,106,333 | 51,448,001 | 95,746,957,680 | 0.999463 |
| 2016 | 11,037,599 | 278,098 | 40,901,021 | 78,101,848 | 96,689,367,240 | 0.999192 |
| 2016** | 11,037,599 | 266,913 | 36,530,085 | 60,555,694 | 96,689,367,240 | 0.999374 |

*** Excludes Significant Events*

**INTERNATIONAL UTILITIES IN 2016**

| | | | | | | |
|---|---|---|---|---|---|---|
| 2011 | 122,049 | 2,826 | 839,078 | 706,115 | 1,069,149,240 | 0.999340 |
| 2012 | 61,192 | 571 | 640,714 | 723,712 | 536,041,920 | 0.998650 |
| 2013 | 532,925 | 13,818 | 2,913,019 | 3,597,344 | 4,668,423,000 | 0.999229 |
| 2014 | 717,629 | 17,491 | 6,482,752 | 5,602,845 | 6,286,430,040 | 0.999109 |
| 2015 | 273,620 | 1,801 | 2,089,429 | 2,832,030 | 2,396,911,200 | 0.998818 |
| 2016 | 276,529 | 2,447 | 2,273,771 | 4,224,430 | 2,422,394,040 | 0.998256 |
| 2016** | 276,529 | 2,418 | 2,154,361 | 2,481,424 | 2,422,394,040 | 0.998976 |

**(A) = SUMMATION OF THE NUMBER OF CUSTOMERS x RESTORATION TIME IN HOURS OF EACH INTERRUPTION**

**(B) = TWELVE MONTH AVERAGE NUMBER OF CUSTOMERS x 8,760 HOURS (ONE YEAR)**

**(C) = INDEX OF RELIABILITY: 1 - (A)/(B)**

**TABLE 7-2 (REGION 2)**

**SYSTEM CAUSES OF SERVICE INTERRUPTIONS**

**FOR YEAR 2016**

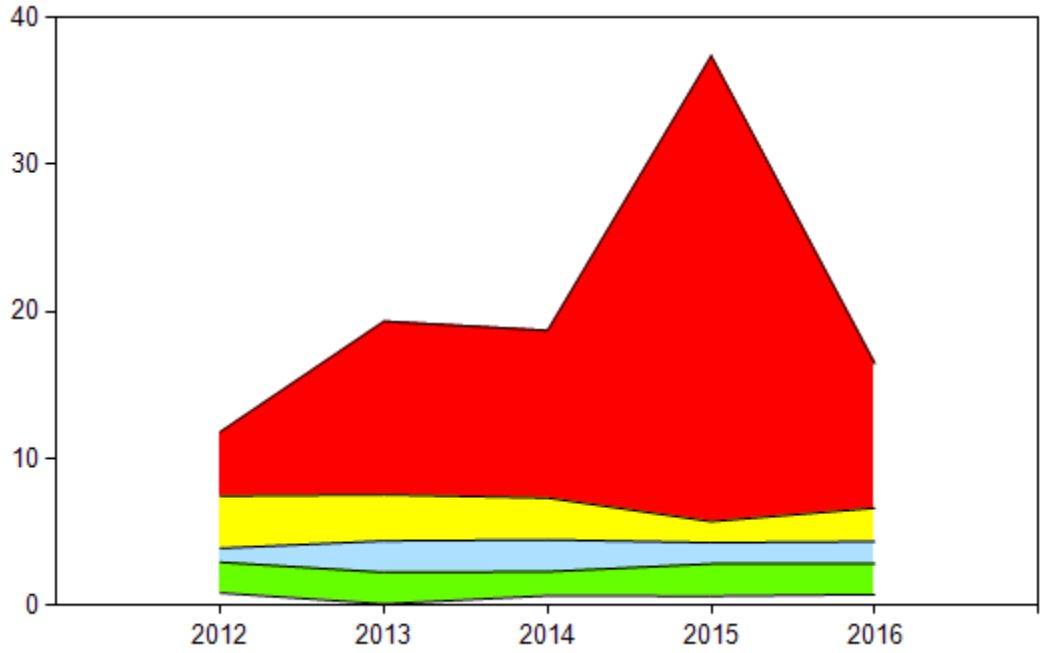
***Canadian***

**11,037,599 CUSTOMERS IN 2016**

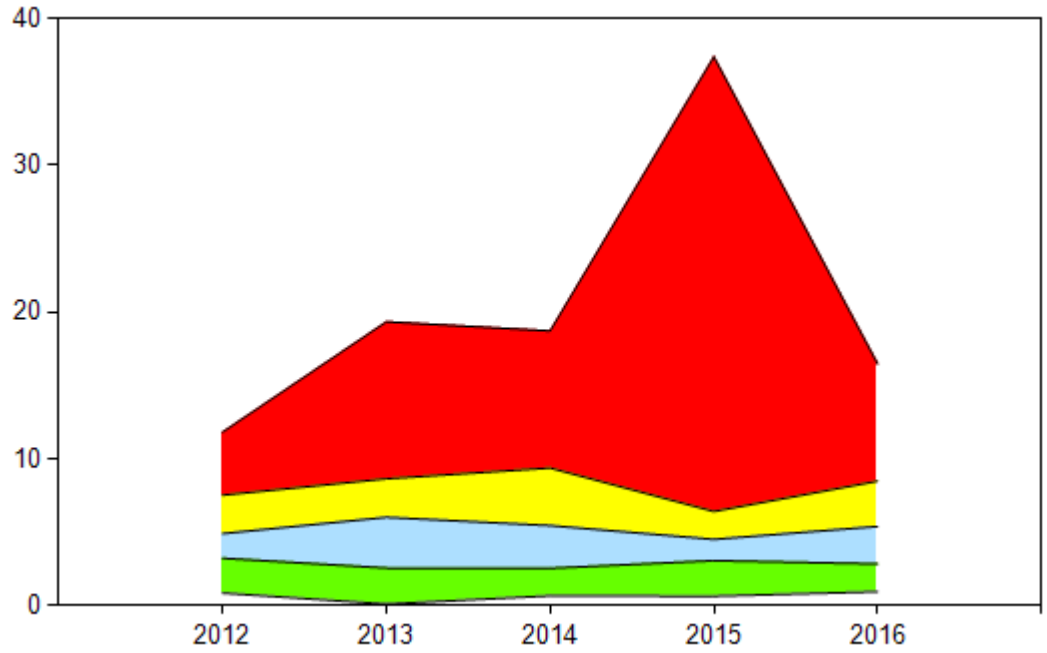
**10,930,018 CUSTOMERS IN 2015**

| PRIMARY CAUSE | NUMBER OF INTERRUPTIONS | | CUSTOMER INTERRUPTIONS | | CUSTOMER HOUR INTERRUPTIONS | | SAIFI | SAIDI | CAIDI | CHIKM | CIKM |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | NUMBER | % | NUMBER | % | NUMBER | % | | (HRS) | (HRS) | | |
| **Unknown/Other** | | | | | | | | | | | |
| 2016 | 37,753 | 13.6 | 5,699,218 | 13.9 | 7,011,326 | 9.0 | 0.52 | 0.64 | 1.23 | 9.00 | 8.00 |
| 2015 | 27,440 | 11.4 | 4,458,964 | 15.6 | 5,471,059 | 8.0 | 0.41 | 0.50 | 1.23 | 7.00 | 6.00 |
| 5 YEAR AVERAGE | 30,802 | 12.4 | 4,618,402 | 14.5 | 7,241,071 | 9.2 | 0.43 | 0.67 | 1.57 | 8.00 | 5.00 |
| **Scheduled Outage** | | | | | | | | | | | |
| 2016 | 57,814 | 20.8 | 6,876,095 | 16.8 | 6,843,620 | 8.8 | 0.62 | 0.62 | 1.00 | 9.00 | 9.00 |
| 2015 | 57,749 | 24.0 | 2,927,644 | 10.2 | 6,710,068 | 9.8 | 0.27 | 0.61 | 2.29 | 9.00 | 4.00 |
| 5 YEAR AVERAGE | 51,127 | 20.5 | 3,442,529 | 10.8 | 6,635,464 | 8.4 | 0.32 | 0.61 | 1.93 | 8.00 | 4.00 |
| **Loss of Supply** | | | | | | | | | | | |
| 2016 | 8,126 | 2.9 | 9,125,731 | 22.3 | 7,793,843 | 10.0 | 0.83 | 0.71 | 0.85 | 10.00 | 12.00 |
| 2015 | 6,332 | 2.6 | 6,792,015 | 23.7 | 7,322,239 | 10.7 | 0.62 | 0.67 | 1.08 | 10.00 | 9.00 |
| 5 YEAR AVERAGE | 6,794 | 2.7 | 8,004,255 | 25.1 | 7,957,037 | 10.1 | 0.74 | 0.74 | 0.99 | 9.00 | 9.00 |
| **Tree Contacts** | | | | | | | | | | | |
| 2016 | 46,434 | 16.7 | 7,345,355 | 18.0 | 28,722,698 | 36.8 | 0.67 | 2.60 | 3.91 | 38.00 | 10.00 |
| 2015 | 35,811 | 14.9 | 4,762,459 | 16.6 | 20,356,619 | 29.7 | 0.44 | 1.86 | 4.27 | 27.00 | 6.00 |
| 5 YEAR AVERAGE | 43,879 | 17.6 | 5,705,953 | 17.9 | 28,917,870 | 36.6 | 0.53 | 2.68 | 5.07 | 33.00 | 7.00 |
| **Lightning** | | | | | | | | | | | |
| 2016 | 17,754 | 6.4 | 718,873 | 1.8 | 1,144,266 | 1.5 | 0.07 | 0.10 | 1.59 | 2.00 | 1.00 |
| 2015 | 12,149 | 5.0 | 429,084 | 1.5 | 928,044 | 1.4 | 0.04 | 0.08 | 2.16 | 1.00 | 1.00 |
| 5 YEAR AVERAGE | 13,876 | 5.6 | 645,436 | 2.0 | 1,303,645 | 1.7 | 0.06 | 0.12 | 2.02 | 2.00 | 1.00 |
| **Defective Equipment** | | | | | | | | | | | |
| 2016 | 51,112 | 18.4 | 5,032,039 | 12.3 | 10,965,985 | 14.0 | 0.46 | 0.99 | 2.18 | 15.00 | 7.00 |
| 2015 | 48,713 | 20.2 | 4,576,404 | 16.0 | 10,911,565 | 15.9 | 0.42 | 1.00 | 2.38 | 15.00 | 6.00 |
| 5 YEAR AVERAGE | 47,929 | 19.2 | 4,525,740 | 14.2 | 11,255,815 | 14.3 | 0.42 | 1.04 | 2.49 | 13.00 | 5.00 |
| **Adverse Weather** | | | | | | | | | | | |
| 2016 | 13,840 | 5.0 | 1,845,054 | 4.5 | 6,086,224 | 7.8 | 0.17 | 0.55 | 3.30 | 8.00 | 2.00 |
| 2015 | 10,543 | 4.4 | 1,361,807 | 4.8 | 10,770,078 | 15.7 | 0.12 | 0.99 | 7.91 | 14.00 | 0.00 |
| 5 YEAR AVERAGE | 12,201 | 4.9 | 1,581,905 | 5.0 | 7,244,340 | 9.2 | 0.15 | 0.67 | 4.58 | 8.00 | 2.00 |
| **Adverse Environment** | | | | | | | | | | | |
| 2016 | 4,145 | 1.5 | 678,809 | 1.7 | 4,166,482 | 5.3 | 0.06 | 0.38 | 6.14 | 6.00 | 1.00 |
| 2015 | 3,676 | 1.5 | 443,874 | 1.5 | 967,647 | 1.4 | 0.04 | 0.09 | 2.18 | 1.00 | 1.00 |
| 5 YEAR AVERAGE | 4,592 | 1.8 | 614,913 | 1.9 | 1,870,098 | 2.4 | 0.06 | 0.17 | 3.04 | 2.00 | 1.00 |
| **Human Element** | | | | | | | | | | | |
| 2016 | 5,414 | 1.9 | 1,293,573 | 3.2 | 1,615,658 | 2.1 | 0.12 | 0.15 | 1.25 | 2.00 | 2.00 |
| 2015 | 5,190 | 2.2 | 967,982 | 3.4 | 1,113,550 | 1.6 | 0.09 | 0.10 | 1.15 | 1.00 | 1.00 |
| 5 YEAR AVERAGE | 4,100 | 1.6 | 775,721 | 2.4 | 934,372 | 1.2 | 0.07 | 0.09 | 1.20 | 1.00 | 1.00 |
| **Foreign Interference** | | | | | | | | | | | |
| 2016 | 35,706 | 12.8 | 2,286,274 | 5.6 | 3,751,746 | 4.8 | 0.21 | 0.34 | 1.64 | 5.00 | 3.00 |
| 2015 | 33,113 | 13.8 | 1,925,880 | 6.7 | 3,923,241 | 5.7 | 0.18 | 0.36 | 2.04 | 5.00 | 3.00 |
| 5 YEAR AVERAGE | 33,941 | 13.6 | 1,983,750 | 6.2 | 5,589,862 | 7.1 | 0.18 | 0.52 | 2.82 | 6.00 | 2.00 |
| **Total** | | | | | | | | | | | |
| 2016 | 278,098 | 100.0 | 40,901,021 | 100.0 | 78,101,848 | 100.0 | 3.71 | 7.08 | 1.91 | 104.00 | 54.00 |
| 2015 | 240,716 | 100.0 | 28,646,113 | 100.0 | 68,474,108 | 100.0 | 2.62 | 6.26 | 2.39 | 91.00 | 38.00 |
| 5 YEAR AVERAGE | 249,241 | 100.0 | 31,898,605 | 100.0 | 78,949,572 | 100.0 | 2.96 | 7.32 | 2.48 | 90.00 | 37.00 |

Note: Quartiles include Canadian and International Utilities

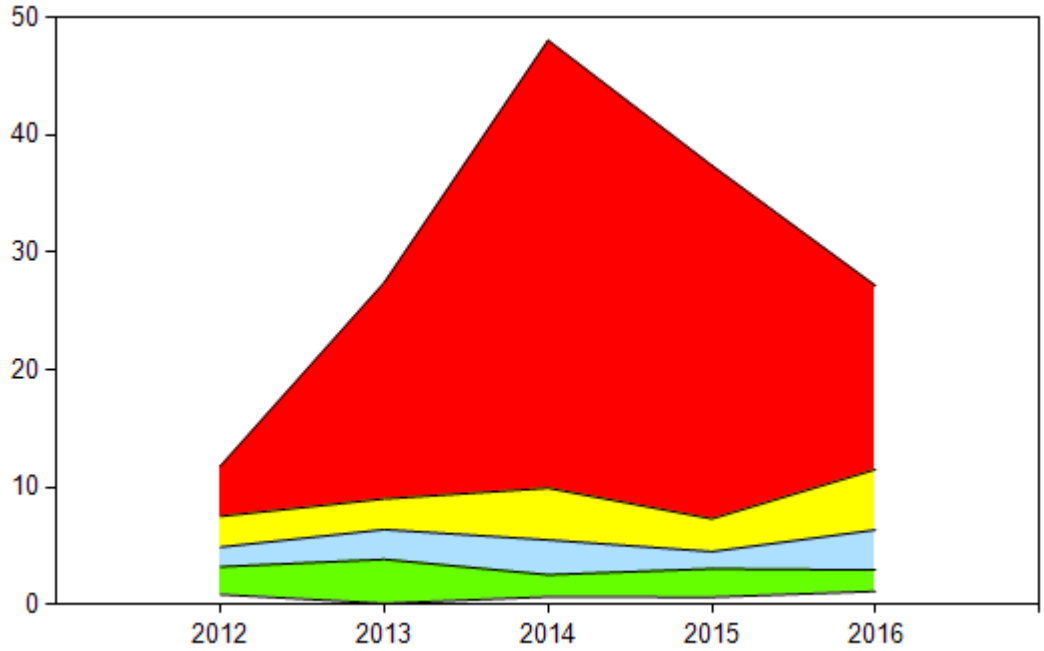



**Graph 7-1: Region 2 SAIDI, Excluding MPEs**

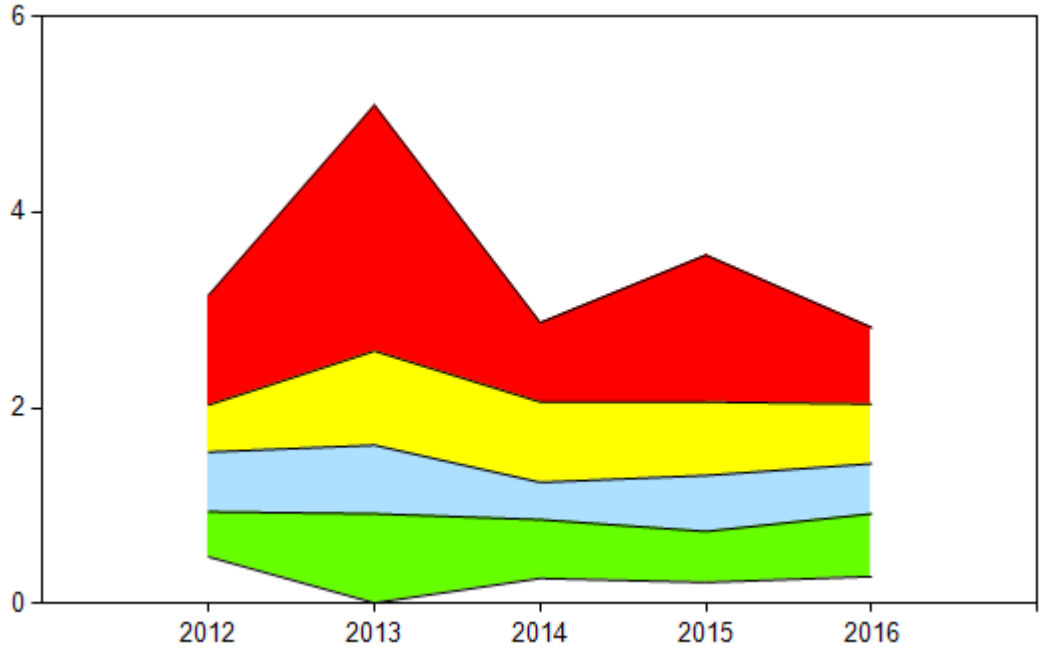



**Graph 7-2: Region 2 SAIDI, Excluding Significant Events**

Note: Quartiles include Canadian and International Utilities

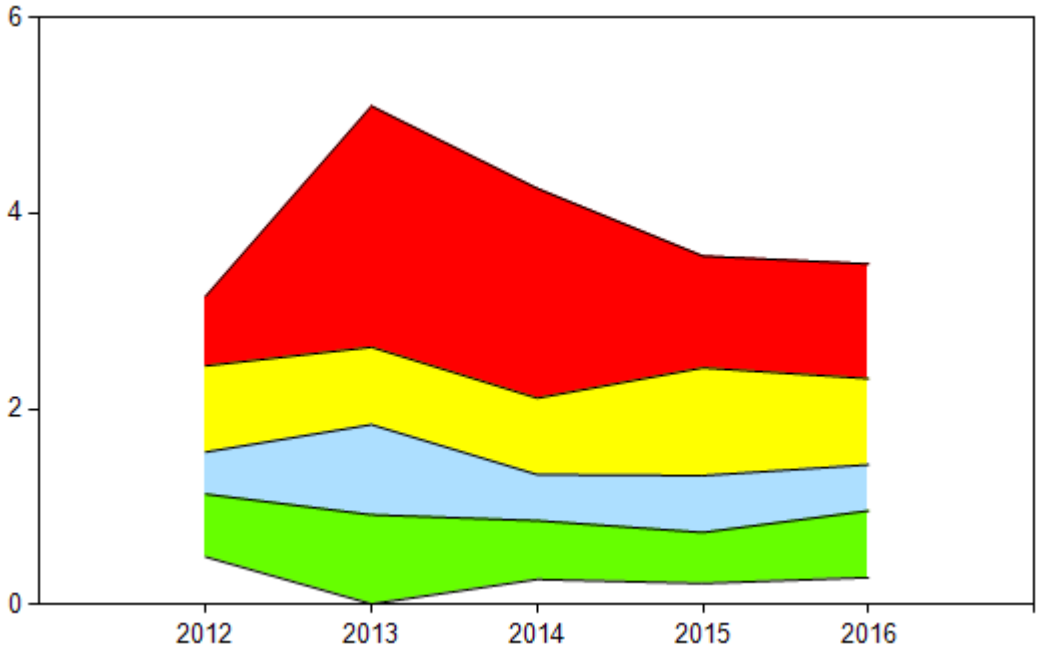



**Graph 7-3: Region 2 SAIDI, Including All Events**

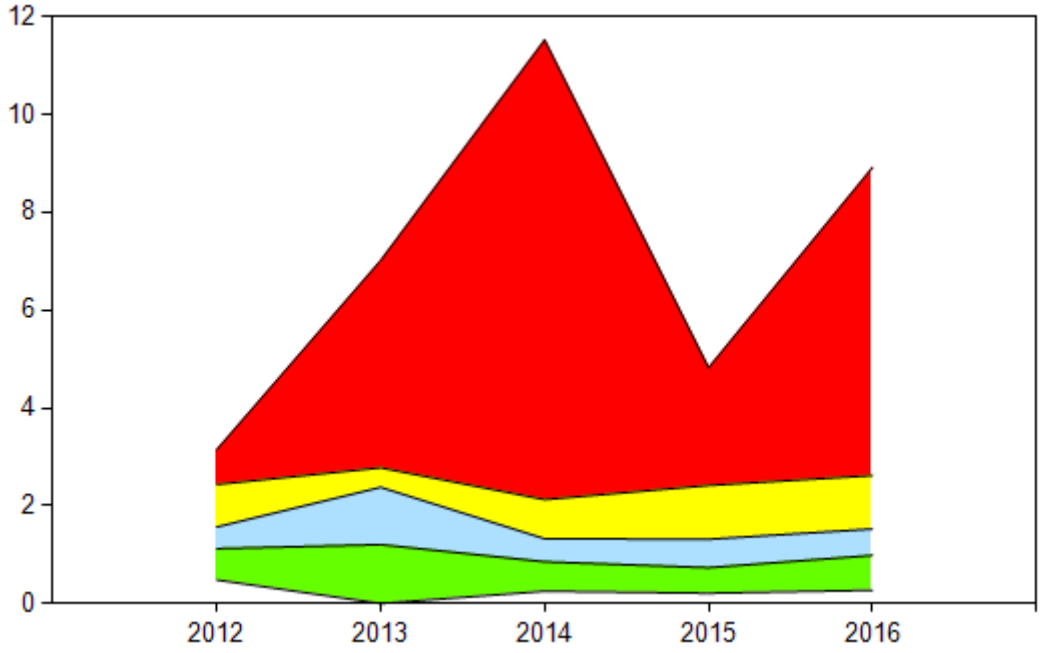



**Graph 7-4: Region 2 CAIDI, Excluding MPEs**

Note: Quartiles include Canadian and International Utilities

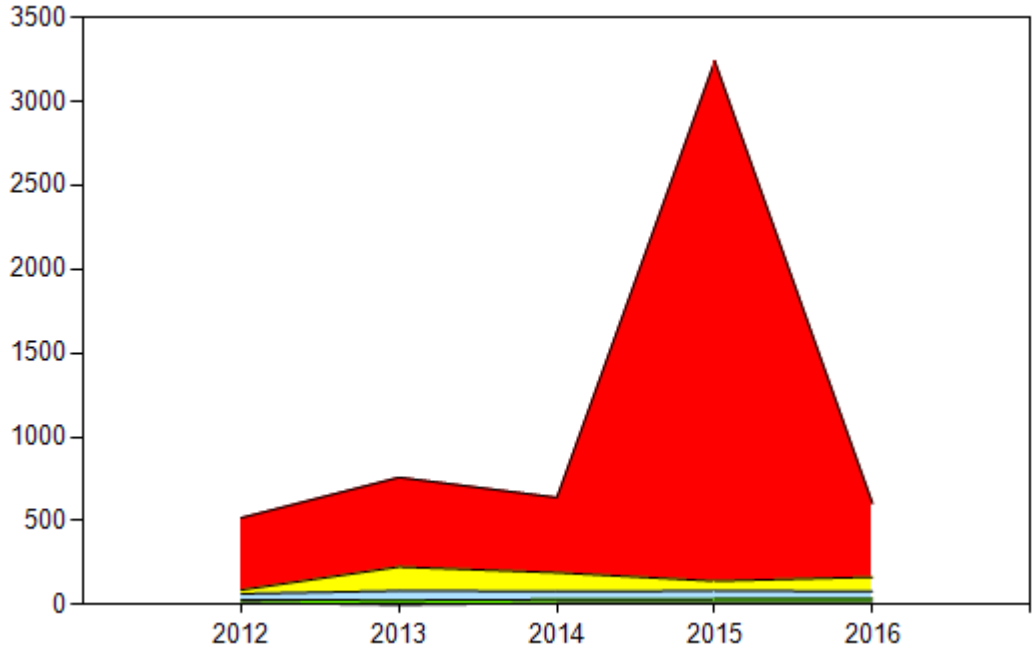



**Graph 7-5: Region 2 CAIDI, Excluding Significant Events**

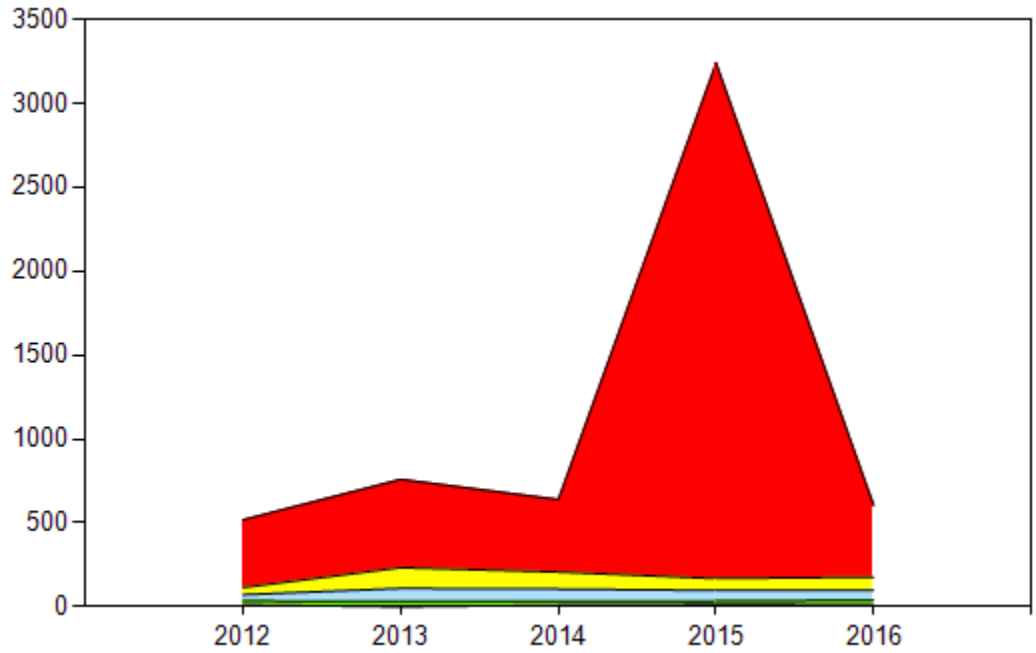



**Graph 7-6: Region 2 CAIDI, Including All Events**

Note: Quartiles include Canadian and International Utilities

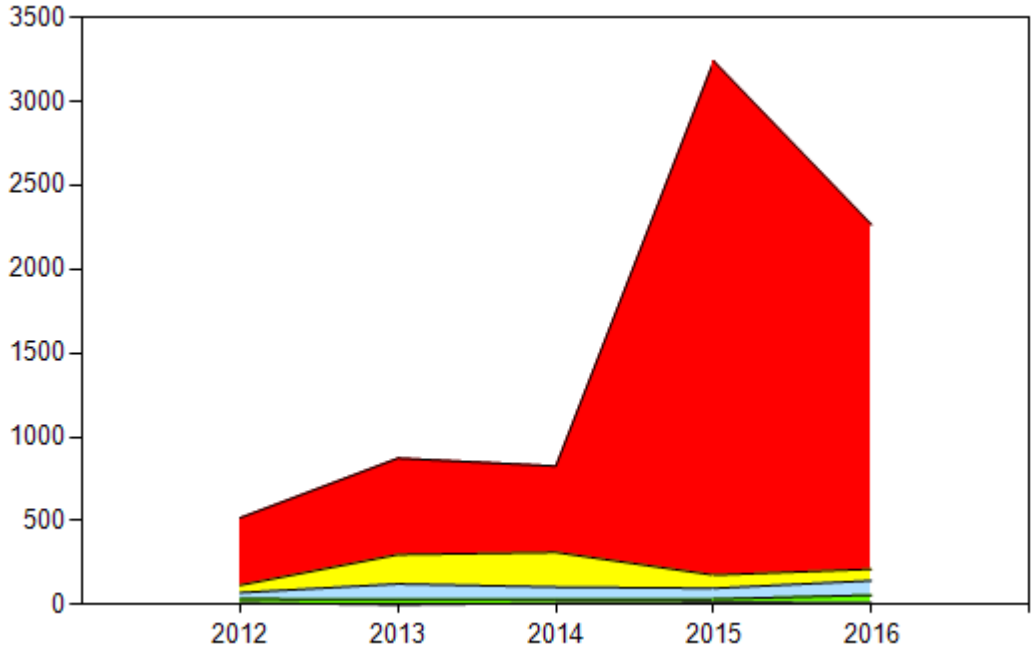



**Graph 7-7: Region 2 CHIKM, Excluding MPEs**

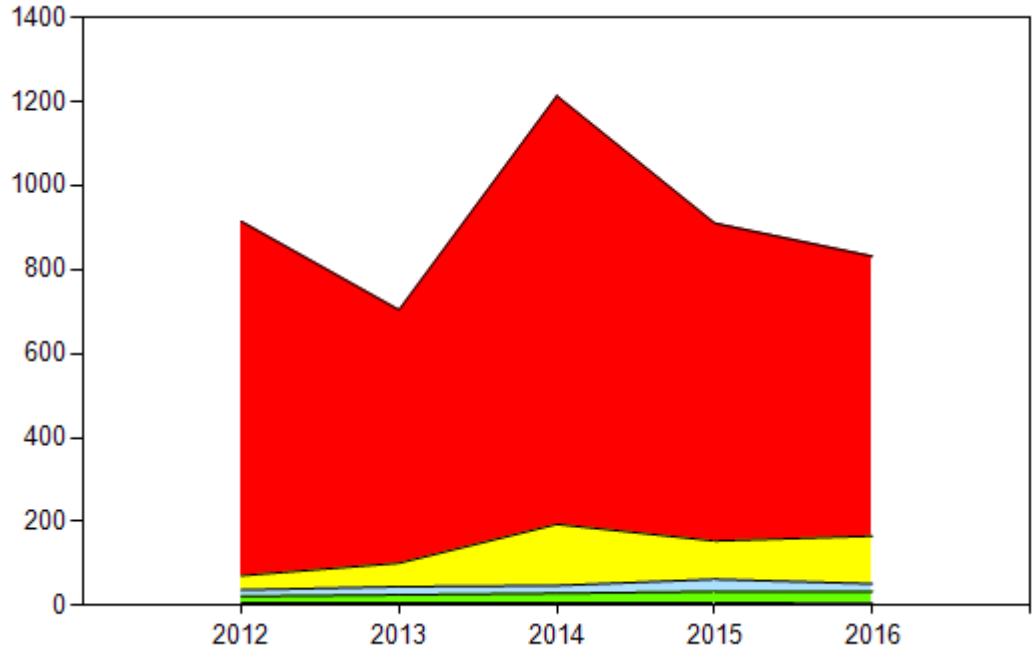



**Graph 7-8: Region 2 CHIKM, Excluding Significant Events**

Note: Quartiles include Canadian and International Utilities

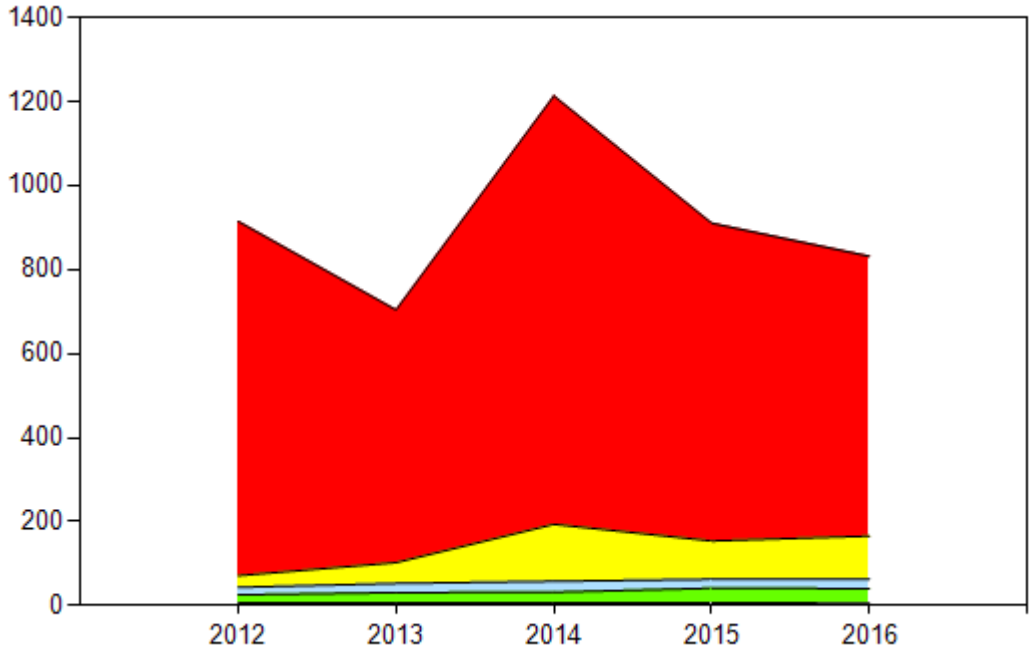



**Graph 7-9: Region 2 CHIKM, Including All Events**

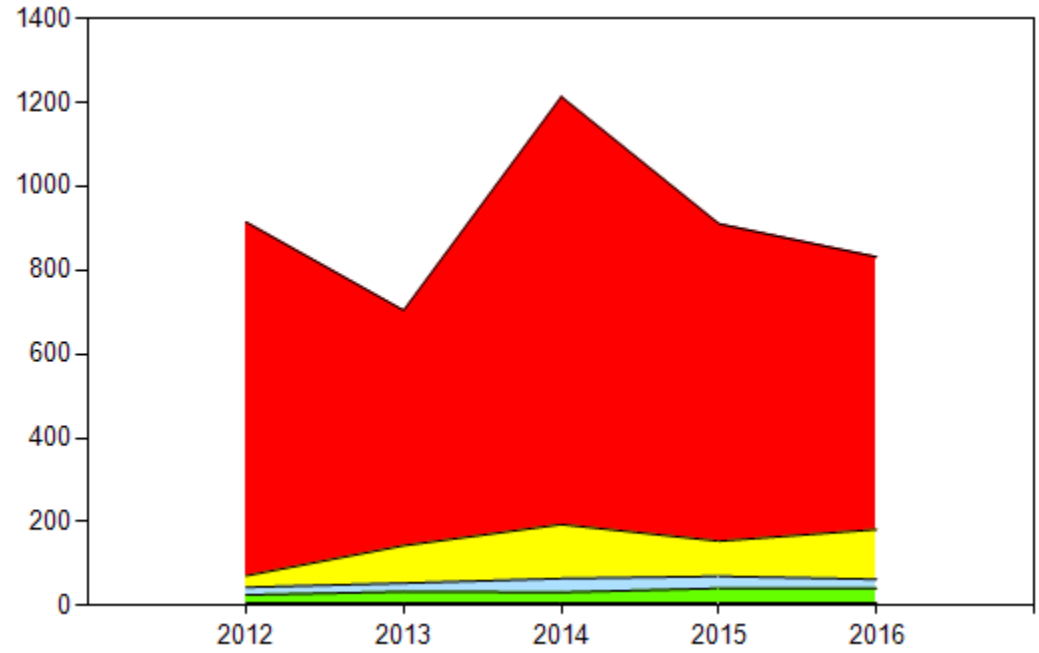



**Graph 7-10: Region 2 CIKM, Excluding MPEs**

Note: Quartiles include Canadian and International Utilities

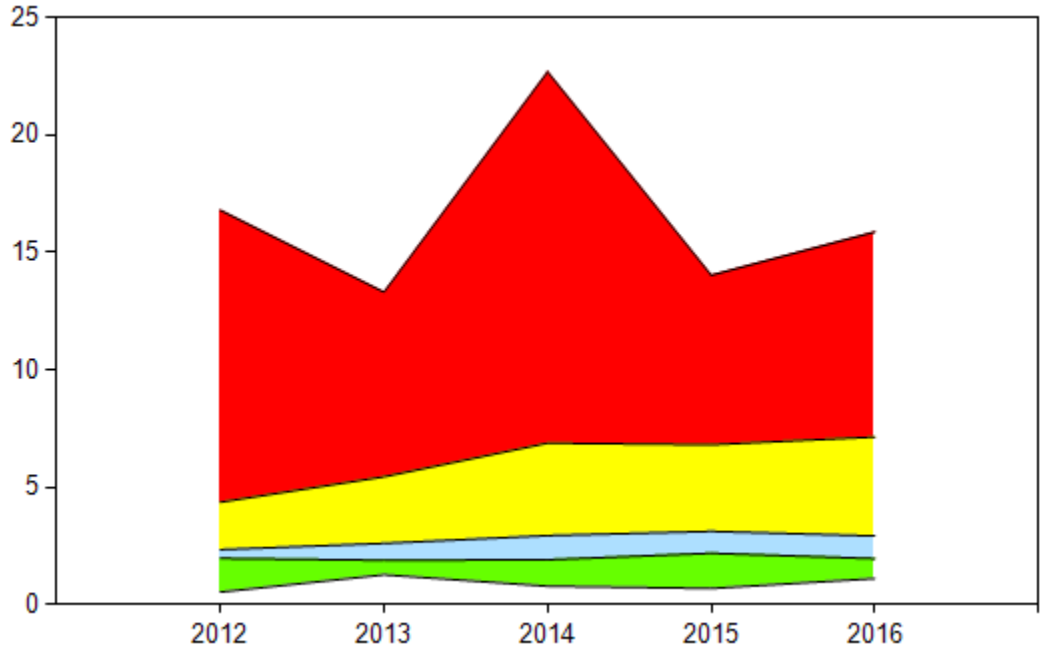



**Graph 7-11: Region 2 CIKM, Excluding Significant Events**

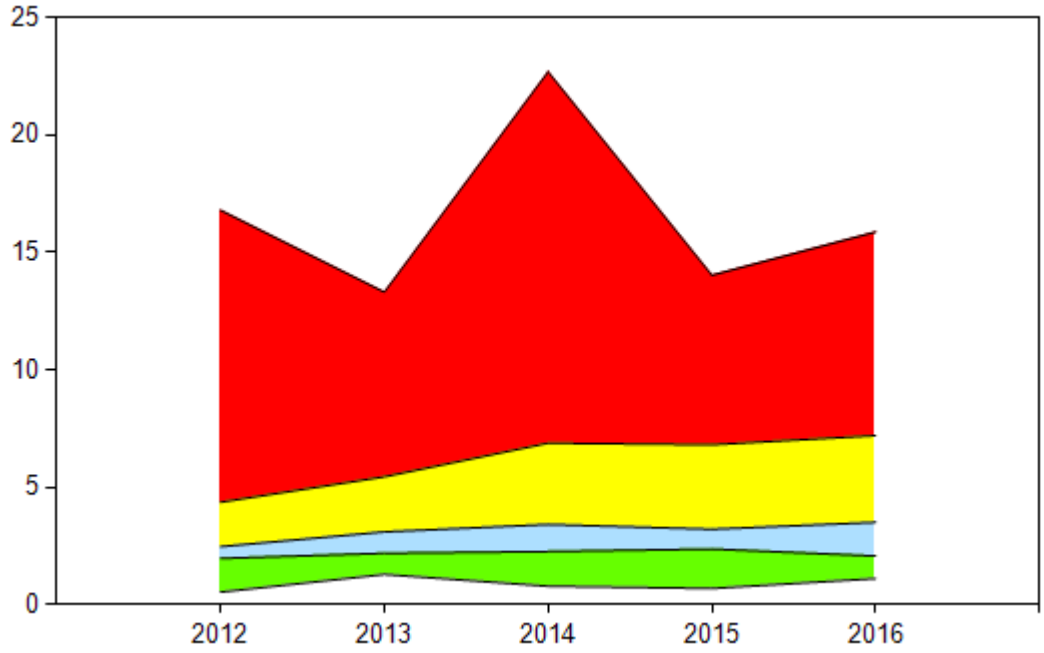



**Graph 7-12: Region 2 CIKM, Including All Events**

Note: Quartiles include Canadian and International Utilities

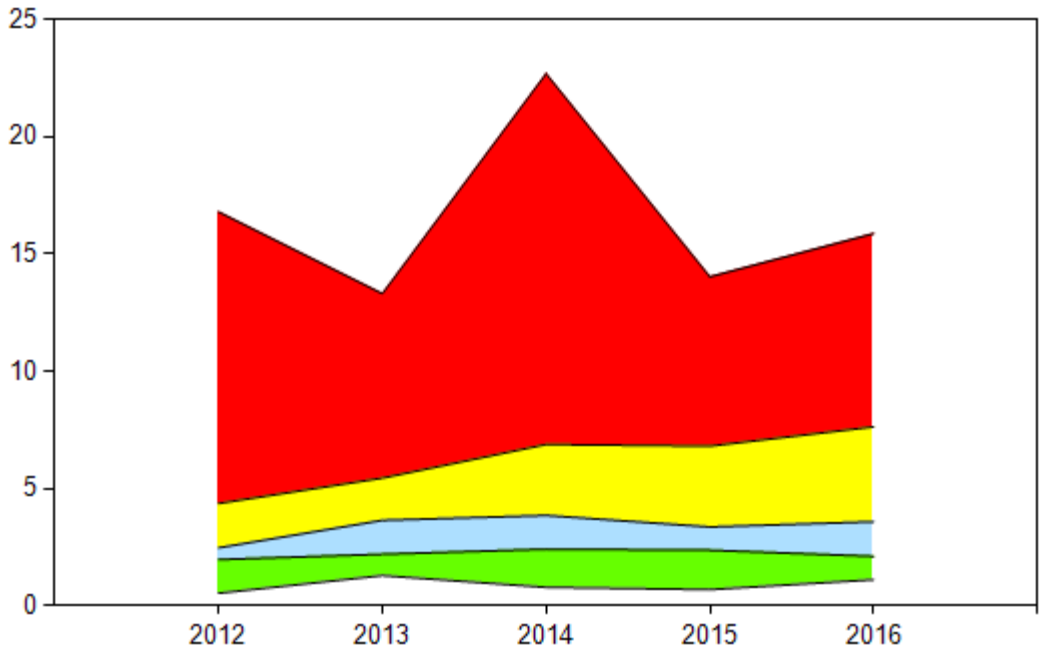



**Graph 7-13: Region 2 SAIFI, Excluding MPEs**




**Graph 7-14: Region 2 SAIFI, Excluding Significant Events**

Note: Quartiles include Canadian and International Utilities




**Graph 7-15: Region 2 SAIFI, Including All Events**

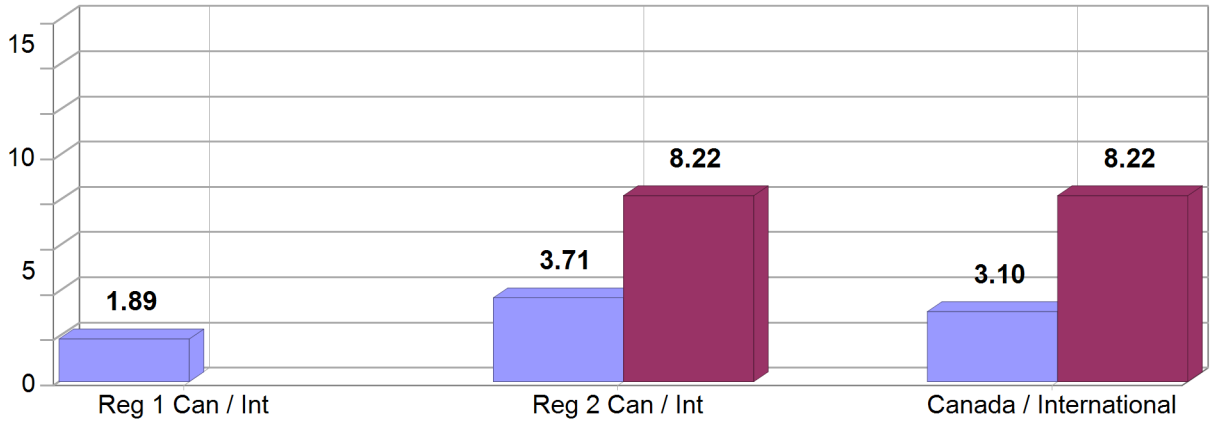
# 8.0 SYSTEM INDICES FOR REGIONS

## 8.0 SYSTEM INDICES FOR REGIONS

Graph 8.1 below shows the variations in the services indices of SAIFI, SAIDI, CAIDI, the Index of Reliability, CHIKM, CIKM for 2016 total Canadian and International data and by regions.

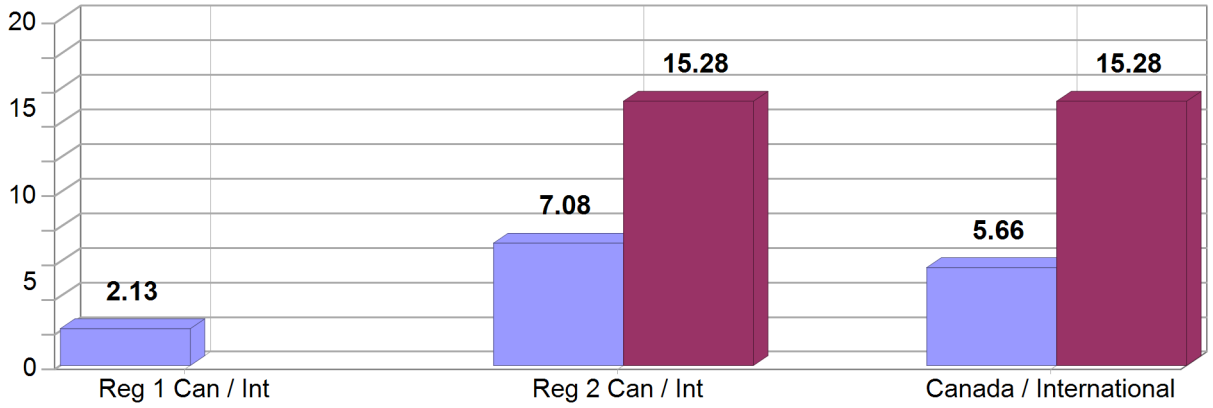
### SAIFI

***System Average Interruption Frequency Index***



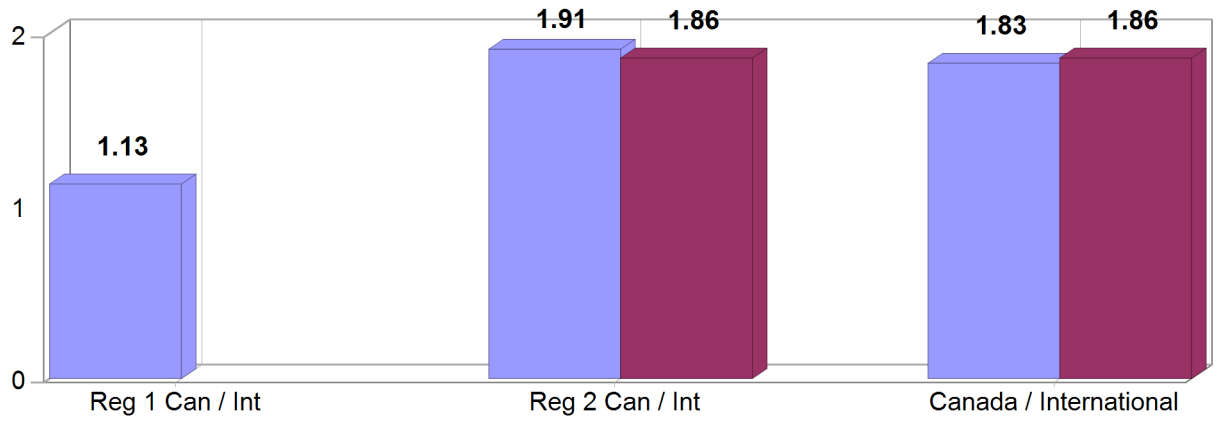

### SAIDI

***System Average Interruption Duration Index***

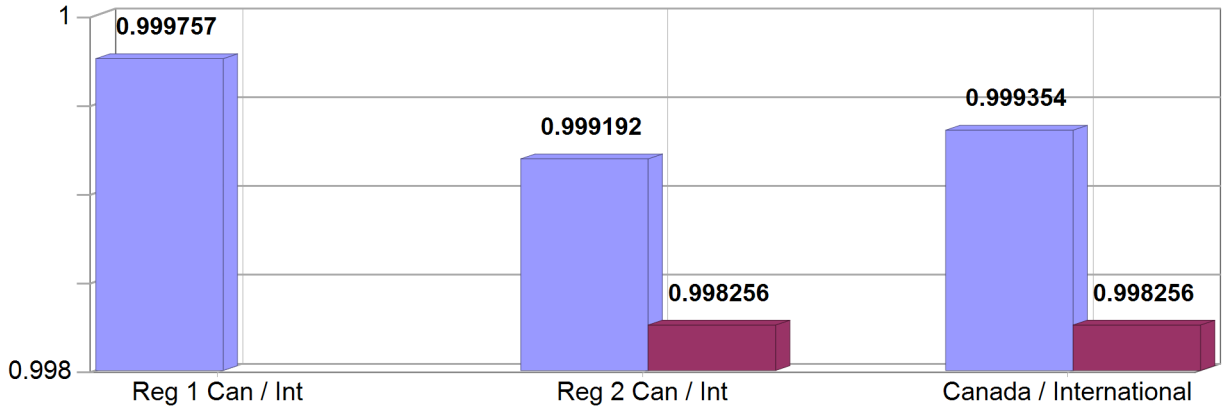


## CAIDI

***Customer Average Interruption Duration Index***

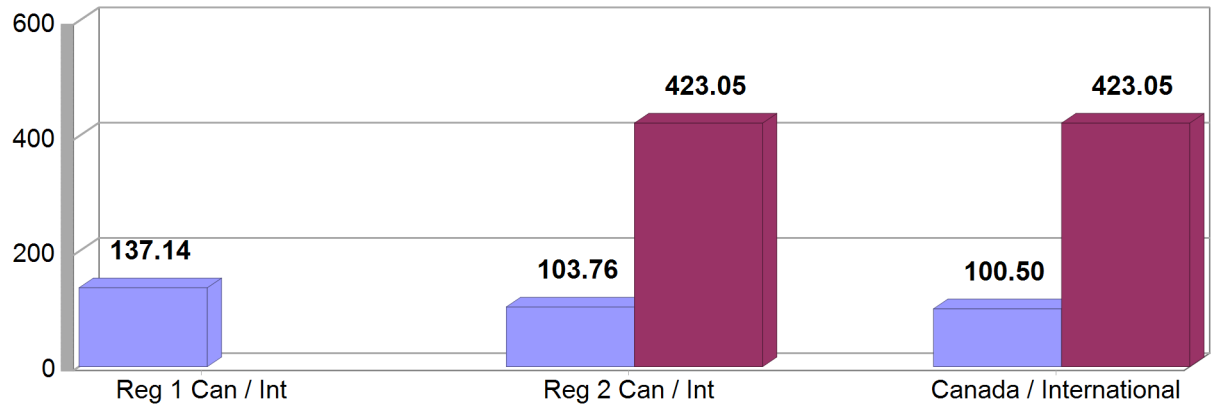



## Index of Reliability



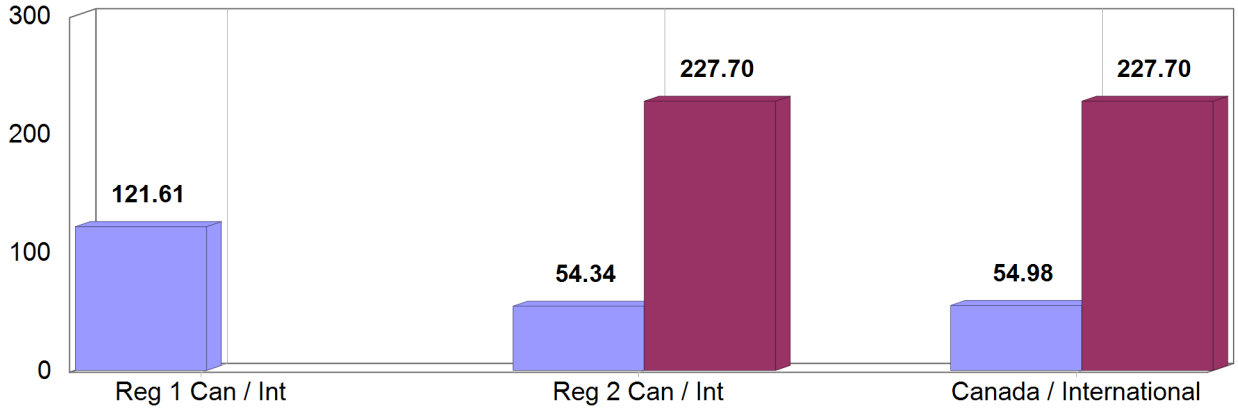
## CHIKM

***Customer Hour Interruptions per KM***




## CIKM

***Customer Interruptions per KM***



## NOTES

Canadian Electricity Association | Association canadienne de l'électricité

275 Slater Street, Suite 1500
Ottawa, Ontario  K1P 5H9

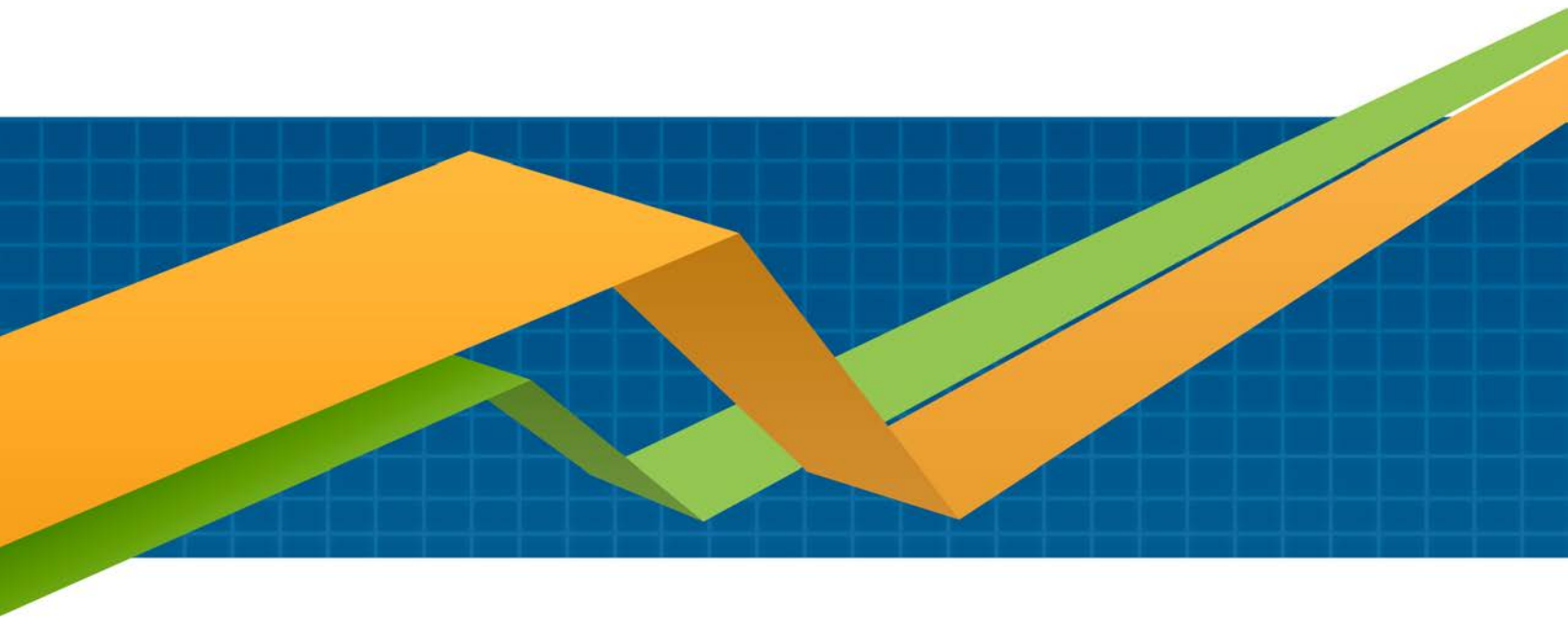
tel: 613·230·9263
fax: 613·230·9326

analytics@electricity.ca
www.electricity.ca

275, rue Slater, bureau 1500
Ottawa (Ontario)  K1P 5H9

tél. 613·230·9263
téléc. 613·230·9326

analyse@electricite.ca
www.electricite.ca



**BOMA-80**

**Reference(s): DSP, p103, Table 19**

**(a) Do these numbers include scheduled outages?**

**(b) Please explain the substantial drop in customers affected by outages in 2014, 2015, and 2016, relative to 2011, 2012, and 2013.**

**Response:**

(a) The values in Table 19 include scheduled outages.

(b) The substantial drop in customers affected by outages in 2014-2016 relative to 2011-2013 is driven by three major categories:

a. Loss of Supply dropped 86% during the 2014-2016 period compared to the 2011-2013 period.

b. Tree contacts dropped 58% during the 2014-2016 period compared to the 2011-2013 period.

c. Human Error dropped 40% during the 2014-2016 period compared to the 2011-2013 period.

**BOMA-81**

**Reference(s): DSP, p108**

**(a) Please break down the "Foreign Interference" number (214) into components and discuss.**

**(b) Given that scheduled outages constitute more than fifty percent of sustained customer interruptions:**

**(i) Please provide numbers for each of the last five years.**

**(ii) What is Alectra's plan to rationalize scheduled outages?**

**(iii) What is forecast for 2017, 2018, and the remaining years of the DSP?**

**Response:**

a) Table 1 provides the break down of the 214 Foreign Interference events.

Table 1 – Foreign interference by cause code

| Cause Code | CM | Customer Affected | #of Outages | Description |
|---|---|---|---|---|
| 901_FWLD | 464196 | 17096 | 143 | Foreign: Wildlife |
| 902_FVEH | 264805 | 4549 | 26 | Foreign: Vehicle |
| 905_FDIG | 232282 | 4245 | 20 | Foreign: Dig-in |
| 906_FCEQ | 77859 | 301 | 10 | Foreign: Customer Equipment |
| 907_FOBJ | 11406 | 4602 | 4 | Foreign: Foreign Objects |
| 910_FOTU | 20580 | 5181 | 6 | Foreign: Other Utilities |
| 911_FINT | 207710 | 4161 | 5 | Foreign: Interference |
| **Total** | **1278838** | **40135** | **214** | |

b) i) Table 2 provides a breakdown of scheduled outages over the last five years..

Table 2 – Scheduled Outages (2012-2016)

| Stats for year 2016 (Scheduled Outages) | | | | |
|---|---|---|---|---|
| **Cause Code** | **CM** | **Customer Outages** | **Total # of Outages** | **Description** |
| 102_SCCN | 1517408 | 7674 | 678 | Scheduled: Construction |
| 103_SCMN | 263747 | 1011 | 56 | Scheduled: Maintenance |
| 104_SCVM | 11475 | 41 | 2 | Scheduled: Vegetation Management |

| | | | | |
|---|---|---|---|---|
| 105_SCFS | 63701 | 335 | 8 | Scheduled: Forced Switching |
| 106_SCSC | 47 | 47 | 2 | Scheduled: Open Trans Switching |
| 107_SCHL | 42 | 6 | 1 | Scheduled: Bulding/ High Load Move |
| **Stats for year 2015 (Scheduled Outages)** | | | | |
| **Cause Code** | **Customer Minutes** | **Customer Outages** | **Total Number of Outages** | **Description** |
| 102_SCCN | 988262 | 4856 | 457 | Scheduled: Construction |
| 103_SCMN | 349679 | 2242 | 214 | Scheduled: Maintenance |
| 104_SCVM | 29192 | 62 | 4 | Scheduled: Vegetation Management |
| 105_SCFS | 29990 | 409 | 11 | Scheduled: Forced Switching |
| 106_SCSC | 496 | 62 | 1 | Scheduled: Open Trans Switching |
| 108_SCOT | 73332 | 99 | 6 | Scheduled: Other Sched/. Outages |
| **Stats for year 2014 (Scheduled Outages)** | | | | |
| **Cause Code** | **Customer Minutes** | **Customer Outages** | **Total Number of Outages** | **Description** |
| 102_SCCN | 488354 | 2066 | 206 | Scheduled: Construction |
| 103_SCMN | 378671 | 2090 | 222 | Scheduled: Maintenance |
| 105_SCFS | 9034 | 226 | 3 | Scheduled: Forced Switching |
| 106_SCSC | 9114 | 229 | 8 | Scheduled: Open Trans Switching |
| 108_SCOT | 97935 | 765 | 59 | Scheduled: Other Sched/. Outages |
| **Stats for year 2013 (Scheduled Outages)** | | | | |
| **Cause Code** | **Customer Minutes** | **Customer Outages** | **Total Number of Outages** | **Description** |
| 103_SCMN | 990732 | 8158 | 419 | Scheduled: Maintenance |
| **Stats for year 2012 (Scheduled Outages)** | | | | |
| **Cause Code** | **Customer Minutes** | **Customer Outages** | **Total Number of Outages** | **Description** |
| 103_SCMN | 411417 | 2718 | 243 | Scheduled: Maintenance |

ii) Scheduled outages are coordinated to minimize customer interruption and ensure a safe working environment for employees.

iii) Alectra Utilities has not forecasted scheduled outages over the DSP forecast period.

**BOMA-82**

**Reference(s): DSP, p111**

**Please explain the phrase "spot cable replacement".**

**Response:**

Spot cable Replacement is similar to ‘underground replacements’. Please see Alectra Utilities response to BOMA-76 (f).

**BOMA-83**

**Reference(s): DSP, p113**

**Please provide a copy of the ESQR metrics for each of the last five years. Please explain the box "Improves customer experience (a large user or 1,000 residential customers)".**

**Response:**

Table 1 below provides ESQR metrics for the Enersource RZ for years 2012-2016.

**Table 1: Enersource RZ ESQR Metrics by Year**

| ESQR | Annual Rate (%) | | | | |
|---|---|---|---|---|---|
| | 2012 | 2013 | 2014 | 2015 | 2016 |
| Connection of New Services - Low Voltage | 99.20 | 98.60 | 97.60 | 99.10 | 99.40 |
| Connection of New Services - High Voltage | 0.00 | 0.00 | 0.00 | 100.00 | 0.00 |
| Appointment Scheduling | 98.40 | 97.90 | 97.60 | 98.70 | 97.80 |
| Appointments Met | 99.00 | 99.20 | 99.80 | 99.70 | 99.90 |
| Rescheduling a Missed Appointment | 100.00 | 95.00 | 100.00 | 100.00 | 100.00 |
| Telephone Accessibility | 84.90 | 84.30 | 84.80 | 84.00 | 83.40 |
| Telephone Call Abandon Rate | 2.30 | 2.70 | 1.50 | 1.60 | 1.80 |
| Written Responses to Inquiries | 99.90 | 100.00 | 100.00 | 100.00 | 99.40 |
| Emergency Response- Urban | 94.50 | 68.30 | 96.40 | 100.00 | 98.70 |
| Emergency Response- Rural | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Reconnection Performance | 99.10 | 99.70 | 99.20 | 99.30 | 99.40 |
| New Micro-Embedded Generation Facilities | N/A | 98.44 | 100.00 | 96.67 | 99.17 |

As identified in Table 25 – Customer Focus in the Enersource Rate Zone DSP, p.113, when developing project business cases, Alectra Utilities evaluates the customer satisfaction (i.e. project adds customer value) benefit of each project on a score from 0 to 10. For a project that improves customer experience for either a large user or 1,000 residential customers, the project is scored a 5 for the customer satisfaction business value criteria. For example, projects that improve customer experience may include investments to renew substandard assets to ensure reliable supply of service.

**BOMA-84**

**Reference(s): DSP p125-131**

**(a) Please explain the history, rationale, and current use for the number of HONI Transmission stations and the municipal substations for each of the three or four areas of Enersource zones.**

**(b) Please explain the influence of the location of the HONI substations on the build-up of the Enersource system and the converse.**

**(c) Please confirm that deduction from the Enersource capital budget (for pacing and other reasons) were made before the size of the necessary ICM was determined.**

**Response:**

a) As a distributor in the City of Mississauga, Alectra Utilities distributes electricity from Hydro One Networks Inc. ("HONI") owned transmission stations to residents and local businesses in its Enersource RZ, via overhead lies, underground cables, transformers and Alectra Utilities owned municipal substations. HONI transmission stations are typically built near the HONI transmission lines to lower connection costs. They were located throughout the City of Mississauga along the Ontario Hydro Rights of Way to provide electricity to load centers. HONI stations have been added over the years as load growth occurred with the development of the City of Mississauga. The municipal substations are allocated throughout the City of Mississauga in locations near the load requirements. These substations further reduce the voltage of the subtransmission system down to local distribution voltage required for the local areas. There are four voltage systems in Mississauga which include 44kV, 27.6kV, 13.8kV and 4.16kV. Substations located north of the Highway 403 in Mississauga are typically 44/13.8kV; those south of Highway 403 are typically 27.6/4.16kV. The central area of Mississauga is directly fed from the 27.6kV system which does not require municipal substations.

b) The location of HONI transmission stations are typically determined by the proximity to HONI transmission lines and Ontario Hydro Rights of Way in order to reduce connection costs.

c) The adjustment to 2017-2022 Capital Investment Plan by Alectra Utilities in the Enersource Rate Zone was completed to incorporate the customer preferences and priorities. Based on this feedback, Alectra Utilities revised its 2018 capital forecast from $83.118MM to $77.233MM; and ICM request from $28.643MM to $24.247MM. Hence, the deduction to the 2018 capital forecast was made in order to finalize and file the ICM request.

**BOMA-85**

**Reference(s): Exhibit 2, Tab 4, Schedule 11, p42; ICM Projects**

**(a) Please explain the meaning of "1980s open bus secondary configuration", perhaps using text plus a diagram. Please indicate what pieces are often stolen or vandalized.**

**(b) Please describe how the use of porcelain insulation leads to pole fires and provide data on how many such fires have occurred in each of the last three years, for this, and (separately) other reasons.**

**Response:**

a) Open-bus construction is an overhead secondary voltage (e.g. 120/240) type of power distribution. It was common around the 1980s. There are two main differences between open-bus secondary and today's type of construction for overhead secondary distribution. First, open-bus utilizes exposed conductors (i.e. not insulated). The lack of insulation poses a safety concern for construction crews and increases outages due to animal contact. Secondly, mechanical support for the conductor in open-bus construction, is provided by the actual current carrying conductor. As electricity demand varies from high to low, the conductor experiences a heating and cooling cycle, which over time, can degrade the conductor at the support fittings, resulting in conductor failure. Today's standard for secondary construction is a messenger wire that carries the tension only and electrical conductors are insulated. The latter are wrapped around the messenger wire. Open-bus poses a significant safety risk and increases the risk of outages due to animal contacts.

The vandalism refers to copper-wire theft. Copper-wires are used for grounding the distribution system and are imperative components for the distribution system. In 1980s type of construction, copper-wires were guided down the poles and attached to ground rods with no protection against theft (i.e. no cover up or guard). Copper-theft is a serious safety concern in electrical distribution. Today's standard of construction utilizes copper-wires that are shielded from theft using solid enclave and are not exposed to the public. Alternatively they can be copper clad steel wire.

b) Insulators support high voltage conductors and provide an insulation level between the energized current carrying conductors and the grounded structures (e.g. poles). Insulators

are exposed to contaminants, which over time accumulate on the surface of the insulating surface. When contaminated insulators are exposed to moisture from rain in spring and melting ice in winter, the moisture mixes with the contaminants effectively reducing the insulating levels and in some case leading to small electrical current paths known as leakage current and tracking. As the leakage current increases it begins to form arc paths across the components, which connect the insulator to the pole such as brackets and fastening hardware and causes burning of the wood pole. Today's standard of construction uses hydrophobic polymer based insulators, which resist the accumulation of contaminants and significantly reduce leakage currents and tracking.

Enersource has experienced pole fires in the last three years.

2016 - 1

2015 - 14

2014 - 4

**BOMA-86**

**Reference(s): ICM Projects, p44 – Transformer Replacement Program**

**Please describe in more detail the difference between "transformers indicating signs of leaking" as compared with "transformers indicating leaking oil" in columns 4 and 2, respectively, of the graph. Please discuss.**

**Response:**

There is no difference between the terminologies; both terms have been used interchangeably.

**BOMA-87**

**Reference(s): ICM Projects**, **p46 – York MS Upgrade**

**(a) Is it necessary to install a 20 MVA power transformer at this time? What would be the reduction in cost, if it were not built at this time?**

**(b) What would the cost savings be from installing a smaller transformer; say 12 or 15 MVA?**

**Response:**

a) Please refer to the York MS business case in Exhibit 3, Tab 1, Schedule 1, Attachment 47 – ICM Business Cases Enersource RZ, p. 69 for the options considered.

Two options are identified in the business case.

OPTION 1: Upgrade York MS to standard and increase station capacity by additional 20MVA.

This project consists of the following scope:

This option will provide the required capacity for additional loads, provide reliable back-up for other substations in the area and also offer required substation transformer protection. Total capital expenditure for the first option is $3.232 M.

OPTION 2: Upgrade York MS to standard configuration and defer station capacity increase.

This project consists of the following scope:

This option does not provide additional capacity for the projected growth, but would permit the addition of a second transformer in the future. The required substation transformer protection configuration would be attained. Total capital expenditure for the second option is $ 2.3 M.

If the second transformer is not added at this time, the reduction in costs will be $930K.

b) Alectra Utilities would not install a smaller transformer, as this station also provides reliable back-up for other substations in the area, which have 20 MVA transformers installed. The typical material cost difference of a 10MVA compared to a 20MVA transformer can range from $150K to $200K.

**BOMA-88**

**Ref: Ibid, Schedule 12, p1 of 2 - See also Table 150**

**(a) Please provide an additional Table showing the 2018 percentage rate impact of the proposed rate rider over the 2018 IRM price cap driven rate.**

**(b) Please explain why, in Table 149, the impact of the rate rider is stated to be an 11.86% increase (2018 over 2017) in the GS-50-499 kW rate class and in Table 150, the impact of the Distribution Bill and All Rate Riders (including the ICM driven rate rider) is minus 1.38% for the same rate class. What would be the impact of:**

**(i) the ICM rate rider only; and**

**(ii) the distribution bill plus the ICM rate rider, without the other rate riders.**

**Response:**

a) The 2018 IRM Price Cap rate of 1.6% is provided in the updated Rate Generator and IRM Models filed in Alectra Utilities' response to G-Staff-2. This rate will be updated when the 2018 Inflation Factor is published by the Ontario Energy Board. Exhibit 2, Tab 4, Schedule 11, Table 147 – Incremental Capital Funding Rate Riders – Enersource RZ, identifies the bill impacts by rate class as a result of the addition of the 2018 incremental capital funding rate riders.

Table 1 below, identifies the average monthly bill amount from the Price Cap increase compared to the average monthly bill amount from the proposed ICM rate riders.

**Table 1 – ICM Rate Rider and 2018 Price Cap Monthly Bill Amount – Enersource RZ**

| Customer Class | Billing Units | Average Monthly Volume | Impacts Related to: | |
|---|---|---|---|---|
| | | | 2018 Price Cap | ADD: ICM Impact (excl. HST) |
| Residential | kWh | 750 | $ 0.18 | $ 0.36 |
| GS<50 | kWh | 2,000 | $ 1.10 | $ 1.05 |
| GS 50-499 kW | kW | 230 | $ 18.23 | $ 17.06 |
| GS 500-4,999 kW | kW | 2,250 | $ 113.48 | $ 106.30 |
| Large User | kW | 5,000 | $ 456.60 | $ 427.57 |
| Street Lighting | kW | 0.1 | $ 0.04 | $ 0.04 |

b) The difference in the impact of the rate rider is due to the grouping of the bill components. Table 149 (Exhibit 2, Tab 4, Schedule 12, page 1) presents a summary of the bill impact for the typical customer by rate class for the distribution portion of the bill only (section Sub-A of the bill impact template, which includes the monthly fixed charge, variable rate, ICM rate riders and LRAMVA rate riders), and Table 150 (Exhibit 2, Tab 4, Schedule 12, page 1) presents a summary of the bill impact for the distribution portion and other applicable rate riders. For example, the bill impact presented in Table 150 includes a proposed Global Adjustment refund, which offsets the distribution only bill impacts presented in Table 149.

i. Table 148 (Exhibit 2, Tab 4, Schedule 11, page 49) identifies the bill impacts by rate class as a result of the addition of the 2018 incremental capital funding rate riders as compared to the total bill including HST. The last column of Table 148 identifies the percentage impact on each rate class of the ICM rate rider.

ii. Table 2 below presents the distribution bill plus the ICM rate rider, without the other rate riders. The bill impacts presented is based on the updated 2018 Rate Generator and IRM Models filed in Alectra Utilities' response to G-Staff-2.

**Table 2 – Distribution Rate and ICM Rate Riders Only Impacts – Enersource RZ**

| Distribution Bill Impacts | | | | |
|---|---|---|---|---|
| Customer Class | Billing Units | Average Monthly Volume | 2018 vs. 2017 | |
| | | | $ | % |
| Residential | kWh | 750 | $ 0.54 | 2.15% |
| GS<50 | kWh | 2,000 | $ 2.15 | 3.04% |
| GS 50-499 kW | kW | 230 | $ 35.29 | 3.02% |
| GS 500-4,999 kW | kW | 2,250 | $ 219.78 | 3.02% |
| Large User | kW | 5,000 | $ 884.17 | 3.02% |
| Street Lighting | kW | - | $ 0.08 | 2.77% |

Table excludes the impact of HST (13%) & Provinicial Rebate (8%)

**BOMA-89**

**Reference(s): Attachment 47**

**(a) Are any of the ICM projects now likely to be completed in 2019 instead of the fourth quarter of 2018?**

**(b) By what date does Enersource require a Board decision in order to have each ICM project in service in 2018? Please answer for each of the eleven projects separately.**

**Response:**

a) All listed ICM projects are on plan to be completed in 2018.

b) A decision from the Board before February would ensure all the ICM projects proposed would be completed before year end. For the ICM projects, Alectra Utilities plans to have all designs and permits ready before the end of 2017.

1. Road Widening Project – QEW (Evans to Cawthra): This project is mandatory and is on plan to be implemented in 2018.
2. Overhead Rebuild – Lake/John – March 2018 to notify customers in area of project.
3. Overhead Rebuild – Church: March 2018 to notify customers in area of project.
4. Leaking Transformer Replacement Project: Start in February 2018 to complete 2018 project scope.
5. Subdivision Rebuilds – Credit Woodlands Crt/Wiltshire - March 2018 to notify customers in area of project.
6. Subdivision Rebuilds – Glen Erin & Montevideo - March 2018 to notify customers in area of project.
7. Subdivision Rebuilds – Tenth Line Main Feeder - March 2018 to notify customers in area of project.
8. Subdivision Rebuilds – Folkway & Erin Mills Main Feeder - March 2018 to notify customers in area of project.
9. Subdivision Rebuilds – Glen Erin & Battleford - March 2018 to notify customers in area of project.
10. Subdivision Rebuilds – City Centre Drive Rebuild - March 2018 to notify customers in area of project.
11. Substation Upgrade – York MS: February 2018 to schedule civil and electrical construction, notify customers of outage requirements.

**BOMA-90**

**Reference(s): Attachment 47, 2018-COS31-1**

**(a) What is the reason for the deferral of the start date on the project?**

**(b) Please confirm that the start date is determined by the MTO. When will the true-up of any overspend/underspend on the project occur? Please explain fully with reference to the Board's ICM policy. Will any underspend be refunded or credited to ratepayers in 2019? Which approach will be used?**

**(c) Can you provide a diagram which explains the project's before/after configuration?**

**Response:**

(a) The overall project is driven by the Ministry of Transportation ("MTO"). The deferral of the start of the QEW Improvements, from Cawthra to The East Mall, are due to challenges with the design of the highway overpass and securing the necessary land for all utilities to relocate assets, which includes easements and land expropriation.

(b) The project start date and the associated relocations are driven and determined by the MTO.

The true-up of the ICM project will be in accordance with the Ontario Energy Board's ("OEB") ICM policy. Section 7.4 of the *Report of the Board – New Policy Options for the Funding of Capital Investments: The Advanced Capital Module*, dated September 18, 2014, states that "*At the time of the next cost of service or Custom IR application, a distributor will need to file calculations showing the actual ACM/ICM amounts to be incorporated into the test year rate base. At that time, the Board will make a determination on the treatment of any difference between forecasted and actual capital spending under the ACM/ICM, if applicable, and the amounts recovered through ACM/ICM rate riders and what should have been recovered in the historical period during the preceding Price Cap IR plan term. Where there is a material difference between what was collected based on the approved ACM/ICM rate riders and what should have been recovered as the revenue requirement for the approved ACM/ICM project(s), based on actual amounts, the Board may direct that over- or under-collection be refunded or recovered from the distributor's ratepayers.*"

(c) Alectra Utilities provides 7 design drawings with details on before and after configuration.

BOMA-90_Attach 1_Evans_Part1;

BOMA-90_Attach 2_ Evans_Part2;

BOMA-90_Attach 3_ Evans_Part3;

BOMA-90_Attach 4_ Evans_Part4;

BOMA-90_Attach 5_ Evans_Part5;

BOMA-90_Attach 6_ Evans_Part6;

BOMA-90_Attach 7_ Evans_Part7

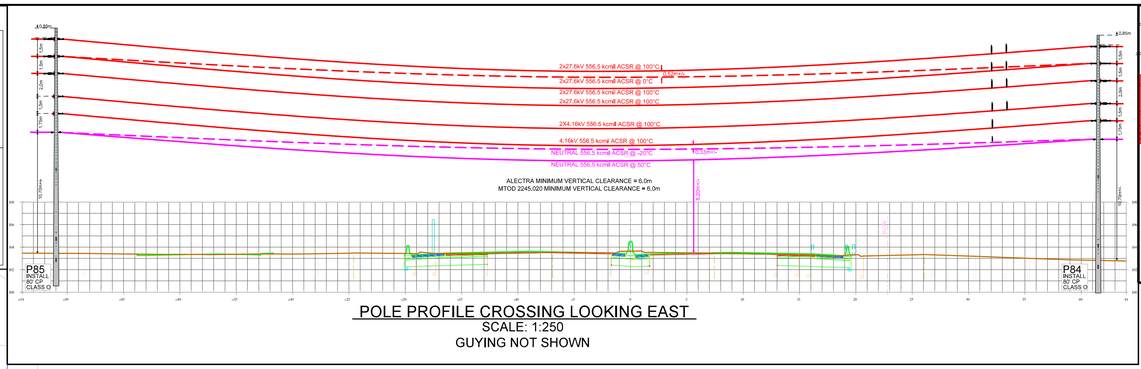
# LEGEND (CONSTRUCTION)

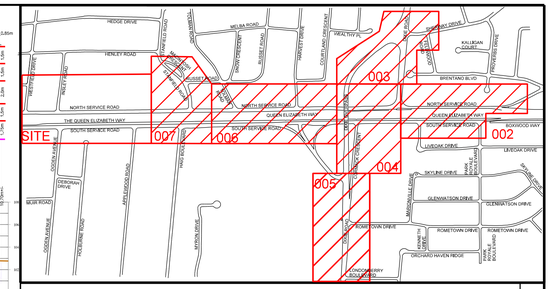
- PROPOSED POLE, TYPE AND SIZE INDICATED ON DRAWING
- CP — CONCRETE POLE
- WP — WOOD POLE
- P1 — POLE LOCATION NUMBER
- TP1 — TEMPORARY HYDRO POLE, ANY TYPE
- EP1 — EXISTING HYDRO POLE, ANY TYPE
- PROPOSED OVERHEAD WIRE/S, ANY TYPE and VOLTAGE
- PROPOSED SPUN SECONDARY BUS
- PROPOSED DOWN GUY AND ANCHOR
- POLE TO BE REPLACED AT THE SAME LOCATION
- EXISTING POLE AND ASSOCIATED HARDWARE TO BE REMOVED
- TRANSFER SPUN SECONDARY BUS
- ST — STREETLIGHTING SEC. BUS
- DOWN GUY/ANCHOR
- 1 PHASE TX, POLEMOUNT
- 3 PHASE TX, POLEMOUNT
- LINE SWITCH
- LINE CUTOUT
- EXISTING POLE TO REMAIN
- EXISTING BELL POLE
- PROPOSED TRANSFORMER, SINGLE PHASE UNIT
- PROPOSED TRANSFORMER, THREE PHASE BANK
- PROPOSED LOAD INTERUPTER
- PROPOSED INLINE SWITCH
- PROPOSED GROUNDING
- DENOTES REMOVAL, ANY PLANT
- OPEN POINT
- P/L — EXISTING PROPERTY LINE
- F/P/L — FUTURE PROPERTY LINE
- FUTURE ROADS/SIDEWALKS
- EXISTING ROADS
- EXISTING SIDEWALKS
- OVERHEAD WIRE/S, ANY TYPE
- TRANSFER OVERHEAD WIRE/S, ANY TYPE
- PLANT TO BE REMOVED
- 410mm — PRIMARY CABLES
- 410mm — SECONDARY CABLES
- 100x2 — DUCT BANK, SIZE & QTY
- EXISTING METERBASE
- EXISTING 3PH TRANSFORMER

TRUE NORTH

CONSTRUCTION NORTH

## POLE PROFILE CROSSING LOOKING EAST
SCALE: 1:250
GUYING NOT SHOWN



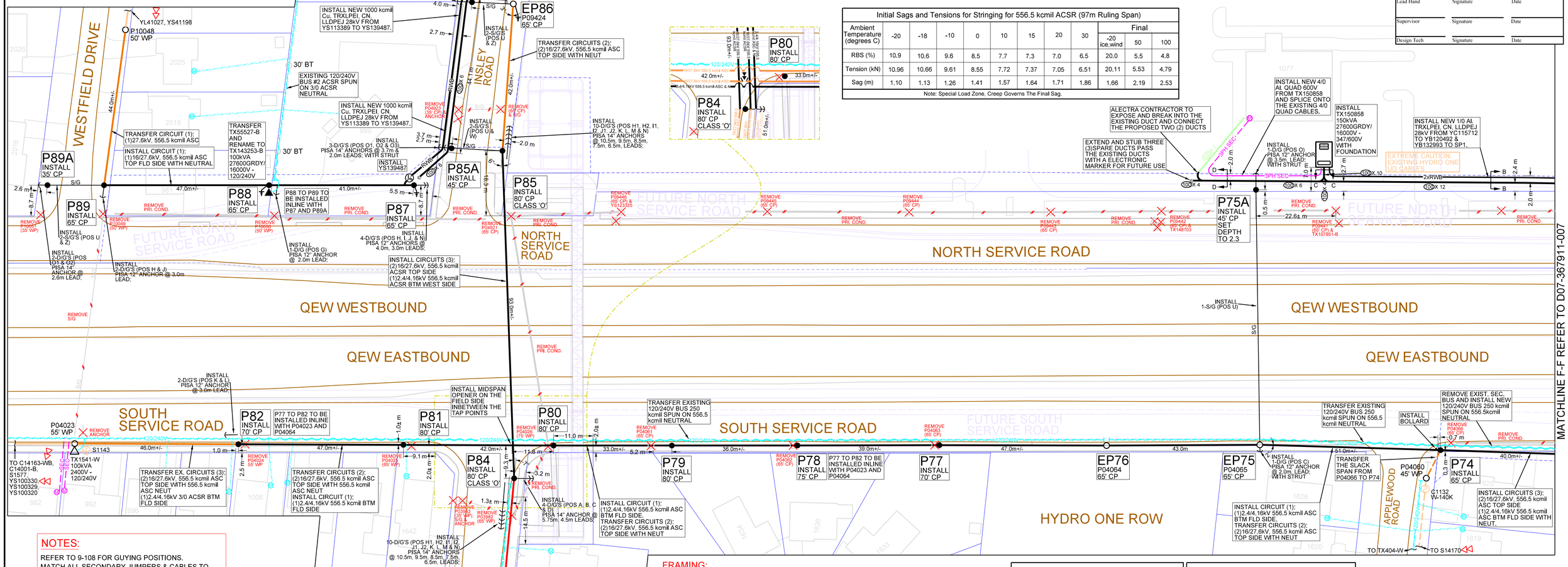

| Initial Sags and Tensions for Stringing for 556.5 kcmil ACSR (97m Ruling Span) | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Ambient Temperature (degrees C) | -20 | -18 | -10 | 0 | 10 | 15 | 20 | 30 | Final | | |
| | | | | | | | | | -20 ice,wind | 50 | 100 |
| RBS (%) | 10.9 | 10.6 | 9.6 | 8.5 | 7.7 | 7.3 | 7.0 | 6.5 | 20.0 | 5.5 | 4.8 |
| Tension (kN) | 10.96 | 10.66 | 9.61 | 8.55 | 7.72 | 7.37 | 7.05 | 6.51 | 20.11 | 5.53 | 4.79 |
| Sag (m) | 1.10 | 1.13 | 1.26 | 1.41 | 1.57 | 1.64 | 1.71 | 1.86 | 1.66 | 2.19 | 2.53 |

Note: Special Load Zone, Creep Governs The Final Sag.

Certificate

This is to certify that the construction as recorded in this drawing is consistent with the approved plan, Standard Designs, or work instruction and that approved equipment has been used:

| | | |
|---|---|---|
| Lead Hand | Signature | Date |
| Supervisor | Signature | Date |
| Design Tech | Signature | Date |

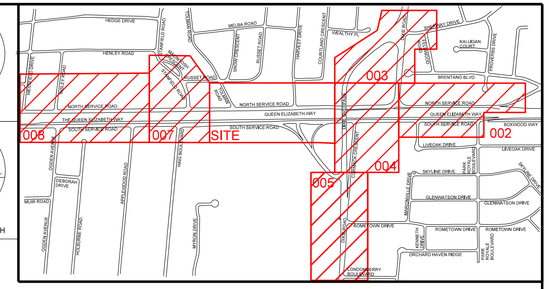

WESTFIELD DRIVE
INSLEY ROAD
OGDEN AVENUE
APPLEWOOD ROAD
NORTH SERVICE ROAD
QEW WESTBOUND
QEW EASTBOUND
SOUTH SERVICE ROAD
FUTURE NORTH SERVICE ROAD
FUTURE SOUTH SERVICE ROAD
HYDRO ONE ROW
P10048 50' WP
YL41027, YS41198
P89A INSTALL 35' CP
P89 INSTALL 65' CP
P88 INSTALL 65' CP
P87 INSTALL 65' CP
P86A INSTALL 35' CP
P85A INSTALL 45' CP
P85 INSTALL 80' CP CLASS 'O'
P84 INSTALL 80' CP CLASS 'O'
P83 INSTALL 70' CP
P82 INSTALL 70' CP
P81 INSTALL 80' CP
P80 INSTALL 80' CP
P79 INSTALL 80' CP
P78 INSTALL 75' CP
P77 INSTALL 70' CP
EP86 P09424 65' CP
EP76 P04064 65' CP
EP75 P04065 65' CP
P75A INSTALL 45' CP SET DEPTH TO 2.3
P74 INSTALL 65' CP
P04023 55' WP
P04080 45' WP
S1143
S1140
P03980 65' WP
TX1541-W 100kVA 2400V - 120/240V
TX143253-B 100kVA 27600GRDY/16000V - 120/240V
TX150858 150kVA 27600GRDY/16000V - 347/600V WITH FOUNDATION
TO YC121526, YS134251
TO C14163-WB, C14001-B, S1577, YS100330, YS100329, YS100320
TO TX401-W
TO C1138, C14164-W, C1136, YS11161, C14110-R, S1274, YL11120
TO TX404-W
TO S14170
INSTALL NEW 1000 kcmil Cu. TRXLPEI, CN, LLDPEJ 28kV FROM YS113389 TO YS139487.
INSTALL NEW 1000 kcmil Cu. TRXLPEI, CN, LLDPEJ 28kV FROM YS113389 TO YS139487.
EXISTING 120/240V BUS #2 ACSR SPUN ON 3/0 ACSR NEUTRAL
TRANSFER CIRCUITS (2): (2)16/27.6kV, 556.5 kcmil ASC TOP SIDE WITH NEUT
TRANSFER CIRCUIT (1): (1)27.6kV, 556.5 kcmil ASC
INSTALL CIRCUIT (1): (1)16/27.6kV, 556.5 kcmil ASC TOP FLD SIDE WITH NEUTRAL
TRANSFER TX55527-B AND RENAME TO TX143253-B 100kVA 27600GRDY/ 16000V - 120/240V
INSTALL 10-D/G'S (POS H1, H2, I1, I2, J1, J2, K, L, M & N) PISA 14" ANCHORS @ 10.5m, 9.5m, 8.5m, 7.5m, 6.5m, LEADS;
INSTALL 3-D/G'S (POS O1, O2 & O3) PISA 14" ANCHORS @ 3.7m & 2.0m LEADS; WITH STRUT
INSTALL 4-D/G'S (POS H, I, J, & N) PISA 12" ANCHORS @ 4.0m, 3.0m LEADS;
INSTALL 1-D/G (POS G) PISA 12" ANCHOR @ 2.0m LEAD;
INSTALL 2-D/G'S (POS K & L) PISA 12" ANCHOR @ 3.0m LEAD;
INSTALL 2-D/G'S (POS O1 & O2) PISA 12" ANCHOR @ 4.0m LEAD;
INSTALL 2-D/G'S (POS H & J) PISA 12" ANCHOR @ 3.0m LEAD;
INSTALL 2-D/G'S (POS Q1 & Q2) PISA 14" ANCHOR @ 2.6m LEAD;
INSTALL 2-S/G'S (POS U & Z)
INSTALL 2-S/G (POS U & W)
INSTALL 1-S/G (POS U)
INSTALL 1-D/G (POS O) PISA 12" ANCHOR @ 3.5m, LEAD; WITH STRUT
INSTALL CIRCUITS (3): (2)16/27.6kV, 556.5 kcmil ACSR TOP SIDE (1)2.4/4.16kV 556.5 kcmil ACSR BTM WEST SIDE
INSTALL CIRCUIT (1): (1)2.4/4.16kV 556.5 kcmil ACSR BTM FLD SIDE. TRANSFER CIRCUITS (2): (2)16/27.6kV, 556.5 kcmil ASC TOP SIDE WITH NEUT
INSTALL CIRCUITS (3): (2)16/27.6kV, 556.5 kcmil ASC TOP SIDE (1)2.4/4.16kV 556.5 kcmil ASC BTM FLD SIDE WITH NEUT.
INSTALL CIRCUIT (1): (1)2.4/4.16kV 556.5 kcmil ASC BTM FLD SIDE. TRANSFER CIRCUITS (2): (2)16/27.6kV, 556.5 kcmil ASC TOP SIDE WITH NEUT
INSTALL NEW 4/0 AL QUAD 600V FROM TX150858 AND SPLICE ONTO THE EXISTING 4/0 QUAD CABLES.
INSTALL NEW 1/0 AL TRXLPEI, CN, LLDPEJ 28kV FROM YC115712 TO YB120492 & YB132993 TO SP1.
EXTREME CAUTION: EXISTING HYDRO ONE UG CABLES
ALECTRA CONTRACTOR TO EXPOSE AND BREAK INTO THE EXISTING DUCT AND CONNECT THE PROPOSED TWO (2) DUCTS
EXTEND AND STUB THREE (3)SPARE DUCTS PASS THE EXISTING DUCTS WITH A ELECTRONIC MARKER FOR FUTURE USE
TRANSFER EXISTING 120/240V BUS 250 kcmil SPUN ON 556.5 kcmil NEUTRAL
TRANSFER THE SLACK SPAN FROM P04066 TO P74
INSTALL BOLLARD
REMOVE EXIST. SEC. BUS AND INSTALL NEW 120/240V BUS 250 kcmil SPUN ON 556.5kcmil NEUTRAL
INSTALL MIDSPAN OPENER ON THE FIELD SIDE INBETWEEN THE TAP POINTS
TRANSFER EXISTING 120/240V BUS 250 kcmil SPUN ON 556.5 kcmil NEUTRAL
P77 TO P82 TO BE INSTALLED INLINE WITH P04023 AND P04064
P77 TO P82 TO BE INSTALLED INLINE WITH P04023 AND P04064
TRANSFER EXISTING 120/240V BUS 250 kcmil SPUN ON 556.5 kcmil NEUTRAL
TRANSFER EX. CIRCUITS (3): (2)16/27.6kV, 556.5 kcmil ASC TOP SIDE WITH 556.5 kcmil ASC NEUT (1)2.4/4.16kV 3/0 ACSR BTM FLD SIDE
TRANSFER CIRCUITS (2): (2)16/27.6kV, 556.5 kcmil ASC TOP SIDE WITH 556.5 kcmil ASC NEUT INSTALL CIRCUIT (1): (1)2.4/4.16kV 556.5 kcmil BTM FLD SIDE
TRANSFER CIRCUITS (3): (2)16/27.6kV, 556.5 kcmil ASC TOP SIDE (1)2.4/4.16kV 266.8 kcmil ACSR BTM FLD SIDE WITH NEUT.
TRANSFER CIRCUITS (3): (2)16/27.6kV, 556.5 kcmil ASC TOP SIDE (1)2.4/4.16kV 266.8 kcmil ACSR BTM FLD SIDE WITH NEUT
REMOVE P09446 (65' CP) & YS123325
REMOVE P09445 (65' CP)
REMOVE P09444 (65' CP)
REMOVE P09442 (65' CP) & TX146103
REMOVE P04052 (65' CP)
REMOVE P04053 (65' CP)
REMOVE P04061 (65' CP)
REMOVE P04062 (65' CP)
REMOVE P04063 (65' CP)
REMOVE P04066 (65' CP)
REMOVE P04067 (65' CP)
REMOVE P04068 (65' CP)
REMOVE P04069 (65' CP)
REMOVE P04070 (65' CP)
REMOVE P04071 (65' CP)
REMOVE P04072 (65' CP)
REMOVE P04073 (65' CP)
REMOVE P04074 (65' CP)
REMOVE P04075 (65' CP)
REMOVE

## LEGEND (CONSTRUCTION)

- PROPOSED POLE, TYPE AND SIZE INDICATED ON DRAWING
- CP CONCRETE POLE
- WP WOOD POLE
- P1 POLE LOCATION NUMBER
- TP1 TEMPORARY HYDRO POLE, ANY TYPE
- EP1 EXISTING HYDRO POLE, ANY TYPE
- PROPOSED OVERHEAD WIRE/S, ANY TYPE and VOLTAGE
- PROPOSED SPUN SECONDARY BUS
- PROPOSED DOWN GUY AND ANCHOR
- POLE TO BE REPLACED AT THE SAME LOCATION
- EXISTING POLE AND ASSOCIATED HARDWARE TO BE REMOVED
- TRANSFER SPUN SECONDARY BUS
- STREETLIGHTING SEC. BUS
- DOWN GUY/ANCHOR
- 1 PHASE TX. POLEMOUNT
- 3 PHASE TX. POLEMOUNT
- LINE SWITCH
- LINE CUTOUT
- EXISTING POLE TO REMAIN
- EXISTING BELL POLE
- PROPOSED TRANSFORMER, SINGLE PHASE UNIT
- PROPOSED TRANSFORMER, THREE PHASE BANK
- PROPOSED LOAD INTERUPTER
- PROPOSED INLINE SWITCH
- PROPOSED GROUNDING
- DENOTES REMOVAL, ANY PLANT
- OPEN POINT
- P/L EXISTING PROPERTY LINE
- P/L FUTURE PROPERTY LINE
- FUTURE ROADS/SIDEWALKS
- EXISTING ROADS
- EXISTING SIDEWALKS
- OVERHEAD WIRE/S, ANY TYPE
- TRANSFER OVERHEAD WIRE/S, ANY TYPE
- PLANT TO BE REMOVED
- PRIMARY CABLES
- SECONDARY CABLES
- 100V2 DUCT BANK, SIZE & QTY
- EXISTING METERBASE

TRUE NORTH

CONSTRUCTION NORTH




MATCHLINE E-E REFER TO D07-367911-007




### FRAMING:

P48: FRAME PER 7-512, 7-706.1 FIG 1, 9-101, 9-107, 9-108 & 25-151 FIG 4

P49: FRAME PER 7-537, 7-706.2 FIG 2, 9-101, 9-107, & 9-108.

EP50: REFRAME PER 7-502 & 7-702

P51: FRAME PER 7-503, 7-702 & 25-151 FIG 1

P52: FRAME PER 7-503, 7-702 & 25-151 FIG 1

P53: FRAME PER 7-503, 7-702 & 25-151 FIG 1

P54: FRAME PER 7-503, 7-702 19-101, 19-112, 19-150, 25-150, 25-151 FIG 1, 41-99, 41-103 & 41-109

P55: FRAME PER 7-503, 7-702 & 25-151 FIG 1

P56: FRAME PER 7-503, 7-702, 7-706.3, 25-151 FIG 1, & 25-153

P57: FRAME PER 7-503, 7-702 & 25-151 FIG 1

P58: FRAME PER 7-503, 7-702 & 25-151 FIG 1

### NOTES:

REFER TO 9-108 FOR GUYING POSITIONS.

MATCH ALL SECONDARY JUMPERS & CABLES TO EXISTING SERVICE OR BUS CABLE CAPACITY (REF. STD. 25U-120).

ALL DOWN-GUYS TO BE ATTACHED ON INDIVIDUAL GUY- HOOKS, MAX. 1 DOWN-GUY PER HOLE.

REFER TO 25-150 FOR TRANSFORMER SECONDARY CONNECTIONS.

REMOVE ALL PLANT AS INDICATED ON SITE PLAN.

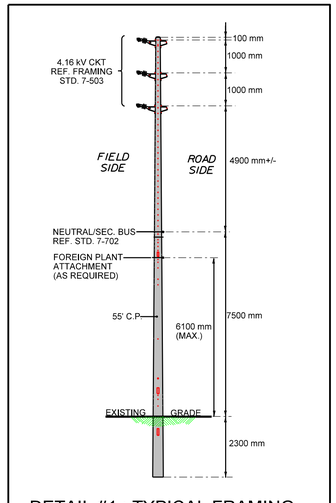
TRANSFER EXISTING SECONDARY BUS TO THE PROPOSED POLES.

COORDINATE WITH STREETLIGHTING

MTO TO HAVE GIVEN/WRITTEN PERMISSION TO INSTALL POLES ON EXPROPRIATED PROPERTY.

COORDINATE WITH MTO'S SURVEYOR CONSULTANT TO VERIFY STAKED POLES ARE IN THE CORRECT POSITION.

NOTE:
USE EXTREME CAUTION WHEN WORKING IN CLOSE PROXIMITY OF OTHER UTILITIES. ALL MEASURES MUST BE TAKEN TO ENSURE THE STABILITY OF ALL EXISTING INFRASTRUCTURE ADJACENT TO PROPOSED WORK LOCATION. ALL LOCATES MUST BE OBTAINED PRIOR TO STARTING ANY CONSTRUCTION. ALL H.V. CABLES TO BE MINIMUM OF 0.6M ANY EXISTING UTILITIES WITHIN THE BOULEVARD. ANY WORKS WITHIN 0.6M OF EXISTING UTILITIES MUST BE HAND-DUG.




DETAIL #1 : TYPICAL FRAMING

N.T.S.

Certificate

This is to certify that the construction as recorded in this drawing is consistent with the approved plan, Standard Designs, or work instruction and that approved equipment has been used:

| | | | |
|---|---|---|---|
| Lead Hand | | Signature | Date |
| Supervisor | | Signature | Date |
| Design Tech | | Signature | Date |

| REV No. | REVISION | REV BY | APPD | DATE |
|---|---|---|---|---|
| R3 | | | | |
| R2 | | | | |
| R1 | | | | |

PRELIMINARY NOT FOR CONSTRUCTION

APPD

DATE


enersource | alectra utilities
3240 Mavis Road
Mississauga, Ontario
L5L 5K1
Tel.: (905) 273-9050
Fax: (905) 566-2737
www.alectrautilities.com


# QEW DIXIE ROAD INTERCHANGE

## MTO QEW ROAD EXPANSION

### GENERAL ARRANGEMENT

SCALE 1 : 500 (0 5 10 20 30 METRES)

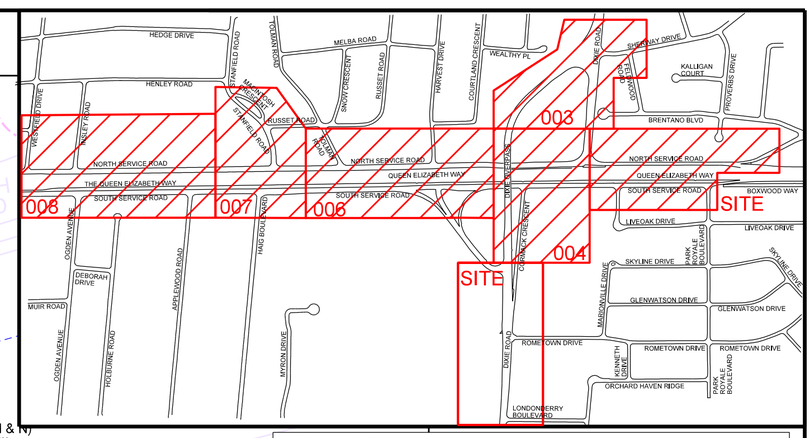
| DES. TECH. | DRAWN | SERVICE ORDER | DATE |
|---|---|---|---|
| M. WATTERS | M. WATTERS | 367911 | JUN-14-2017 |
| REVIEWED | AREA | SHEET | |
| T. ANTONAKOS | 05 | 6 of 10 | D07-367911-006 |

SIZE: 24X36

MATCHLINE D-D REFER TO D07-367911-004

CONSTRUCTION NORTH | TRUE NORTH

REFER TO SERVICE ORDER 377300




## LEGEND (CONSTRUCTION)

- PROPOSED POLE, TYPE AND SIZE INDICATED ON DRAWING
- CP — CONCRETE POLE
- WP — WOOD POLE
- P1 — POLE LOCATION NUMBER
- TP1 — TEMPORARY HYDRO POLE, ANY TYPE
- EP1 — EXISTING HYDRO POLE, ANY TYPE
- PROPOSED OVERHEAD WIRE/S, ANY TYPE and VOLTAGE
- PROPOSED SPUN SECONDARY BUS
- PROPOSED DOWN GUY AND ANCHOR
- POLE TO BE REPLACED AT THE SAME LOCATION
- EXISTING POLE AND ASSOCIATED HARDWARE TO BE REMOVED
- TRANSFER SPUN SECONDARY BUS
- S/L — STREETLIGHTING SEC. BUS
- DOWN GUY/ANCHOR
- 1 PHASE TX, POLEMOUNT
- 3 PHASE TX, POLEMOUNT
- LINE SWITCH
- LINE CUTOUT
- EXISTING POLE TO REMAIN
- EXISTING BELL POLE
- PROPOSED TRANSFORMER, SINGLE PHASE UNIT
- PROPOSED TRANSFORMER, THREE PHASE BANK
- PROPOSED LOAD INTERUPTER
- PROPOSED INLINE SWITCH
- PROPOSED GROUNDING
- DENOTES REMOVAL, ANY PLANT
- OPEN POINT
- P/L — EXISTING PROPERTY LINE
- FUTURE PROPERTY LINE
- FUTURE ROADS/SIDEWALKS
- EXISTING ROADS
- EXISTING SIDEWALKS
- OVERHEAD WIRE/S, ANY TYPE
- TRANSFER OVERHEAD WIRE/S, ANY TYPE
- PLANT TO BE REMOVED
- 4kV — PRIMARY CABLES
- 600 — SECONDARY CABLES
- 100x2 — DUCT BANK, SIZE & QTY
- M — EXISTING METERBASE

P30 INSTALL 70' CP — INSTALL 8-D/G'S (POS H1, H2, I, J, K, L, M & N) PISA 14" ANCHORS @ 9.0m, 7.5m, 6.0m, 4.5m LEADS;

P29 INSTALL 80' CP — INSTALL 8-D/G'S (POS H1, H2, I, J, K, L, M & N) PISA 12" ANCHORS @ 9.0m, 7.5m, 6.0m, 4.5m LEADS;

INSTALL CIRCUITS (4); (2)16/27.6kV, 556.5 kcmil ASC TOP SIDE (2)2.4/4.16kV 556.5 kcmil ASC BTM SIDE WITH NEUT.

INSTALL NEW 120/240V BUS 250 kcmil SPUN ON 556.5kcmil NEUTRAL

INSTALL CIRCUITS (4); (2)16/27.6kV, 556.5 kcmil ASC TOP SIDE (2)2.4/4.16kV 556.5 kcmil ASC BTM SIDE WITH NEUT.

TX12629 3-167kVA 4160GRDY/ 2400V - 347/600V

P04120 65' CP

#1250 SEC. SVC.: 600A, 347/600V 3PH, 4WIRE MAX kVA LOADING = 171.60

TRANSFER CIRCUITS (2); (1)16/27.6kV, 556.5 kcmil ASC ... 5 kcmil ASC ... WITH NEUT.

INSTALL 2-D/G'S (POS A & D) PISA 12" ANCHOR @ 5.0m LEAD;

P47 INSTALL 65' CP

INSTALL CIRCUITS (2); (1)16/27.6kV, 556.5 kcmil ASC TOP S/W SIDE (1)2.4/4.16kV 556.5 kcmil ASC BTM S/W SIDE WITH NEUT.

P31 INSTALL 70' CP

INSTALL TX133428-W 100kVA 27600GRDY/ 16000V - 120/240V

P35 TO P31 TO BE INSTALLED INLINE WITH P36 AND P30

INSTALL CIRCUITS (2); (1)16/27.6kV, 556.5 kcmil ASC TOP SOUTH SIDE (1)2.4/4.16kV 556.5 kcmil ASC BTM SOUTH SIDE WITH NEUT.

P32A INSTALL 70' CP

INSTALL 6-D/G'S (POS H, I, J, K, M & N) PISA 12" ANCHORS @ 6.5m, 5.5m, 4.5m LEADS;

INSTALL 4-D/G'S (POS H, J, K & M) PISA 12" ANCHORS @ 5.5m, 4.0m LEADS;

P46 INSTALL 65' CP

P32 INSTALL 70' CP

P32 TO BE INSTALLED INLINE WITH P32A AND P46

INSTALL NEW 120/240V BUS 250 kcmil SPUN ON 556.5kcmil NEUTRAL

INSTALL 4-D/G'S (POS H, J, K & M) PISA 12" ANCHORS @ 6.0m, 4.5m LEADS;

INSTALL CIRCUITS (4); (2)16/27.6kV, 556.5 kcmil ASC TOP SIDE (2)2.4/4.16kV 556.5 kcmil ASC BTM SIDE WITH NEUT.

P33 INSTALL 70' CP

INSTALL 1-D/G (POS N) PISA 12" ANCHORS @ 2.0m LEAD;

P45 INSTALL 45' CP

INSTALL CIRCUITS (2); (1)16/27.6kV, 556.5 kcmil ASC TOP R/D SIDE (1)2.4/4.16kV 556.5 kcmil ASC BTM R/D SIDE WITH NEUT. TRANSFER EXIST CIRCUITS (2); (1)16/27.6kV, 556.5 kcmil ASC TOP FLD SIDE (1)2.4/4.16kV 556.5 kcmil ASC BTM FLD SIDE

REMOVE EXIST. SEC. BUS AND INSTALL NEW 120/240V BUS 250 kcmil SPUN ON 556.5kcmil NEUTRAL

INSTALL 1-D/G (POS G) PISA 12" ANCHORS @ 2.0m LEAD;

P44 INSTALL 45' CP

TRANSFER YS111537 TO FLD SIDE CKT

P34 INSTALL 65' CP

INSTALL CIRCUIT (1); (1)16/27.6kV, 556.5 kcmil ASC TOP R/D SIDE & NEUT TRANSFER EXIST CIRCUITS (3); (1)16/27.6kV, 556.5 kcmil ASC TOP FLD SIDE (2)2.4/4.16kV 556.5 kcmil ASC BTM R/D & FLD SIDE

TRANSFER EXIST. CIRCUIT; (1) 2.4/4.16kV 556.5 kcmil ASC WITH 266.8 kcmil ACSR NEUT. TAP TO RD SIDE AT P35

EP43 P01534 35' CP

EP42 P01466 35' WP

EP42A P01464 35' WP

EP42 P01466 35' WP — REMOVE OVERHEAD SECONDARY SERVICES. INSTALL NEW O/H TRIPLEX 2-#2 AWG. Al. CONDUCTOR

EP43 P01534 35' CP — REMOVE SEC SERVICE

INSTALL NEW 4 - 750 kcmil 600V SEC CABLES FROM P29 TO THE EXISTING OH TO UG DIP. REMOVE UG DIP AND SPLICE THE EXISTING CABLES TO THE PROPOSED CABLES

INSTALL NEW 3/0 Al. 600V SEC CABLES FROM P29 TO THE EXISTING BELL POLE. INSTALL UG RISER AND CONNECT TO THE EXISTING OH SEC SERVICE.

#1583 SEC. SVC.: 400A, 347/600V 3PH, 4WIRE MAX kVA LOADING = 44.24

#1490, #1250, #1480 SEC. SVC.: 400A, 200A, 200A 120/208V 3PH, 4WIRE MAX kVA LOADING = 92.99

TRANSFER TX158279 FROM P04129 AND RENAME TO TX136573 3-50kVA 4160GRDY/ 2400V - 120/208V

INSTALL NEW 4 - 750 kcmil 600V AND TWO(2) 4/0 QUAD SEC CABLES FROM P36 AND SPLICE ON THE CORRECT EXISTING SIZE SEC CABLES

P36 INSTALL 65' CP

TRANSFER EXIST. SEC.120/240V BUS 250 kcmil SPUN ON 556.5kcmil NEUTRAL

INSTALL CIRCUIT (1); (1)16/27.6kV, 556.5 kcmil ASC TOP R/D SIDE TRANSFER EXIST CIRCUITS (3); (1)16/27.6kV, 556.5 kcmil ASC TOP FLD SIDE (2)2.4/4.16kV 556.5 kcmil ASC BTM R/D & FLD SIDE WITH NEUT

INSTALL CIRCUITS (3); (2)16/27.6kV, 556.5 kcmil ASC TOP SIDE (1)2.4/4.16kV 556.5 kcmil ASC BTM FLD SIDE TRANSFER EXIST CIRCUITS (1); (1)2.4/4.16kV 556.5 kcmil ASC BTM R/D SIDE WITH NEUT

SLEEVE THROUGH THE EXISTING AND PROPOSED OVERHEAD CONDUCTORS

P37 INSTALL 70' CP

INSTALL CIRCUITS (4); (2)16/27.6kV, 556.5 kcmil ASC TOP SIDE (2)2.4/4.16kV 556.5 kcmil ASC BTM SIDE WITH NEUT

REMOVE 27.6kV JUMPER FROM ROAD SIDE AND EXTEND THE PRI. CONDUCTOR EP39 TO P41. CLOSE YL109802 SWITCH AT P04134

INSTALL CIRCUIT (2); (2)16/27.6kV, 556.5 kcmil ASC TOP SIDE TRANSFER EXIST CIRCUITS (2); (2)2.4/4.16kV 556.5 kcmil ASC BTM SIDE WITH NEUT

P40 TO BE INSTALLED INLINE WITH P41 AND EP39

P40 INSTALL 70' CP

P41 INSTALL 70' CP

EP39 P04133 65' CP

P04134 65' CP

YL109802

TO YL116577, S106841, S109489, YS138644, YS143514

P35 INSTALL 65' CP — INSTALL 3-D/G'S (POS D, F, & G) PISA 12" ANCHORS @ 6.0m, 4.0m LEADS; WITH STRUT BAR

P35 TO P31 TO BE INSTALLED INLINE WITH P36 AND P30

INSTALL C133864 R-65K

SUPPLY AND INSTALL NEW 1/0 Al. TRXLPEI, CN, LLDPEJ 28kV FROM C133864 TO C157513

INSTALL C157513 R-65K

P38 INSTALL 70' CP — INSTALL S157259 TO RD CKT

INSTALL 4-D/G'S (POS A, C, D & F) PISA 12" ANCHORS @ 5.0m, 3.5m LEADS;

TRANSFER EXIST. CIRCUITS (2); (1)16/27.6kV, 556.5 kcmil TREE WIRE ACSR (1)2.4/4.16kV 556.5 kcmil TREE WIRE ACSR WITH NEUT

EXISTING SEC.120/240V BUS 250 kcmil SPUN ON 556.5kcmil NEUTRAL

P04142 40' WP — C1120 RB-100K

P01359 40' CP — P01360 40' CP

EXIST. PHASES (RB); 2x 2.4kV #4 Cu. WITH #2 Cu. NEUT

TO YS11142, C101759, C101619, S1112

TO TX224-B

TO TX1650-B

DEAD END

TX1390-B 75kVA 2400-120/240V

USC5003 30' WP

P01467 30' WP

TO C1110, S132689

DIXIE ROAD

CORMACK CRESCENT

ROMETOWN DRIVE

LONDONDERRY BOULEVARD

FUTURE EASTBOUND OFF RAMP

FUTURE SOUTH SERVICE ROAD

SOUTH SERVICE ROAD

TEMPORARY ACCESS ROAD

PERMANENT ACCESS ROAD

## FRAMING:

P29: FRAME PER TOP & BTM CKT 7-517, 7-705 FIG 1, 9-101, 9-107, 9-108, 25-151 FIG 4(2x), 25U-120 FIG 2(2x), & 25U-301

P30: FRAME PER TOP & BTM CKT 7-517, 7-705 FIG 1, 9-101, 9-107, 9-108 & 25-151 FIG 3

P31: FRAME PER TOP & BTM CKT 7-515, 7-540, 7-702, 19-100A, 19-112, 25-150, 25-151 FIG 1, 41-99, 41-103 & 41-109

P32: FRAME PER TOP & BTM CKT 7-515 & 7-526(x2), 7-702, 7-706.3(x2), & 25-151 FIG 1

P32A: FRAME PER TOP & BTM CKT 7-512, 7-706.1 FIG 1, 9-101, 9-107 & 9-108

P33: FRAME PER TOP & BTM CKT 7-515, 7-702, & 25-151 FIG 1

P34: FRAME PER TOP & BTM CKT 7-515, 7-702, & 25-151 FIG 1

P35: FRAME PER TOP CKT 7-515, BTM CKT 7-515 & 7-526, 7-702, 7-706.3, 9-101, 9-107, 9-108, & 25-151 FIG 1

P36: FRAME PER TOP & BTM CKT 7-515, 7-538 FIG 1, 7-702, 9-101, 9-107, 9-108, 19-106 ,19-112, 19-150, 25-154 FIG 1, 25U-120 FIG 1(x3), 25U-301(x3), 41-99, 41-103, & 41-109

P37: FRAME PER TOP & BTM CKT 7-515 & 7-536, 7-702, & 25-151 FIG 1

P38: FRAME PER TOP & BTM CKT 7-519, 7-528 & 7-536, 7-706.2 FIG 1, 9-101, 9-107, 9-108, 25-151 FIG 1 & 29-103

EP39: REFRAME PER TOP CKT 7-515

P40: FRAME PER TOP & BTM CKT 7-515 & 7-536, & 7-702

P41: FRAME PER TOP & BTM CKT 7-519 & 7-536, 7-706.1 FIG 1, 9-101, 9-107, & 9-108

EP42A: REFRAME PER 7-720 FIG 1, 7-706.1 FIG 1, 37-105, 37-190, 41-99, & 41-103

EP42: REFRAME PER 37-105, 37-190, 41-99, & 41-103

EP43: ADDITIONAL FRAMING PER 7-702 & 25-151 FIG 1

P44: FRAME PER 7-702, 9-101, 9-107, 9-108, & 25-151 FIG 1

P45: FRAME PER 7-706.1 FIG 1, 9-101, 9-107, 9-108 & 25-151 FIG 4

P46: FRAME PER TOP & BTM CKT 7-509, 7-705 FIG 2, 9-101, 9-107 & 9-108

P47: FRAME PER TOP & BTM CKT 7-503, 7-704, 9-101, 9-107 & 9-108

## NOTES:

REFER TO 9-108 FOR GUYING POSITIONS.

MATCH ALL SECONDARY JUMPERS & CABLES TO EXISTING SERVICE OR BUS CABLE CAPACITY (REF. STD. 25U-120).

ALL DOWN-GUYS TO BE ATTACHED ON INDIVIDUAL GUY- HOOKS, MAX. 1 DOWN-GUY PER HOLE.

REFER TO 25-150 FOR TRANSFORMER SECONDARY CONNECTIONS.

REMOVE ALL PLANT AS INDICATED ON SITE PLAN.

TRANSFER EXISTING SECONDARY BUS TO THE PROPOSED POLES.

COORDINATE WITH STREETLIGHTING

MTO TO HAVE GIVEN/WRITTEN PERMISSION TO INSTALL POLES ON EXPROPRIATED PROPERTY.

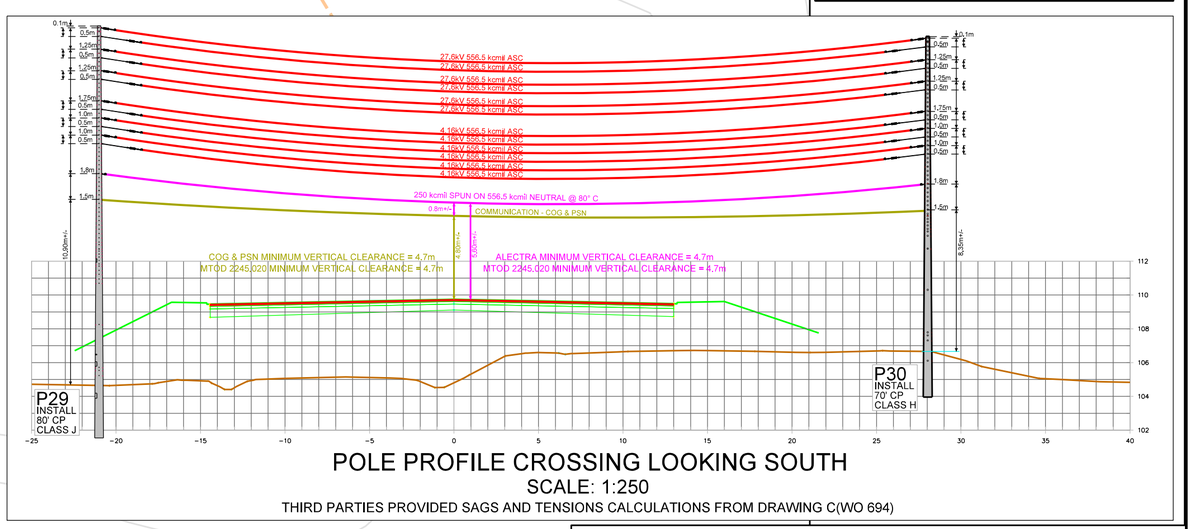
COORDINATE WITH MTO'S SURVEYOR CONSULTANT TO VERIFY STAKED POLES ARE IN THE CORRECT POSITION.

NOTE:
USE EXTREME CAUTION WHEN WORKING IN CLOSE PROXIMITY OF OTHER UTILITIES. ALL MEASURES MUST BE TAKEN TO ENSURE THE STABILITY OF ALL EXISTING INFRASTRUCTURE ADJACENT TO PROPOSED WORK LOCATION. ALL LOCATES MUST BE OBTAINED PRIOR TO STARTING ANY CONSTRUCTION. ALL H.V. CABLES TO BE MINIMUM OF 0.6M ANY EXISTING UTILITIES WITHIN THE BOULEVARD. ANY WORKS WITHIN 0.6M OF EXISTING UTILITIES MUST BE HAND-DUG.

Certificate

This is to certify that the construction as recorded in this drawing is consistent with the approved plan, Standard Designs, or work instruction and that approved equipment has been used:

| | | |
|---|---|---|
| Lead Hand | Signature | Date |
| Supervisor | Signature | Date |
| Design Tech | Signature | Date |




POLE PROFILE CROSSING LOOKING SOUTH
SCALE: 1:250
THIRD PARTIES PROVIDED SAGS AND TENSIONS CALCULATIONS FROM DRAWING C(WO 694)

## GRADE ELEVATIONS AND POLE SETTING

| POLE NUMBER | EXISTING GRADE ELEVATION | PROPOSED GRADE ELEVATION | GRADE CHANGE | POLE SETTING BASE ON EXISTING GRADE | POLE SIZE |
|---|---|---|---|---|---|
| P29 | 104.60 | 107.30 | 2.7m FILL | 3.1m | 80' |
| P30 | 106.70 | 106.70 | NO CHANGE | 2.7m | 70' |
| P31 | 105.10 | 105.10 | NO CHANGE | 2.7m | 70' |
| P32 | 104.50 | 105.00 | 0.5m FILL | 2.7m | 70' |
| P32A | 104.50 | 107.10 | 2.6m FILL | 2.0m | 45' |
| P33 | 104.30 | 104.70 | 0.5m FILL | 2.7m | 70' |
| P45 | 104.30 | 105.50 | 1.2m FILL | 2.0m | 45' |
| P44 | 104.00 | 104.80 | 0.8m FILL | 2.0m | 45' |
| P34 | 103.90 | 103.90 | NO CHANGE | 2.6m | 65' |

| REV. No. | REVISION | REV. BY | APPD. | DATE |
|---|---|---|---|---|
| R3 | | | | |
| R2 | | | | |
| R1 | | | | |

PRELIMINARY NOT FOR CONSTRUCTION — ISSUED TO CONTROL DRAWING REVISIONS

APPD _____
DATE _____


enersource | alectra utilities
3240 Mavis Road
Mississauga, Ontario
L5C 3K1
Tel : (905) 273-9050
Fax: (905) 566-2737
www.alectrautilities.com


# QEW DIXIE ROAD INTERCHANGE
## MTO QEW ROAD EXPANSION
### GENERAL ARRANGEMENT

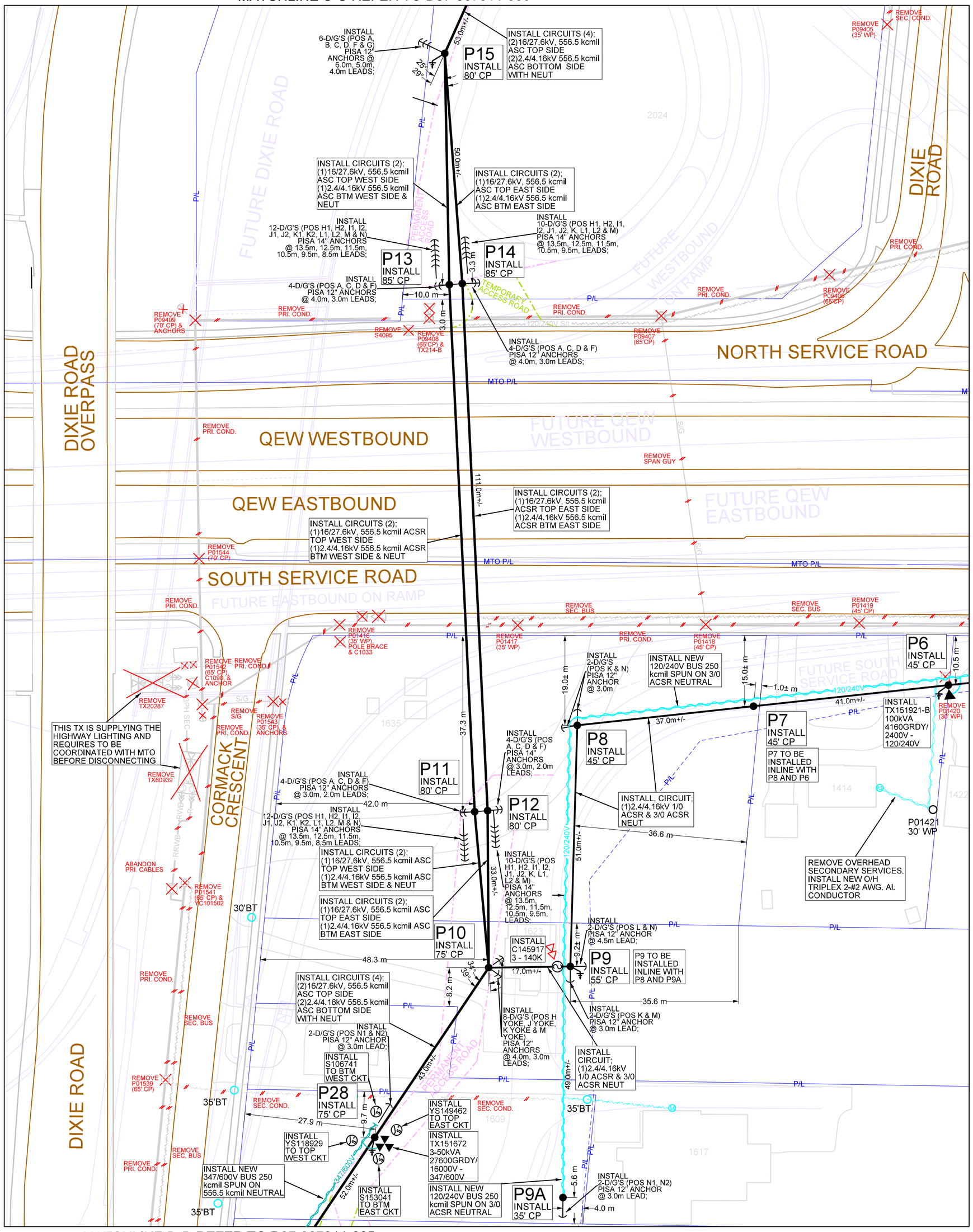
SCALE 1 : 500 (0 5 10 20 30 METRES)

| DES. TECH. | DRAWN | SERVICE ORDER | DATE |
|---|---|---|---|
| M. WATTERS | M. WATTERS | 367911 | JUL-04-2017 |

| REVIEWED | AREA | SHEET | |
|---|---|---|---|
| T. ANTONAKOS | 05 | 5 of 10 | D07-367911-005 |

SIZE: 24X36

MATCHLINE C-C REFER TO D07-367911-003




MATCHLINE A-A REFER TO D07-367911-002

MATCHLINE D-D REFER TO D07-367911-005

## LEGEND (CONSTRUCTION)

- PROPOSED POLE, TYPE AND SIZE INDICATED ON DRAWING
- CP — CONCRETE POLE
- WP — WOOD POLE
- P1 — POLE LOCATION NUMBER
- TP1 — TEMPORARY HYDRO POLE, ANY TYPE
- EP1 — EXISTING HYDRO POLE, ANY TYPE
- PROPOSED OVERHEAD WIRE/S, ANY TYPE and VOLTAGE
- PROPOSED SPUN SECONDARY BUS
- PROPOSED DOWN GUY AND ANCHOR
- POLE TO BE REPLACED AT THE SAME LOCATION
- EXISTING POLE AND ASSOCIATED HARDWARE TO BE REMOVED
- TRANSFER SPUN SECONDARY BUS
- S/L — STREETLIGHTING SEC. BUS
- DOWN GUY/ANCHOR
- 1 PHASE TX, POLEMOUNT
- 3 PHASE TX, POLEMOUNT
- LINE SWITCH
- LINE CUTOUT
- EXISTING POLE TO REMAIN
- EXISTING BELL POLE
- PROPOSED TRANSFORMER, SINGLE PHASE UNIT
- PROPOSED TRANSFORMER, THREE PHASE BANK
- PROPOSED LOAD INTERUPTER
- PROPOSED INLINE SWITCH
- PROPOSED GROUNDING
- DENOTES REMOVAL, ANY PLANT
- OPEN POINT
- P/L — EXISTING PROPERTY LINE
- P/L — FUTURE PROPERTY LINE
- FUTURE ROADS/SIDEWALKS
- EXISTING ROADS
- EXISTING SIDEWALKS
- OVERHEAD WIRE/S, ANY TYPE
- TRANSFER OVERHEAD WIRE/S, ANY TYPE
- PLANT TO BE REMOVED
- RWB — PRIMARY CABLES
- SEC — SECONDARY CABLES
- 100x2 — DUCT BANK, SIZE & QTY
- M — EXISTING METERBASE

## FRAMING:

P6: FRAME PER 7-501, 7-702, 19-101, 19-112, 19-150, 25-150, 25-151 FIG 1, 41-99, 41-103, & 41-109

P7: FRAME PER 7-502, 7-702 & 25-151 FIG 1

P8: FRAME PER 7-509, 7-705 FIG 2, 9-101, 9-107, 9-108 & 25-151 FIG 3

P9: FRAME PER 7-509, 7-537, 7-702, 7-706.3, 9-101, 9-107, 9-108, 25-151 FIG 1, 41-99 & 41-103

P9A: FRAME PER 7-706.1 FIG 1, 9-101, 9-107, 9-108, & 25-151 FIG 4

P10: FRAME PER TOP & BTM CKT 7-516, BTM CKT 7-526, 7-704, 9-101, 9-107, 9-108 & 25-151 FIG 2

P11: FRAME PER TOP & BTM CKT 7-535(SEE POLE PROFILE CROSSING SPACING), 7-706.2, 9-101, 9-107, & 9-108

P12: FRAME PER TOP & BTM CKT 7-535(SEE POLE PROFILE CROSSING SPACING), 9-101, 9-107, & 9-108

P13: FRAME PER TOP & BTM CKT 7-535(SEE POLE PROFILE CROSSING SPACING), 7-706.2, 9-101, 9-107 & 9-108

P14: FRAME PER TOP & BTM CKT 7-535(SEE POLE PROFILE CROSSING SPACING), 9-101, 9-107, & 9-108

P15: FRAME PER TOP & BTM CKT 7-516, 7-704, 9-101, 9-107, 9-108, 25-151 FIG 2, 41-99 & 41-103

P28: FRAME PER TOP & BTM 7-515, 7-539 FIG 1, 7-702, 19-104, 19-112, 25-150, 25-151 FIG 4, 29-103(x4), 41-99, 41-103 & 41-109

## NOTES:

REFER TO 9-108 FOR GUYING POSITIONS.

MATCH ALL SECONDARY JUMPERS & CABLES TO EXISTING SERVICE OR BUS CABLE CAPACITY (REF. STD. 25U-120).

ALL DOWN-GUYS TO BE ATTACHED ON INDIVIDUAL GUY- HOOKS, MAX. 1 DOWN-GUY PER HOLE.

REFER TO 25-150 FOR TRANSFORMER SECONDARY CONNECTIONS.

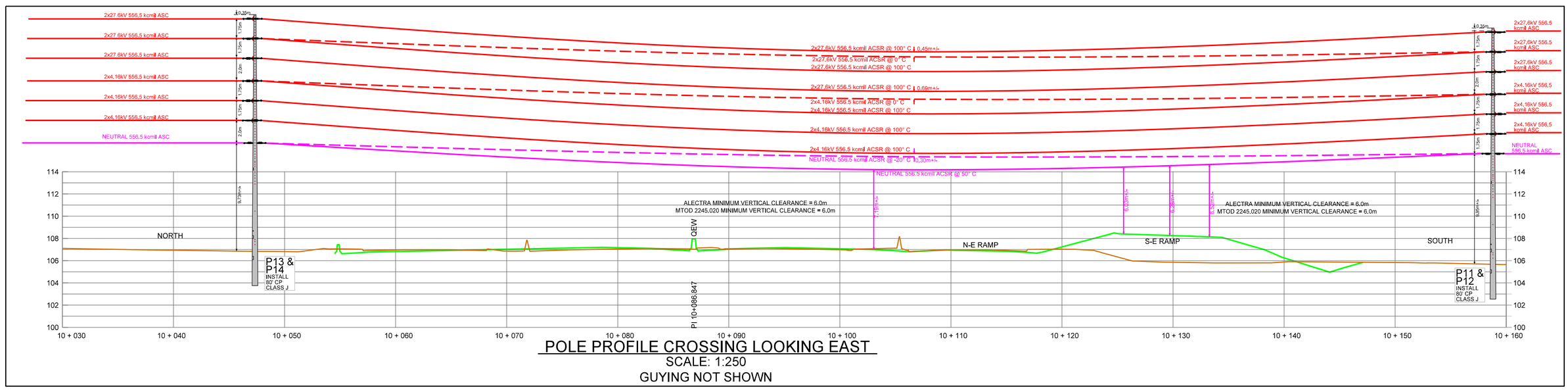
REMOVE ALL PLANT AS INDICATED ON SITE PLAN.

TRANSFER EXISTING SECONDARY BUS TO THE PROPOSED POLES.

COORDINATE WITH STREETLIGHTING

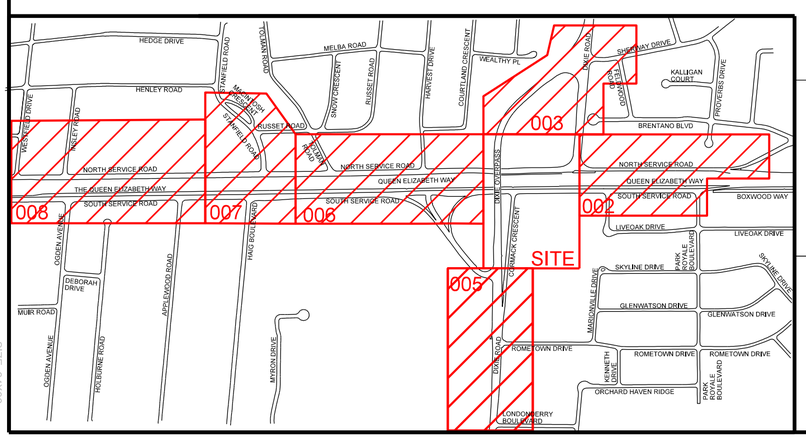
MTO TO HAVE GIVEN/WRITTEN PERMISSION TO INSTALL POLES ON EXPROPRIATED PROPERTY.

COORDINATE WITH MTO'S SURVEYOR CONSULTANT TO VERIFY STAKED POLES ARE IN THE CORRECT POSITION.



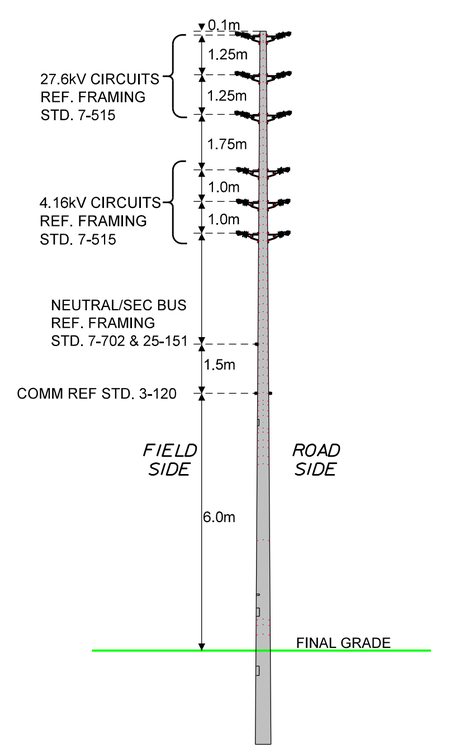

POLE PROFILE CROSSING LOOKING EAST
SCALE: 1:250
GUYING NOT SHOWN

| Initial Sags and Tensions for Stringing for 556.5 kcmil ACSR (111m Ruling Span) | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Ambient Temperature (degrees C) | -20 | -18 | -10 | 0 | 10 | 15 | 20 | 30 | Final | | |
| | | | | | | | | | -20 ice,wind | 50 | 100 |
| RBS (%) | 26.4 | 25.9 | 23.7 | 21.0 | 18.4 | 17.2 | 16.1 | 14.0 | 32.0 | 9.0 | 7.3 |
| Tension (kN) | 26.55 | 26.00 | 23.80 | 21.10 | 18.53 | 17.32 | 16.18 | 14.12 | 32.18 | 9.00 | 7.36 |
| Sag (m) | 0.65 | 0.66 | 0.72 | 0.81 | 0.93 | 0.99 | 1.06 | 1.22 | 1.47 | 1.91 | 2.34 |
| Note: Special Load Zone, Creep Governs The Final Sag. | | | | | | | | | | | |




TRUE NORTH

CONSTRUCTION NORTH




TYPICAL FRAMING DETAIL
N.T.S.

Certificate

This is to certify that the construction as recorded in this drawing is consistent with the approved plan, Standard Designs, or work instruction and that approved equipment has been used:

| | | |
|---|---|---|
| Lead Hand | Signature | Date |
| Supervisor | Signature | Date |
| Design Tech | Signature | Date |

| REV. No. | REVISION | REV. BY | APPD. | DATE |
|---|---|---|---|---|
| R3 | | | | |
| R2 | | | | |
| R1 | | | | |

PRELIMINARY NOT FOR CONSTRUCTION REFER TO CONTRACT DRAWINGS FOR UPDATED INFORMATION

APPD
DATE

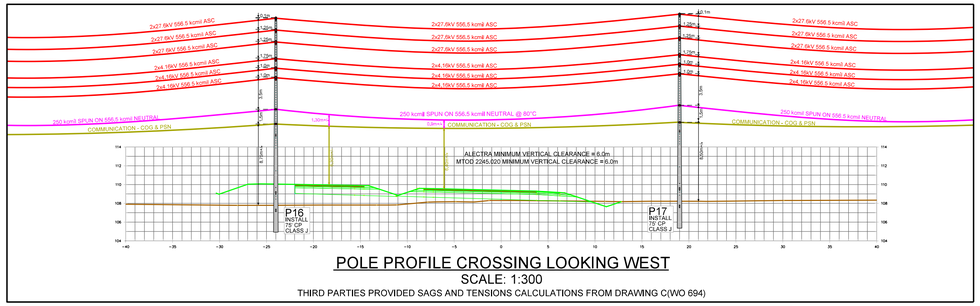

enersource | alectra utilities
3240 Mavis Road
Mississauga, Ontario
L5C 3K1
Tel : (905) 273-9050
Fax: (905) 566-2737
www.alectrautilities.com


# QEW DIXIE ROAD INTERCHANGE
## MTO QEW ROAD EXPANSION
### GENERAL ARRANGEMENT

SCALE 1 : 500 (0 5 10 20 30 METRES)

| DES. TECH. | DRAWN | SERVICE ORDER | DATE |
|---|---|---|---|
| M. WATTERS | M. WATTERS | 367911 | JUL-04-2017 |
| REVIEWED | AREA | SHEET | |
| T. ANTONAKOS | 05 | 4 of 10 | D07-367911-004 |

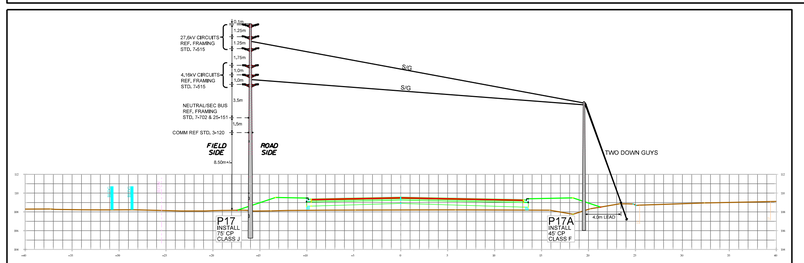
SIZE: 24X36




## POLE PROFILE CROSSING LOOKING WEST

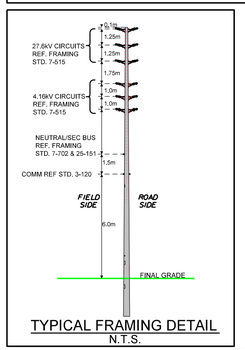
SCALE: 1:300

THIRD PARTIES PROVIDED SAGS AND TENSIONS CALCULATIONS FROM DRAWING C(WO 694)



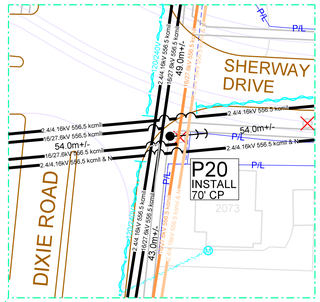

## POLE PROFILE CROSSING LOOKING SOUTH

SCALE: 1:300



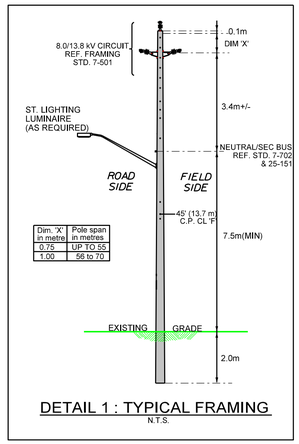

## TYPICAL FRAMING DETAIL

N.T.S.



## LEGEND (CONSTRUCTION)

- PROPOSED POLE, TYPE AND SIZE INDICATED ON DRAWING
- CP — CONCRETE POLE
- WP — WOOD POLE
- P1 — POLE LOCATION NUMBER
- TP1 — TEMPORARY HYDRO POLE, ANY TYPE
- EP1 — EXISTING HYDRO POLE, ANY TYPE
- PROPOSED OVERHEAD WIRE/S, ANY TYPE and VOLTAGE
- PROPOSED SPUN SECONDARY BUS
- PROPOSED DOWN GUY AND ANCHOR
- POLE TO BE REPLACED AT THE SAME LOCATION
- EXISTING POLE AND ASSOCIATED HARDWARE TO BE REMOVED
- TRANSFER SPUN SECONDARY BUS
- STREETLIGHTING SEC. BUS
- DOWN GUY/ANCHOR
- 1 PHASE TX, POLEMOUNT
- 3 PHASE TX, POLEMOUNT
- LINE SWITCH
- LINE CUTOUT
- EXISTING POLE TO REMAIN
- EXISTING BELL POLE
- PROPOSED TRANSFORMER, SINGLE PHASE UNIT
- PROPOSED TRANSFORMER, THREE PHASE BANK
- PROPOSED GROUNDING
- DENOTES REMOVAL, ANY PLANT
- OPEN POINT
- EXISTING PROPERTY LINE
- FUTURE PROPERTY LINE
- FUTURE ROADS/SIDEWALKS
- EXISTING ROADS
- EXISTING SIDEWALKS
- OVERHEAD WIRE/S, ANY TYPE
- TRANSFER OVERHEAD WIRE/S, ANY TYPE
- PLANT TO BE REMOVED
- PRIMARY CABLES
- SECONDARY CABLES
- DUCT BANK, SIZE & QTY
- EXISTING METERBASE




| Dim. 'X' in metre | Pole span in metres |
|---|---|
| 0.75 | UP TO 55 |
| 1.00 | 56 to 70 |

## DETAIL 1 : TYPICAL FRAMING
N.T.S.

## NOTES:

REFER TO 9-108 FOR GUYING POSITIONS.

MATCH ALL SECONDARY JUMPERS & CABLES TO EXISTING SERVICE OR BUS CABLE CAPACITY (REF. STD. 25U-120).

ALL DOWN-GUYS TO BE ATTACHED ON INDIVIDUAL GUY- HOOKS, MAX. 1 DOWN-GUY PER HOLE.

REFER TO 25-150 FOR TRANSFORMER SECONDARY CONNECTIONS.

REMOVE ALL PLANT AS INDICATED ON SITE PLAN.

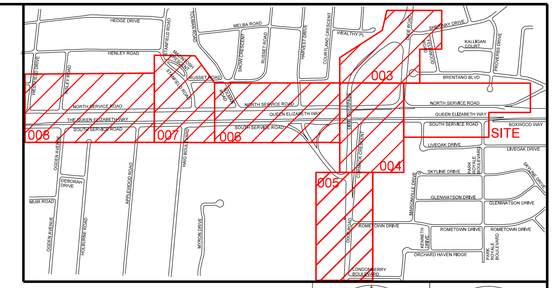
TRANSFER EXISTING SECONDARY BUS TO THE PROPOSED POLES.

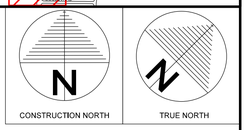
COORDINATE WITH STREETLIGHTING

MTO TO HAVE GIVEN/WRITTEN PERMISSION TO INSTALL POLES ON EXPROPRIATED PROPERTY.

COORDINATE WITH MTO'S SURVEYOR CONSULTANT TO VERIFY STAKED POLES ARE IN THE CORRECT POSITION.

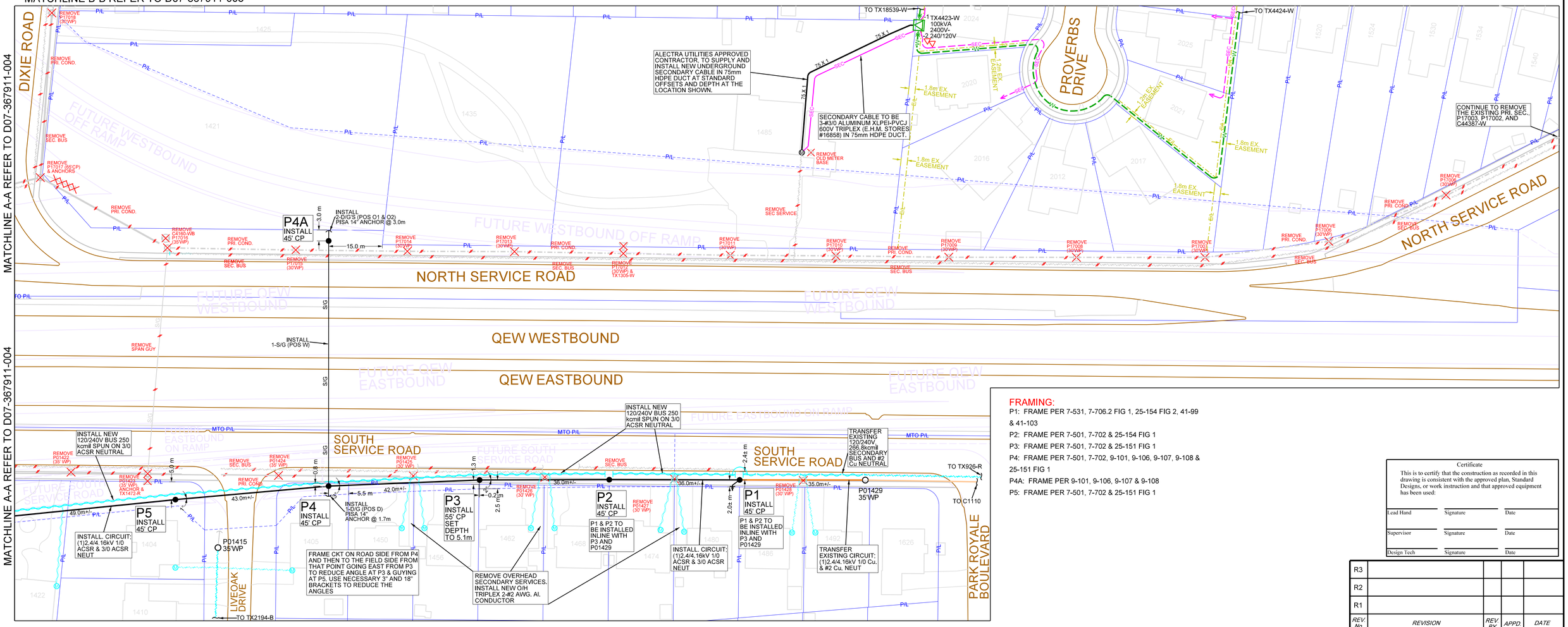
NOTE:
USE EXTREME CAUTION WHEN WORKING IN CLOSE PROXIMITY OF OTHER UTILITIES. ALL MEASURES MUST BE TAKEN TO ENSURE THE STABILITY OF ALL EXISTING INFRASTRUCTURE ADJACENT TO PROPOSED WORK LOCATION. ALL LOCATES MUST BE OBTAINED PRIOR TO STARTING ANY CONSTRUCTION. ALL H.V. CABLES TO BE MINIMUM OF 0.6M FROM ANY EXISTING UTILITIES WITHIN THE BOULEVARD. ANY WORKS WITHIN 0.6M OF EXISTING UTILITIES MUST BE HAND-DUG.




MATCHLINE B-B REFER TO D07-367911-003

MATCHLINE A-A REFER TO D07-367911-004




## FRAMING:

P1: FRAME PER 7-531, 7-706.2 FIG 1, 25-154 FIG 2, 41-99 & 41-103

P2: FRAME PER 7-501, 7-702 & 25-154 FIG 1

P3: FRAME PER 7-501, 7-702 & 25-151 FIG 1

P4: FRAME PER 7-501, 7-702, 9-101, 9-106, 9-107, 9-108 & 25-151 FIG 1

P4A: FRAME PER 9-101, 9-106, 9-107 & 9-108

P5: FRAME PER 7-501, 7-702 & 25-151 FIG 1

Certificate

This is to certify that the construction as recorded in this drawing is consistent with the approved plan, Standard Designs, or work instruction and that approved equipment has been used:

| | | |
|---|---|---|
| Lead Hand | Signature | Date |
| Supervisor | Signature | Date |
| Design Tech | Signature | Date |

| REV. No. | REVISION | REV. BY | APPD | DATE |
|---|---|---|---|---|
| R3 | | | | |
| R2 | | | | |
| R1 | | | | |

PRELIMINARY NOT FOR CONSTRUCTION

APPD _____
DATE _____

enersource | alectra utilities

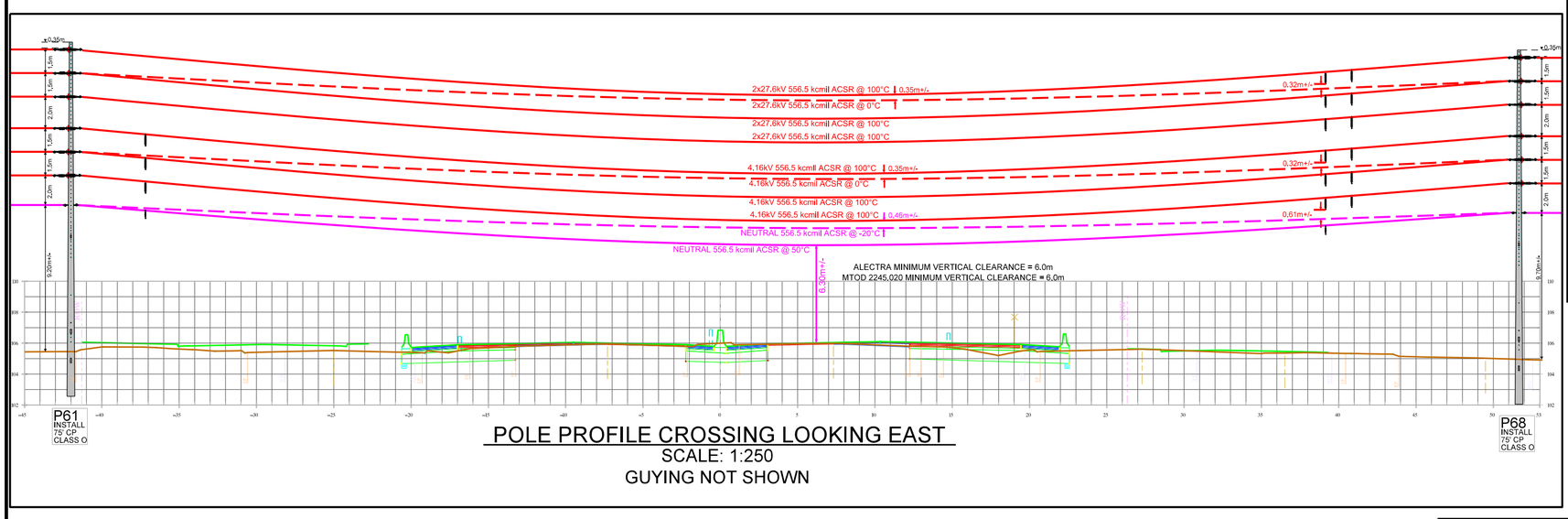
3240 Mavis Road
Mississauga, Ontario
L5C 3K1
Tel : (905) 273-9050
Fax: (905) 566-2737
www.alectrautilities.com

# QEW DIXIE ROAD INTERCHANGE
## MTO QEW ROAD EXPANSION
### GENERAL ARRANGEMENT

SCALE 1 : 500 (0 5 10 20 30 METRES)

| DES. TECH. | DRAWN | SERVICE ORDER | DATE |
|---|---|---|---|
| M. WATTERS | M. WATTERS | 367911 | JUL-04-2017 |
| REVIEWED | AREA | SHEET | |
| T. ANTONAKOS | 05 | 2 of 10 | D07-367911-002 |

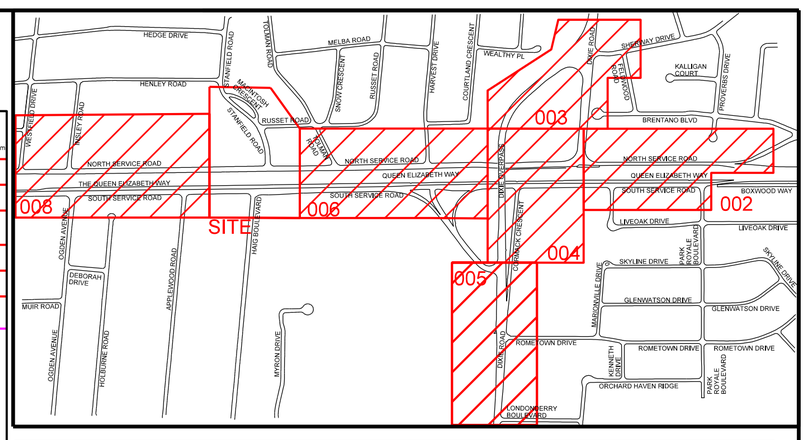
SIZE: 24X36




## POLE PROFILE CROSSING LOOKING EAST

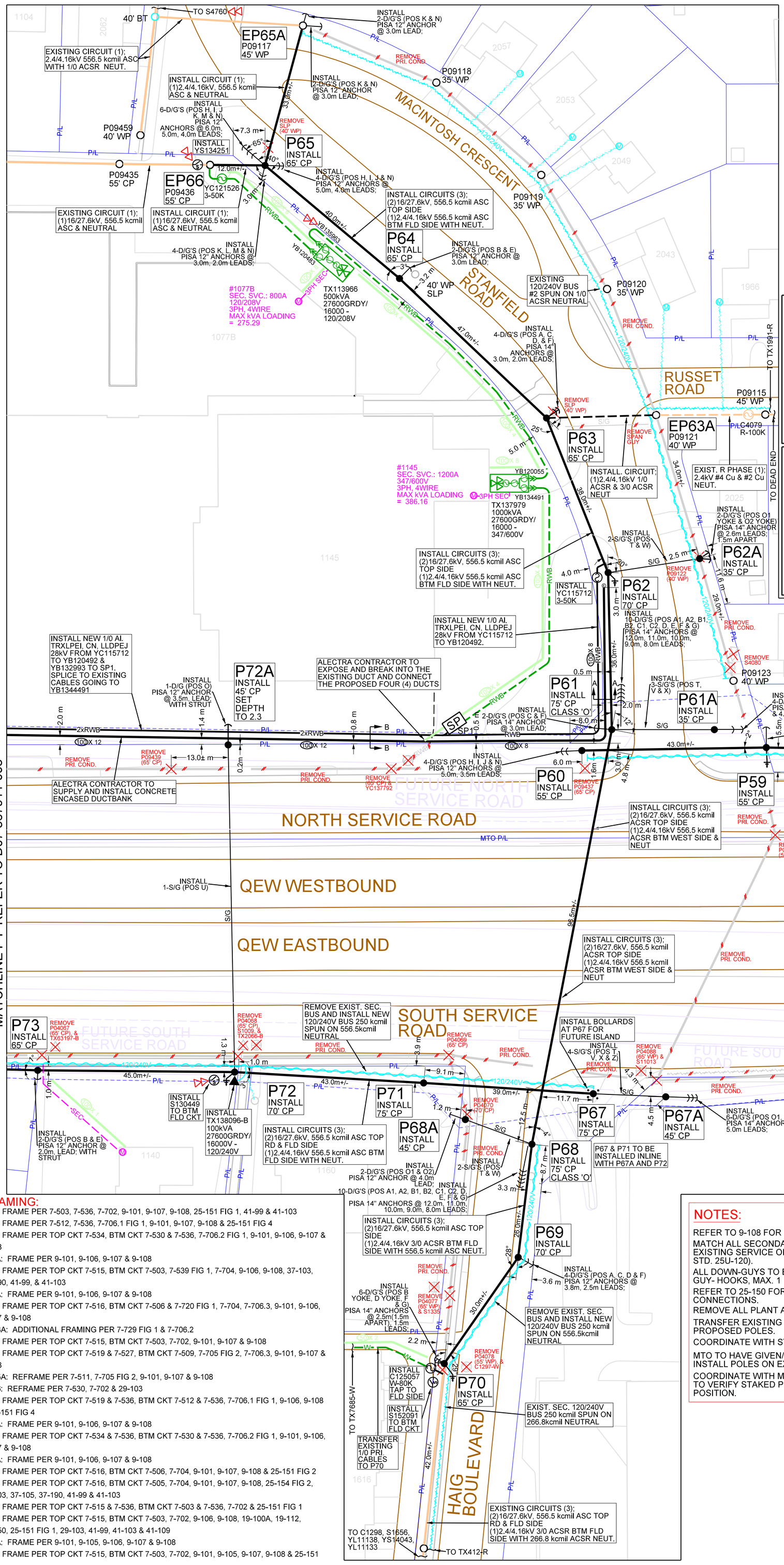
SCALE: 1:250

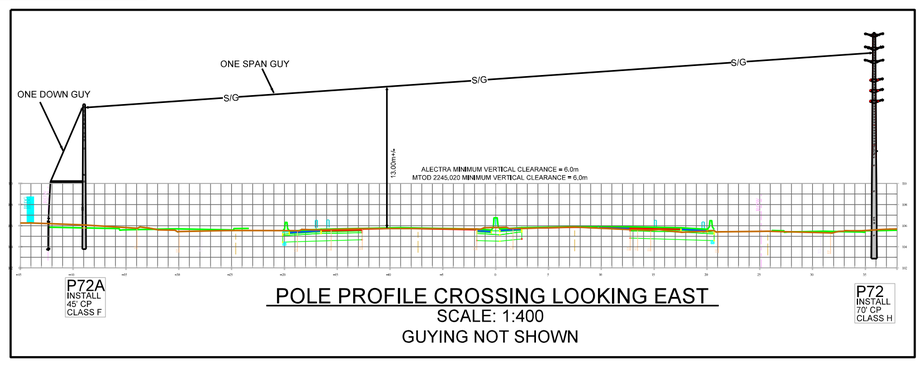
GUYING NOT SHOWN




| Initial Sags and Tensions for Stringing for 556.5 kcmil ACSR (97m Ruling Span) | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Ambient Temperature (degrees C) | -20 | -18 | -10 | 0 | 10 | 15 | 20 | 30 | Final | | |
| | | | | | | | | | -20 ice,wind | 50 | 100 |
| RBS (%) | 10.6 | 10.3 | 9.4 | 8.4 | 7.6 | 7.3 | 7.0 | 6.5 | 20.0 | 5.6 | 4.9 |
| Tension (kN) | 10.63 | 10.36 | 9.41 | 8.45 | 7.69 | 7.36 | 7.07 | 6.56 | 20.11 | 5.61 | 4.89 |
| Sag (m) | 1.24 | 1.27 | 1.40 | 1.56 | 1.71 | 1.79 | 1.86 | 2.00 | 1.80 | 2.34 | 2.69 |

Note: Special Load Zone, Creep Governs The Final Sag.

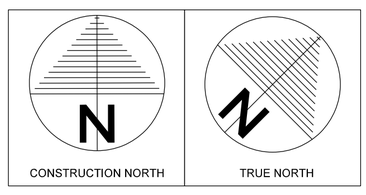


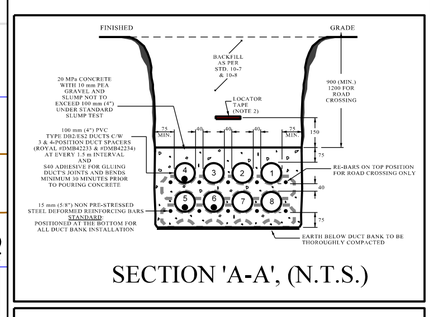




## POLE PROFILE CROSSING LOOKING EAST

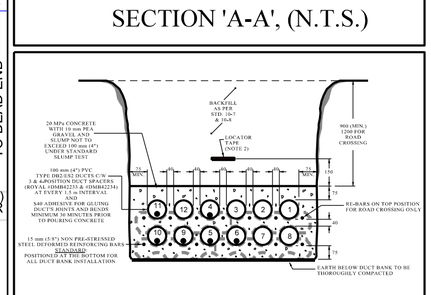
SCALE: 1:400

GUYING NOT SHOWN

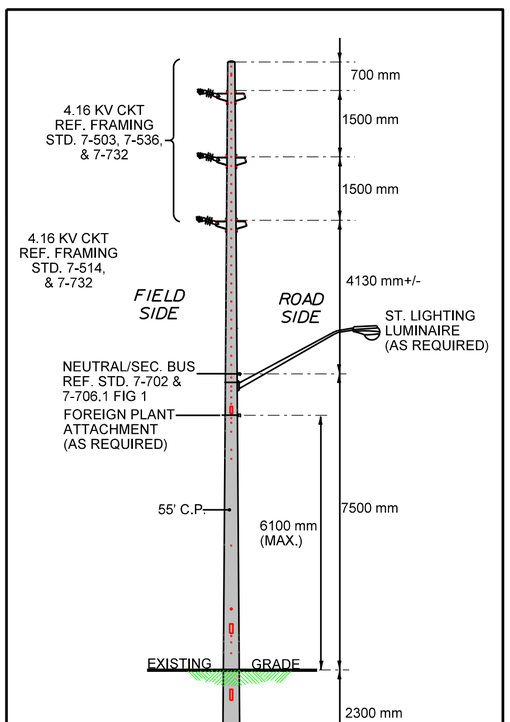



SECTION 'A-A', (N.T.S.)




SECTION 'B-B', (N.T.S.)




## DETAIL #1 : P59 FRAMING

N.T.S

GUYING NOT SHOWN

## LEGEND (CONSTRUCTION)

- PROPOSED POLE, TYPE AND SIZE INDICATED ON DRAWING
- CP CONCRETE POLE
- WP WOOD POLE
- P1 POLE LOCATION NUMBER
- TP1 TEMPORARY HYDRO POLE, ANY TYPE
- EP1 EXISTING HYDRO POLE, ANY TYPE
- PROPOSED OVERHEAD WIRE/S, ANY TYPE and VOLTAGE
- PROPOSED SPUN SECONDARY BUS
- PROPOSED DOWN GUY AND ANCHOR
- POLE TO BE REPLACED AT THE SAME LOCATION
- EXISTING POLE AND ASSOCIATED HARDWARE TO BE REMOVED
- TRANSFER SPUN SECONDARY BUS
- S/L STREETLIGHTING SEC. BUS
- DOWN GUY/ANCHOR
- 1 PHASE TX, POLEMOUNT
- 3 PHASE TX, POLEMOUNT
- LINE SWITCH
- LINE CUTOUT
- EXISTING POLE TO REMAIN
- EXISTING BELL POLE
- PROPOSED TRANSFORMER, SINGLE PHASE UNIT
- PROPOSED TRANSFORMER, THREE PHASE BANK
- PROPOSED LOAD INTERUPTER
- PROPOSED INLINE SWITCH
- PROPOSED GROUNDING
- DENOTES REMOVAL, ANY PLANT
- OPEN POINT
- P/L EXISTING PROPERTY LINE
- P/L FUTURE PROPERTY LINE
- FUTURE ROADS/SIDEWALKS
- EXISTING ROADS
- EXISTING SIDEWALKS
- OVERHEAD WIRE/S, ANY TYPE
- TRANSFER OVERHEAD WIRE/S, ANY TYPE
- PLANT TO BE REMOVED
- 4xRWB PRIMARY CABLES
- 4SEC SECONDARY CABLES
- 100x2 DUCT BANK, SIZE & QTY
- M EXISTING METERBASE
- EXISTING 3PH TRANSFORMER

## FRAMING:

P59: FRAME PER 7-503, 7-536, 7-702, 9-101, 9-107, 9-108, 25-151 FIG 1, 41-99 & 41-103

P60: FRAME PER 7-512, 7-536, 7-706.1 FIG 1, 9-101, 9-107, 9-108 & 25-151 FIG 4

P61: FRAME PER TOP CKT 7-534, BTM CKT 7-530 & 7-536, 7-706.2 FIG 1, 9-101, 9-106, 9-107 & 9-108

P61A: FRAME PER 9-101, 9-106, 9-107 & 9-108

P62: FRAME PER TOP CKT 7-515, BTM CKT 7-503, 7-539 FIG 1, 7-704, 9-106, 9-108, 37-103, 37-190, 41-99, & 41-103

P62A: FRAME PER 9-101, 9-106, 9-107 & 9-108

P63: FRAME PER TOP CKT 7-516, BTM CKT 7-506 & 7-720 FIG 1, 7-704, 7-706.3, 9-101, 9-106, 9-107 & 9-108

EP63A: ADDITIONAL FRAMING PER 7-729 FIG 1 & 7-706.2

P64: FRAME PER TOP CKT 7-515, BTM CKT 7-503, 7-702, 9-101, 9-107 & 9-108

P65: FRAME PER TOP CKT 7-519 & 7-527, BTM CKT 7-509, 7-705 FIG 2, 7-706.3, 9-101, 9-107 & 9-108

EP65A: REFRAME PER 7-511, 7-705 FIG 2, 9-101, 9-107 & 9-108

EP66: REFRAME PER 7-530, 7-702 & 29-103

P67: FRAME PER TOP CKT 7-519 & 7-536, BTM CKT 7-512 & 7-536, 7-706.1 FIG 1, 9-106, 9-108 & 25-151 FIG 4

P67A: FRAME PER 9-101, 9-106, 9-107 & 9-108

P68: FRAME PER TOP CKT 7-534 & 7-536, BTM CKT 7-530 & 7-536, 7-706.2 FIG 1, 9-101, 9-106, 9-107 & 9-108

P68A: FRAME PER 9-101, 9-106, 9-107 & 9-108

P69: FRAME PER TOP CKT 7-516, BTM CKT 7-506, 7-704, 9-101, 9-107, 9-108 & 25-151 FIG 2

P70: FRAME PER TOP CKT 7-516, BTM CKT 7-505, 7-704, 9-101, 9-107, 9-108, 25-154 FIG 2, 29-103, 37-105, 37-190, 41-99 & 41-103

P71: FRAME PER TOP CKT 7-515 & 7-536, BTM CKT 7-503 & 7-536, 7-702 & 25-151 FIG 1

P72: FRAME PER TOP CKT 7-515, BTM CKT 7-503, 7-702, 9-106, 9-108, 19-100A, 19-112, 25-150, 25-151 FIG 1, 29-103, 41-99, 41-103 & 41-109

P72A: FRAME PER 9-101, 9-105, 9-106, 9-107 & 9-108

P73: FRAME PER TOP CKT 7-515, BTM CKT 7-503, 7-702, 9-101, 9-105, 9-107, 9-108 & 25-151 FIG 1

## NOTES:

REFER TO 9-108 FOR GUYING POSITIONS.

MATCH ALL SECONDARY JUMPERS & CABLES TO EXISTING SERVICE OR BUS CABLE CAPACITY (REF. STD. 25U-120).

ALL DOWN-GUYS TO BE ATTACHED ON INDIVIDUAL GUY- HOOKS, MAX. 1 DOWN-GUY PER HOLE.

REFER TO 25-150 FOR TRANSFORMER SECONDARY CONNECTIONS.

REMOVE ALL PLANT AS INDICATED ON SITE PLAN.

TRANSFER EXISTING SECONDARY BUS TO THE PROPOSED POLES.

COORDINATE WITH STREETLIGHTING

MTO TO HAVE GIVEN/WRITTEN PERMISSION TO INSTALL POLES ON EXPROPRIATED PROPERTY.

COORDINATE WITH MTO'S SURVEYOR CONSULTANT TO VERIFY STAKED POLES ARE IN THE CORRECT POSITION.

NOTE:
USE EXTREME CAUTION WHEN WORKING IN CLOSE PROXIMITY OF OTHER UTILITIES. ALL MEASURES MUST BE TAKEN TO ENSURE THE STABILITY OF ALL EXISTING INFRASTRUCTURE ADJACENT TO PROPOSED WORK LOCATION. ALL LOCATES MUST BE OBTAINED PRIOR TO STARTING ANY CONSTRUCTION. ALL H.V. CABLES TO BE MINIMUM OF 0.6M ANY EXISTING UTILITIES WITHIN THE BOULEVARD. ANY WORKS WITHIN 0.6M OF EXISTING UTILITIES MUST BE HAND-DUG.

| REV. No. | REVISION | REV. BY | APPD. | DATE |
|---|---|---|---|---|
| R3 | | | | |
| R2 | | | | |
| R1 | | | | |

PRELIMINARY NOT FOR CONSTRUCTION

APPD _____

DATE _____


enersource | alectra utilities
3240 Mavis Road
Mississauga, Ontario
L5C 3K1
Tel : (905) 273-9050
Fax: (905) 566-2737
www.alectrautilities.com


# QEW DIXIE ROAD INTERCHANGE

## MTO QEW ROAD EXPANSION

### GENERAL ARRANGEMENT

SCALE 1 : 500 (0 5 10 20 30 METRES)

| DES. TECH. | DRAWN | SERVICE ORDER | DATE |
|---|---|---|---|
| M.WATTERS | M.WATTERS | 367911 | JUL-04-2017 |
| REVIEWED | AREA | SHEET | |
| T.ANTONAKOS | 05 | 7 of 10 | D07-367911-007 |

SIZE: 24X36

**BOMA-91**

**Reference(s): 2018-COS05-1 – Glen Erin/Montevideo**

**Please elaborate on the decision not to attempt to rehabilitate the cable with cable injection, given the success that some other utilities have had with this technique.**

**Response:**

Please see Alectra Utilities response to BOMA-59.

**BOMA-92**

**Reference(s): 2018-COS05-1 – Glen Erin/Montevideo, p10**

**Please provide a justification for the statement that replacement of underground cable in emergency conditions is more expensive than a planned replacement of the same cable. Please explain on average, and for the replacement proposal, how much more expensive emergency replacement would be. Please show the calculation of the cost in both contexts.**

**Response:**

Alectra Utilities' practice in the Enersource RZ is to repair cable faults through the process of splicing cable. Cables that have experienced multiple faults may not be repairable and will require replacement under emergency conditions.

Typically, a planned job is completed during regular business hours, with full consideration of all related scheduling activities, prior to execution. Activities such as: the crew arrangement; stakeouts; switching; materials and trucks readiness; as well as notices to affected customers, are all part of a planned job. This approach ensures crews are available to perform the work as scheduled, and that all materials, vehicles and tools are available. It also allows customers the time to make alternative arrangements, including arranging for back-up power, if necessary, and amending schedules or vacating their premises during the work period.

By contrast, in an emergency or unplanned urgent job, as a result of a cable fault, the work would likely be done during overtime hours when crews are unscheduled but on-call. Generally, this work would be done in a more difficult environment, which has not been prepared as needed. This can lead to longer job lengths. In order to restore power as quickly as possible, the job may be completed in a temporary manner, which would require further work at a point in the future, increasing the cost of the job and potentially the inconvenience to customers. Alectra Utilities must act with urgency in such situations, not necessarily in the most efficient and cost effective manner, in order to coordinate all the activities listed above. All of these elements result in a premium paid to perform the same work as a planned replacement.

Below is an example of an estimate for a 200 meter cable segment replacement for a scheduled versus emergency replacement. The unplanned option assumes that extra time is spent on diagnosing the problem, organizing the crew, travel time, time to obtain materials (assuming they are available), organize stakeouts, switching and coordinating all activities. In the event that materials are not available, more time is spent in arranging alternative options or waiting for the items to become available. The emergency cable replacement leads to 15-36% premium over the planned cable replacement job.

The average cost range to isolate, locate, excavate, install a splice and restore the cable into service under an emergency situation is estimated at $9,900 to $11,800, the range is largely dependent on the excavation, backfill and restoration effort (e.g. grass, asphalt, concrete, interlock). The table below provides a comparison between planned and unplanned restoration after one fault repair and replacement.

**Table 1: Average Estimated Planned vs. Reactive Rebuild Costs for One Cable Fault**

| Activities | Planned | Reactive | % Difference |
|---|---|---|---|
| Cable Replacement (200m segment) | $ 66,400 | $ 66,400 | |
| Investigation and Repair Low Estimate | | $ 9,900 | |
| | $ 66,400 | $ 76,300 | 15% |

| Activities | Planned | Reactive | % Difference |
|---|---|---|---|
| Cable Replacement (200m segment) | $ 66,400 | $ 66,400 | |
| Investigation and Repair High Estimate | | $ 11,800 | |
| | $ 66,400 | $ 78,200 | 18% |

Considering the situation where a second splice is implemented before a cable is determined to be irreparable, the premium to repair twice and then proceed to an emergency replacement increases the costs of replacement from 30% to 36%, as identified in Table 2.

In some circumstances, where the alternative supply cable also fails, all the work will be required to be completed in overtime. Alectra Utilities is unable to estimate the average costs of an emergency repair or replacement of both the primary and alternative cables due to the number of factors to be considered, including location, type of landscape, proximity to other

underground utilities and congestion in the trench. All of these are variables that would alter the approach and costs of replacement.

**Table 2: Planned vs. Reactive Rebuild Costs for Two Cable Faults**

| Activities | Planned | Reactive | % Difference |
|---|---|---|---|
| Replacement cost (200 m segment) | $ 66,400 | $ 66,400 | |
| Investigation and Repair Low Estimate | | $ 19,800 | |
| Total | $ 66,400 | $ 86,200 | 30% |

| Activities | Planned | Reactive | % Difference |
|---|---|---|---|
| Cable Replacement (200 m segment) | $ 66,400 | $ 66,400 | |
| Investigation and Repair High Estimate | | $ 23,600 | |
| Total | $ 66,400 | $ 90,000 | 36% |

An unplanned interruption of electricity due to a cable failure is more than just inconvenient, from a customer perspective. Most functions require electricity, and not all customers have the benefit of back-up power sources. Customers who operate businesses or work from home may likely suffer financial consequences when power is interrupted unexpectedly. Such costs have not been incorporated in the average estimated cost provided above.

Finally, emergency repair and replacement also interferes with planned work. Emergency repairs are prioritized at the expense of planned work. Planned work may be deferred or cancelled completely. This may result in a delay to important system remediation, which negatively affects customers who were expecting and prepared for the work to be completed. This change of plans detrimentally affects both Alectra Utilities and its customers. Such costs have not been incorporated in the average estimate provided above.

**BOMA-93**

**Reference(s): 2018-COS05-1 – Glen Erin/Montevideo, pp 7, 10**

**(a)** **Is the intent of the project to replace all of the underground cable and pole-mounted transformers in the area, outlined in red on Figure 1, and replace the 6 km of cable, with 4.5 km of new cable at a cost of $2.06 million?**

**(b)** **How much of the 6 km of cable and how many of the pole mounded transformers are in poor or very poor condition? How much of the total cost would be spent on these cables and transformers?**

**(c)** **Please provide a before/after diagram, showing the new 4.5 km configuration vs. existing 6 km configuration.**

**(d)** **Please provide a detailed breakdown of the $2.09 million budget for the project.**

**(e)** **Please identify any reduced maintenance costs arising from implementation of the project, or increased OM&A costs that the project would generate.**

**(f)** **Please reconcile the statements of impact on customers of a past and future failure in the area, at pp 7 and 10, respectively.**

**(g)** **How was the area initially identified as a "rebuild area", in relation to the other potential "rebuild areas", and the other parts of the franchise? How many potential rebuild areas are there?**

**(h)** **How did Enersource determine the condition of the 6 km of cable and the transformers, through visual inspection of a sample length(s) or otherwise? Please discuss fully.**

**(i)** **Does Enersource have data from the ACM or otherwise an asset condition based on type of cable installed?**

**(j)** **How was the area originally identified, and delineated from adjacent areas, and more distant areas? In other words, how did Enersource determine where to draw the red line on Figure 1.**

**(k)** **What is meant by the phrase "as well as other renewal needs related to transformers and service configurations"?**

**(l)** **How does the "overlay system", referred to at p6, identify "specific system areas", which have experienced multiple failures? Does it simply provide a map over areas where a concentration of previous interruption can be noted?**

**(m)** **What would the approximate cost be to replace the underground system in the defined area with an overhead system? Did Enersource consider this option? If not, why not?**

**(n) Has Enersource prioritized the nine specific system areas requiring rebuilds? If no, please provide a prioritized list. How many other specific system areas will require rebuilds in each of the years of the DSP, and what is their priority? What are the key factors underlying the stated priority?**

**Response:**

(a) As filed in Exhibit 2, Tab 4, Schedule 11, page 34 this project involves the replacement of 8 padmounted transformers and the install of 4.5km of cable in duct, with removal/abandonment of 6km of direct buried cable for $1.96MM. This is not a complete replacement of all the underground cables or padmounted transformers within the red border in Figure 1.

(b) All the cables in the Glen Erin and Montevideo project area are in poor or very poor condition. The condition of the transformers varies; one is in fair condition; five are in good condition; and two are in very good condition, based on the 2015 Asset Condition Assessment ("ACA"). However, due to the age of the equipment, the connections from the cable to the transformers are likely to failure during operation, which will require replacement of the transformer itself. If these connections fail then under the ACA model this new information would result in the transformers having a poor condition.

(c) Diagrams showing the new 4.5 km configuration versus the existing 6 km configuration is provided in BOMA-93_Attach 1_Existing 6km configuration diagram and BOMA-93_Attach 2_New 4.5km configuration diagram.

(d) The budget for this project is $1.96MM as provided in Table 1.

Table 1 – Glen Erin/Montevideo project costs by cost category

| Cost Category | Project Cost | |
|---|---|---|
| **Labour** | $ | 117,669 |
| **Equipment** | $ | 19,611 |
| **Material** | $ | 29,417 |
| **Contractor Costs** | $ | 1,765,028 |
| **Total** | $ | 1,961,142 |

(e) No additional OM&A is expected from the completion of this project. Alectra Utilities estimated a reduction in OM&A from lower maintenance and repairs as provided in the Glen Erin & Montevideo Business Case in Appendix E of the DSP.

(f) The historic values are based on the cumulative impact that all 16 events have had. The future predicted impact is based on the median of the last 3 years in terms of number of customers affected and duration.

(g) Using the overlay methodology, this area had a significant number of cable faults.. Furthermore, additional transformer related condition information showed 8 transformers in need of replacement. The Glen Erin/Montevideo area was identified as a rebuild due to the combination of the significant number of cable faults and transformers in need of replacement in the area. Provided on pages 268-270 of the DSP are the subdivision rebuilds that Alectra Utilities is currently aware of in the Enersource Rate Zone. Including the projects for 2018 there are 23 known subdivision rebuilds.,.

(h) The cable condition information known for this subdivision is based on previous cable faults in this area that have been analyzed. This is used as a proxy for cable assets within the vicinity of the failed assets. The transformer condition information is based on visual inspection.

(i) Please see Alectra Utilities response to part b).

(j) Please see Alectra Utilities response to part g).The rebuild area is identified by plotting cable failures in the area. The rebuild area is mapped based on this information and a further assessment by the Design team to complete an in-depth review of the proposed rebuild area. The project scope is then finalized and the rebuild area is outlined as shown in Figure 1 of the Enersource Rate Zone DSP.

(k) This refers to the overlay methodology, where additional asset condition needs are also repaired/replaced in the same area to reduce truck roles and bundle work effectively. For example, the transformers in this area are fully depreciated and of an older vintage which requires an outage, in order to isolate cable segments. Replacing these transformers at the same time is more effective than replacing them on failure, since an outage is already required. The additional work and incremental cost to replace the transformer is significantly lower compared to the overall cost to replace the unit reactively.

(l) The mapping of cable failures is part of the overlay methodology. Please see page 194 of the Enersource Rate Zone DSP for further details.

(m) Alectra Utilities did not consider this option for this project in the Enersource Rate Zone. The additional costs to replace an underground system with an overhead system include costs to remove the transformers civil foundation; tree trimming; and conversion of residential

services from underground to overhead. An overhead distribution system is also subject to adverse weather conditions, impacting reliability in the area. Further, customers and municipalities prefer underground infrastructure.

(n) Please refer to Alectra Utilities response to BOMA 112.

**BOMA-94**

**Reference(s): DSP, Table 32, p133**

**(a) Please confirm that the Average Age column is an arithmetic unweighted average age of the equipment units in question, eg. for Substation Transformer, it is the aggregate number of years of each of the 108 transformers divided by 108. If not, please discuss.**

**(b) Please explain how cohorts were defined and determined from very good to very poor. For example, is the very good cohort simply the best performing fifteen percent of the equipment?**

**(c) How is the Average Health Index calculated? Please explain fully with Figure 42 on p138 as an example. In other words, what is the methodology used to assign transformers or other assets, or in the term used in evidence the "H1 computation methodology" (p138)?**

**(d) Why is there no category for overhead cables?**

**(e) What are the average term and supplier performance guarantees for each type of equipment in Table 32? Do the guarantees of performance differ much from supplier to supplier? Please provide examples of the supplier guarantees from lines, transformers and switchgear.**

**(f) Is the role of spares to replace defective transformers or to temporarily provide the service while repairs are being done or before the replacement is installed? Please show quantitatively, if possible, how spares are deployed.**

**(g) When will the company have inspection data on one hundred percent of the transformers? How was the Health Index determined for the fifteen percent of transformers which had not been inspected? How often are each of the transformers inspected, including the spares?**

**(h) Please explain the meaning of the internal faults.**

**Response:**

a) Alectra Utilities confirms that the average age column is arithmetic unweighted average age of equipment.

b) Cohorts were defined based on the asset condition assessment in terms of health index as provided below:

| | |
|---|---|
| Very Poor | HI < 25% |
| Poor | 25% <= HI < 50% |
| Fair | 50% <= HI < 70% |

Good 70% <= HI < 85%

Very Good 85% <= HI < 100%

c) Average Health Index is calculated by taking arithmetic unweighted average of health index values of all the transformers (or other assets). Health Index (HI) computation methodology means the method proposed and used by Kinectrics to quantify the asset condition.

d) Overhead cable systems were not included in the asset condition assessments at this time.

e) The average term and supplier performance guarantees for each type of equipment in Table 32 of the Enersource Rate Zone DSP is provided in Table 1 below.

1 Table 1 – Warranty terms and supplier guarantees by asset category

| Asset Category | | Average Term of Warranty | Examples of Warranty |
|---|---|---|---|
| Substation Transformers | In Service | 5 Year warranty | 5 Year warranty with PTI (Formerly CG Canada) |
| | Spares | | |
| Circuit Breakers | All | (Part of Switchgear housed in switchgear cell in substation equipment) 30 months from ready ship date/24 months energization | 30 month from ready ship date or 24 months from equipment Energization- warranty with ABB |
| | High Voltage | | |
| | Low Voltage | | |
| Pole Mounted Transformers | | 36 month warranty | 36 month warranty from Siemens Transformers Canada |
| Pad Mounted Transformers | 1 Phase | 18 months from ship date or 12 months equipment energization | 18 months from ship date or 12 months equipment energization- warranty with ABB |
| | 3 Phase | 18 months from ship date or 12 months equipment energization | 18 months from ship date or 12 months equipment energization- warranty with ABB |
| Vault Transformers | | 36 month warranty | 36 month warranty from Siemens Transformers Canada |
| Pad Mounted Switchgear | | 30 month warranty | 36 month warranty from G& W Canada, 24 month warranty from T&B |
| Overhead Switches | 44 kV | 12 month warranty-all O/H Switches- All | 12 month warranty with S&C Electric |
| | 27.6 kV | | |
| | Inline | | |
| | Motorized | | |
| Underground Cables | Main Feeder | 36 month warranty-all | 36 months after receipt of cable |
| *Note that results are given in terms of conductor-km | Distribution | | |
| Poles | Wood | 25 year warranty | 25 year warranty with Stella Jones |
| | Concrete | 62.5 year limited lifetime warranty | 75 year limited lifetime warranty with StressCrete, 50 year warranty - USI |

2

f) Spare transformers are retained as a contingency on the loss of supply of an in-service unit.

g) All in-service station transformers and spares have full inspection data. Station transformers are inspected approximately every two months and undergo full routine testing annually. Distribution class transformers are inspected on a three year rotation.

h) Internal transformer faults include; arcing, partial discharge, and thermal faults where insulating component integrity is lost resulting in short circuits in the transformer winding.

**BOMA-95**

**Reference(s): DSP, p140**

**(a) What is the breakdown between high voltage circuit breakers and low voltage circuit breakers? Please discuss their respective functions and criticality.**

**(b) What was the average replacement cost for each type of breaker?**

**(c) Why is the H1 of circuit breaker so high? Why is the H1 index for high voltage fifteen percent higher than for low voltage breakers?**

**(d) How many of the switchgear are in each station?**

**(e) Please explain the difference between circuit breakers and switchgear, using diagrams and reasonably detailed description of function, average life, cost, number of suppliers.**

**(f) Most of your switches are "load-break". What other types of switches are there, and how is each type used?**

**(g) Please describe motorized switches. How do they differ from non-motorized switches?**

**Response:**

a) A power substation transforms voltage from high to low. The voltage transformation is done by a power transformer. The circuit breaker protecting the high side of the power transformer is called high voltage circuit breaker and the circuit breaker on the secondary side of the transformer is called low voltage circuit breaker. Alectra Utilities has the following three types of substations in the Enersource Rate Zone:

1. 44kV – 27.6 kV
2. 44kV – 13.8 kV
3. 27.6 kV – 4.16 kV

For the aforementioned substations the high voltage circuit breakers are rated 44kV (for substation 1 & 2) and 27.6 for substation 3.

The low voltage circuit breakers are rated 27.6 kV (substation 1), 13.8 kV (substation 2) and 4.16 kV (substation 3).

b) The average replacement costs for each type of breaker is provided in Table 1 below. These costs include replacement parts, materials and labour.

Table 1 – Circuit breaker replacement costs

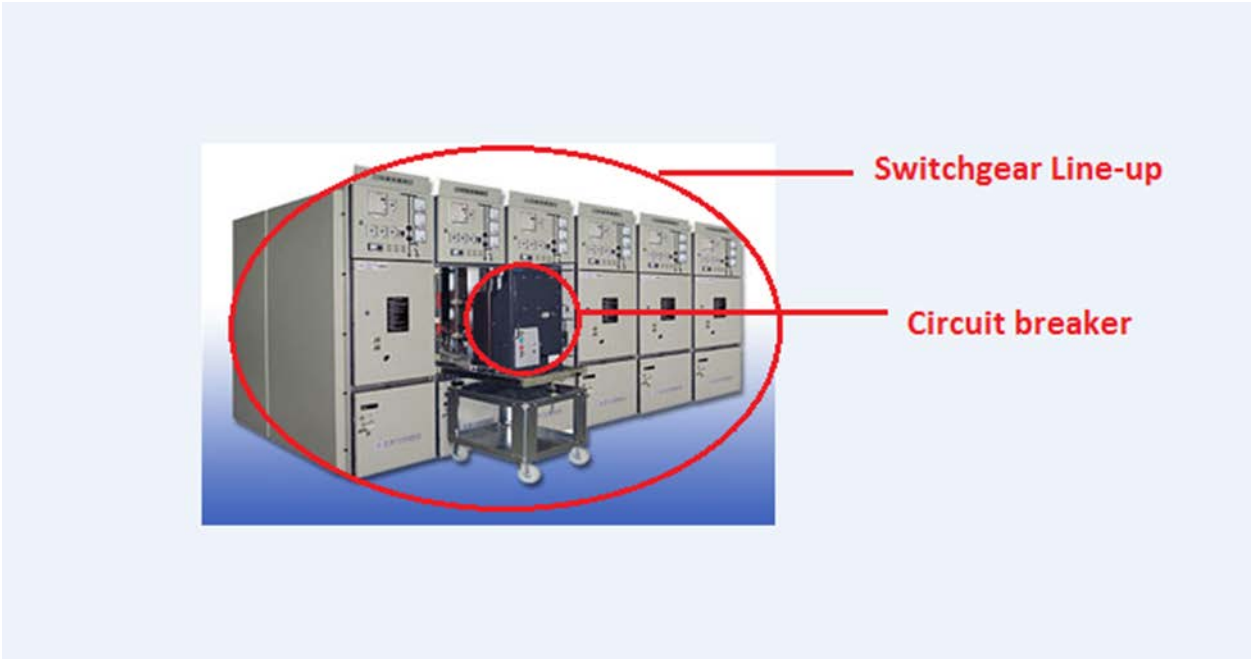
| Circuit Breaker | Replacement Cost |
|---|---|
| **44 kV** | **$165,000** |
| **27.6 kV** | **$115,000** |
| **13.8 KV** | **$120,000*** |
| **4.16 kV** | **$120,000*** |

***** The cost includes the replacement of the entire switchgear cell in addition to the circuit breaker.

c) Health Index ("HI") is calculated based on condition parameter data collected for each circuit breaker. Condition parameters include; operating mechanism, contact performance, arc extension medium, insulation type and service record. The data returned from field inspections and testing resulted in the very good ratings for both High Voltage ("HV") and Low Voltage ("LV") circuit breakers. The difference in HI for HV breakers compared to LV breakers is mainly attributed to the difference in age of the units. The average age of HV breakers is 23 years with 7% of the breaker population being greater than 40 years. For LV breakers the average age is 21 years; however, 16% of the LV breaker population is greater than 40 years.

d) There are two types of substations: single substation (with one power transformer) or double substation (with two power transformers). The single substation is contains one high voltage switchgear and one low voltage switchgear. The double substation contains two high voltage switchgear units and two low voltage switchgear units tied together with a tie circuit breaker.

e) The switchgear is the apparatus used for switching, controlling and protecting the equipment and electrical circuits. It consists of switching and protecting devices such as circuit breakers, protective relays, control panels, currents transformers, potential transformers, and various associated equipment. The circuit breaker is an automatically operated electrical switch designed to protect an electrical circuit or equipment from damage caused by excess current from a short circuit. Its basic function is to interrupt current flow after a fault is detected. The circuit breaker is part of a switchgear unit.




f) There are two types of switches:

- load-break switches which are designed to provide making or breaking of specified currents; they cannot make or interrupt fault current
- non-load switch which are suitable for opening at no-load

g) The motorized switches consist of the switch disconnector and the motor operator. They are electrically operated and can be remotely monitored and controlled. The non-motorized switches can be only manually operated using the switch handle.

**BOMA-96**

**Reference(s): DSP, p147**

**What is the purpose of an infrared thermal scan for overhead switches?**

**Response:**

The purpose of an infrared thermal scan on overhead switches is part of preventative maintenance. Using infrared cameras, 'hot' spots on connections to/from a switch can be detected and the connection replaced/repaired before failure. Infrared scans can also show hot spots on the switchblade interface with the contacts, to determine if the blade is making proper contact. Both of these situations, if detected and remedied in time could prevent an outage and potential failure of the switch.

**BOMA-97**

**Reference(s): DSP, p148, Table 133, Figure 53 / 44 kW switchgear**

**(a) Table 32 and the average 44 kW load switches of eighty-nine percent (also stated on p148). Figure 53 shows seventy-nine percent of 44 kW switches in very good condition. Please explain how the calculation is made.**

**(b) Please answer the same question for Figure 54 (27.6 kW load break switches and Figure 55.**

**Response:**

a) Average Health Index is calculated as the arithmetic unweighted average of individual health index values of all 44 kV switches. It is the summation of health index values of all 44 kV switches divided by the total population of 44 kV switches.

Individual health index calculations for switches are based on the parameters of age, visual inspections and operations records. The parameters are then scored based on information obtained regarding individual switches and weighted to provide a health index. The Asset Condition Assessment Report is provided in Alectra Utilities response to SEC-ERZ-16.

b) Average Health Index is calculated as the arithmetic unweighted average of individual health index values of all 27.6 kV switches. It is the summation of health index values of all 27.6 kV switches divided by the total population of 27.6 kV switches. Individual health index calculations for switches are based on the parameters of age, visual inspections and operations records. The parameters are then scored based on information obtained regarding individual switches and weighted to provide a health index. The Asset Condition Assessment Report is provided in Alectra Utilities response to SEC-ERZ-16.

**BOMA-98**

**Reference(s): DSP, p154**

**The evidence is that Enersource has 6,415 km of underground circuits of polymer conductor. Typically, the conductor is of the cross-linked polyethylene type.**

**(a) Of the total km, how many km are XCPE type cable? What type are the remaining cables, if any? How many km of cable are:**

- **(i) installed in concrete encased duct;**
- **(ii) installed in buried duct (please describe the difference between (i) and (ii));**
- **(iii) direct buried (no duct);**
- **(iv) how many of the 4,076 km of 200 amp distribution circuit are installed in (i), (ii), and (iii) above;**
- **(v) how many km of 600 amp main feeder cables are installed in (i), (ii), and (iii) above;**
- **(vi) when did the practice of installing all underground cables in duct (which type of duct) begin? Are all Enersource new underground cables or repaired cables installed in ducts?**

**Response:**

a) Alectra Utilities cables in the Enersource Rate Zone are all XLPE cables.

(i) The total length of cables that are in-duct (concrete-encased or buried duct) is 3,692 km.

(ii) Please see Alectra Utilities response to part (i)

(iii) The total length of cables that are direct buried is 2,622 km.

(iv) The total length of 200 amp distribution cables that are in-duct (concrete-encased or buried duct) is 2,186 km.

The total length of 200 amp distribution cables that are direct buried is 1,890 km.

(v) The total length of 600 amp main feeder cables that are in-duct (concrete encased or buried duct) is 1,506 km.

The total length of 600 amp main feeder cables that are direct buried is 732 km.

(vi) The practice of installing all underground feeder and distribution cables in duct began in1994. All new underground cables or repaired cables in the Enersource Rate Zone are installed in ducts.

**BOMA-99**

**Reference(s): DSP, p155**

**The evidence is that the failure rate of its underground direct buried cables is seven times the industry average. Is that the industry average for underground cables, or underground and overhead cables? What is the failure rate for each of the 600 amp feeder cables, and the 200 amp distribution circuits?**

**Response:**

Alectra Utilities clarifies that the evidence should state "the failure rate of its underground direct buried cables is seven times higher than Alectra Utilities' average of 0.5 failures per 100 km." Alectra Utilities does not record the failure rates of 600 amp feeder cables and 200 amp distribution circuits.

**BOMA-100**

**Reference(s): DSP, p156**

**"Rebuild areas are then identified and ranked according to operational risk, impact to customers, financial consequences, which considering labour availability and other contracts".**

**(a) Please apply that ranking method to the proposed underground projects in the DSP for 2018 construction. Please rank the Enersource underground projects against similar projects from the other three divisions.**

**(b) Please provide a copy of the internal cable study, cited at p155.**

**Response:**

a) Alectra Utilities four rate zones have different existing asset management practices, investment needs and prioritization practices. Alectra Utilities cannot provide a ranking of projects amongst the four rate zones. Please see Alectra Utilities response to BOMA 112 for a ranking of all projects within the Enersource Rate Zone.

b) The internal cable study referenced on p, 155 is provided as BOMA-100_Attach 1_Cable Failure Study.

Ongoing cable failure investigation carried out so far starting January 2014:

Total cable failures (As of March 31st 2016): 295
# of cables collected & investigated: 124 - (97 - 1/0 & 27 main feeder)

95.2% of cables that failed are direct buried (not in ducts) and without cable jacket.

Most of these cables are older than 35 years.



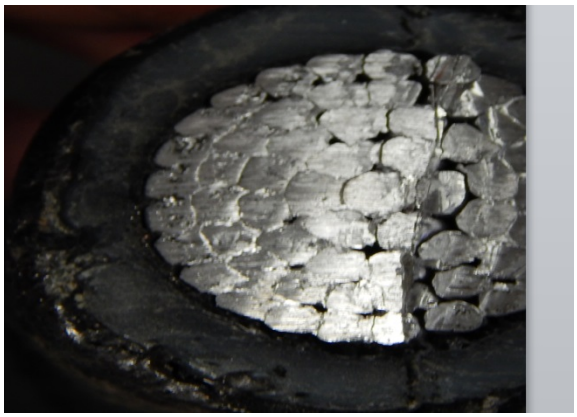
Solid Conductor - 1/0 - AL
(62.1% failure rate)



Stranded Conductor - 1/0 and Main feeder - CU
(16.9% failure rate)



Stranded Conductor - 1/0 - AL
(1.6% failure rate)



Stranded Conductor - Main feeder - AL
(19.4% failure rate)




Direct buried conductors without a jacket, solid or stranded - 1/0 & main feeder (95.2% failure rate – 2014 – March 2016)
Note: All primary cables installed over last 22 years are with jacket (4.8% failure rate - only six cables)

**BOMA-101**

**Reference(s): DSP, p160, Figures 62 and 63**

**Why is the health index of the main feeder cables much better than the lower amperage distribution cables (poor and very poor of twelve percent and twenty-one percent, respectively)? Some calculations of H1 distribution – seventy percent very good in graph vs. average all of eighty-two percent; same for Figure 63, fifty-seven percent vs. (p161 vs. seventy-five percent (p134) average.**

**Response:**

When comparing the age demographics between main feeder and distribution cables, there are less old cables in the feeder cable population than older cables in the distribution cable population. Since age is the only condition parameter for cables, it is expected that feeder cables will have a lower percentage in the very poor and poor categories than distribution cable.

**BOMA-102**

**Reference(s): DSP, p162**

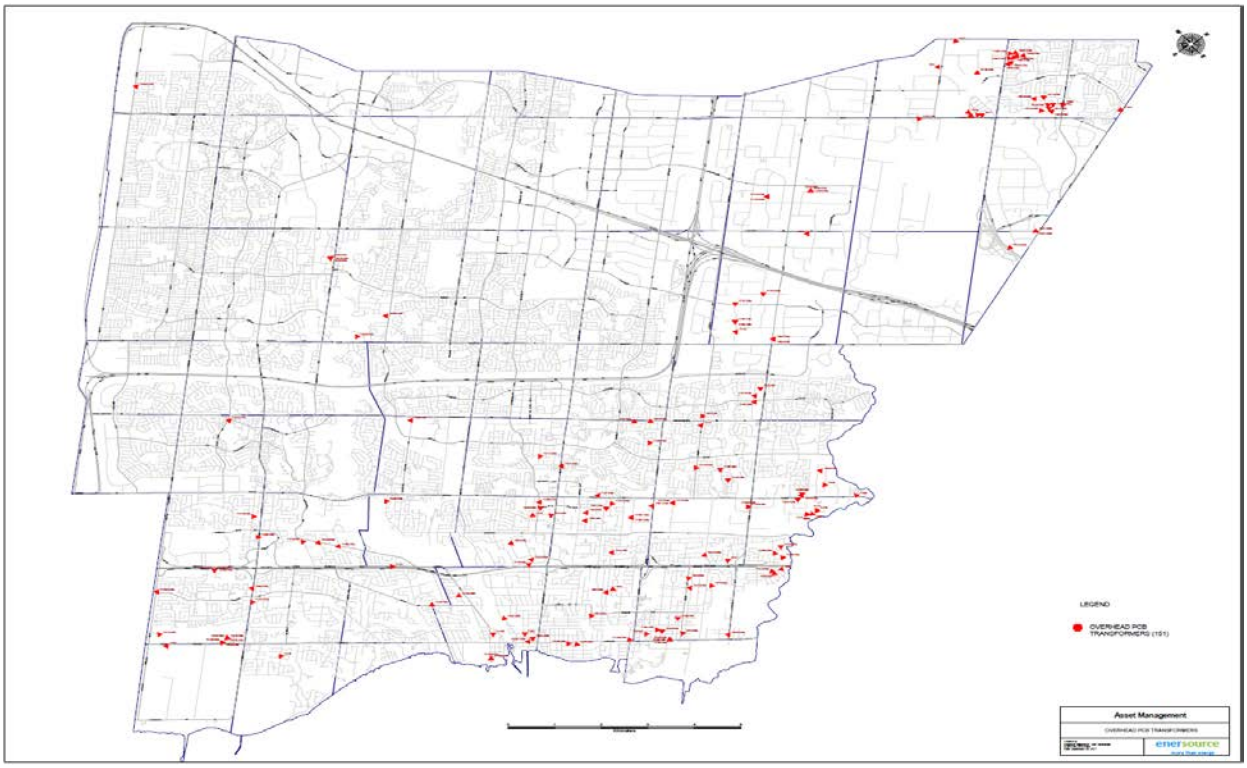
**(a) How many of the pole mounted transformers contain PCB mineral insulating oil? Does Enersource know which ones they are and where they are located? Is there a map showing the location of all of them?**

**(b) Of the four percent of pole mounted transformers in poor or very poor condition, how many:**

**(i) contained PCB oil and exhibited sign of leaking;**
**(ii) contained PCB oil, but do not show signs of leaking;**
**(iii) exhibited sign of leaking but do not contain PCB oil?**

**Response:**

a) The Asset Condition Assessment ("ACA") has identified one hundred and fifty one (151) overhead transformers containing PCB mineral insulating oil in the Enersource Rate Zone. All overhead transformers with PCB can be identified and located. The map below shows the locations of the 151 overhead transformers.




b) i) Forty-nine (49) overhead transformers contained PCB oil and exhibited sign of leaking.

(ii) One hundred and two (102) overhead transformers contained PCB oil, but do not show signs of leaking.

iii) Six hundred and one (601) overhead transformers exhibited sign of leaking but do not contain PCB oil.

**BOMA-103**

**Reference(s): DSP**

**a) How are the units inspected? How often? Are all units inspected every year? Please discuss.**

**b) What is the significance of thermal overloading data? How many transformers are loaded in excess of standard or regulation? How is the loading standard expressed, and how is it tested?**

**c) Please explain how the ninety-two percent average H1 number was calculated.**

**d) i. What is actual average life of the units, based on what amount of data.**
**ii. Please show historical data and forecast trend.**

**Response:**

a) Pole mounted transformers are inspected approximately once every three years. Inspections are performed from grade by qualified persons using binoculars. The inspection process captures defined conditions parameters observed, following a documented process.

b) Thermal overloading data represents data for events when a transformer was subjected to demands exceeding 1.5 times its rated capacity. Overload events can result in deterioration of the transformer due to the generation of excessive heat in the windings, which accelerate the breakdown of paper insulation eventually leading to failure.

In 2015 approximately 233 transformers experienced loading levels beyond 1.5 of their rated capacity.

The loading standard is expressed as a percentage of rated capacity and is measured based on actual metering data.

c) The average Health Index ("HI") of pole mounted transformers was found to be 90%. The reference to 92 % was in error. Average HI is calculated by taking arithmetic unweighted average of health index values of all the transformers. It is the summation of health index values of all pole mounted transformers divided by the total population of pole mounted transformers (i.e. 5353).

d) i) The average life of in service pole mounted transformers is 21 years as calculated from the arithmetic sum of the ages of each transformer divided by the total count (5353) of pole mounted transformers.

ii. Alectra Utilities has provided the average life of in service transformers based on the last five asset condition assessments, in Table 1. Forecast trend of average life values are not presently available.

Table 1 – Average Age of In Service Transformers

| Year | Average Transformer Age Years |
|---|---|
| 2011 | 21 |
| 2012 | 21 |
| 2013 | 22 |
| 2014 | 21 |
| 2015 | 20 |

**BOMA-104**

**Reference(s): DSP, pp 163-164; Single Phase Pad Mounted Transformer (5,363 units)**
**The evidence states:**

**"The average H1 for the fleet of single phase pad mounted transformers as 86%".**

**a) How was average H1 of eighty-six percent calculated, given the data on Figure 67? Please show calculations.**

**b) Of the two percent (351) and four percent (581) in very poor or poor condition, respectively, how many of them contained PCB mineral insulating oil and showed signs of leakage?**

**Response:**

a) Average Health Index is calculated by taking arithmetic unweighted average of health index values of all the transformers. It is the summation of health index values of all single phase pad mounted transformers (MPs) divided by the total population of single phase pad mounted transformer (i.e. 14261 MPs).

b) There are 932 (351+581) transformers in total that are in the category of poor and very poor category. 3 transformers containing PCBs were found to be leaking oil.

**BOMA-105**

**Reference(s): DSP, p165; Three Phase Pad Mounted Transformers (1,860 units)**

**a) Please explain "percentage impedance" and how that affects the health index or is otherwise significant.**

**b) Please show the sizes of the transformers in ranges.**

**c) How many of them are operating at above standard ratings? Please discuss. What are the standard ratings?**

**d) How is the H1 index number of ninety-three percent determined (see p165)?**

**e) Please describe the restrictions the city plans to place on pad mounted transformers on downtown boulevards. Are existing transformers grandfathered? Does the city plan to pay for the relocation costs? Has Alectra insisted the city pay the cost? What legislation, if any, applies?**

**f) Please explain DA1. When did Enersource acquire infrared screening equipment?**

**g) What is the average installed cost of a vault transformer vs. equal size pad mounted transformer? Has Enersource attempted to negotiate easements to install pad transformers on private land? Would this be more cost-effective than increasing and improving the vaults?**

**h) How was sixty-seven percent HI index calculated?**

**Response:**

a) The percentage impedance of a transformer is the percentage of the nominal primary voltage that is required to circulate full load current under short circuit conditions at the secondary side. Although the percentage impedance has a major effect on fault levels as it determines the maximum value of current that will flow under fault conditions, it does not affect the transformer's health index.

b) The sizes of the transformers in ranges are; 75, 150, 225, 300, 500, 750, 1000, 1500, 2000, 2500, 3000, 4000 KVA.

c) The capacity of a transformer to supply power is determined by its KVA size. If the total load being supplied by the transformer exceeds the KVA size, it is said to be operating at above standard rating. Nine units out of 1,860 were overloaded 100% of the time.

d) The average Health Index ("HI") for the group was 93%. It was calculated as the sum of all individual HIs divided by sample size of 1,860.

e) The conditions and restrictions for the installation of pad mounted equipment in the downtown core are mandated by municipal guidelines and requirements. As per the attached document from 2003, the City requires a maximized hard surface for the boulevard and a streetscape corridor, which involves the removal of pad mounted equipment from the boulevard area. Additionally, the requirements for the location of the utility infrastructure are based on the City planning departments and are communicated during the site plan application process and PUCC (please define PUCC) process. The requirements and guidelines consider boulevard treatments and a pedestrian friendly atmosphere including aesthetics. The majority of the existing pad mounted infrastructure in the downtown core has been grandfathered, however in the past year, Alectra Utilities was asked to convert some of the existing infrastructure in the downtown area.

f) DAI is data availability index which is the ratio of number of available condition data to the sum of all condition parameter weights. This number allows the analyst to verify the validity of the calculated health index. The higher the DAI, the more trustworthy the health index is.

g) Vault installations may cost 50% more than 3-phase padmount installations. In situations where access to vaults causes operational issues, Alectra Utilities had negotiated easements to install padmounts on private land. This would be more cost-effective than maintaining vaults.

h) This was calculated by dividing the 2,565 units by the total sample size of 3,854.

**BOMA-106**

**Reference(s): DSP, p165;**

**(a) Which of the capital budget projects (general plant investments, previously planned by Enersource) by Enersource have been removed by Alectra from the Enersource DSP? Please describe the type and amount of their investment according to the categories on p168?**

**(b)**

**(i) Was the current 2018 capital budget for general plant of $6,672,000 (see Exhibit 2, Tab 4, Schedule 11, p4) calculated after the removal of the items discussed in (a)?**

**(ii) How does the 2018 overall capital budget compare to what had previously been planned (in the 2015 draft DSP)? Please discuss.**

**(c) Please provide the Alectra evaluation, which have led to the proposed centralization of certain parts of general plant budget.**

**Response:**

a) The table below shows the General Plant investments that have been excluded from the Enersource RZ DSP:

**Table 1 – General plant capital expenditures excluded from DSP**

| Business Unit | 2018 |
|---|---|
| C0581 - Engineering & Asset Systems Total | $235,000 |
| C0585 - Computer Equip Total | $686,000 |
| C0588 - ERP System Total | $1,950,000 |
| C0589 - Meter to Cash Total | $1,680,000 |
| **Grand Total** | **$4,551,000** |

b)

i. Yes, the General Plant of $6,672,000 was after the removal of the above items.

ii. The 2018 overall capital budget is $1,959,000 lower than previously presented in the 2015 draft DSP. Please see Alectra Utilities response to VECC-24.

c) In light of the formation of Alectra in February 2017, certain General Plant investments that were planned by the former Enersource Hydro as a stand-alone utility, prior to the merger were deemed to be no longer specific to the Enersource Zone and therefore were excluded from the EZ-DSP. It was determined that the specific investments for certain information

systems may be abandon after Alectra converged its systems or would benefit all four rate zones. The majority of the investments that were planned related to Enersource's ERP, CC&B, or specific computer programs, such as client computing for example were reviewed and validated by the Alectra IT Leadership team on a line by line basis to determine if the budget would be allocated for the purposes of the legacy utility programs or for Alectra. An example is the client computing budget. This is considered "shared" as Alectra is allocating spending on client computing initiatives for Alectra staff and not simply new PCs for specific individuals from legacy utilities.

**BOMA-107**

**Reference(s): DSP, p72 et seq**

**(a) Please provide the year in which the warranty expires for each of the equipment makes/models in Tables 36, 37, 38 and 41.**

**(b) To what extend does Enersource negotiate warranty extensions?**

**(c) What are best practices in this area?**

**(d) What is the book value of each category of its current equipment?**

**(e) What is depreciation rate, CCA category, and amortization rate?**

**(f) Much of the equipment shown in the above table is IBM. Does the company's near exclusive use of IBM inhibit Enersource from getting the most effective service, including warranties? Did the company use an RFP driven competitive billing process for each IT contract? If not, why not? Please discuss for each major contract.**

**Response:**

a) Alectra Utilities' provides the year in which the warranty expires for each of the equipment makes/models in Tables 36, 37, 38 and 41 below.

Table 36 - List of Servers Deployed by Alectra Utilities (Enersource RZ)

| Model/Warranty Info<br><br>Warranty Expiration Info | Manufacturer<br><br>GENERIC | HP | IBM | Grand Total | Hardware Depreciation Categories |
|---|---|---|---|---|---|
| **2018** | | | **2** | **2** | |
| 7914-B3U | | | 2 | 2 | 5 Years |
| **Expired** | **1** | **2** | **13** | **16** | |
| 1U GENERIC CPU | 1 | | | 1 | 5 Years |
| Blade Center eServer | | | 1 | 1 | 5 Years |
| Blade Center System X | | | 4 | 4 | 5 Years |
| INTELLISTATIO N Z PRO | | | 1 | 1 | 5 Years |
| System x3650 | | | 1 | 1 | 5 Years |
| X3250 m4 | | | 2 | 2 | 5 Years |
| X336 Series | | | 1 | 1 | 5 Years |
| X3650 M3 series | | | 1 | 1 | 5 Years |
| xSeries 336 | | | 1 | 1 | 5 Years |
| xSeries 345 | | | 1 | 1 | 5 Years |
| Z400 | | 2 | | 2 | 5 Years |
| **Grand Total** | **1** | **2** | **15** | **18** | |

Table 37 – List of VM Hosts Deployed by Alectra Utilities (Enersource RZ) by Year of Warranty Expiration

1

| Model/Warranty Info / Warranty Expiration Info | Manufacturer: CISCO | IBM | Lenovo | Grand Total | Hardware Depreciation Categories |
|---|---|---|---|---|---|
| **2017** | **3** | **9** | | **12** | |
| 8731-AC1 | | 2 | | 2 | 5 Years |
| 8737-AC1 | | 7 | | 7 | 5 Years |
| UCS C220 M3S | 3 | | | 3 | 5 Years |
| **2018** | | **6** | | **6** | |
| 8737-AC1 | | 6 | | 6 | 5 Years |
| **2019** | | | **1** | **1** | |
| 9532-AC1 | | | 1 | 1 | 5 Years |
| **Expired** | | **27** | | **27** | |
| 8205-E6B | | 1 | | 1 | 10 Years |
| 8737-AC1 | | 8 | | 8 | 5 Years |
| 9117-MMB | | 1 | | 1 | 10 Years |
| 9406-MMA | | 1 | | 1 | 10 Years |
| HS22-7870-AC1 | | 5 | | 5 | 5 Years |
| HS22-7870-H4U | | 4 | | 4 | 5 Years |
| HS22V-7871-AC1 | | 7 | | 7 | 5 Years |
| **Grand Total** | **3** | **42** | **1** | **46** | |

Table 38 – List of Deployed Storage Area Network (SAN) by Manufacture and Warranty Expiration

| Model/Warranty Info / Warranty Expiration Info | Manufacturer: BROCADE | IBM | Grand Total | Hardware Depreciation Categories |
|---|---|---|---|---|
| **2017** | **4** | **5** | **9** | |
| 1815-82H | | 1 | 1 | 10 Years |
| 1815-84A | | 1 | 1 | 10 Years |
| 1818-80C | | 1 | 1 | 10 Years |
| 2076-124 | | 2 | 2 | 10 Years |
| 2498-F48 | 4 | | 4 | 10 Years |
| **2018** | | **6** | **6** | |
| 8721-HC1 | | 2 | 2 | 10 Years |
| 8852-4XU | | 1 | 1 | 10 Years |
| 8852-4YU | | 1 | 1 | 10 Years |
| 8852-HC1 | | 2 | 2 | 10 Years |
| **2019** | | **1** | **1** | |
| 8721-HC2 | | 1 | 1 | 10 Years |
| **Grand Total** | **4** | **12** | **16** | |

Table 41 – Infrastructure Deployed at Alectra Utilities (Enersource RZ) for Engineering Applications by Manufacturer and Warranty Expiration

| Model/Warranty Info / Warranty Expiration Info | Manufacturer IBM | Lenovo | Grand Total | Hardware Depreciation Categories |
|---|---|---|---|---|
| **2013** | **3** | | **3** | |
| HS22 / 7870 | 1 | | 1 | 5 Years |
| X3650 M2 / 7947 | 1 | | 1 | 5 Years |
| X3650 M3 /7945 | 1 | | 1 | 5 Years |
| **2014** | **3** | | **3** | |
| X3650 M3 /7945 | 3 | | 3 | 5 Years |
| **2015** | **1** | | **1** | |
| HS22 / 7870 | 1 | | 1 | 5 Years |
| **2016** | **2** | | **2** | |
| X3650 M3 /7945J4U | 2 | | 2 | 5 Years |
| **2017** | **19** | | **19** | |
| HS22 / 7870 | 1 | | 1 | 5 Years |
| X3550 / 7914 AC1 | 10 | | 10 | 5 Years |
| X3550 M4 /7914 AC1 | 2 | | 2 | 5 Years |
| X3650 M3 /7945 | 4 | | 4 | 5 Years |
| X3650 M4 /7915 AC1 | 2 | | 2 | 5 Years |
| **2018** | **5** | | **5** | |
| DS3524 / 1746 C4A | 2 | | 2 | 5 Years |
| X3550 / 7914 AC1 | 2 | | 2 | 5 Years |
| X3550 M4 /7914 AC1 | 1 | | 1 | 5 Years |
| **2019** | | **3** | **3** | |
| X3650 M5 /8871 | | 3 | 3 | 5 Years |
| **Grand Total** | **33** | **3** | **36** | |

b) Alectra Utilities' negotiates warranty extensions and utilizes third party support services in order to maximize the life of the asset in the Enersource Rate Zone. When hardware is purchased, three years warranty is included. This is the case for all platforms; after three years and if warranty extension is required as it is the case with critical hardware such as servers, SAN, AIX platforms, etc., then warranty extension is negotiated with the original vendor from where the hardware was purchased. Alectra Utilities' practice is to purchase a one year warranty extension at the time until the hardware is refreshed with new hardware, as the cost of new equipment is less than the maintenance cost of the old equipment.

c) The best practices in this area generally stipulate that if hardware is at the end of warranty, it has to be refreshed by new hardware. This is generally straightforward with the user platforms such as PC's, laptops, tablets, etc., but difficult with critical servers, SAN storage, and network appliances, etc. as they impact business operation. As such, there is always a period of time needed after the purchase warranty expires where extended warranty will need to be purchased until the hardware is refreshed by new hardware.

d) The net book value for each category of current equipment is provided in the table below.

| Useful Life | CCA Class | CCA Amortization Rate | Asset Category Description | Net Book Value |
|---|---|---|---|---|
| 3 | 50 | 55% | Computer Equipment - Desktops/Laptops/ Security Infrastructure | $ 233,808 |
| 5 | 50 | 55% | Computer Equipment – Intel/ Networking/Printing | $ 1,372,548 |
| 10 | 50 | 55% | Computer Equipment – Corporate Enterprise Systems | $ 6,877 |
| 2 | 12 | 100% | Minor Software | $ 35,732 |
| 5 | 12 | 100% | Software – Departmental, Office Automation & Collaboration | $ 2,120,910 |
| 10 | 12 | 100% | Software – Corporate Enterprise | $ 9,408,401 |

e) See d) above

f) Alectra Utilities' follow the procurement procedure and RFP limits as required in the Enersource Rate Zone. Even in the cases where the purchase cost is less than the RFP limit, quotations from multiple vendors are obtained and assessed before selecting the vendor. Also, with hardware vendors, there are normally dedicated manufacturers with "Premier Business Partner" programs which provide volume discounts. These are programs offered by the manufacturers e.g. IBM, Cisco, etc. which allows the hardware vendor to pass savings to the customer. Finally, maintaining hardware compatibility is a critical aspect of any data centre, as such equipment compatibility could dictate the purchase of certain equipment.

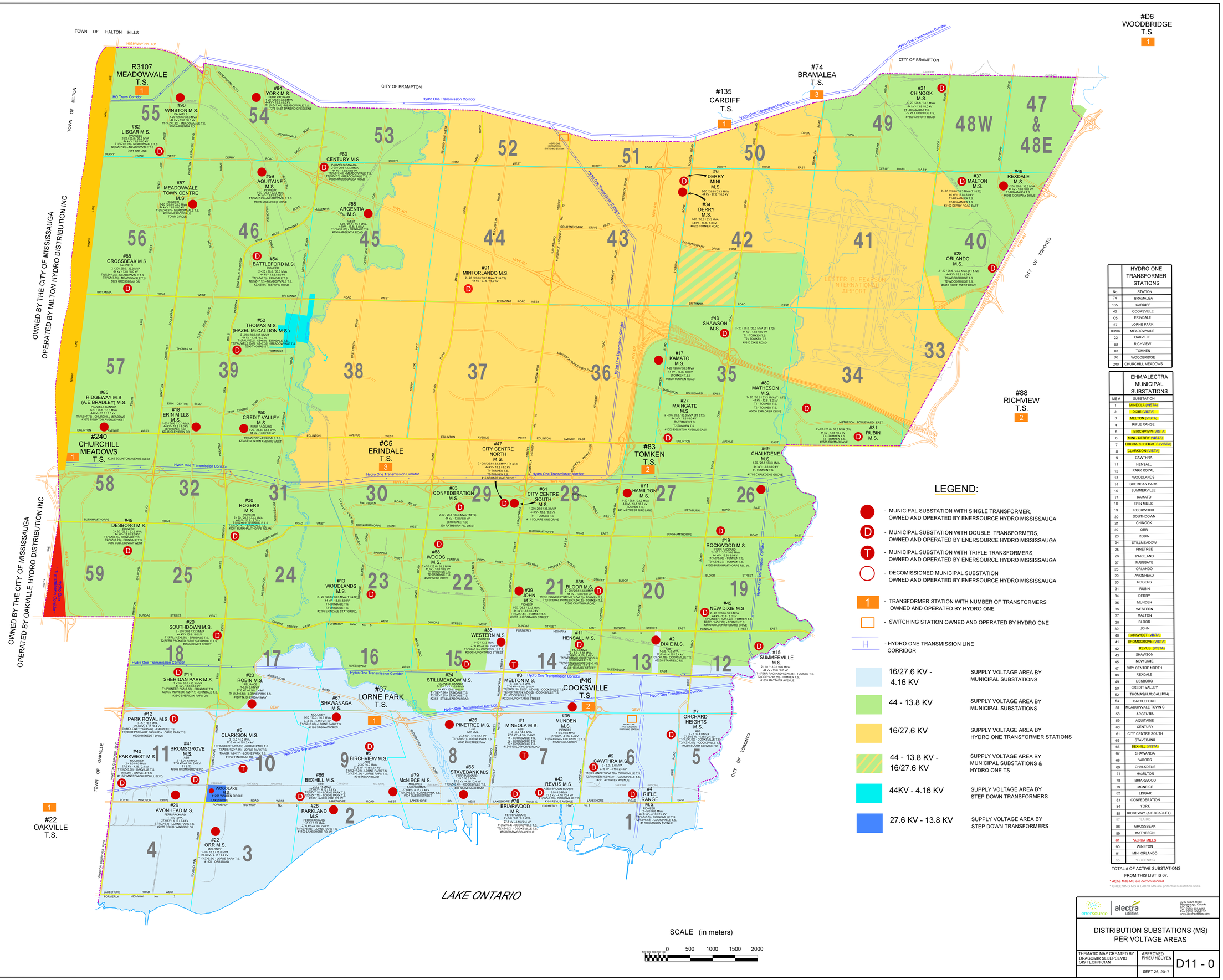
**BOMA-108**

**Reference(s): DSP, p182**

**Please provide a map showing the configuration of Hydro One TSS, Enersource MS, and the three voltage areas, as described at pp 182-183. Please provide the different system in different colours.**

**Response:**

Alectra Utilities provides the map showing the configuration of the Hydro One TS's, Enersource MS's, and voltage areas described at p. 182-183 as BOMA-108_Attach 1_Voltage Area Map.




| | HYDRO ONE TRANSFORMER STATIONS |
|---|---|
| No. | STATION |
| 74 | BRAMALEA |
| 135 | CARDIFF |
| 48 | COOKSVILLE |
| C5 | ERINDALE |
| 67 | LORNE PARK |
| R3107 | MEADOWVALE |
| 22 | OAKVILLE |
| 88 | RICHVIEW |
| 83 | TOMKEN |
| D6 | WOODBRIDGE |
| 240 | CHURCHILL MEADOWS |

| | EHM/ALECTRA MUNICIPAL SUBSTATIONS |
|---|---|
| MS # | SUBSTATION |
| 1 | MINEOLA (VISTA) |
| 2 | DIXIE (VISTA) |
| 3 | MELTON (VISTA) |
| 4 | RIFLE RANGE |
| 5 | BIRCHVIEW (VISTA) |
| 6 | MINI - DERRY (VISTA) |
| 7 | ORCHARD HEIGHTS (VISTA) |
| 8 | CLARKSON (VISTA) |
| 9 | CAWTHRA |
| 11 | HENSALL |
| 12 | PARK ROYAL |
| 13 | WOODLANDS |
| 14 | SHERIDAN PARK |
| 15 | SUMMERVILLE |
| 16 | ERIN MILLS |
| 17 | KAMATO |
| 18 | ERIN MILLS |
| 19 | ROCKWOOD |
| 20 | SOUTHDOWN |
| 21 | CHINOOK |
| 22 | ORR |
| 23 | ROBIN |
| 24 | STILLMEADOW |
| 25 | PINETREE |
| 26 | PARKLAND |
| 27 | MAINGATE |
| 28 | ORLANDO |
| 29 | AVONHEAD |
| 30 | ROGERS |
| 31 | RUBIN |
| 34 | DERRY |
| 35 | MUNDEN |
| 36 | WESTERN |
| 37 | MALTON |
| 38 | BLOOR |
| 39 | JOHN |
| 40 | PARKWEST (VISTA) |
| 41 | BROMSGROVE (VISTA) |
| 42 | REVUS (VISTA) |
| 43 | SHAWSON |
| 45 | NEW DIXIE |
| 47 | CITY CENTRE NORTH |
| 48 | REXDALE |
| 49 | DESBORO |
| 50 | CREDIT VALLEY |
| 52 | THOMAS(H.McCALLION) |
| 54 | BATTLEFORD |
| 57 | MEADOWVALE TOWN C |
| 58 | ARGENTIA |
| 59 | AQUITAINE |
| 60 | CENTURY |
| 61 | CITY CENTRE SOUTH |
| 63 | STAVEBANK |
| 66 | BEXHILL (VISTA) |
| 67 | SHAWANGA |
| 68 | WOODS |
| 69 | CHALKDENE |
| 71 | HAMILTON |
| 78 | BRIARWOOD |
| 79 | MCNEICE |
| 82 | LISGAR |
| 83 | CONFEDERATION |
| 84 | YORK |
| 85 | RIDGEWAY (A.E.BRADLEY) |
| 87 | *LAIRD |
| 88 | GROSSBEAK |
| 89 | MATHESON |
| 81 | *ALPHA MILLS |
| 90 | WINSTON |
| 91 | MINI ORLANDO |
| 55 | *GREENING |

TOTAL # OF ACTIVE SUBSTATIONS FROM THIS LIST IS 67.

* Alpha Mills MS are decomissioned.

* GREENING MS & LAIRD MS are potential substation sites.

## LEGEND:

- MUNICIPAL SUBSTATION WITH SINGLE TRANSFORMER, OWNED AND OPERATED BY ENERSOURCE HYDRO MISSISSAUGA
- D - MUNICIPAL SUBSTATION WITH DOUBLE TRANSFORMERS, OWNED AND OPERATED BY ENERSOURCE HYDRO MISSISSAUGA
- T - MUNICIPAL SUBSTATION WITH TRIPLE TRANSFORMERS, OWNED AND OPERATED BY ENERSOURCE HYDRO MISSISSAUGA
- DECOMMISSIONED MUNICIPAL SUBSTATION OWNED AND OPERATED BY ENERSOURCE HYDRO MISSISSAUGA
- 1 - TRANSFORMER STATION WITH NUMBER OF TRANSFORMERS OWNED AND OPERATED BY HYDRO ONE
- SWITCHING STATION OWNED AND OPERATED BY HYDRO ONE
- H - HYDRO ONE TRANSMISSION LINE CORRIDOR

| | |
|---|---|
| 16/27.6 KV - 4.16 KV | SUPPLY VOLTAGE AREA BY MUNICIPAL SUBSTATIONS |
| 44 - 13.8 KV | SUPPLY VOLTAGE AREA BY MUNICIPAL SUBSTATIONS |
| 16/27.6 KV | SUPPLY VOLTAGE AREA BY HYDRO ONE TRANSFORMER STATIONS |
| 44 - 13.8 KV - 16/27.6 KV | SUPPLY VOLTAGE AREA BY MUNICIPAL SUBSTATIONS & HYDRO ONE TS |
| 44KV - 4.16 KV | SUPPLY VOLTAGE AREA BY STEP DOWN TRANSFORMERS |
| 27.6 KV - 13.8 KV | SUPPLY VOLTAGE AREA BY STEP DOWN TRANSFORMERS |


enersource | alectra utilities
3240 Mavis Road
Mississauga, Ontario
L5C 1T7
Tel: (905) 273-9050
Fax: (905) 566-2737
www.electricalbbw.com


DISTRIBUTION SUBSTATIONS (MS) PER VOLTAGE AREAS

| | |
|---|---|
| THEMATIC MAP CREATED BY DRAGOMIR SLIJEPCEVIC GIS TECHNICIAN | APPROVED PHIEU NGUYEN |
| | SEPT 26, 2017 |

D11 - 0

**BOMA-109**

**Reference(s): DSP, p184**

**(a) How is "most recent peak demand" defined, over how many years does Enersource go back to deliver it?**

**(b) Is the "most recent peak demand" used to forecast loading? What other factors are considered?**

**(c) What is forecast for peak demand in 2017, 2018?**

**(d) What has been forecast vs. actual in each year since 2006?**

**(e) What has been peak demand to date in 2017?**

**(f) What has been kW/h energy consumption forecast/actual each year since 2006?**

**(g) What month has peak occurred in each year since 2006?**

**(h) What are forecast and actual peak demand by Enersource's three utility zones for each year since 2006? What is each zone forecast for 2017, 2018?**

**(i) Is the downtown core a separate "system area"? What has been forecast peak demand for [defined] downtown core for each of last five years to 2016, 2017 actual to date, and forecast for 2018?**

**(j) To what extent are the feeder utilizations in the system areas and more generally consistent over time?**

**(k) To what extent can load from an overloaded feeder be directed from one feeder to another if one feeder fails? Please discuss. What is the redundancy of the Enersource system, in layman's terms?**

**(l) What was the duration of the excess utilization for each category of feeder in Table 42 in 2011, both 350 and 450?**

**Response:**

a) The peak demand is defined as the maximum coincident demand at a given time and is expressed in kW.

b) The most recent peak demand forecast is not being used for forecasting load. One of the key distinctions between the peak demand and load forecast is the use of different weather

scenarios. Namely, normal weather is used for load forecasting, while extreme weather is used for the peak demand forecast.

c) Alectra Utilities peak demand forecast for 2017 and 2018 in the North, South, West and East system planning zones in the Enersource Rate Zone are provided in Table 1 below.

| | 2017 Peak Demand Forecast (MW) | 2018 Peak Demand Forecast (MW) |
|---|---|---|
| NORTH | 400 | 417 |
| SOUTH | 270 | 281 |
| WEST | 540 | 583 |
| EAST | 430 | 475 |

d) Please see Alectra Utilities response to part h).

e) The peak demand to date in 2017 occurred on September 25 2017 at 1,390 MW.

f) Alectra Utilities provides the kW/h energy consumption forecast/actual each year since 2006 for the Enersource Rate Zone in Table 2.

Table 2 – Actual and forecasted energy consumption (2006-2016)

| Year | Actual Energy Consumption (kWh) | Forecasted Energy Consumption (kWh) |
|---|---|---|
| 2006 | 8,038,676,000 | 8,153,097,000 |
| 2007 | 8,249,692,000 | 8,244,528,000 |
| 2008 | 8,096,552,000 | 8,234,669,000 |
| 2009 | 7,742,344,000 | 8,064,633,000 |
| 2010 | 7,949,146,000 | 7,866,814,000 |
| 2011 | 7,880,490,000 | 7,914,667,000 |
| 2012 | 7,838,842,6 | 7,842,232,228 |
| 2013 | 7,688,147,4 | 7,698,594,205 |
| 2014 | 7,574,043,0 | 7,673,075,566 |
| 2015 | 7,439,309,0 | 7,618,885,088 |
| 2016 | 7,569,393,9 | 7,325,595,110 |

g) Table 3 identifies the month when the system peak has occurred since 2006.

Table 3 – System peak (month) 2006-2017

| Year | Peak (Month) |
|---|---|
| 2017 YTD | September |
| 2016 | September |
| 2015 | September |
| 2014 | August |
| 2013 | July |
| 2012 | July |
| 2011 | July |
| 2010 | July |
| 2009 | August |
| 2008 | June |
| 2007 | August |
| 2006 | August |

h) Enersource has been forecasting the peak demand by the system planning zones since 2012 and is able to provide the forecast figures since 2012. The actual peak demand has been provided from 2006, in Table 4 below. It's important to note that the peak demand forecasted figures were derived using the extreme weather and are meant to provide an indication of loading in each of the system planning zones under extreme weather conditions.

Table 4 – Actual and forecasted peak demand by system planning zone (2006-2018)

| *(in MW)* | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **North Actual** | 396 | 394 | 382 | 379 | 372 | 390 | 369 | 378 | 323 | 331 | 339 | 373 | |
| **North Forecasted** | | | | | | | 413 | 423 | 414 | 422 | 427 | 400 | 417 |
| | | | | | | | | | | | | | |
| **South Actual** | 267 | 260 | 254 | 238 | 260 | 271 | 255 | 256 | 231 | 219 | 206 | 167 | |
| **South Forecasted** | | | | | | | 273 | 262 | 276 | 272 | 271 | 270 | 281 |
| | | | | | | | | | | | | | |
| **West Actual** | 513 | 494 | 472 | 485 | 532 | 551 | 546 | 523 | 436 | 461 | 470 | 428 | |
| **West Forecasted** | | | | | | | 577 | 582 | 588 | 592 | 595 | 540 | 583 |
| | | | | | | | | | | | | | |
| **East Actual** | 456 | 433 | 421 | 405 | 421 | 419 | 407 | 426 | 381 | 389 | 418 | 422 | |
| **East Forecasted** | | | | | | | 464 | 475 | 462 | 473 | 481 | 430 | 475 |

i) The downtown core area is not identified as a separate system planning zone. Alectra Utilities is unable to extract the actual and forecasted growth in the downtown core. The load forecast in the downtown district is completed for the substation planning at 13.8kV level

j) Once the feeders are balanced in a normal operation, the utilization is fairly consistent.

k) Switching points are available through station and feeder ties. Alectra Utilities utilizes a loop system and plans the system using n-1 redundancy in the Enersource Rate Zone. The use of n-1 redundancy means that if the station/feeder fails it can be backed up by one or multiple feeders/stations. Alectra Utilities has established a planning limit of 350A during normal conditions and 600A during contingency conditions which ensures that during contingency condition (i.e. loss of the feeder), the load can be picked up by other feeder(s) in the network.

l) The duration for excess feeder loading from Table 42 is not available.

**BOMA-110**

**Reference(s): DSP, p186**

**When will additional capacity be required in the South (16/27.6 kV) system, given that it currently has 100 MW of spare capacity?**

**Response:**

Alectra Utilities forecasts that additional capacity will be required to support intensification and future developments in the South system area. There are few known large developments in the South:

- LRT TPSS (Transit Power Switching Stations). This will add approximately 3MW;
- Texaco Lands consultants have indicated a development potential of 33MW however Alectra Utilities does not have a firm timeframe;
- The Inspiration Port Credit Marina development would add another 4.5MW; and
- A proposed Lakeview development and other intensification projects being developed.

Based on the current growth projections additional transformation capacity on 27.6 kV would only be required in a longer time frame of over 15 – 20 years. This timeline may be advanced depending on the intensity of the current and future developments.

**BOMA-111**

**Reference(s): Attachment 48**

**Please provide the 2018 forecast addition to rate base as a result of the ten ICM-funded capital projects listed on p1. Please show the calculations necessary to arrive at the incremental revenue requirement of $1,962,111.**

**Response:**

Alectra Utilities relied on the Ontario Energy Board's ("OEB") Capital Module Applicable to ACM and ICM ("Capital Module") to calculate incremental revenue requirement for the Enersource rate zone. The Capital Module for the Enersource rate zone is provided in Exhibit 3, Tab 1, Schedule 1, Attachment 45 – Incremental Capital Module Enersource RZ. The detailed calculations of incremental revenue requirement by project as summarized in Exhibit 3, Tab 1, Schedule 1, Attachment 48 – ICM Revenue Requirement by Project Enersource RZ, is included as Attachments 1 to 11 of BOMA-111.

Ontario Energy Board

# Capital Module
# Applicable to ACM and ICM

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

| | *Cost of Service* | *Price Cap IR* | | | |
|---|---|---|---|---|---|
| | Test Year 2013 | Year 2 2015 | Year 3 2016 | Year 4 2017 | Year 5 2018 |
| Distribution System Plan CAPEX | | | | | $ 72,682,772 |
| Materiality Threshold | | $ 42,869,478 | $ 43,074,036 | $ 43,282,305 | $ 43,494,353 |
| Maximum Eligible Incremental Capital (Forecasted Capex less Threshold) | $ - | $ - | $ - | $ - | $ 29,188,419 |

| Project Descriptions: | Type | Test Year 2013 | Year 2 2015 | Year 3 2016 | Year 4 2017 | Year 5 2018 | Total |
|---|---|---|---|---|---|---|---|
| QEW - Evans to Cawthra Roads Project | | | | | | $ 1,294,220 | **$ 1,294,220** |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | $ - |
| | | | | | | | $ - |
| | | | | | | | $ - |
| | | | | | | | $ - |
| | | | | | | | $ - |
| | | | | | | | $ - |
| | | | | | | | $ - |
| Total Cost of ACM Projects | | $ - | $ - | $ - | $ - | $ 1,294,220 | **$ 1,294,220** |
| Maximum Allowed Incremental Capital | | | $ - | $ - | $ - | $ 1,294,220 | $ 1,294,220 |

| | | *Price Cap IR* | | | |
|---|---|---|---|---|---|
| | Test Year 2013 | Year 1 2015 | Year 2 2016 | Year 3 2017 | Year 4 2018 |
| Distribution System Plan CAPEX | $ - | $ - | $ - | $ - | $ 72,682,772 |
| Materiality Threshold | | $ 42,869,478 | $ 43,074,036 | $ 43,282,305 | $ 43,494,353 |
| Maximum Eligible Incremental Capital (Forecasted Capex less Threshold) | $ - | $ - | $ - | $ - | $ 29,188,419 |

| | | Test Year | Year 1 2015 | | | Year 2 2016 | | | Year 3 2017 | | | Year 4 2018 | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Project Descriptions: | Type | 2013 | Proposed ACM/ICM | Amortization Expense | CCA | Proposed ACM/ICM | Amortization Expense | CCA | Proposed ACM/ICM | Amortization Expense | CCA | Proposed ACM/ICM | Amortization Expense | CCA |
| QEW - Evans to Cawthra Roads Project | | | $ - | | | $ - | | | $ - | | | **$ 1,294,220** | $ 25,295 | $ 103,504 |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| Total Cost of Projects | | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ 1,294,220 | $ 25,295 | $ 103,504 |

Ontario Energy Board

# Capital Module
# Applicable to ACM and ICM

0

**Incremental Capital Adjustment**

| Current Revenue Requirement | | | | | |
|---|---|---|---|---|---|
| Current Revenue Requirement - Total | | | $ | 117,989,982 | A |

| Return on Rate Base | | | | | |
|---|---|---|---|---|---|
| Incremental Capital | | | $ | 1,294,220 | B |
| Depreciation Expense | | | $ | 25,295 | C |
| Incremental Capital to be included in Rate Base | | | $ | 1,268,925 | D = B - C |
| Deemed ShortTerm Debt % | 4.0% | E | $ | 50,757 | G = D * E |
| Deemed Long Term Debt % | 56.0% | F | $ | 710,598 | H = D * F |
| Short Term Interest | 2.08% | I | $ | 1,056 | K = G * I |
| Long Term Interest | 5.09% | J | $ | 36,169 | L = H * J |
| Return on Rate Base - Interest | | | $ | 37,225 | M = K + L |
| Deemed Equity % | 40.00% | N | $ | 507,570 | P = D * N |
| Return on Rate Base -Equity | 8.93% | O | $ | 45,326 | Q = P * O |
| Return on Rate Base - Total | | | $ | 82,551 | R = M + Q |

| Amortization Expense | | | | | |
|---|---|---|---|---|---|
| Amortization Expense - Incremental | | C | $ | 25,295 | S |

| Grossed up PIL's | | | | | |
|---|---|---|---|---|---|
| Regulatory Taxable Income | | O | $ | 45,326 | T |
| Add Back Amortization Expense | | S | $ | 25,295 | U |
| Deduct CCA | | | $ | 103,504 | V |
| Incremental Taxable Income | | | -$ | 32,882 | W = T + U - V |
| Current Tax Rate | 26.5% | X | | | |
| PIL's Before Gross Up | | | -$ | 8,714 | Y = W * X |
| Incremental Grossed Up PIL's | | | -$ | 11,856 | Z = Y / ( 1 - X ) |

| Incremental Revenue Requirement | | | | | |
|---|---|---|---|---|---|
| Return on Rate Base - Total | | Q | $ | 82,551 | AA |
| Amortization Expense - Total | | S | $ | 25,295 | AB |
| Incremental Grossed Up PIL's | | Z | -$ | 11,856 | AC |
| Incremental Revenue Requirement | | | $ | 95,991 | AD = AA + AB + AC |

Ontario Energy Board

# Capital Module
# Applicable to ACM and ICM

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

| | *Cost of Service* | *Price Cap IR* | | | |
|---|---|---|---|---|---|
| | Test Year 2013 | Year 2 2015 | Year 3 2016 | Year 4 2017 | Year 5 2018 |
| Distribution System Plan CAPEX | | | | | $ 72,682,772 |
| Materiality Threshold | | $ 42,869,478 | $ 43,074,036 | $ 43,282,305 | $ 43,494,353 |
| Maximum Eligible Incremental Capital (Forecasted Capex less Threshold) | $ - | $ - | $ - | $ - | $ 29,188,419 |

| Project Descriptions: | Type | Test Year 2013 | Year 2 2015 | Year 3 2016 | Year 4 2017 | Year 5 2018 | Total |
|---|---|---|---|---|---|---|---|
| Leaking Transformer Replacement Project - Overhead | New ICM | | | | | $ 8,447,243 | **$ 8,447,243** |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | $ - |
| | | | | | | | $ - |
| | | | | | | | $ - |
| | | | | | | | $ - |
| | | | | | | | $ - |
| | | | | | | | $ - |
| | | | | | | | $ - |
| Total Cost of ACM Projects | | $ - | $ - | $ - | $ - | $ 8,447,243 | **$ 8,447,243** |
| Maximum Allowed Incremental Capital | | | $ - | $ - | $ - | $ 8,447,243 | $ 8,447,243 |

| | | *Price Cap IR* | | | |
|---|---|---|---|---|---|
| | Test Year 2013 | Year 1 2015 | Year 2 2016 | Year 3 2017 | Year 4 2018 |
| Distribution System Plan CAPEX | $ - | $ - | $ - | $ - | $ 72,682,772 |
| Materiality Threshold | | $ 42,869,478 | $ 43,074,036 | $ 43,282,305 | $ 43,494,353 |
| Maximum Eligible Incremental Capital (Forecasted Capex less Threshold) | $ - | $ - | $ - | $ - | $ 29,188,419 |

| | | Test Year 2013 | Year 1 2015 | | | Year 2 2016 | | | Year 3 2017 | | | Year 4 2018 | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Project Descriptions: | Type | | Proposed ACM/ICM | Amortization Expense | CCA | Proposed ACM/ICM | Amortization Expense | CCA | Proposed ACM/ICM | Amortization Expense | CCA | Proposed ACM/ICM | Amortization Expense | CCA |
| Leaking Transformer Replacement Project - Overhead | New ICM | | $ - | | | $ - | | | $ - | | | **$ 8,447,243** | $ 223,559 | $ 675,614 |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| Total Cost of Projects | | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ 8,447,243 | $ 223,559 | $ 675,614 |

Ontario Energy Board

# Capital Module
# Applicable to ACM and ICM

0

**Incremental Capital Adjustment**

| | | | | | |
|---|---|---|---|---|---|
| **Current Revenue Requirement** | | | | | |
| Current Revenue Requirement - Total | | | $ | 117,989,982 | **A** |
| **Return on Rate Base** | | | | | |
| Incremental Capital | | | $ | 8,447,243 | **B** |
| Depreciation Expense | | | $ | 223,559 | **C** |
| Incremental Capital to be included in Rate Base | | | $ | 8,223,683 | **D = B - C** |
| Deemed ShortTerm Debt % | 4.0% | **E** | $ | 328,947 | **G = D * E** |
| Deemed Long Term Debt % | 56.0% | **F** | $ | 4,605,263 | **H = D * F** |
| Short Term Interest | 2.08% | **I** | $ | 6,842 | **K = G * I** |
| Long Term Interest | 5.09% | **J** | $ | 234,408 | **L = H * J** |
| Return on Rate Base - Interest | | | $ | 241,250 | **M = K + L** |
| Deemed Equity % | 40.00% | **N** | $ | 3,289,473 | **P = D * N** |
| Return on Rate Base -Equity | 8.93% | **O** | $ | 293,750 | **Q = P * O** |
| Return on Rate Base - Total | | | $ | 535,000 | **R = M + Q** |
| **Amortization Expense** | | | | | |
| Amortization Expense - Incremental | | **C** | $ | 223,559 | **S** |
| **Grossed up PIL's** | | | | | |
| Regulatory Taxable Income | | **O** | $ | 293,750 | **T** |
| Add Back Amortization Expense | | **S** | $ | 223,559 | **U** |
| Deduct CCA | | | $ | 675,614 | **V** |
| Incremental Taxable Income | | | -$ | 158,305 | **W = T + U - V** |
| Current Tax Rate | 26.5% | **X** | | | |
| PIL's Before Gross Up | | | -$ | 41,951 | **Y = W * X** |
| Incremental Grossed Up PIL's | | | -$ | 57,076 | **Z = Y / ( 1 - X )** |
| **Incremental Revenue Requirement** | | | | | |
| Return on Rate Base - Total | | **Q** | $ | 535,000 | **AA** |
| Amortization Expense - Total | | **S** | $ | 223,559 | **AB** |
| Incremental Grossed Up PIL's | | **Z** | -$ | 57,076 | **AC** |
| Incremental Revenue Requirement | | | $ | 701,483 | **AD = AA + AB + AC** |

Ontario Energy Board

# Capital Module
# Applicable to ACM and ICM

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

| | *Cost of Service* | *Price Cap IR* | | | |
|---|---|---|---|---|---|
| | Test Year 2013 | Year 2 2015 | Year 3 2016 | Year 4 2017 | Year 5 2018 |
| Distribution System Plan CAPEX | | | | | $ 72,682,772 |
| Materiality Threshold | | $ 42,869,478 | $ 43,074,036 | $ 43,282,305 | $ 43,494,353 |
| Maximum Eligible Incremental Capital (Forecasted Capex less Threshold) | $ - | $ - | $ - | $ - | $ 29,188,419 |

| Project Descriptions: | Type | Test Year 2013 | Year 2 2015 | Year 3 2016 | Year 4 2017 | Year 5 2018 | Total |
|---|---|---|---|---|---|---|---|
| York MS | | | | | | $ 3,268,463 | **$ 3,268,463** |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | $ - |
| | | | | | | | $ - |
| | | | | | | | $ - |
| | | | | | | | $ - |
| | | | | | | | $ - |
| | | | | | | | $ - |
| | | | | | | | $ - |
| Total Cost of ACM Projects | | $ - | $ - | $ - | $ - | $ 3,268,463 | **$ 3,268,463** |
| Maximum Allowed Incremental Capital | | | $ - | $ - | $ - | $ 3,268,463 | $ 3,268,463 |

| | *Price Cap IR* | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | Test Year 2013 | Year 1 2015 | | Year 2 2016 | | Year 3 2017 | | Year 4 2018 |
| Distribution System Plan CAPEX | $ - | $ - | | $ - | | $ - | | $ 72,682,772 |
| Materiality Threshold | | $ 42,869,478 | | $ 43,074,036 | | $ 43,282,305 | | $ 43,494,353 |
| Maximum Eligible Incremental Capital (Forecasted Capex less Threshold) | $ - | $ - | | $ - | | $ - | | $ 29,188,419 |

| | | Test Year | Year 1 2015 | | | Year 2 2016 | | | Year 3 2017 | | | Year 4 2018 | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Project Descriptions: | Type | 2013 | Proposed ACM/ICM | Amortization Expense | CCA | Proposed ACM/ICM | Amortization Expense | CCA | Proposed ACM/ICM | Amortization Expense | CCA | Proposed ACM/ICM | Amortization Expense | CCA |
| York MS | | | $ - | | | $ - | | | $ - | | | **$ 3,268,463** | $ 62,142 | $ 217,124 |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| Total Cost of Projects | | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ 3,268,463 | $ 62,142 | $ 217,124 |

Ontario Energy Board

# Capital Module
# Applicable to ACM and ICM

0

**Incremental Capital Adjustment**

| | | | | | |
|---|---|---|---|---|---|
| **Current Revenue Requirement** | | | | | |
| Current Revenue Requirement - Total | | | $ | 117,989,982 | **A** |
| **Return on Rate Base** | | | | | |
| Incremental Capital | | | $ | 3,268,463 | **B** |
| Depreciation Expense | | | $ | 62,142 | **C** |
| Incremental Capital to be included in Rate Base | | | $ | 3,206,321 | **D = B - C** |
| Deemed ShortTerm Debt % | 4.0% | **E** | $ | 128,253 | **G = D * E** |
| Deemed Long Term Debt % | 56.0% | **F** | $ | 1,795,540 | **H = D * F** |
| Short Term Interest | 2.08% | **I** | $ | 2,668 | **K = G * I** |
| Long Term Interest | 5.09% | **J** | $ | 91,393 | **L = H * J** |
| Return on Rate Base - Interest | | | $ | 94,061 | **M = K + L** |
| Deemed Equity % | 40.00% | **N** | $ | 1,282,528 | **P = D * N** |
| Return on Rate Base -Equity | 8.93% | **O** | $ | 114,530 | **Q = P * O** |
| Return on Rate Base - Total | | | $ | 208,590 | **R = M + Q** |
| **Amortization Expense** | | | | | |
| Amortization Expense - Incremental | | **C** | $ | 62,142 | **S** |
| **Grossed up PIL's** | | | | | |
| Regulatory Taxable Income | | **O** | $ | 114,530 | **T** |
| Add Back Amortization Expense | | **S** | $ | 62,142 | **U** |
| Deduct CCA | | | $ | 217,124 | **V** |
| Incremental Taxable Income | | | -$ | 40,453 | **W = T + U - V** |
| Current Tax Rate | 26.5% | **X** | | | |
| PIL's Before Gross Up | | | -$ | 10,720 | **Y = W * X** |
| Incremental Grossed Up PIL's | | | -$ | 14,585 | **Z = Y / ( 1 - X )** |
| **Incremental Revenue Requirement** | | | | | |
| Return on Rate Base - Total | | **Q** | $ | 208,590 | **AA** |
| Amortization Expense - Total | | **S** | $ | 62,142 | **AB** |
| Incremental Grossed Up PIL's | | **Z** | -$ | 14,585 | **AC** |
| Incremental Revenue Requirement | | | $ | 256,147 | **AD = AA + AB + AC** |

Ontario Energy Board

# Capital Module
# Applicable to ACM and ICM

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

| | *Cost of Service* | *Price Cap IR* | | | |
|---|---|---|---|---|---|
| | Test Year 2013 | Year 2 2015 | Year 3 2016 | Year 4 2017 | Year 5 2018 |
| Distribution System Plan CAPEX | | | | | $ 72,682,772 |
| Materiality Threshold | | $ 42,869,478 | $ 43,074,036 | $ 43,282,305 | $ 43,494,353 |
| Maximum Eligible Incremental Capital (Forecasted Capex less Threshold) | $ - | $ - | $ - | $ - | $ 29,188,419 |

| Project Descriptions: | Type | Test Year 2013 | Year 2 2015 | Year 3 2016 | Year 4 2017 | Year 5 2018 | Total |
|---|---|---|---|---|---|---|---|
| Glen Erin & Montevideo Subdivision Rebuild | | | | | | $ 1,961,142 | **$ 1,961,142** |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | $ - |
| | | | | | | | $ - |
| | | | | | | | $ - |
| | | | | | | | $ - |
| | | | | | | | $ - |
| | | | | | | | $ - |
| Total Cost of ACM Projects | | $ - | $ - | $ - | $ - | $ 1,961,142 | **$ 1,961,142** |
| Maximum Allowed Incremental Capital | | | $ - | $ - | $ - | $ 1,961,142 | $ 1,961,142 |

| | *Price Cap IR* | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | Test Year 2013 | Year 1 2015 | | Year 2 2016 | | Year 3 2017 | | Year 4 2018 | |
| Distribution System Plan CAPEX | $ - | $ - | | $ - | | $ - | | $ 72,682,772 | |
| Materiality Threshold | | $ 42,869,478 | | $ 43,074,036 | | $ 43,282,305 | | $ 43,494,353 | |
| Maximum Eligible Incremental Capital (Forecasted Capex less Threshold) | $ - | $ - | | $ - | | $ - | | $ 29,188,419 | |

| | | Test Year | Year 1 2015 | | | Year 2 2016 | | | Year 3 2017 | | | Year 4 2018 | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Project Descriptions: | Type | 2013 | Proposed ACM/ICM | Amortization Expense | CCA | Proposed ACM/ICM | Amortization Expense | CCA | Proposed ACM/ICM | Amortization Expense | CCA | Proposed ACM/ICM | Amortization Expense | CCA |
| Glen Erin & Montevideo Subdivision Rebuild | | | $ - | | | $ - | | | $ - | | | **$ 1,961,142** | $ 48,174 | $ 156,891 |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| Total Cost of Projects | | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ 1,961,142 | $ 48,174 | $ 156,891 |

Ontario Energy Board

# Capital Module
# Applicable to ACM and ICM

0

**Incremental Capital Adjustment**

| Current Revenue Requirement | | | | | |
|---|---|---|---|---|---|
| Current Revenue Requirement - Total | | | $ | 117,989,982 | A |

| Return on Rate Base | | | | | |
|---|---|---|---|---|---|
| Incremental Capital | | | $ | 1,961,142 | B |
| Depreciation Expense | | | $ | 48,174 | C |
| Incremental Capital to be included in Rate Base | | | $ | 1,912,968 | D = B - C |
| Deemed ShortTerm Debt % | 4.0% | E | $ | 76,519 | G = D * E |
| Deemed Long Term Debt % | 56.0% | F | $ | 1,071,262 | H = D * F |
| Short Term Interest | 2.08% | I | $ | 1,592 | K = G * I |
| Long Term Interest | 5.09% | J | $ | 54,527 | L = H * J |
| Return on Rate Base - Interest | | | $ | 56,119 | M = K + L |
| Deemed Equity % | 40.00% | N | $ | 765,187 | P = D * N |
| Return on Rate Base -Equity | 8.93% | O | $ | 68,331 | Q = P * O |
| Return on Rate Base - Total | | | $ | 124,450 | R = M + Q |

| Amortization Expense | | | | | |
|---|---|---|---|---|---|
| Amortization Expense - Incremental | | C | $ | 48,174 | S |

| Grossed up PIL's | | | | | |
|---|---|---|---|---|---|
| Regulatory Taxable Income | | O | $ | 68,331 | T |
| Add Back Amortization Expense | | S | $ | 48,174 | U |
| Deduct CCA | | | $ | 156,891 | V |
| Incremental Taxable Income | | | -$ | 40,386 | W = T + U - V |
| Current Tax Rate | 26.5% | X | | | |
| PIL's Before Gross Up | | | -$ | 10,702 | Y = W * X |
| Incremental Grossed Up PIL's | | | -$ | 14,561 | Z = Y / ( 1 - X ) |

| Incremental Revenue Requirement | | | | | |
|---|---|---|---|---|---|
| Return on Rate Base - Total | | Q | $ | 124,450 | AA |
| Amortization Expense - Total | | S | $ | 48,174 | AB |
| Incremental Grossed Up PIL's | | Z | -$ | 14,561 | AC |
| Incremental Revenue Requirement | | | $ | 158,063 | AD = AA + AB + AC |

Ontario Energy Board

# Capital Module
# Applicable to ACM and ICM

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

| | *Cost of Service* | *Price Cap IR* | | | |
|---|---|---|---|---|---|
| | Test Year 2013 | Year 2 2015 | Year 3 2016 | Year 4 2017 | Year 5 2018 |
| Distribution System Plan CAPEX | | | | | $ 72,682,772 |
| Materiality Threshold | | $ 42,869,478 | $ 43,074,036 | $ 43,282,305 | $ 43,494,353 |
| Maximum Eligible Incremental Capital (Forecasted Capex less Threshold) | $ - | $ - | $ - | $ - | $ 29,188,419 |

| Project Descriptions: | Type | Test Year 2013 | Year 2 2015 | Year 3 2016 | Year 4 2017 | Year 5 2018 | Total |
|---|---|---|---|---|---|---|---|
| Glen Erin & Battleford Subdivison Rebuild | | | | | | $ 2,064,360 | **$ 2,064,360** |
| | | | | | | | $ - |
| | | | | | | | $ - |
| | | | | | | | $ - |
| | | | | | | | $ - |
| | | | | | | | $ - |
| | | | | | | | $ - |
| | | | | | | | $ - |
| | | | | | | | $ - |
| Total Cost of ACM Projects | | $ - | $ - | $ - | $ - | $ 2,064,360 | **$ 2,064,360** |
| Maximum Allowed Incremental Capital | | | $ - | $ - | $ - | $ 2,064,360 | $ 2,064,360 |

| | | *Price Cap IR* | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Test Year 2013 | Year 1 2015 | | Year 2 2016 | | Year 3 2017 | | Year 4 2018 | |
| Distribution System Plan CAPEX | $ - | $ - | | $ - | | $ - | | $ 72,682,772 | |
| Materiality Threshold | | $ 42,869,478 | | $ 43,074,036 | | $ 43,282,305 | | $ 43,494,353 | |
| Maximum Eligible Incremental Capital (Forecasted Capex less Threshold) | $ - | $ - | | $ - | | $ - | | $ 29,188,419 | |

| | | Test Year | Year 1 2015 | | | Year 2 2016 | | | Year 3 2017 | | | Year 4 2018 | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Project Descriptions: | Type | 2013 | Proposed ACM/ICM | Amortization Expense | CCA | Proposed ACM/ICM | Amortization Expense | CCA | Proposed ACM/ICM | Amortization Expense | CCA | Proposed ACM/ICM | Amortization Expense | CCA |
| Glen Erin & Battleford Subdivison Rebuild | | | $ - | | | $ - | | | $ - | | | **$ 2,064,360** | $ 50,710 | $ 165,149 |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| Total Cost of Projects | | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ 2,064,360 | $ 50,710 | $ 165,149 |

Ontario Energy Board

# Capital Module
# Applicable to ACM and ICM

0

**Incremental Capital Adjustment**

| **Current Revenue Requirement** | | | | | |
|---|---|---|---|---|---|
| Current Revenue Requirement - Total | | | $ | 117,989,982 | **A** |
| **Return on Rate Base** | | | | | |
| Incremental Capital | | | $ | 2,064,360 | **B** |
| Depreciation Expense | | | $ | 50,710 | **C** |
| Incremental Capital to be included in Rate Base | | | $ | 2,013,650 | **D = B - C** |
| Deemed ShortTerm Debt % | 4.0% | **E** | $ | 80,546 | **G = D * E** |
| Deemed Long Term Debt % | 56.0% | **F** | $ | 1,127,644 | **H = D * F** |
| Short Term Interest | 2.08% | **I** | $ | 1,675 | **K = G * I** |
| Long Term Interest | 5.09% | **J** | $ | 57,397 | **L = H * J** |
| Return on Rate Base - Interest | | | $ | 59,072 | **M = K + L** |
| Deemed Equity % | 40.00% | **N** | $ | 805,460 | **P = D * N** |
| Return on Rate Base -Equity | 8.93% | **O** | $ | 71,928 | **Q = P * O** |
| Return on Rate Base - Total | | | $ | 131,000 | **R = M + Q** |
| **Amortization Expense** | | | | | |
| Amortization Expense - Incremental | | **C** | $ | 50,710 | **S** |
| **Grossed up PIL's** | | | | | |
| Regulatory Taxable Income | | **O** | $ | 71,928 | **T** |
| Add Back Amortization Expense | | **S** | $ | 50,710 | **U** |
| Deduct CCA | | | $ | 165,149 | **V** |
| Incremental Taxable Income | | | -$ | 42,512 | **W = T + U - V** |
| Current Tax Rate | 26.5% | **X** | | | |
| PIL's Before Gross Up | | | -$ | 11,266 | **Y = W * X** |
| Incremental Grossed Up PIL's | | | -$ | 15,327 | **Z = Y / ( 1 - X )** |
| **Incremental Revenue Requirement** | | | | | |
| Return on Rate Base - Total | | **Q** | $ | 131,000 | **AA** |
| Amortization Expense - Total | | **S** | $ | 50,710 | **AB** |
| Incremental Grossed Up PIL's | | **Z** | -$ | 15,327 | **AC** |
| Incremental Revenue Requirement | | | $ | 166,382 | **AD = AA + AB + AC** |

Ontario Energy Board

# Capital Module
# Applicable to ACM and ICM

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

| | *Cost of Service* | *Price Cap IR* | | | |
|---|---|---|---|---|---|
| | Test Year 2013 | Year 2 2015 | Year 3 2016 | Year 4 2017 | Year 5 2018 |
| Distribution System Plan CAPEX | | | | | $ 72,682,772 |
| Materiality Threshold | | $ 42,869,478 | $ 43,074,036 | $ 43,282,305 | $ 43,494,353 |
| Maximum Eligible Incremental Capital (Forecasted Capex less Threshold) | $ - | $ - | $ - | $ - | $ 29,188,419 |

| Project Descriptions: | Type | Test Year 2013 | Year 2 2015 | Year 3 2016 | Year 4 2017 | Year 5 2018 | Total |
|---|---|---|---|---|---|---|---|
| Credit Woodlands & Wiltshire Subdivision Rebuild | | | | | | $ 1,548,270 | **$ 1,548,270** |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | $ - |
| | | | | | | | $ - |
| | | | | | | | $ - |
| | | | | | | | $ - |
| | | | | | | | $ - |
| | | | | | | | $ - |
| Total Cost of ACM Projects | | $ - | $ - | $ - | $ - | $ 1,548,270 | **$ 1,548,270** |
| Maximum Allowed Incremental Capital | | | $ - | $ - | $ - | $ 1,548,270 | $ 1,548,270 |

| | *Price Cap IR* | | | |
|---|---|---|---|---|
| | Test Year 2013 | Year 1 2015 | Year 2 2016 | Year 3 2017 | Year 4 2018 |
| Distribution System Plan CAPEX | $ - | $ - | $ - | $ - | $ 72,682,772 |
| Materiality Threshold | | $ 42,869,478 | $ 43,074,036 | $ 43,282,305 | $ 43,494,353 |
| Maximum Eligible Incremental Capital (Forecasted Capex less Threshold) | $ - | $ - | $ - | $ - | $ 29,188,419 |

| | | Test Year 2013 | Year 1 2015 | | | Year 2 2016 | | | Year 3 2017 | | | Year 4 2018 | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Project Descriptions: | Type | | Proposed ACM/ICM | Amortization Expense | CCA | Proposed ACM/ICM | Amortization Expense | CCA | Proposed ACM/ICM | Amortization Expense | CCA | Proposed ACM/ICM | Amortization Expense | CCA |
| Credit Woodlands & Wiltshire Subdivision Rebuild | | | $ - | | | $ - | | | $ - | | | **$ 1,548,270** | $ 38,032 | $ 123,862 |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| Total Cost of Projects | | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ 1,548,270 | $ 38,032 | $ 123,862 |

Ontario Energy Board

# Capital Module
# Applicable to ACM and ICM

0

**Incremental Capital Adjustment**

| Current Revenue Requirement | | | | | |
|---|---|---|---|---|---|
| Current Revenue Requirement - Total | | | $ | 117,989,982 | A |

| Return on Rate Base | | | | | |
|---|---|---|---|---|---|
| Incremental Capital | | | $ | 1,548,270 | B |
| Depreciation Expense | | | $ | 38,032 | C |
| Incremental Capital to be included in Rate Base | | | $ | 1,510,238 | D = B - C |
| Deemed ShortTerm Debt % | 4.0% | E | $ | 60,410 | G = D * E |
| Deemed Long Term Debt % | 56.0% | F | $ | 845,733 | H = D * F |
| Short Term Interest | 2.08% | I | $ | 1,257 | K = G * I |
| Long Term Interest | 5.09% | J | $ | 43,048 | L = H * J |
| Return on Rate Base - Interest | | | $ | 44,304 | M = K + L |
| Deemed Equity % | 40.00% | N | $ | 604,095 | P = D * N |
| Return on Rate Base -Equity | 8.93% | O | $ | 53,946 | Q = P * O |
| Return on Rate Base - Total | | | $ | 98,250 | R = M + Q |

| Amortization Expense | | | | | |
|---|---|---|---|---|---|
| Amortization Expense - Incremental | | C | $ | 38,032 | S |

| Grossed up PIL's | | | | | |
|---|---|---|---|---|---|
| Regulatory Taxable Income | | O | $ | 53,946 | T |
| Add Back Amortization Expense | | S | $ | 38,032 | U |
| Deduct CCA | | | $ | 123,862 | V |
| Incremental Taxable Income | | | -$ | 31,884 | W = T + U - V |
| Current Tax Rate | 26.5% | X | | | |
| PIL's Before Gross Up | | | -$ | 8,449 | Y = W * X |
| Incremental Grossed Up PIL's | | | -$ | 11,495 | Z = Y / ( 1 - X ) |

| Incremental Revenue Requirement | | | | | |
|---|---|---|---|---|---|
| Return on Rate Base - Total | | Q | $ | 98,250 | AA |
| Amortization Expense - Total | | S | $ | 38,032 | AB |
| Incremental Grossed Up PIL's | | Z | -$ | 11,495 | AC |
| Incremental Revenue Requirement | | | $ | 124,787 | AD = AA + AB + AC |

Ontario Energy Board

# Capital Module
# Applicable to ACM and ICM

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

| | *Cost of Service* | *Price Cap IR* | | | |
|---|---|---|---|---|---|
| | Test Year 2013 | Year 2 2015 | Year 3 2016 | Year 4 2017 | Year 5 2018 |
| Distribution System Plan CAPEX | | | | | $ 72,682,772 |
| Materiality Threshold | | $ 42,869,478 | $ 43,074,036 | $ 43,282,305 | $ 43,494,353 |
| Maximum Eligible Incremental Capital (Forecasted Capex less Threshold) | $ - | $ - | $ - | $ - | $ 29,188,419 |

| Project Descriptions: | Type | Test Year 2013 | Year 2 2015 | Year 3 2016 | Year 4 2017 | Year 5 2018 | Total |
|---|---|---|---|---|---|---|---|
| enth Line Main Feeder Subdivision Renewal | | | | | | $ 1,135,398 | **$ 1,135,398** |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | $ - |
| | | | | | | | $ - |
| | | | | | | | $ - |
| | | | | | | | $ - |
| | | | | | | | $ - |
| | | | | | | | $ - |
| | | | | | | | $ - |
| Total Cost of ACM Projects | | $ - | $ - | $ - | $ - | $ 1,135,398 | **$ 1,135,398** |
| Maximum Allowed Incremental Capital | | | $ - | $ - | $ - | $ 1,135,398 | $ 1,135,398 |

| | *Price Cap IR* | | | |
|---|---|---|---|---|
| | Test Year 2013 | Year 1 2015 | Year 2 2016 | Year 3 2017 | Year 4 2018 |
| Distribution System Plan CAPEX | $ - | $ - | $ - | $ - | $ 72,682,772 |
| Materiality Threshold | | $ 42,869,478 | $ 43,074,036 | $ 43,282,305 | $ 43,494,353 |
| Maximum Eligible Incremental Capital (Forecasted Capex less Threshold) | $ - | $ - | $ - | $ - | $ 29,188,419 |

| | | Test Year 2013 | Year 1 2015 | | | Year 2 2016 | | | Year 3 2017 | | | Year 4 2018 | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Project Descriptions: | Type | | Proposed ACM/ICM | Amortization Expense | CCA | Proposed ACM/ICM | Amortization Expense | CCA | Proposed ACM/ICM | Amortization Expense | CCA | Proposed ACM/ICM | Amortization Expense | CCA |
| enth Line Main Feeder Subdivision Renewal | | | $ - | | | $ - | | | $ - | | | **$ 1,135,398** | $ 27,890 | $ 90,832 |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| Total Cost of Projects | | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ 1,135,398 | $ 27,890 | $ 90,832 |

Ontario Energy Board

# Capital Module
# Applicable to ACM and ICM

0

**Incremental Capital Adjustment**

| Current Revenue Requirement | | | | | |
|---|---|---|---|---|---|
| Current Revenue Requirement - Total | | | $ | 117,989,982 | A |

| Return on Rate Base | | | | | |
|---|---|---|---|---|---|
| Incremental Capital | | | $ | 1,135,398 | B |
| Depreciation Expense | | | $ | 27,890 | C |
| Incremental Capital to be included in Rate Base | | | $ | 1,107,508 | D = B - C |
| Deemed ShortTerm Debt % | 4.0% | E | $ | 44,300 | G = D * E |
| Deemed Long Term Debt % | 56.0% | F | $ | 620,204 | H = D * F |
| Short Term Interest | 2.08% | I | $ | 921 | K = G * I |
| Long Term Interest | 5.09% | J | $ | 31,568 | L = H * J |
| Return on Rate Base - Interest | | | $ | 32,490 | M = K + L |
| Deemed Equity % | 40.00% | N | $ | 443,003 | P = D * N |
| Return on Rate Base -Equity | 8.93% | O | $ | 39,560 | Q = P * O |
| Return on Rate Base - Total | | | $ | 72,050 | R = M + Q |

| Amortization Expense | | | | | |
|---|---|---|---|---|---|
| Amortization Expense - Incremental | | C | $ | 27,890 | S |

| Grossed up PIL's | | | | | |
|---|---|---|---|---|---|
| Regulatory Taxable Income | | O | $ | 39,560 | T |
| Add Back Amortization Expense | | S | $ | 27,890 | U |
| Deduct CCA | | | $ | 90,832 | V |
| Incremental Taxable Income | | | -$ | 23,381 | W = T + U - V |
| Current Tax Rate | 26.5% | X | | | |
| PIL's Before Gross Up | | | -$ | 6,196 | Y = W * X |
| Incremental Grossed Up PIL's | | | -$ | 8,430 | Z = Y / ( 1 - X ) |

| Incremental Revenue Requirement | | | | | |
|---|---|---|---|---|---|
| Return on Rate Base - Total | | Q | $ | 72,050 | AA |
| Amortization Expense - Total | | S | $ | 27,890 | AB |
| Incremental Grossed Up PIL's | | Z | -$ | 8,430 | AC |
| Incremental Revenue Requirement | | | $ | 91,510 | AD = AA + AB + AC |

Ontario Energy Board

# Capital Module
# Applicable to ACM and ICM

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

| | *Cost of Service* | *Price Cap IR* | | | |
|---|---|---|---|---|---|
| | Test Year 2013 | Year 2 2015 | Year 3 2016 | Year 4 2017 | Year 5 2018 |
| Distribution System Plan CAPEX | | | | | $ 72,682,772 |
| Materiality Threshold | | $ 42,869,478 | $ 43,074,036 | $ 43,282,305 | $ 43,494,353 |
| Maximum Eligible Incremental Capital (Forecasted Capex less Threshold) | $ - | $ - | $ - | $ - | $ 29,188,419 |

| Project Descriptions: | Type | Test Year 2013 | Year 2 2015 | Year 3 2016 | Year 4 2017 | Year 5 2018 | Total |
|---|---|---|---|---|---|---|---|
| olkway & Erin Mills Main Feeder Subdivison Rebuild | | | | | | $ 1,032,180 | **$ 1,032,180** |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | **$ -** |
| | | | | | | | **$ -** |
| | | | | | | | **$ -** |
| | | | | | | | **$ -** |
| | | | | | | | **$ -** |
| | | | | | | | **$ -** |
| | | | | | | | **$ -** |
| Total Cost of ACM Projects | | $ - | $ - | $ - | $ - | $ 1,032,180 | **$ 1,032,180** |
| Maximum Allowed Incremental Capital | | | $ - | $ - | $ - | $ 1,032,180 | $ 1,032,180 |

| | | *Price Cap IR* | | | |
|---|---|---|---|---|---|
| | Test Year 2013 | Year 1 2015 | Year 2 2016 | Year 3 2017 | Year 4 2018 |
| Distribution System Plan CAPEX | $ - | $ - | $ - | $ - | $ 72,682,772 |
| Materiality Threshold | | $ 42,869,478 | $ 43,074,036 | $ 43,282,305 | $ 43,494,353 |
| Maximum Eligible Incremental Capital (Forecasted Capex less Threshold) | $ - | $ - | $ - | $ - | $ 29,188,419 |

| | | Test Year | Year 1 2015 | | | Year 2 2016 | | | Year 3 2017 | | | Year 4 2018 | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Project Descriptions: | Type | 2013 | Proposed ACM/ICM | Amortization Expense | CCA | Proposed ACM/ICM | Amortization Expense | CCA | Proposed ACM/ICM | Amortization Expense | CCA | Proposed ACM/ICM | Amortization Expense | CCA |
| olkway & Erin Mills Main Feeder Subdivison Rebuild | | | $ - | | | $ - | | | $ - | | | **$ 1,032,180** | $ 25,355 | $ 82,574 |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| Total Cost of Projects | | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ 1,032,180 | $ 25,355 | $ 82,574 |

Ontario Energy Board

# Capital Module
# Applicable to ACM and ICM

0

**Incremental Capital Adjustment**

| | | | | | |
|---|---|---|---|---|---|
| **Current Revenue Requirement** | | | | | |
| Current Revenue Requirement - Total | | | $ | 117,989,982 | **A** |
| **Return on Rate Base** | | | | | |
| Incremental Capital | | | $ | 1,032,180 | **B** |
| Depreciation Expense | | | $ | 25,355 | **C** |
| Incremental Capital to be included in Rate Base | | | $ | 1,006,825 | **D = B - C** |
| Deemed ShortTerm Debt % | 4.0% | **E** | $ | 40,273 | **G = D * E** |
| Deemed Long Term Debt % | 56.0% | **F** | $ | 563,822 | **H = D * F** |
| Short Term Interest | 2.08% | **I** | $ | 838 | **K = G * I** |
| Long Term Interest | 5.09% | **J** | $ | 28,699 | **L = H * J** |
| Return on Rate Base - Interest | | | $ | 29,536 | **M = K + L** |
| Deemed Equity % | 40.00% | **N** | $ | 402,730 | **P = D * N** |
| Return on Rate Base -Equity | 8.93% | **O** | $ | 35,964 | **Q = P * O** |
| Return on Rate Base - Total | | | $ | 65,500 | **R = M + Q** |
| **Amortization Expense** | | | | | |
| Amortization Expense - Incremental | | **C** | $ | 25,355 | **S** |
| **Grossed up PIL's** | | | | | |
| Regulatory Taxable Income | | **O** | $ | 35,964 | **T** |
| Add Back Amortization Expense | | **S** | $ | 25,355 | **U** |
| Deduct CCA | | | $ | 82,574 | **V** |
| Incremental Taxable Income | | | -$ | 21,256 | **W = T + U - V** |
| Current Tax Rate | 26.5% | **X** | | | |
| PIL's Before Gross Up | | | -$ | 5,633 | **Y = W * X** |
| Incremental Grossed Up PIL's | | | -$ | 7,664 | **Z = Y / ( 1 - X )** |
| **Incremental Revenue Requirement** | | | | | |
| Return on Rate Base - Total | | **Q** | $ | 65,500 | **AA** |
| Amortization Expense - Total | | **S** | $ | 25,355 | **AB** |
| Incremental Grossed Up PIL's | | **Z** | -$ | 7,664 | **AC** |
| Incremental Revenue Requirement | | | $ | 83,191 | **AD = AA + AB + AC** |

Ontario Energy Board

# Capital Module
# Applicable to ACM and ICM

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

| | | *Cost of Service* | *Price Cap IR* | | | |
|---|---|---|---|---|---|---|
| | | Test Year | Year 2 | Year 3 | Year 4 | Year 5 |
| | | 2013 | 2015 | 2016 | 2017 | 2018 |
| Distribution System Plan CAPEX | | | | | | $ 72,682,772 |
| Materiality Threshold | | | $ 42,869,478 | $ 43,074,036 | $ 43,282,305 | $ 43,494,353 |
| Maximum Eligible Incremental Capital (Forecasted Capex less Threshold) | | $ - | $ - | $ - | $ - | $ 29,188,419 |

| Project Descriptions: | Type | Test Year 2013 | Year 2 2015 | Year 3 2016 | Year 4 2017 | Year 5 2018 | Total |
|---|---|---|---|---|---|---|---|
| City Centre Drive Rebuild | | | | | | $ 1,548,270 | **$ 1,548,270** |
| | | | | | | | $ - |
| | | | | | | | $ - |
| | | | | | | | $ - |
| | | | | | | | $ - |
| | | | | | | | $ - |
| | | | | | | | $ - |
| | | | | | | | $ - |
| Total Cost of ACM Projects | | $ - | $ - | $ - | $ - | $ 1,548,270 | **$ 1,548,270** |
| Maximum Allowed Incremental Capital | | | $ - | $ - | $ - | $ 1,548,270 | $ 1,548,270 |

| | | *Price Cap IR* | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | Test Year | Year 1 | | Year 2 | | Year 3 | | Year 4 |
| | | 2013 | 2015 | | 2016 | | 2017 | | 2018 |
| Distribution System Plan CAPEX | | $ - | $ - | | $ - | | $ - | | $ 72,682,772 |
| Materiality Threshold | | | $ 42,869,478 | | $ 43,074,036 | | $ 43,282,305 | | $ 43,494,353 |
| Maximum Eligible Incremental Capital (Forecasted Capex less Threshold) | | $ - | $ - | | $ - | | $ - | | $ 29,188,419 |

| | | Test Year | Year 1 2015 | | | Year 2 2016 | | | Year 3 2017 | | | Year 4 2018 | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Project Descriptions: | Type | 2013 | Proposed ACM/ICM | Amortization Expense | CCA | Proposed ACM/ICM | Amortization Expense | CCA | Proposed ACM/ICM | Amortization Expense | CCA | Proposed ACM/ICM | Amortization Expense | CCA |
| City Centre Drive Rebuild | | | $ - | | | $ - | | | $ - | | | **$ 1,548,270** | $ 38,032 | $ 123,862 |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| Total Cost of Projects | | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ 1,548,270 | $ 38,032 | $ 123,862 |

Ontario Energy Board

# Capital Module
# Applicable to ACM and ICM

0

**Incremental Capital Adjustment**

| Current Revenue Requirement | | | | | |
|---|---|---|---|---|---|
| Current Revenue Requirement - Total | | | $ | 117,989,982 | A |

| Return on Rate Base | | | | | |
|---|---|---|---|---|---|
| Incremental Capital | | | $ | 1,548,270 | B |
| Depreciation Expense | | | $ | 38,032 | C |
| Incremental Capital to be included in Rate Base | | | $ | 1,510,238 | D = B - C |
| Deemed ShortTerm Debt % | 4.0% | E | $ | 60,410 | G = D * E |
| Deemed Long Term Debt % | 56.0% | F | $ | 845,733 | H = D * F |
| Short Term Interest | 2.08% | I | $ | 1,257 | K = G * I |
| Long Term Interest | 5.09% | J | $ | 43,048 | L = H * J |
| Return on Rate Base - Interest | | | $ | 44,304 | M = K + L |
| Deemed Equity % | 40.00% | N | $ | 604,095 | P = D * N |
| Return on Rate Base -Equity | 8.93% | O | $ | 53,946 | Q = P * O |
| Return on Rate Base - Total | | | $ | 98,250 | R = M + Q |

| Amortization Expense | | | | | |
|---|---|---|---|---|---|
| Amortization Expense - Incremental | | C | $ | 38,032 | S |

| Grossed up PIL's | | | | | |
|---|---|---|---|---|---|
| Regulatory Taxable Income | | O | $ | 53,946 | T |
| Add Back Amortization Expense | | S | $ | 38,032 | U |
| Deduct CCA | | | $ | 123,862 | V |
| Incremental Taxable Income | | | -$ | 31,884 | W = T + U - V |
| Current Tax Rate | 26.5% | X | | | |
| PIL's Before Gross Up | | | -$ | 8,449 | Y = W * X |
| Incremental Grossed Up PIL's | | | -$ | 11,495 | Z = Y / ( 1 - X ) |

| Incremental Revenue Requirement | | | | | |
|---|---|---|---|---|---|
| Return on Rate Base - Total | | Q | $ | 98,250 | AA |
| Amortization Expense - Total | | S | $ | 38,032 | AB |
| Incremental Grossed Up PIL's | | Z | -$ | 11,495 | AC |
| Incremental Revenue Requirement | | | $ | 124,787 | AD = AA + AB + AC |

Ontario Energy Board

# Capital Module
# Applicable to ACM and ICM

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

| | | *Cost of Service* | *Price Cap IR* | | | |
|---|---|---|---|---|---|---|
| | | Test Year | Year 2 | Year 3 | Year 4 | Year 5 |
| | | 2013 | 2015 | 2016 | 2017 | 2018 |
| Distribution System Plan CAPEX | | | | | | $ 72,682,772 |
| Materiality Threshold | | | $ 42,869,478 | $ 43,074,036 | $ 43,282,305 | $ 43,494,353 |
| Maximum Eligible Incremental Capital (Forecasted Capex less Threshold) | | $ - | $ - | $ - | $ - | $ 29,188,419 |

| Project Descriptions: | Type | Test Year 2013 | Year 2 2015 | Year 3 2016 | Year 4 2017 | Year 5 2018 | Total |
|---|---|---|---|---|---|---|---|
| Overhead Rebuild - Lake/John | | | | | | $ 927,370 | $ 927,370 |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | $ - |
| | | | | | | | $ - |
| | | | | | | | $ - |
| | | | | | | | $ - |
| | | | | | | | $ - |
| | | | | | | | $ - |
| Total Cost of ACM Projects | | $ - | $ - | $ - | $ - | $ 927,370 | $ 927,370 |
| Maximum Allowed Incremental Capital | | | $ - | $ - | $ - | $ 927,370 | $ 927,370 |

| | | *Price Cap IR* | | | |
|---|---|---|---|---|---|
| | Test Year | Year 1 | Year 2 | Year 3 | Year 4 |
| | 2013 | 2015 | 2016 | 2017 | 2018 |
| Distribution System Plan CAPEX | $ - | $ - | $ - | $ - | $ 72,682,772 |
| Materiality Threshold | | $ 42,869,478 | $ 43,074,036 | $ 43,282,305 | $ 43,494,353 |
| Maximum Eligible Incremental Capital (Forecasted Capex less Threshold) | $ - | $ - | $ - | $ - | $ 29,188,419 |

| | | Test Year | Year 1 2015 | | | Year 2 2016 | | | Year 3 2017 | | | Year 4 2018 | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Project Descriptions: | Type | 2013 | Proposed ACM/ICM | Amortization Expense | CCA | Proposed ACM/ICM | Amortization Expense | CCA | Proposed ACM/ICM | Amortization Expense | CCA | Proposed ACM/ICM | Amortization Expense | CCA |
| Lake/John Area Overhead Rebuild | | | $ - | | | $ - | | | $ - | | | $ 927,370 | $ 23,816 | $ 74,168 |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| Total Cost of Projects | | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ 927,370 | $ 23,816 | $ 74,168 |

Ontario Energy Board

# Capital Module
# Applicable to ACM and ICM

0

**Incremental Capital Adjustment**

| Current Revenue Requirement | | | | | |
|---|---|---|---|---|---|
| Current Revenue Requirement - Total | | | $ | 117,989,982 | A |

| Return on Rate Base | | | | | |
|---|---|---|---|---|---|
| Incremental Capital | | | $ | 927,370 | B |
| Depreciation Expense | | | $ | 23,816 | C |
| Incremental Capital to be included in Rate Base | | | $ | 903,554 | D = B - C |
| Deemed ShortTerm Debt % | 4.0% | E | $ | 36,142 | G = D * E |
| Deemed Long Term Debt % | 56.0% | F | $ | 505,990 | H = D * F |
| Short Term Interest | 2.08% | I | $ | 752 | K = G * I |
| Long Term Interest | 5.09% | J | $ | 25,755 | L = H * J |
| Return on Rate Base - Interest | | | $ | 26,507 | M = K + L |
| Deemed Equity % | 40.00% | N | $ | 361,422 | P = D * N |
| Return on Rate Base -Equity | 8.93% | O | $ | 32,275 | Q = P * O |
| Return on Rate Base - Total | | | $ | 58,782 | R = M + Q |

| Amortization Expense | | | | | |
|---|---|---|---|---|---|
| Amortization Expense - Incremental | | C | $ | 23,816 | S |

| Grossed up PIL's | | | | | |
|---|---|---|---|---|---|
| Regulatory Taxable Income | | O | $ | 32,275 | T |
| Add Back Amortization Expense | | S | $ | 23,816 | U |
| Deduct CCA | | | $ | 74,168 | V |
| Incremental Taxable Income | | | -$ | 18,077 | W = T + U - V |
| Current Tax Rate | 26.5% | X | | | |
| PIL's Before Gross Up | | | -$ | 4,790 | Y = W * X |
| Incremental Grossed Up PIL's | | | -$ | 6,518 | Z = Y / ( 1 - X ) |

| Incremental Revenue Requirement | | | | | |
|---|---|---|---|---|---|
| Return on Rate Base - Total | | Q | $ | 58,782 | AA |
| Amortization Expense - Total | | S | $ | 23,816 | AB |
| Incremental Grossed Up PIL's | | Z | -$ | 6,518 | AC |
| Incremental Revenue Requirement | | | $ | 76,080 | AD = AA + AB + AC |

Ontario Energy Board

# Capital Module
# Applicable to ACM and ICM

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

| | *Cost of Service* | *Price Cap IR* | | | |
|---|---|---|---|---|---|
| | Test Year 2013 | Year 2 2015 | Year 3 2016 | Year 4 2017 | Year 5 2018 |
| Distribution System Plan CAPEX | | | | | $ 72,682,772 |
| Materiality Threshold | | $ 42,869,478 | $ 43,074,036 | $ 43,282,305 | $ 43,494,353 |
| Maximum Eligible Incremental Capital (Forecasted Capex less Threshold) | $ - | $ - | $ - | $ - | $ 29,188,419 |

| Project Descriptions: | Type | Test Year 2013 | Year 2 2015 | Year 3 2016 | Year 4 2017 | Year 5 2018 | Total |
|---|---|---|---|---|---|---|---|
| Church St. Area Overhead Rebuild | | | | | | $ 1,020,107 | **$ 1,020,107** |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | $ - |
| | | | | | | | $ - |
| | | | | | | | $ - |
| | | | | | | | $ - |
| | | | | | | | $ - |
| | | | | | | | $ - |
| | | | | | | | $ - |
| Total Cost of ACM Projects | | $ - | $ - | $ - | $ - | $ 1,020,107 | **$ 1,020,107** |
| Maximum Allowed Incremental Capital | | | $ - | $ - | $ - | $ 1,020,107 | $ 1,020,107 |

| | | *Price Cap IR* | | | |
|---|---|---|---|---|---|
| | Test Year 2013 | Year 1 2015 | Year 2 2016 | Year 3 2017 | Year 4 2018 |
| Distribution System Plan CAPEX | $ - | $ - | $ - | $ - | $ 72,682,772 |
| Materiality Threshold | | $ 42,869,478 | $ 43,074,036 | $ 43,282,305 | $ 43,494,353 |
| Maximum Eligible Incremental Capital (Forecasted Capex less Threshold) | $ - | $ - | $ - | $ - | $ 29,188,419 |

| | | Test Year | Year 1 2015 | | | Year 2 2016 | | | Year 3 2017 | | | Year 4 2018 | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Project Descriptions: | Type | 2013 | Proposed ACM/ICM | Amortization Expense | CCA | Proposed ACM/ICM | Amortization Expense | CCA | Proposed ACM/ICM | Amortization Expense | CCA | Proposed ACM/ICM | Amortization Expense | CCA |
| Church St. Area Overhead Rebuild | | | $ - | | | $ - | | | $ - | | | **$ 1,020,107** | $ 26,198 | $ 81,585 |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| | | | $ - | | | $ - | | | $ - | | | $ - | | |
| Total Cost of Projects | | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ 1,020,107 | $ 26,198 | $ 81,585 |

Ontario Energy Board

# Capital Module
# Applicable to ACM and ICM

0

**Incremental Capital Adjustment**

| Current Revenue Requirement | | | | | |
|---|---|---|---|---|---|
| Current Revenue Requirement - Total | | | $ | 117,989,982 | A |

| Return on Rate Base | | | | | |
|---|---|---|---|---|---|
| Incremental Capital | | | $ | 1,020,107 | B |
| Depreciation Expense | | | $ | 26,198 | C |
| Incremental Capital to be included in Rate Base | | | $ | 993,910 | D = B - C |
| Deemed ShortTerm Debt % | 4.0% | E | $ | 39,756 | G = D * E |
| Deemed Long Term Debt % | 56.0% | F | $ | 556,589 | H = D * F |
| Short Term Interest | 2.08% | I | $ | 827 | K = G * I |
| Long Term Interest | 5.09% | J | $ | 28,330 | L = H * J |
| Return on Rate Base - Interest | | | $ | 29,157 | M = K + L |
| Deemed Equity % | 40.00% | N | $ | 397,564 | P = D * N |
| Return on Rate Base -Equity | 8.93% | O | $ | 35,502 | Q = P * O |
| Return on Rate Base - Total | | | $ | 64,660 | R = M + Q |

| Amortization Expense | | | | | |
|---|---|---|---|---|---|
| Amortization Expense - Incremental | | C | $ | 26,198 | S |

| Grossed up PIL's | | | | | |
|---|---|---|---|---|---|
| Regulatory Taxable Income | | O | $ | 35,502 | T |
| Add Back Amortization Expense | | S | $ | 26,198 | U |
| Deduct CCA | | | $ | 81,585 | V |
| Incremental Taxable Income | | | -$ | 19,885 | W = T + U - V |
| Current Tax Rate | 26.5% | X | | | |
| PIL's Before Gross Up | | | -$ | 5,269 | Y = W * X |
| Incremental Grossed Up PIL's | | | -$ | 7,169 | Z = Y / ( 1 - X ) |

| Incremental Revenue Requirement | | | | | |
|---|---|---|---|---|---|
| Return on Rate Base - Total | | Q | $ | 64,660 | AA |
| Amortization Expense - Total | | S | $ | 26,198 | AB |
| Incremental Grossed Up PIL's | | Z | -$ | 7,169 | AC |
| Incremental Revenue Requirement | | | $ | 83,688 | AD = AA + AB + AC |

**BOMA-112**

**Reference(s): Attachment 49**

**Background**

**(a) Please see list of Enersource's material 2018 capital projects. The list contains forty-eight material projects, divided into the four traditional categories of System Access, System Renewal, System Service, and General Plant. Of the forty-eight projects, the ten listed on Attachment 48 are proposed to be funded by the proposed 2018 ICM.**

**Please provide the following information:**

- **(i) Why were the ten projects listed in Attachment 48 chosen for ICM funding, as opposed to others among the forty-eight projects? Please explain fully for each of the ten projects.**
- **(ii) Please provide a priority listing of the forty-eight projects from 1 to 48, regardless of which traditional category they fall.**
- **(iii) For the projects in each of the four categories, please provide a priority listing within the category.**
- **(iv) Please explain the derivation (the reason) for the priority listing in each category and in the overall (1 to 48) list.**

**(b) For each of the forty-eight projects, please indicate whether, and to what extent, they are parts of projects that commenced in 2017, or prior to 2017.**

**(c) Please indicate which, if any, of the projects will, per the DSP, involve capital expenditures in 2019 (or in subsequent years of the DSP).**

**(d) Has each of the forty-eight projects, and the ten projects, been included in the 2018-2022 DSP? If any are not, please explain fully.**

**(e) Is it Alectra's intent to apply for ICMs to fund parts of its proposed capital expenditures, as disclosed in the DSP for Enersource's division:**

- **(i) in 2019, along with the approval of the Alectra DSP;**
- **(ii) in the remaining years covered under the Enersource division DSP;**
- **(iii) in years beyond the end of the DSP.**

**(f) Will the Enersource division's DSP continue to be valid when Alectra's planned 2019 DSP is released? Please discuss.**

**Response:**

a) i) Alectra Utilities has capital investment needs for the Enersource RZ that are not funded through existing distribution rates. Furthermore, each eligible project is a discrete project that meets or exceed the materiality level for the Enersource RZ. Each project is distinct,

unrelated to a recurring annual capital project, and has been evaluated in the asset management and capital planning process as required in 2018.

(ii) Table 1 must be assessed in the context of Alectra Utilities' Asset Management Practice and Capital Investment Plan Optimization process. Pursuant to this process, Alectra Utilities evaluates each project in the capital investment plan to pace and prioritize investments based on business values, objectives and risks. The portfolio of projects presented, that is, those listed below, reflect prudent investment needs and the most cost effective option for ratepayers. They are all necessary and produce positive outcomes for ratepayers.

**Table 1 – Project list ranking – Enersource RZ**

| Project Name | Rank |
|---|---|
| New Subdivisions | 1 |
| Industrial/Commercial Services | 2 |
| Residential Service Upgrades | 3 |
| Metering Renewal | 4 |
| New Metering Installations | 5 |
| New IMS | 6 |
| QEW - Evans To Cawthra | 7 |
| Creditview - Britannia To Argentia | 8 |
| QEW - Various Bridge Rehabilitations | 9 |
| LRT - Underground & Overhead | 10 |
| Equipment Replacement | 11 |
| Pole Installations | 12 |
| Underground & Overhead Transformer & Equipment Renewal | 13 |
| PCB & Leaking Transformer Replacement Project – Underground & Overhead | 14 |
| Pad Mounted Switchgear Replacement | 15 |
| Cable & Splice Replacements | 16 |
| City Centre North | 17 |
| York MS | 18 |
| Glen Erin & Battleford | 19 |
| Glen Erin & Montevideo - Section 1 | 20 |
| Copenhagen - Section 1 | 21 |
| Gananoque - Section 1 | 22 |
| Credit Woodlands Crt/Wiltshire (design complete) | 23 |
| City Centre Drive Cables | 24 |
| Tenth Line Main Feeder | 25 |
| Derry - Winston Churchill to Argentia | 26 |
| Western MS | 27 |

| | |
|---|---|
| RTU System Enhancements & Equipment Upgrades | 28 |
| Stanfield - North Service to Queensway | 29 |
| Appledore - Section 1 | 30 |
| Southdown - ROW to Lakeshore | 31 |
| Folkway & Erin Mills Main Feeder | 32 |
| Boughbeeches - Section 1 | 33 |
| Holburne/Ogden | 34 |
| Church | 35 |
| Lake/John | 36 |
| Park Royal | 37 |
| Courtney Park - Dixie To Ordan | 38 |
| Hensall MS | 39 |
| Churchill Meadows Feeder Egress - TS to Winston Churchill | 40 |
| Munden/Pear Tree | 41 |
| O/H installation of SCADA/Automation switches | 42 |
| Bloor MS | 43 |
| WiMAX Wireless Network Project | 44 |
| U/G installation of SCADA/Automation switches | 45 |
| Cars/Light Trucks/Vans | 46 |
| Heavy Trucks/RBDs/Buckets | 47 |
| Mavis Building Envelope | 48 |

(iii) Table 2 provides the priority listing for the projects in each of the four categories.

**Table 2 – Priority ranking by category**

| System Access<br>Project Name | Rank |
|---|---|
| New Subdivisions | 1 |
| Industrial/Commercial Services | 2 |
| Residential Service Upgrades | 3 |
| Metering Renewal | 4 |
| New Metering Installations | 5 |
| New IMS | 6 |
| QEW - Evans To Cawthra | 7 |
| Creditview - Britannia To Argentia | 8 |
| QEW - Various Bridge Rehabilitations | 9 |
| LRT - Underground & Overhead | 10 |

| System Renewal |
|---|

| Project Name | Rank |
|---|---|
| Equipment Replacement | 11 |
| Pole Installations | 12 |
| Underground & Overhead Transformer & Equipment Renewal | 13 |
| PCB & Leaking Transformer Replacement Project – Underground & Overhead | 14 |
| Pad Mounted Switchgear Replacement | 15 |
| Cable & Splice Replacements | 16 |
| Glen Erin & Battleford | 19 |
| Glen Erin & Montevideo - Section 1 | 20 |
| Copenhagen - Section 1 | 21 |
| Gananoque - Section 1 | 22 |
| Credit Woodlands Crt/Wiltshire (design complete) | 23 |
| City Centre Drive Cables | 24 |
| Tenth Line Main Feeder | 25 |
| Stanfield - North Service to Queensway | 29 |
| Appledore - Section 1 | 30 |
| Southdown - ROW to Lakeshore | 31 |
| Folkway & Erin Mills Main Feeder | 32 |
| Boughbeeches - Section 1 | 33 |
| Holburne/Ogden | 34 |
| Church | 35 |
| Lake/John | 36 |
| Courtney Park - Dixie To Ordan | 38 |
| Munden/Pear Tree | 41 |

1

| System Service<br>Project Name | Rank |
|---|---|
| City Centre North | 17 |
| York MS | 18 |
| Derry - Winston Churchill to Argentia | 26 |
| Western MS | 27 |
| RTU System Enhancements & Equipment Upgrades | 28 |
| Park Royal | 37 |
| Hensall MS | 39 |
| Churchill Meadows Feeder Egress - TS to Winston Churchill | 40 |
| O/H installation of SCADA/Automation switches | 42 |
| Bloor MS | 43 |

| | |
|---|---|
| WiMAX Wireless Network Project | 44 |
| U/G installation of SCADA/Automation switches | 45 |

| General Plant<br>Project Name | Rank |
|---|---|
| Cars/Light Trucks/Vans | 46 |
| Heavy Trucks/RBDs/Buckets | 47 |
| Mavis Building Envelope | 48 |

(iv) Alectra Utilities ranks project in the Enersource Rate Zone based on the following criteria:

- **Customer Focus (30% weigthing):**
  Service Quality: 20%
  Customer Satisfaction: 60%
  Reputational Risk: 20%

- **Operational Effectiveness (50 % weighting):**
  Safety: 25%
  Environmental: 15%
  System Reliability/Expansion/Renewal: 60% (20% each)

- **Financial Performance (20% weighting):**
  Cost Efficiencies: 50%
  Ongoing costs: 50%

The total score is then multiplied by the project cost divided by the total budget, to normalize scores.

b) Attachment 49 contains the capital expenditure required in 2018. Certain system access investments include development project and road widening works that are driven by customer and road authority schedules beyond the control of Alectra Utilities. In these certain system access investments, there are portions that may have commenced in or prior to 2017. Only the work expended in 2018 has been considered and budgeted in the attachment.

1. New Subdivisions
2. Industrial/Commercial Services
3. New Individual Metered Suites (IMS)
4. The Leaking Transformer Replacement project, is a multi-year project to address the remaining backlog of transformer identified as showing signs of oil leaks and/or containing PCBs. The level of investment each year is provided in Exhibit 3, Tab 1, Schedule 1, Attachment 50 – Enersource Rate Zone DSP, Table 55, p.275.

Alectra Utilities distinguishes between multi-year projects from typical annual capital programs. Multi-year projects are larger complex projects that are paced over several years with a defined scope, budget and end date. Phases of multi-year projects may be staged to meet the resource availability and pacing to smooth rate impacts as is the case with Leaking transformer replacement project. The Leaking Transformer project is a multi-year project that is separate from a recurring annual capital program.

c) Attachment 49 contains the capital expenditure required in 2018. The system access investments included in response to part b) above are driven by customer schedules beyond the control of Alectra Utilities. In these certain system access investments, there are portions that may have work carry into 2019 or later. Only the work to be expended in 2018 has been considered and budgeted in the attachment.

d) Alectra Utilities confirms that all of the projects, including the ICM projects are part of the Enersource Rate Zone DSP.

e) i) Please see Alectra Utilities response to G-SEC-5 c).
ii) Please see Alectra Utilities response to G-SEC-5 c).
iii) Please see Alectra Utilities response to G-SEC-5 c).

f) Alectra Utilities will use the predecessor utilities' Distribution System Plans ("DSP") and the ERZ DSP filed with this application in order to inform and influence the development of the consolidated Alectra DSP. The consolidated Alectra DSP will supersede the individual DSPs of the predecessor entities.

**BOMA-113**

**Reference(s): Attachment 45, pp 10, 11**

**Does the company propose a return on ICM capital expenditures in 2018, in addition to depreciation, CCA, and taxes? Please discuss.**

**Response:**

Alectra Utilities relied on the Ontario Energy Board's ("OEB") Capital Module Applicable to ACM and ICM ("Capital Module") to calculate incremental revenue requirement for each rate zone. The Capital Module for the Brampton, PowerStream and Enersource rate zones is provided in Exhibit 3, Tab 1, Schedule 1, Attachment 18 – Incremental Capital Module Brampton RZ, Exhibit 3, Tab 1, Schedule 1, Attachment 31 – Incremental Capital Module PowerStream RZ, and Exhibit 3, Tab 1, Schedule 1, Attachment 45 – Incremental Capital Module Enersource RZ. The ICM revenue for each rate zone incorporates a return on rate base, amortization and PILs, as summarized in Table 67 – Incremental Revenue Requirement Brampton RZ in Exhibit 2, Tab 2, Schedule 10, p.12; Table 104 – Incremental Revenue Requirement PowerStream RZ in Exhibit 2, Tab 3, Schedule 10, p.33; and Table 145 – Incremental Revenue Requirement Enersource RZ in Exhibit 2, Tab 4, Schedule 11, p.46.

**BOMA-114**

**Reference(s): Exhibit 2, Tab 4, Schedule 11, pp 46-48**

**a) Is the proposed rate rider only in place for 2018, or does it extend beyond December 31, 2018, and, if so, for how long? Please show calculations of the revenue generated by the rate rider each year it is in effect until rebasing, and how that amount is reconciled with the 2018 ICM driven capex that needs to be funded.**

**b) Please advise whether the amount of the rider would remain constant for the duration of its existence, or change from one year to the next.**

**Response:**

a) The proposed ICM rate riders would be in place until the next rebasing as is the normal course for ICM rate riders.

Table BOMA 1 below summarizes the notional revenue generated by the rate riders over the nine years 2018 to 2026 inclusive leading to the scheduled rebasing in 2027.

**Table BOMA 1: Notional Revenue from ICM Rate Riders**

| | 2018 Incremental Capital and Annual Funding | | | | 2018 to 2026 (nine years) |
|---|---|---|---|---|---|
| Description | BRZ | PRZ | ERZ | Total | |
| Incremental capital spending above threshold | $ 6,800,377 | $ 25,136,316 | $ 24,247,022 | $ 56,183,715 | |
| Funding Amounts: | | | | | |
| Return | $ 473,674 | $ 1,411,555 | $ 1,539,083 | $ 3,424,312 | $ 30,818,808 |
| Amortization | $ 226,679 | $ 615,688 | $ 589,204 | $ 1,431,571 | $ 12,884,139 |
| Taxes | $ 6,440 | -$ 192,550 | -$ 166,176 | -$ 352,286 | -$ 3,170,574 |
| Total | $ 706,793 | $ 1,834,693 | $ 1,962,111 | $ 4,503,597 | $ 40,532,373 |

As can be seen in the above table, the revenue of approximately $40.5 million is used to finance the investment of $56.2 million, recoup some of the cost of the investments over the useful lives of the assets through amortization and an adjustment for the impact on taxes which is a reduction of the revenue requirement on this asset.

b) The current proposal is that the rate rider would remain constant over this period. At the time of rebasing there would be a true-up between the actual revenue requirement over the period and the funding adders collected.

**BOMA-115**

**Reference(s): DSP, Appendix E – Business Cases Project 2018 – C0504-1 [York MS]**

**(a) Please explain the derivation of the claim that the project would prevent 100,000 customer minutes of outages. How was the amount calculated?**

**(b) The York Project creates additional ongoing costs of $36,000 per annum. What are the costs for? Are these costs offset by any reduced maintenance costs? Please specify.**

**(c) Are the ongoing OM&A costs embedded in the rate rider designed to fund the ICM?**

**(d) Why do the Appendix E (coloured) sheets contain information not included in "Attachment 47 – ICM Business Cases Enersource"?**

**Response:**

a) In a worst-case scenario without this project completed, Alectra Utilities' predecessor Enersource ran contingency situations and determined the estimated outage impact at over 100,000 customer minutes in duration. This was determined by simulating a station transformer failure and estimating how long all necessary switching or generator installations would take until all customers are restored.

b) The York Project will not increase ongoing operating costs. However, the $36,000 per annum will continue. This average Substation cost is calculated by the number of Substations and the Substation Department operating budget.

This ongoing operating cost is for inspection, repairs, overhaul and upkeep of Substation equipment, building and property. It also includes property taxes.

c) The ICM rate rider is calculated based on the ICM revenue requirement calculation provided in Exhibit 3, Tab 1, Schedule 1, Attachment 45 – Incremental Capital Module Enersource RZ, Tab 11 Incremental Capital Adj. Ongoing OM&A costs are not embedded in the rate rider.

d) The ICM Business Cases for the Enersource Rate Zone address the ICM criteria which includes materiality, need and prudence. The business cases contained in Appendix E of the Alectra Utilities (Enersource Rate Zone) DSP meet the Chapter 5 Consolidated Distribution System Plan Filing Requirements.

**BOMA-116**

**Reference(s): General**

**Is it Alectra's understanding that the Enersource division will continue under price cap IR for the next ten years, according to Board Guidelines, and that Alectra will be entitled to bring forward an ICM in any of those years? Please discuss.**

**Response:**

Alectra Utilities confirms its understanding that the Enersource Rate Zone ("ERZ") will continue on Price Cap IR for the rebasing deferral period. Please see Alectra Utilities' response to G-SEC-5 c).

**BOMA-117**

**Reference(s): Exhibit 2, Tab 4, Schedule 11, p18, Table 131**

**(a) Generally, the planned expenditures in the DSP year do not reflect a quantum increase from historical levels, eg. levels in 2015, 2016, 2017, and one would expect that, as Dr. Kaufman pointed out, in such circumstances, the price cap formula and growth would yield revenues sufficient to finance the capital expenditure program. In the circumstances, why is the ICM for 2018 justified?**

**(b) Please reconcile the 2018 capex forecast of $72.6 million, including general plant, shown on Table 129, Exhibit 2, Tab 4, Schedule 1, p4, and the $83.1 million at Table 136 of the same exhibit. Please reconcile the table on Attachment 49 with the number and comments at pp 27-28.**

**Response:**

a) Enersource's last rebasing application, EB-2012-0033, was for rates effective January 1, 2013. The comparison of planned expenditures in the DSP year, reflect a quantum increase from historical levels in 2013. The Ontario Energy Board's Capital Module for ACM and ICM ("ICM Model") for the Enersource Rate Zone is included in Exhibit 3, Tab 1, Schedule 1, Attachment 45 – Incremental Capital Module Enersource RZ. Section 4.1.5 of the *Report of the Board – New Policy Options for the Funding of Capital Investments: The Advanced Capital Module*, issued September 18, 2014, states "*a capital budget will be deemed to be material, and as such reflect eligible projects, if it exceeds the Board-defined materiality threshold."* The Board-defined materiality threshold, which incorporates the price cap formula and growth, results in a materiality threshold of $43,494,353 for the Enersource RZ as identified in Exhibit 3, Tab 1, Schedule 1, Attachment 47 – Incremental Capital Module Enersource RZ, Tab 9. Threshold Test. The 2018 capital budget for the Enersource RZ exceeds the materiality threshold by 39,624,419 (i.e. the maximum eligible incremental capital). Alectra Utilities forecasted ICM projects for the Enersource RZ are below the Board's maximum eligible incremental capital as provided in Exhibit 2, Tab 4, Schedule 11, p.30-31.

b) Table 1 provides a reconciliation between the capital expenditure forecast in Table 129 and Table 136 in Exhibit 2, Tab 4, Schedule 1 of the application.

Table 1 – Capital expenditure reconciliation (Table 136 and Table 129)

| Category | 2018 per Table 136 | Pacing Adjustments | Synergy Savings | 2018 per Table 129 |
|---|---|---|---|---|
| System Access | $14,179 | ($2,500) | $0 | $11,679 |
| System Renewal | $40,910 | $0 | $0 | $40,910 |
| System Service | $16,007 | ($2,585) | $0 | $13,422 |
| General Plant | $12,023 | ($800) | ($4,551) | $6,672 |
| **Total** | **$83,119** | **($5,885)** | **($4,551)** | **$72,683** |

Total capital expenditures of $72,683K reported in Table 129 reflect the impact of pacing adjustments to planned projects and synergy savings. The projects that were impacted by the pacing adjustments were deferred to later years or accelerated to balance the work-load. Table 2 provides the pacing adjustments that have been incorporated into the 2018 capital forecast.

| Project | CAPEX ($000) | Adjustment |
|---|---|---|
| Webb MS (2018 Expenditure) | ($2,591) | Deferred to 2020 |
| LRT Project | ($2,500) | Delayed Start 6 Months |
| Webb MS Feeders | ($1,249) | Deferred to 2020 |
| Canopy – Mavis Facility | ($731) | Cancelled |
| Derry-WCB to Argentia | $1,186 | Brought forward into 2018 from 2019 |
| **Total** | **($5,885)** | |

The reduction to Alectra Utilities' revised 2018 capital forecast was due to the deferral of the Webb MS ICM project based on customer priorities and preferences. The construction of Webb MS was planned to start in 2017 with an in-service date in 2018.The ICM request for Webb MS included expenditure for both 2017 and 2018 in the amount of $1,841,997 and $2,590,753 respectively, for a total of $4,432,750. This was partially offset by an update to the York MS project investment by $36,433.

**BOMA-118**

**Reference(s): "ACM Report", p6**

**"Any incremental capital amounts approved for recovery must fit within the total eligible incremental capital amount (as defined in this ACM Report) and must clearly have a significant influence on the operation of the distributor; otherwise they should be dealt with at rebasing" (our emphasis).**

**(a) What does Alectra interpret the phrase "must clearly have a significant influence on the operation of the distributor" to mean? What type of projects would not meet this test?**

**(b) Given that Alectra is allowed under the MAADs decision to defer rebasing for ten years, and to retain savings derived from the merger for that period to, inter alia, offset transaction costs, to what extent will Alectra use savings achieved to date to offset capex costs prior to seeking an ICM? To what extent does it intend to do so in the future? Please discuss.**

**(c) Please explain why the "ICM proposal" is an ICM, rather than as an ACM. Please explain fully.**

**(d) Does Alectra intend to ask for ICM modules for its Enersource division in each or some of the next nine years? Please discuss.**

**(e) Why has Enersource not included any general plant capital expenditures in its list of ICM funded projects? Please explain fully.**

**Response:**

a) Alectra Utilities understands this phrase in the context of the OEB's subsequent discussion in the above-referenced ACM Report, in which the OEB states that, "*minor expenditures in comparison to the overall capital budget should be considered ineligible for ACM or ICM treatment.*" In Alectra Utilities' view, the projects contained in this application meet the materiality criteria, as defined by the OEB and are eligible for ICM treatment.

b) The OEB's *Report of the Board – Rate Making Associated with Distributor Consolidations*, dated March 26, 2015 (the "MAADs Report") provides the rationale for the rebasing deferral for up to ten years, on p.6. At p.9-10, the MAADs Report provides that consolidating distributors that are on Price Cap IR are eligible for ICM funding. The rationale does not include using savings from the consolidation to offset necessary capital expenditure.

c) The ICM proposal referenced in the question pertains to the Enersource Rate Zone ("ERZ"). Alectra Utilities' predecessor, Enersource Hydro Mississauga ("Enersource"), last filed a rebasing application in 2012 for rates effective January 1, 2013. The Ontario Energy Board ("OEB") released the Report of the Board: New Policy Options for the Funding of Capital Investments: The Advanced Capital Module on September 18, 2014. This was several years after Enersource's last rebasing. As a result, Alectra Utilities, through its predecessor, would not have had an opportunity to identify ACM investments in its last Cost of Service application. Therefore, the application before the OEB currently is in the form of an ICM application.

d) Please see Alectra Utilities' response to G-SEC-5 c).

e) Alectra Utilities did not include any general plant projects in the ICM request for the Enersource RZ, as there were no projects that met the ICM eligibility criteria.

**BOMA-119**

**Reference(s): Exhibit 2, Tab 3, Schedule 10, p15, Tables 79 and 100**

**Do the two tables distinguish between those that support one hundred percent of the requested increase, and fifty percent of the proposed increase, or are both groups included in the percentage of Respondents Supporting Incremental Capital Funding for system service and system renewal projects?**

**Response:**

Tables 99 and 100 refer only to respondents that support "one hundred percent" of the requested increase.

**BOMA-120**

**Reference(s): Exhibit 2, Tab 3, Schedule 10, p15, Tables 79 and 100**

**Please confirm that the ICM model and the proposed rate increases are modified to reflect the removal of the Queen/Goreway project.**

**Response:**

The ICM model and proposed rate increases were modified to incorporate the removal of the Queen/Goreway as provided in Exhibit 2, Tab 3, Schedule 10, Table 103 – 2018 Eligible Capital Projects by Category – PowerStream RZ, p.19.

**BOMA-121**

**Reference(s): Exhibit 2, Tab 3, Schedule 10, p15 of 36**

**On which pages of the Innovative PowerStream Survey does Alectra rely in constructing Tables 99 and 100? Please specify the pages and describe how the data from those pages (responses) was used to produce the tables. See, for example, at p18 of Appendix 1 to the Innovative Report, when asked about the proposed residential rate increase of twenty-six cents per month to fund the incremental capital, only twenty-nine percent agreed the rate increase was reasonable. Forty percent thought the proposed increase was unreasonable and unaffordable, and twenty-five percent said they wanted to know how the increase was going to be invested, before they could accept it (p22).**

**Response:**

Tables 99 and 100 provided in Exhibit 2, Tab 3, Schedule 10, p.15, summarize the percentage of residential, GS<50 kW and GS>50 kW customers that support Alectra Utilities' request for incremental capital funding for the PowerStream RZ, by investment category. The data used to construct the tables is provided in Exhibit 3, Tab 1, Schedule 1, Attachment 51 – Innovative Customer Engagement Report, p.15-16. The tables in the Customer Engagement Report are also provided as Tables 1 and 2, below.

Two scenarios are presented in Tables 99 and 100 of the Application: (i) the % of customers who support the incremental funding request is based on the total number of respondents completing the survey. This corresponds to the % of customers that support investments to 'Maintain' reliability, provided in Tables 1 and 2, below. The second scenario presented is: (ii) the % of customers who support the incremental funding request is based on the total number of respondents who felt they knew enough to answer the question *"Given the varying levels of reliability under each scenario below and the projected customer rate impact of each, please indicate which approach* [maintain reliability, reliability declines, reliability significantly declines] *you want PowerStream to pursue in 2018?"* This corresponds to the % of customers that support investments to 'Maintain' reliability as a % of the total customers that provided a response to the survey question.

1 **Table 1 – Online Feedback Portal PowerStream RZ**

| Online Feedback Portal: PowerStream ICM | Residential (n=6,962) | Small Business (n=131) |
|---|---|---|
| **System Service \| Growth Pressures** [new and increased substation, transformer station and powerline capacity] | | |
| Maintain [Res: 0.05$; Small Business: $0.13] | 50% ✓ | 36% |
| Eventually Decline [Res: 0.03$; Small Business: $0.06] | 7% | 8% |
| Significantly Decline [No additional charges] | 27% | 34% |
| **System Renewal \| Aging Infrastructure Pressures** [rear lot conversion; underground cable; obsolete switches] | | |
| Maintain [Res: $0.10; Small Business: $0.26] | 43% | 32% |
| Eventually Decline [Res: $0.05; Small Business: $0.13] | 12% | 7% |
| Significantly Decline [No additional charges] | 29% | 36% |

**Note:** Res = Residential Rate Class; SB = Small Business (GS < 50kW) Rate Class.
"Don't know" not shown in the table above.

2

**Table 2 – Telephone Feedback PowerStream RZ**

| PowerStream ICM: Telephone | Residential (Res) | Small Business (SB) | Mid-Market (MM) |
|---|---|---|---|
| **System Service \| Growth Pressures** [new and increased substation, transformer station and powerline capacity] | | | |
| Maintain [Res: $0.05; SB: $0.13; MM: $2.18] | 41% | 54% ✓ | 52% ✓ |
| Eventually Decline [Res: $0.03; SB: $0.06; MM: $1.09] | 6% | 9% | 9% |
| Significantly Decline [No additional charges] | 44% | 35% | 36% |
| **System Renewal \| Aging Infrastructure Pressures** [rear lot conversion; underground cable; obsolete switches] | | | |
| Maintain [Res: $0.10; SB: $0.26; MM: $4.32] | 38% | 52% ✓ | 44% |
| Eventually Decline [Res: $0.05; SB: $0.13; MM: $2.16] | 5% | 11% | 16% |
| Significantly Decline [No additional charges] | 48% | 34% | 39% |

**Note:** Percentages in the table above include recoded data to include those who are not interested in receiving more information because they have already made up their mind (either support increase or can't afford it).
"Don't know" not shown in the table above.

**BOMA-122**

**Reference(s): Attachment 51**

**Why did Innovative not ask a question about the acceptability of the total monthly incremental charge (for each class) rather than only on the disaggregated basis?**

**Response:**

For the Enersource RZ DSP, customers were presented with aggregate rate impacts and asked about their preferred investment approach.

For the ICM rate impacts, customer were presented with both aggregated and disaggregated information. For respondents who wanted additional information on specific ICM projects, acceptability questions were asked on a disaggregated basis.

**BOMA-123**

**Reference(s): Attachment 51, p21**

**Please explain why the customers were asked whether they would pay an additional five cents or three cents per month, for different levels of reliability, when the discussion at the top of the page talks about total of fifty-six cents per month, in incremental funding, and eleven cents for the York Transit project.**

**Response:**

The above question does not pertain to Attachment 51, p21.

Alectra Utilities assumes that this question is in reference to Attachment 51, p25 and p26 PowerStream ICM Telephone table - Proposed Incremental System Service Investments. The $0.05 represents the estimated rate impact on the typical residential customer if Alectra Utilities were to make investments in system service to maintain existing levels of reliability; the $0.03 is the estimated rate impact if Alectra Utilities were to make partial/deferred system service investments.

Alternatively, under Attachment 51, Appendix 5.0, p40, p43 and p45, references are made to a total incremental cost of $0.26 for PowerStream RZ residential customers; $0.11 for the York Transit project (system access); $0.05/$0.03 for system service investments; and $0.10/$0.05 for system renewal investments. The $0.26 ICM rate impact on PowerStream RZ residential customers is the summation of $0.11 + $0.05 + $0.10.

Additional information pertaining to PowerStream RZ residential customer question wording can be found under Attachment 51, Appendix 6.4, p8-9.

**BOMA-124**

**Reference(s): Attachment 51, p46**

**Like in many parts of the case of Enersource surveys, the headline on this page of the PowerStream telephone survey does not appear to clearly reflect the actual results of the survey question. For example, the headline states:**

**"Majority are willing to accept some rate increase".**

**Would it not be more accurate to say that while thirty-seven percent support the proposed increase as reasonable, fifty-eight percent either would support only half the requested amount (twenty percent) knowing that reliability would "eventually decline", or are not willing to accept any increase (thirty-eight percent) even knowing that the level of reliability could decline significantly?**

**Response:**

Alectra Utilities does not agree; the existing heading is accurate as originally provided. The additional information referred to in the rephrasing of the statement, is already provided in the results shown on the slide being referenced.

The overall customer engagement research tells a clear story of customer needs and preferences: *The vast majority of Alectra Utilities customers are satisfied with their current level of reliability, and most support some form of investment program (whether that be the proposed amount or a paced approach) that ensures a consistently reliable and modern distribution system.*

**BOMA-125**

**Reference(s): Attachment 51, p15 of 36**

**Aside from the removal of the Queen/Goreway project, $1,457,932, which reduces the 2018 capital forecast from $109,773,500 to $108,315,568, a reduction of approximately one and one-half percent, is PowerStream proposing a further reduction to its 2018 capital spend. Did it seriously consider any further reductions?**

**Please discuss.**

After incorporating customer feedback, Alectra Utilities evaluated the 2018 capital investment plan for the PowerStream RZ and determined that all proposed investments, including ICM projects, are prudent and required in 2018. Alectra Utilities is not proposing further reductions.

**BOMA-126**

**Reference(s): Exhibit 2, Tab 3, Schedule 10, York Region Rapid Transit, p22**

**(a) In suggesting that cost variance be addressed through the ICM true-up mechanism, does the company agree that 2018 project costs remain subject to review for prudency?**

**(b) How were the 97,000 customer outage minutes calculated?**

**Response:**

a) Please see the Applicant's response to Interrogatory CCC-7.

b) There are no customer outage minutes calculated for the York Region Rapid Transit project. The 97,000 customer outage minutes calculated are for the Station Switchgear replacement project- 8th Line MS323. The calculation of customer outage minutes for this project is provided below.

Customer Minute Interruption ("CMI") is estimated as follows:

- Feeder Breaker CMI = 900 customers x 2 hours x 60 minutes/hour x 0.1 failures per year = 10,800 CMI per year
- Transformer Breaker CMI = (3 x 900) customers x 4 hours x 60 minutes/hour x 0.1 failures per year = 64,800 CMI per year
- Total CMI = 3 x 10,800 + 64,800 = 97,200 CMI per year

**BOMA-127**

**Reference(s): Exhibit 2, Tab 3, Schedule 10, p22, BC 102750**

**Please provide a breakdown in costs between replacing the switchgear and the ancillary work and a breakdown of the various components of the ancillary work.**

**Response:**

Table 1 provides the cost breakdown between replacing the switchgear and the ancillary work.

| Project Components | A<br>**Switchgear Replacement** | B<br>**Ancillary Work** | A+B<br>**Total Project** |
|---|---|---|---|
| 13.8kV Switchgear | $666 | | $666 |
| Communications Equipment and Building | $32 | | $32 |
| Station Service Transformer (1) | | $6 | $6 |
| DC System | $23 | | $23 |
| 13.8kV Cable (incl. neutrals and station service) | | $41 | $41 |
| Misc. materials (terminations, arresters, etc.) | | $29 | $29 |
| Engineering Design | $95 | $11 | $105 |
| Contractor Costs - Electrical & Civil | $247 | $27 | $274 |
| Inside Labour Cost | $196 | $22 | $218 |
| | **$1,260** | **$135** | **$1,395** |

Table 1 – Switchgear and ancillary cost breakdown

**BOMA-128**

**Reference(s): Exhibit 2, Tab 3, Schedule 10, p23**

**(a) What would the cost be if the overhead front lot service were installed, compared to the $4.84 million of the current proposal?**

**(b) What is the health index of the length of rear lot overhead cable?**

**(c) What has been the outage experience of the length of cable and poles, transformers, proposed to be replaced?**

**(d) What is the current standard of service being referred to? It is illegal to install front lot overhead. Please discuss.**

**(e) Does the project represent one of the thirty-seven areas currently served by a rear lot overhead system? Does the company intend to continue the program in future years, until all thirty-seven areas have been addressed?**

**Response:**

a) If the overhead front lot service were installed, the cost would be $2,016,634.

b) The asset demographics and health index of the rear lot overhead are provided in Tables 1 and 2 below.

Table 1 – Demographics Data of Distribution Assets in Royal Orchard – North (Markham)

| Location Reference # | Demographic Data | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | Average Pole Age | Number of Poles | Average Transformer Age | Number of Transformers | Number of Customers (Commercial) | Number of Customers (Residential) | Total Number of Customers | Total Number of Services |
| 32B | 49 | 29 | 51 | 14 | 0 | 164 | 164 | 164 |

Table 2 – Asset Condition Data of Distribution Assets in Royal Orchard – North (Markham)

| Location Reference # | Condition Data: 1 (Good) to 10 (Bad) | | | | | | |
|---|---|---|---|---|---|---|---|
| | Pole | Transformer | Secondary Run-offs | Primary Runner | Safety Rating for Workers | Safety Rating for Public | Accessibility |
| 32B | 9 | 8 | 5 | 8 | 8 | 7 | 9 |

c) The data for the outage on only the overhead wire, pole and transformer for asset to be replaced is not available.

d) Alectra Utilities current standard of service to a typical residential subdivision is front lot underground supply. For additional information on this subject please refer to EB-2015-0003 Technical Undertaking JTC.1.14 – Page 19 of 22.

*For new residential subdivisions, subdivision agreements between the Municipality and the Developer include a clause related to electrical servicing by PowerStream. Included in the clause is a requirement for underground. As an example, these are the words on a typical agreement - "…The owner further agrees that all lands shall be serviced by underground electrical distribution systems…".*

*At the point in time when the underground electrical distribution system is required to be replaced, the municipality, as the road authority, has the right to determine where the electrical facilities are located, specifically under the Electricity Act, 1998, S.O. 1998, c. 15, Sched. A,subsection 41. 9, location:*

*(9) The location of any structures, equipment or facilities constructed or installed under subsection (1) shall be agreed on by the transmitter or distributor and the owner of the street or highway, and in case of disagreement shall be determined by the Board. 1998, c. 15, Sched. A, s. 41 (9).*

*This approval is typically governed by the Municipal Consent application process for submission by utilities or their contractors for work within the municipal right of way.*

*The City of Markham's Official Plan approved by the Region in June, 2014, section 7.2.3.5 states:*

*To work with the Region and utility providers to ensure appropriate utility design and placement, including locating cables, electrical circuits and other utility structures underground in order to minimize visual impacts. Markham and the Region shall encourage priority areas for underground installation of utilities in new communities and intensification areas.*

*At the conclusion of the technical conference, a specific request was made to municipal staff, asking:*

*•Can PowerStream obtain approval to move or relocate rear lot poles of an overhead system to the front?;*

*•Would the municipality consider granting municipal consent for rebuilding an existing underground hydro system to overhead?; and*

*•If no approvals are obtained, what are the by-laws or regulations that would prohibit PowerStream from doing so?*

*No response was received.*

*From a technical and practical perspective, design requirements dictate that roads with curves require extensive guying on lands that customers typically value as their own. Also, pole lines could provide issues with mature trees and result in issues with finding acceptable locations with all parties. There is also a perception of decreased property values. The results are dissatisfied rate payers.*

e) This project represents a renewal investment to remediate the rear lot service in the area of Royal Orchard (North) in Markham.

Alectra Utilities intends to address the system renewal needs of other service areas with rear lot supply through individual projects as required by specific drivers, timing and asset conditions of those specific service areas.

**BOMA-129**

**Reference(s): Exhibit 2, Tab 3, Schedule 10, BC 150141, 150142**

**What does PowerStream intend to spend on underground cable replacement each year over the term of the current IRM regime? Was such a program outlined in the recent DSP?**

**Response:**

Alectra Utilities proposed capital spend on underground cable replacement in the PowerStream Rate Zone is provided in Table 1. The cable replacement program was outlined in the PowerStream DSP. Please see Alectra Utilities response to ERZ-Staff-7(a).

**Table 1 – Underground cable replacement capital forecast (2017-2020)**

| Projects | 2017 | 2018 | 2019 | 2020 | Outlined in DSP |
|---|---|---|---|---|---|
| | Budget | Budget | Budget | Budget | |
| (Barrie) - Cook St and Steel St | | $ 963,047 | | | No |
| (Barrie) - Donald St and Simcoe Terrace | | $ 397,144 | | | No |
| (M49) - Steeles and Fairway Heights | | $1,842,953 | | | No |
| (V08) - Steeles Ave and New Westminister | | $2,637,046 | $2,637,700 | $2,638,353 | No |
| (V22) - Doney Cres | | $ 101,077 | | | No |
| (V38) - Rutherford and Weston | $3,408,292 | | | | No |
| (M43) - Steelcase and Idema | | | $2,378,723 | | No |
| (M51) - Henderson and Doncaster | $ 908,059 | | | | No |
| (M51) - Julia St and Candice Gate | $ 664,055 | | | | No |
| (Tottenham) - Mill St and The Boulevard | $ 660,458 | | | | No |
| (V62) - Hedgerow Lane and Hwy 7 | $ 668,651 | | | | No |
| Left Behind Cable | $2,122,271 | $2,207,515 | | | No |
| Planned Cable Replacement | $ - | $ 338,490 | $3,470,845 | $5,848,915 | Yes |
| Emerging Cable Replacement | $ 524,527 | $ 541,127 | $ 558,250 | $ 575,805 | Yes |
| Total | $8,956,314 | $9,028,398 | $9,045,518 | $9,063,074 | |

1

**BOMA-130**

**Reference(s): Attachment 34**

**Please provide the 2018 forecast addition to rate base as a result of the ICM-funded capital projects listed on p1. Please show the calculations necessary to arrive at the incremental revenue requirement of $1,962,111.**

**Response:**

Please see Alectra Utilities response to BOMA-111.

**BOMA-131**

**Reference(s): Attachment 35**

**Background**

**(a) Please see list of material 2018 capital projects. The list contains thirty-six material projects, costing $80,437,263, divided into the four traditional categories of System Access, System Renewal, System Service, and General Plant. Of the thirty-six projects, the ten listed on Attachment 34 are proposed to be funded by the proposed 2018 ICM. Please provide the following:**

- **(i) Why were the ten projects listed in Attachment 34 chosen for ICM funding, as opposed to others among the thirty-six projects? Please explain fully for each project.**
- **(ii) Please provide a priority listing of the thirty-six projects from 1 to 36, regardless of which traditional category they fall.**
- **(iii) For the projects in each of the four categories, please provide a priority listing within the category.**
- **(iv) Please explain the derivation (the reason) for the priority listing in each category and in the overall (1 to 36) list.**

**(b) For each of the thirty-six projects, please indicate whether, and to what extent, they are parts of projects that commenced in 2017, or prior to 2017.**

**(c) Please indicate which, if any, of the projects will involve capital expenditures in 2019 and/or subsequent years.**

**(d) Has each of the thirty-six projects, and the ten projects, been included in PowerStream's most recent 2018-2022 DSP? If any are not, please explain fully.**

**(e) Is it Alectra's intent to apply for ICMs to fund parts of its proposed capital expenditures:**

- **(i) in 2019, along with the approval of the Alectra DSP;**
- **(ii) in the remaining years covered under the current PowerStream DSP;**
- **(iii) in years beyond the end of the DSP, until the end of the ten year period prior to rebasing.**

**(f) Will the PowerStream division's DSP continue to be valid when Alectra's planned 2019 DSP is released?**

**Response:**

(a) (i) Alectra Utilities has capital investment needs for the PowerStream RZ that are not funded through existing distribution rates. Furthermore, each eligible project is a discrete project that meets or exceed the materiality level for the PowerStream RZ. Each project is distinct,

unrelated to a recurring annual capital program, and has been evaluated in the asset management and capital planning process as required in 2018.

(ii) Table 1 must be assessed in the context of Alectra Utilities' Asset Management Practice and Capital Investment Plan Optimization process. Pursuant to this process, Alectra Utilities evaluates each project in the capital investment plan to pace and prioritize investments based on business values, objectives and risks. The portfolio of projects presented, that is, those listed below, reflect prudent investment needs and the most cost effective option for ratepayers. They are all necessary and produce positive outcomes for ratepayers.

Table 1 – Project list ranking – PowerStream RZ

| Project Name | Rank |
|---|---|
| Unforeseen Projects Initiated by PowerStream | 1 |
| Pole Replacement Program | 2 |
| 4-Circuit Pole Storm Hardening | 3 |
| Storm damage - Replacement of distribution equipment due to storm. | 4 |
| Road Authority Expenditure Ps North | 5 |
| Switchgears - Unscheduled Replacement of Failed (end of useful Life) Distribution Equipment | 6 |
| Road Authority YRRT Yonge St | 7 |
| New Subdivision Development - Secondary Service Lateral - South | 8 |
| New Residential Subdivision Development - North | 9 |
| Road Authority Expenditure Ps South | 10 |
| Build double ccts 27.6kV pole line on 19th Ave between Leslie St and Bayview Ave | 11 |
| Unscheduled Replacement of Failed Equipment - Poles, etc | 12 |
| New Residential Subdivision Development - South | 13 |
| Distribution Automation Switches / Reclosers | 14 |
| Pad Mount Transformer Replacement | 15 |
| Customer Information Systems | 16 |
| Rebuild 27.6 kV pole line on Warden Ave into 4 ccts from 16th Ave to Major Mack | 17 |
| Cable Replacement – (V08) - Steeles Ave and New Westminster | 18 |
| Double Circuit existing 23M21 Circuit from Bayfield & Livingstone to Little Lake MS. | 19 |
| Switchgear Replacement Program | 20 |
| Install two additional 27.6 kV ccts on Hwy 7 from Jane St to Weston Rd | 21 |
| Planned Circuit Breaker Replacement - Richmond Hill TS#1 | 22 |
| Rear Lot Supply Remediation - Royal Orchard - North | 23 |
| Station Capacity Projects | 24 |
| New 27.6kV Pole Line on 19th Ave from Leslie to Woodbine Ave | 25 |

| | |
|---|---|
| Install Two 27.6kV Ccts on 16th Ave from Hwy 404 to Woodbine Ave | 26 |
| Station Reliability Projects | 27 |
| Cable Replacement – Left Behind Cable | 28 |
| Cable Replacement – (M49) - Steeles and Fairway Heights | 29 |
| Station Switchgear Replacement (ACA) 8th Line MS323 | 30 |
| Computer Software | 31 |
| Information/Communication Systems | 32 |
| Radial Supply Remediation/Conversion - 13.8 kV to 27.6 kV on Miller Ave | 33 |
| Smart Grid | 34 |
| Smart Grid | 35 |
| Fleet | 36 |

(iii) Table 2 provides the priority listing for the projects in each of the four categories.

Table 2 – Priority ranking by investment category for the PowerStream Rate Zone

| SYSTEM ACCESS<br>Project Name | Rank<br>Rank |
|---|---|
| Road Authority Expenditure Ps North | 5 |
| Road Authority YRRT Yonge St | 7 |
| New Subdivision Development - Secondary Service Lateral - South | 8 |
| New Residential Subdivision Development - North | 9 |
| Road Authority Expenditure Ps South | 10 |
| New Residential Subdivision Development - South | 13 |

| SYSTEM RENEWAL<br>Project Name | Rank |
|---|---|
| Unforeseen Projects Initiated by PowerStream | 1 |
| Pole Replacement Program | 2 |
| 4-Circuit Pole Storm Hardening | 3 |
| Storm damage - Replacement of distribution equipment due to storm. | 4 |
| Switchgears - Unscheduled Replacement of Failed (end of useful Life) Distribution Equipment | 6 |
| Unscheduled Replacement of Failed Equipment - Poles, etc | 12 |
| Pad Mount Transformer Replacement | 15 |
| Cable Replacement – (V08) - Steeles Ave and New Westminster | 18 |
| Switchgear Replacement Program | 20 |
| Planned Circuit Breaker Replacement - Richmond Hill TS#1 | 22 |
| Rear Lot Supply Remediation - Royal Orchard - North | 23 |
| Cable Replacement – Left Behind Cable | 28 |
| Cable Replacement – (M49) - Steeles and Fairway Heights | 29 |

| | |
|---|---|
| Station Switchgear Replacement (ACA) 8th Line MS323 | 30 |
| Radial Supply Remediation/Conversion - 13.8 kV to 27.6 kV on Miller Ave | 33 |

| SYSTEM SERVICE<br>Project Name | Rank |
|---|---|
| Build double ccts 27.6kV pole line on 19th Ave between Leslie St and Bayview Ave | 11 |
| Distribution Automation Switches / Reclosers | 14 |
| Rebuild 27.6 kV pole line on Warden Ave into 4 ccts from 16th Ave to Major Mack | 17 |
| Double Circuit existing 23M21 Circuit from Bayfield & Livingstone to Little Lake MS. | 19 |
| Install two additional 27.6 kV ccts on Hwy 7 from Jane St to Weston Rd | 21 |
| Station Capacity Projects | 24 |
| New 27.6kV Pole Line on 19th Ave from Leslie to Woodbine Ave | 25 |
| Install Two 27.6kV Ccts on 16th Ave from Hwy 404 to Woodbine Ave | 26 |
| Station Reliability Projects | 27 |
| Smart Grid | 34 |

| GENERAL PLANT<br>Project Name | Rank |
|---|---|
| Customer Information Systems | 16 |
| Computer Software | 31 |
| Information/Communication Systems | 32 |
| Smart Grid | 35 |
| Fleet | 36 |

iv) Alectra Utilities paces and prioritizes capital initiatives in the PowerStream rates zone through the utilization of capital work business cases and portfolio optimization which includes asset investment software optimization based on relative value of the investment and risk associated with the investment need. The methodology and criteria of the relative project value development provided for this ranking is consistent with the methodology and criteria used in the development PowerStream's 2016-2020 DSP. The methodology and criteria is provided in the attached file BOMA-131_Attach 1_CopperLeaf Value Framework and was originally filed with as part of PowerStream's Custom IR application under the reference EB-2015-0003 / C-2-1 / II-2-Staff-51 / Appendix 51a.

(b) Exhibit 3, Tab 1, Schedule 1, Attachment 35 – 2018 Capital Spending by project PowerStream RZ, contains the capital expenditure required in 2018. Certain system access

investments include development project and road widening works that are driven by customer and road authority schedules beyond the control of Alectra Utilities. In these certain system access investments, there are portions that may have commenced in or prior to 2017. Only the work expended in 2018 has been considered and budgeted in the attachment.

1. New Residential Subdivision Development – North
2. New Residential Subdivision Development – South
3. New Subdivision Development – Secondary Service Lateral – South
4. Road Authority Expenditure Ps North
5. Road Authority Expenditure Ps South
6. Road Authority YRRT

Alectra Utilities distinguishes between multi-year projects and typical annual capital programs. Multi-year projects are larger complex projects that are paced over several years with a defined scope, budget and end date. Phases of multi-year projects may be staged to meet the requirements of the municipality, region or road authority as is the case with the YRRT project. Alectra Utilities phases each year of a complex multi-year project as a distinct project with a defined annual budget, annual scope and schedule as per the requirements of the customer or road authority. The YRRT multi-year project is unrelated to a recurring annual capital program.

(c) Exhibit 3, Tab 1, Schedule 1, Attachment 35 – 2018 Capital Spending by project PowerStream RZ, contains the capital expenditure required in 2018. The system access investments included in response to part b) above are driven by customer and road authority scheduled beyond the control of Alectra Utilities. In these certain system access investments, there are portions that may have work carry into 2019 or later. Only the work to be expended in 2018 has been considered and budgeted in the attachment.

(d) Alectra Utilities has not developed a 2018-2022 DSP for the PowerStream Rate Zone and continues to use the 2015-2020 PowerStream DSP. Exhibit 3, Tab 1, Schedule 1, Attachment 35 – 2018 Capital Spending by project PowerStream RZ, contains the capital

expenditure required in 2018. The Road Authority YRRT project included in this list is the only project which was not included in the 2016 – 2020 DSP project listing.

On May 22, 2015, PowerStream submitted its 2016-2020 Custom Incentive Regulation ("Custom IR") application (EB-2015-0003). The projects included in the Distribution System Plan ("DSP") included with that application were based on the best available information at the time of the drafting of the DSP in late 2014 and early 2015. Subsequent to the filing of the application, Alectra Utilities' predecessor, PowerStream, was informed of further enhancements to the transportation infrastructure and expansion on several Rapid Transit corridors in early 2016 by York Region Rapid Transit ("YRRT") Road Authority. These were brought to the attention of the OEB, during the course of the application adjudication. The OEB specifically articulated the capital funding required for the York Region Rapid Transit project at page 14 of the Decision:
"…an additional $20.00 million may be needed for York Region Rapid Transit project"

Certain investments were included in the 2016 – 2020 DSP within programs and are now broken out into specific projects as follows:

1. Cable Replacement – (V08) - Steeles Ave and New Westminster
2. Cable Replacement – (M49) - Steeles and Fairway Heights
3. Rear Lot Supply Remediation - Royal Orchard – North

Please see response to PRZ-Staff-7 for additional details regarding the restructuring of the cable replacement and rear lot supply remediation programs into separate individual projects.

(e) i) Please see Alectra Utilities response to G-SEC-5 c).
ii) Please see Alectra Utilities response to G-SEC-5 c).
iii) Please see Alectra Utilities response to G-SEC-5 c).

(f) Alectra Utilities will use the predecessor utilities' Distribution System Plans ("DSP") and the to inform and influence the development of the consolidated Alectra DSP. The consolidated Alectra DSP will supersede the individual DSPs of the predecessor entities.

**BOMA-132**

**Reference(s): Attachment 34**

**Does the company propose a return on ICM capital expenditures in 2018, in addition to depreciation, CCA, and taxes? Please discuss.**

**Response:**

Alectra Utilities relied on the Ontario Energy Board's ("OEB") Capital Module Applicable to ACM and ICM ("Capital Module") to calculate incremental revenue requirement for each rate zone. The Capital Module for the Brampton, PowerStream and Enersource rate zones is provided in Exhibit 3, Tab 1, Schedule 1, Attachment 18 – Incremental Capital Module Brampton RZ, Exhibit 3, Tab 1, Schedule 1, Attachment 31 – Incremental Capital Module PowerStream RZ, and Exhibit 3, Tab 1, Schedule 1, Attachment 45 – Incremental Capital Module Enersource RZ. The ICM revenue for each rate zone incorporates a return on rate base, amortization and PILs, as summarized in Table 67 – Incremental Revenue Requirement Brampton RZ in Exhibit 2, Tab 2, Schedule 10, p.12; Table 104 – Incremental Revenue Requirement PowerStream RZ in Exhibit 2, Tab 3, Schedule 10, p.33; and Table 145 – Incremental Revenue Requirement Enersource RZ in Exhibit 2, Tab 4, Schedule 11, p.46.

**BOMA-133**

**Reference(s): Exhibit 2, Tab 3, Schedule 10, p36**

**a) Is the proposed rate rider only in place for 2018, or does it extend beyond December 31, 2018, and, if so, for how long? Please show calculations that show the revenue generated by the rate rider each year it is in effect until rebasing, and how that amount is reconciled with the 2018 ICM driven capex that needs to be funded.**

**b) Please advise whether the amount of the rider would remain constant for the duration of its existence, or change from one year to the next.**

**Response:**

a) Please see Alectra Utilities response to BOMA-114 (a.

b) Please see Alectra Utilities response to BOMA -114 (b.

**BOMA-134**

**Reference(s): General**

**Is it Alectra's understanding that the PowerStream division will continue under price cap IR for the next ten years, according to Board Guidelines, and that Alectra will be entitled to bring forward an ICM for PowerStream division in any year during that period? Please discuss.**

**Response:**

It is Alectra Utilities' understanding that, consistent with Ontario Energy Board ("OEB") policy, as provided in the *Report of the Board on Rate-Making Associated with Distributor Consolidation*, dated March 26, 2015 and the *Handbook to Electricity Distributor and Transmitter Consolidations*, dated January 21, 2016, the PowerStream Rate Zone ("PRZ") will continue under its current Price Cap IR rate plan for the rebasing deferral period.

Please see Alectra Utilities' response to G-SEC-5 c).

**BOMA-135**

**Reference(s): Exhibit 2, Tab 3, Schedule 10, p14, Table 91**

**(a) Generally, the planned expenditures over the year 2018 do not reflect a significant increase from historical levels, levels in 2014, 2015, 2016, 2017, and one would expect that, as Dr. Kaufman has pointed out, in such circumstances, the price cap formula and growth would yield revenues sufficient to finance such a capital expenditure program. In the circumstances, why is the ICM for 2018 justified?**

**(b) Please describe your interpretation of this passage at p6 of the "ACM Report": "Any incremental capital amounts approved for recovery must fit within the total eligible incremental capital amount (as defined in this ACM Report) and must clearly have a significant influence on the operation of the distributor; otherwise they should be dealt with at rebasing" (our emphasis).**

**What does Alectra interpret the phrase "must clearly have a significant influence on the operation of the distributor" to mean? What type of projects would not meet this test?**

**(c) Given that Alectra is allowed under the MAADs decision to defer rebasing for ten years, and to retain savings derived from the merger for that period to, inter alia, offset transaction costs, to what extent will Alectra use savings achieved to date to offset capex costs prior to seeking an ICM? To what extent does it intend to do so in the future?**

**(d) Please explain why the "ICM proposal" is an ICM, rather than as an ACM. Please explain fully.**

**(e) Does Alectra intend to ask for ICM modules for its PowerStream division each of the next nine years? Please explain fully.**

**(f) Why has PowerStream not included any general plant capital expenditures in its list of ICM funded projects? Please explain fully.**

**(g) PowerStream proposes approximately $28.8 million of miscellaneous projects (under materiality threshold). Please provide a list of each of the projects forecast to exceed $50,000 in 2018.**

**(h) Please prioritize the projects listed in part (g) into four quartiles (a list for each quartile).**

**Response:**

a) Alectra Utilities does not agree with the premise that the capital spending of recent years necessary reflects the funding available in rates under IRM to fund new capital spending.

In EB-2007-0673, the OEB considered the comments of Dr. Kaufman along with other experts and stakeholders. On September 17, 2008 issued the "Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors". In this report the OEB created a threshold formula to assess the need for additional funding for capital which is an integral part of the OEB's Capital Module.

Please see Alectra Utilities' response to PRZ-SEC-12 for further discussion of: the relationship between historic capital expenditures; the amount in rates to fund capital spending in IRM years: and the implications regarding the need for incremental capital funding.

b) Please see Alectra Utilities' response to BOMA-118 a).

c) Please see Alectra Utilities' response to BOMA-118 b).

d) Alectra Utilities' predecessor, PowerStream Inc., filed a Custom Incentive Regulation ("Custom IR") (EB-2015-0004) with the Ontario Energy Board ("OEB") for electricity distribution rates ("EDR") for the 2016-2020 rate plan term. In its decision, the OEB set EDR for 2016 on a Price Cap IR basis; the OEB set 2017 EDR on a cost of service basis. PowerStream had intended to seek capital funding through the Custom IR application. The resulting cost of service-based rates for 2017 were the outcome of the OEB's decision. Consequently, there was no opportunity to file an Advanced Capital Module ("ACM").

e) Please see Alectra Utilities' response to G-SEC-5 c).

f) Please see Alectra Utilities' response to BOMA-118 e).

g) Please see Table 1 below for the list of projects below the materiality threshold that are forecast to exceed $0.05MM in 2018.

**Table 1 – 2018 Capital Expenditures above $0.05MM**

| System Access | |
|---|---|
| **Project Name** | **2018** |
| SMALL NEW and UPGRADE COMMERCIAL SERVICES South | $58,802 |
| NEW O/H and U/G SECONDARY RESIDENTIAL SERVICE CONNECTION North | $62,362 |
| New Services (new and upgrades) - Commercial, Industrial and Institutional (ICI) Projects - NORTH | $66,400 |
| Failed Meter Replacement | $174,838 |
| Subdivision - South Underground Residential Distribution System Final Close out and Inspection. | $104,031 |
| Unforeseen Projects Initiated by the customer PS North | $100,806 |
| Open work order for ICI meter installations - NORTH | $132,720 |
| New Services - new and upgrades - COMMERCIAL, INDUSTRIAL, INSTITUTIONAL (ICI) SERVICES - SOUTH | $200,029 |
| Unforeseen Projects Initiated by the customer PS South | $323,741 |
| NEW O/H and U/G SECONDARY RESIDENTIAL SERVICE CONNECTION South | $372,013 |
| Open work order for ICI meter installations - SOUTH | $396,901 |
| O/H and U/G RESIDENTIAL SERVICE UPGRADES North | $437,415 |
| Commercial/Industrial and Wholesale Meter Re-Verification Program (Commercial meters - Non Smart) | $506,243 |
| New Commercial Subdivision Development - NORTH | $600,000 |
| Suite Meter Re-Verification Program | $493,195 |
| New Subdivision Development - Secondary Service Lateral - North | $585,839 |
| O/H and U/G RESIDENTIAL SERVICE UPGRADES South | $648,021 |
| New Commercial Subdivision Development - SOUTH | $999,999 |
| Upgrade 2.5 Element Services to 3 Element Services. | $163,603 |
| Residential Meter "ICON F" Meter Replacement Program | $872,435 |
| Suite Meter Installation | $347,814 |
| Smart Meter Test Facility | $51,779 |
| Smart Meter Network Expansion and Enhancements | $204,383 |

1

| System Renewal<br>Project Name | 2018 |
|---|---|
| Capital Corrective Equipment Replacement - Stations | $254,863 |
| Cable Replacement Program | $338,490 |
| Wye Transformer Supplying Delta Service Remediation | $254,607 |
| LIS - Unscheduled Replacement of Failed (end of useful Life) Distribution Equipment | $283,415 |
| Non Recoverable replacement of Distribution Equipment due to accident/vandalism | $272,063 |
| Recoverable Replacement of distribution equipment due to Accidents/Vandalism | $658,507 |
| Cable Injection - (V37) - Langstaff and Weston | $613,020 |
| Cable Injection - (M27) - Kennedy - 16th Ave - McCowan - Hwy 7 | $692,134 |
| Mini-Rupter Switch Replacement | $202,363 |
| Cable Injection - (V01) - Young - Steeles - Bathurst - Center | $714,142 |
| Cable Injection - (V36) - Steeles and Pine Valley | $768,592 |
| Cable Injection - (M37) - Woodbine and 14th Ave | $857,442 |
| 27.6kV Insulator Replacement Program | $179,106 |
| Emerging Cable Replacement Projects | $541,127 |
| Joint Use Pole Removal | $529,293 |
| Cable Injection - (M44) - Konrad Cres | $730,436 |
| Rear Lot Supply Remediation - Shirley/Vine | $908,315 |
| Upgrade of the Radio over Internet Protocol (RoIP) Environment of the Operations Voice Radio System | $198,895 |
| Markham TS#2 Line Protections and HMI Upgrade - KDU-10 Replacement | $420,934 |
| 44kV Insulators Replacement Program | $142,342 |
| Replacement of End of Life Automated Switches/Reclosers | $423,221 |
| Station Switchgear Replacement (ACA) Big Bay Point MS304 | $229,258 |
| Station Switchgear Replacement (ACA) Ferndale South MS303 | $229,258 |
| Cable Replacement – (Barrie) - Cook St and Steel St | $963,047 |
| Cable Replacement – (V22) - Doney Cres | $101,077 |
| Cable Replacement – (Barrie) - Donald St and Simcoe Terrace | $397,144 |
| RTU Replacement Program (Reactive) | $97,830 |
| Low Voltage Bushing Replacement - VTS3 - T1/T2 | $306,327 |
| Low Voltage Bushing Replacement - Transformer Station MTS#3 - T1/T2 | $265,777 |
| Major repairs, refurbishment, or modifications to switches/switchgear | $100,000 |
| Upgrade of RTUS in 2 PMH Switchgear to Support Smart Grid Iniatives, | $62,479 |
| Technology Upgrades Improving the System Control Room Environment | $53,797 |

| System Service | |
|---|---|
| **Project Name** | **2018** |
| Build double 27.6kV ccts on Teston Rd and Pine Valley Dr to supply Block 40/47 | $704,083 |
| Hydro One Asset Purchase - Alliston | $299,600 |
| Install One Additional 27.6 kV Cct on Elgin Mills Rd - Part 2 Leslie St to Woodbine Ave | $443,674 |
| Install One Additional 27.6 kV Cct on Elgin Mills Rd - Part 1 Leslie St to Bayview Ave | $353,095 |
| Rebuild BBPR & Yonge Intersection | $482,354 |
| Ground Grid Refurbishments | $109,988 |
| Station Wiring Modifications for WiMax | $83,501 |
| Fault Indicator Installation and Replacement | $465,510 |
| System Remote Fault Indicator Deployment | $90,798 |
| Elder Mill MS Conversion - 8.32kV conductors Removal | $67,084 |
| Convert Three MS's in Barrie to WiMax Communications | $64,719 |
| Installation of SWI Video security system at 4 MS stations per year - Annual Program | $60,000 |
| Upgrade to Station Facilities (Building / Civil work) MultiYear | $92,066 |
| Installation/Retrofit of SWI Video security system at 3 TS stations | $60,000 |
| Upgrade of the Electronic Visual Display Wall (EVDW) to LED Light Engines | $62,674 |
| Design Only budget for Controllable Capital Projects | $370,220 |

| General Plant | |
|---|---|
| **Project Name** | **2018** |
| Interest Capitalization | $1,061,000 |
| Emerging Issues - Operations Capital | $256,800 |
| Server Refresh | $360,000 |
| Security - Additions & Enhancements | $200,090 |
| SQL Expansion | $50,000 |
| Contact Centre Workforce Management | $109,151 |
| Metering Tools and Equipment | $77,040 |
| Purchase of Major Tools | $332,527 |
| Metering WFM - Enhancements | $54,035 |
| Technology changes in Control Room. | $66,875 |
| Emergency Capital work as required for facilities | $410,647 |

h) The projects listed above are in order according to their calculated value to the portfolio.

**BOMA-136**

**Reference(s): Exhibit 2, Tab 3, Schedule 11, p1**

**Please provide a table which shows the percentage impact on each rate class of only the ICM rate rider. In other words, a Table 107 with the final column "percentage increase vs. current rate". Please explain any difference in these percentages from those shown in Tables 107, 108, and 109.**

**Response:**

Table 107 (Exhibit 2, Tab 3, Schedule 11, page 1) identifies the bill impacts by rate class as a result of the addition of the 2018 incremental capital funding rate riders as compared to the total bill including HST. The last column of the abovementioned table shows the percentage impact on each rate class of only the ICM rate rider.

Differences in the percentages, as compared to Tables 108 and 109 are due to the groupings of the bills components. Table 108 (Exhibit 2, Tab 3, Schedule 11, page 2) identifies a summary of bill impacts for the typical customer by rate class for distribution portion of the bill only, while Table 109 (Exhibit 2, Tab 3, Schedule 11, page 2) presents a summary of bill impact for distribution bill as well as of applicable rate riders.

**BOMA-137**

**Reference(s): Exhibit 2, Tab 2, Schedule 10, p3 (Brampton)**

**Please describe how ratepayers will be protected in the event Brampton underspends on ICM capital relative to its budget. Does Brampton intend to adjust the rider in the following year to hold ratepayers harmless?**

**Response:**

Section 7.4 of the *Report of the Board – New Policy Options for the Funding of Capital Investments: The Advanced Capital Module*, dated September 18, 2014, states that "*At the time of the next cost of service or Custom IR application, a distributor will need to file calculations showing the actual ACM/ICM amounts to be incorporated into the test year rate base. At that time, the Board will make a determination on the treatment of any difference between forecasted and actual capital spending under the ACM/ICM, if applicable, and the amounts recovered through ACM/ICM rate riders and what should have been recovered in the historical period during the preceding Price Cap IR plan term. Where there is a material difference between what was collected based on the approved ACM/ICM rate riders and what should have been recovered as the revenue requirement for the approved ACM/ICM project(s), based on actual amounts, the Board may direct that over- or under-collection be refunded or recovered from the distributor's ratepayers."*

**BOMA-138**

**Reference(s): Exhibit 2, Tab 2, Schedule 10, p4**

**(a) Please provide a copy of the HONI model (methodology) used to determine the $6.8 million due HONI in 2018. Please provide the calculation.**

**(b) Please provide the actual energy consumption and demand amounts for Brampton in 2014, 2015, 2016, 2017, 2018, relative to HONI's forecasts for those years.**

**(c) Please provide a copy of the CCRA between HONI and Brampton.**

**Response:**

a) Please see response to BRZ-Staff-5 a)

b) Please see response to BRZ-Staff-5 b)

c) The CCRA between HONI and Brampton is filed as Attachment 20 – Pleasant TS CCRA Agreement.

**BOMA-139**

**Reference(s): Exhibit 2, Tab 2, Schedule 10, p9**

**Background**

**At line 22, Brampton states that to be an eligible capital project, a project must be "distinct, unrelated to a recurring annual capital project, and has been evaluated in the asset management and capital planning processes, as required in 2018" (our emphasis).**

**The same statement is found in the Enersource evidence, but not in PowerStream's.**

**(a) Was the failure to maintain the underlined criteria in the PowerStream evidence an oversight? If not, please discuss why it was omitted.**

**(b) What is Alectra's interpretation of the requirement that an eligible project (for ICM/ACM funding) be unrelated to a "recurring annual project". If possible, please provide examples of capital projects that would not meet the criteria.**

**Response:**

a) The Criteria was included in the Discrete and Material Project section of the evidence for the PowerStream RZ located at E2/T3/S10 Page 20.

b) The statement as provided in evidence was a typo that should have stated:
Each project is distinct, unrelated to a recurring annual capital program, and has been evaluated in the asset management and capital planning process as required in 2018. (Emphasis added).

Alectra Utilities distinguishes between multi-year projects from typical annual capital programs. Multi-year projects are larger complex projects that are paced over several years with a defined scope, budget and end date. Phases of multi-year projects may be staged to meet the requirements of the municipality, region or road authority as is the case with the YRRT project.

**BOMA-140**

**Reference(s): Exhibit 2, Tab 2, Schedule 10, p11**

**Why is the ten year true-up date only three years after 2015, the year the five year true-up payment was made? What was the original cost of the transformer station?**

**Response:**

Pleasant TS expansion was placed in-service June 2, 2008 at a cost of $20,415,600. Due to the high number of true-ups to be completed by Hydro One Networks Inc, the former Hydro One Brampton was delayed in finalizing the five year true up until August 11 2015. The ten year anniversary of the in-service date for the stations is June 2, 2018.

**BOMA-141**

**Reference(s): Exhibit 2, Tab 2, Schedule 10, p14**

**(a) Please provide a table in the form of Table 69, except that the final column on the right side of the Table shows percentage increase vs. current distribution charge of the ICM rate rider, but not any other rate riders.**

**(b) For Table 71, please state the various rate riders, the impacts from which are included in the final column, and their respective contributions to the percentages impacts shown in the final column.**

**Response:**

a) Exhibit 2, Tab 2, Schedule 10, Table 69, p. 14, identifies the bill impacts by rate class as a result of the addition of the 2018 incremental capital funding rate riders as compared to the total bill including HST. The last column of the abovementioned table shows the percentage impact on each rate class of only the ICM rate rider.

b) Please refer to Table 1 for a list of the rate riders by rate class. Please refer to Table 2 for the contribution of the rate riders to the total bill impact presented in Exhibit 2, Tab 2, Schedule 11, Table 71 – Distribution Bill and Rate Rider Impacts by Rate Class – Brampton RZ.

**Table 1 – Rate Riders by Rate Class**

| | Monthly kWh | Monthly kW | DVA (2018) | DVA (non-WMP) | CBR (Class B) | GA Rate Rider |
|---|---|---|---|---|---|---|
| Residential | 750 | - | -$0.0010 | $0.0000 | -$0.00003 | -$0.0009 |
| GS<50 | 2,000 | - | -$0.0010 | $0.0000 | -$0.00003 | -$0.0009 |
| GS 50-699 kW | 182,500 | 500 | $0.0055 | -$0.3604 | -$0.01029 | -$0.0009 |
| GS 700-4,999 kW | 627,216 | 1,432 | $0.0066 | -$0.4199 | -$0.01143 | -$0.0009 |
| Large User | 10,220,000 | 20,000 | -$0.5487 | $0.0000 | $0.00000 | -$0.0009 |
| Street Lighting | 2,787,508 | 7,922 | -$0.3199 | $0.0000 | -$0.00961 | -$0.0009 |

**Table 2 – Rate Riders Contribution to the Bill Impact Percentages**

| | Distr. Bill Impact | Current (2017) Rate Riders Amount | DVA (2018) | DVA (non-WMP) | CBR (Class B) | GA Rate Rider | Total Rate Riders (2018) | Table 71 |
|---|---|---|---|---|---|---|---|---|
| | A | B | C | D | E | F | G = C+D+E+F | G - B + A |
| Residential | $ 0.23 | $ (2.63) | -$0.75 | $0.00 | -$0.02 | $0.00 | -$0.77 | $ 2.09 |
| GS<50 | $ (2.39) | $ (7.00) | -$2.00 | $0.00 | -$0.06 | $0.00 | -$2.06 | $ 2.55 |
| GS 50-699 kW | $ (88.81) | $ 270.50 | $2.75 | -$180.20 | -$5.15 | -$164.25 | -$346.85 | $ (706.16) |
| GS 700-4,999 kW | $ (152.06) | $ 1,025.74 | $9.45 | -$601.30 | -$16.37 | -$564.49 | -$1,172.71 | $ (2,350.51) |
| Large User | $ (4,760.11) | $ (40,412.00) | -$10,974.00 | $0.00 | $0.00 | $0.00 | -$10,974.00 | $ 24,677.89 |
| Street Lighting | $ 1,842.87 | $ 4,615.03 | -$2,534.25 | $0.00 | -$76.13 | -$2,508.76 | -$5,119.14 | $ (7,891.30) |

**BOMA-142**

**Reference(s): Attachment 22**

**Background**

**(a) Please see list of material 2018 capital projects. The list contains twenty-seven material projects, divided into the four traditional categories of System Access, System Renewal, System Service, and General Plant. Of the twenty-seven projects, the ten year true-up contribution to HONI, relevant to the Pleasant Transformer Station ("HONI's Contribution") is proposed to be funded by the proposed 2018 ICM. Please provide the following:**

**(i) Why was the HONI Contribution chosen for ICM funding, as opposed to others among the twenty-seven projects? Please explain fully.**
**(ii) Please provide a priority listing of the twenty-seven projects from 1 to 27, regardless of the traditional category in which they fall.**
**(iii) For the projects in each of the four categories, please provide a priority listing within the category.**
**(iv) Please explain the derivation (the reason) for the priority listing in each category and in the overall (1 to 27) list.**

**(b) For each of the twenty-seven projects, please indicate whether, and to what extent, they are parts of projects that commenced in 2017, or prior to 2017.**

**(c) Please indicate which, if any, of the projects will involve capital expenditures in 2019 (or in subsequent years of the DSP).**

**(d) Has each of the twenty-seven projects, and the Pleasant Transformer project, been included in the most recent DSP? If any are not, please explain fully.**

**(e) Is it Alectra's intent to apply for ICMs to fund parts of its proposed capital expenditures:**

**(i) in 2019, along with the approval of the Alectra DSP;**
**(ii) in the remaining years covered under its DSP;**
**(iii) in years beyond the end of the DSP.**

**(f) Will Brampton's division's DSP continue to be valid when Alectra's planned 2019 DSP is released?**

**Response:**

a) i) Alectra Utilities has a capital investment need for the Brampton RZ that is not funded through existing distribution rates. Furthermore, the Pleasant TS True-Up is a discrete project that exceeds the materiality level for the Brampton RZ. The project is distinct, unrelated to a recurring annual capital project, and has been evaluated in the asset

management and capital planning process as required in 2018. The Pleasant TS true-up payment is a contractual obligation related to the CCRA between Alectra Utilities and Hydro One Networks Inc.

(ii) Table 1 must be assessed in the context of Alectra Utilities' Asset Management Practice and Capital Investment Plan Optimization process for the Brampton rate zone. Pursuant to this process, Alectra Utilities evaluates each project in the capital investment plan to pace and prioritize investments based on mandatory requirements, project benefits and risks. The portfolio of projects presented, that is, those listed below, reflect prudent investment needs and the most cost effective option for ratepayers. They are all necessary and produce positive outcomes for ratepayers.

Table 1 – Project list ranking – Brampton RZ

| Project Name | Rank |
|---|---|
| Reactive Replacement Program | 1 |
| Developer Works & New Connections | 2 |
| New General Service Customers | 3 |
| New Meters - Residential A873-A874 | 4 |
| New C&I Metering Equipment Commissioning | 5 |
| Feeder & Switchgear Installs: New Subdivisions | 6 |
| Load Forecast True-Up For Pleasant TS | 7 |
| Road Widenings | 8 |
| Residential Replacement Of Single Phase Meters | 9 |
| Plant Relocations | 10 |
| Feeder Cable Rehab or Replacement Program | 11 |
| 4.16kV To 27.6kV Conversion Program | 12 |
| Distribution Cable Rehab or Replacement Program | 13 |
| Planned Enhancements & System Improvements | 14 |
| Goreway TS Expansion 27.6kV Egress Program | 15 |
| Pleasant TS Expansion 27.6kV Egress Program | 16 |
| MS10 Switchgear Replacement Ms10 | 17 |
| MS14 Switchgear Replacement Ms14 | 18 |
| Jim Yarrow TS Expansion 27.6kV Egress Program | 19 |
| Other Planned Sustainment Projects | 20 |
| Vacuum Truck | 21 |

| | |
|---|---|
| Digger Derrick | 22 |
| Planned Wood Pole Replacement Program | 23 |
| SCADA Mate Automation Switch Program | 24 |
| Stake Trucks | 25 |
| Underground Cable Puller | 26 |
| IT Hardware | 27 |

1

2 iii) Table 2 provides the priority listing for the projects in each of the four categories.

3 Table 2 – Priority ranking by category

| SYSTEM ACCESS<br>Project Name | Rank |
|---|---|
| Developer Works & New Connections | 2 |
| New General Service Customers | 3 |
| New Meters - Residential A873-A874 | 4 |
| New C&I Metering Equipment Commissioning | 5 |
| Feeder & Switchgear Installs: New Subdivisions | 6 |
| Load Forecast True-Up For Pleasant TS | 7 |
| Road Widenings | 8 |
| Plant Relocations | 10 |
| Planned Enhancements & System Improvements | 14 |
| Goreway TS Expansion 27.6kV Egress Program | 15 |
| Pleasant TS Expansion 27.6kV Egress Program | 16 |
| Jim Yarrow TS Expansion 27.6kV Egress Program | 19 |

4

| SYSTEM RENEWAL<br>Project Name | Rank |
|---|---|
| Reactive Replacement Program | 1 |
| Residential Replacement Of Single Phase Meters | 9 |
| Feeder Cable Rehab or Replacement Program | 11 |
| 4.16kV To 27.6kV Conversion Program | 12 |
| Distribution Cable Rehab or Replacement Program | 13 |
| MS10 Switchgear Replacement Ms10 | 17 |
| MS14 Switchgear Replacement Ms14 | 18 |
| Other Planned Sustainment Projects | 20 |
| Planned Wood Pole Replacement Program | 23 |

5

| SYSTEM SERVICE |
|---|

| Project Name | Rank |
|---|---|
| SCADA Mate Automation Switch Program | 24 |

| GENERAL PLANT<br>Project Name | Rank |
|---|---|
| Vacuum Truck | 21 |
| Digger Derrick | 22 |
| Stake Trucks | 25 |
| Underground Cable Puller | 26 |
| IT Hardware | 27 |

iv) Alectra Utilities ranks projects in the Brampton Rate Zone based on the following criteria:

- Mandatory projects that must be completed as required by regulation, code or contractual obligations are prioritized.
- Non-mandatory projects are then prioritized based on a project score considers project risk and benefits normalized for cost.
- Risk Mitigation Impact Score

  Risk Score = Sum (Risk Mitigation Impact Score x Risk Probability x Weight) / 5

  Table 3 – Risk Criteria, Weight and Scoring Range for Brampton RZ

| Risk Criteria | Weight | Scoring Range |
|---|---|---|
| Safety and Environmental | 30% | 1-low, 5-high |
| Financial | 25% | 1-low, 5-high |
| Customer Reliability | 15% | 1-low, 5-high |
| Regulatory | 10% | 1-low, 5-high |
| Business Efficiency | 10% | 1-low, 5-high |
| Reputation | 10% | 1-low, 5-high |

  Table 4 – Risk Probability and Scoring Range for Brampton RZ

| Risk Probability | Scoring Range |
|---|---|
| Safety and Environmental | 1-low, 5-high |
| Financial | 1-low, 5-high |
| Customer Reliability | 1-low, 5-high |
| Regulatory | 1-low, 5-high |
| Business Efficiency | 1-low, 5-high |
| Reputation | 1-low, 5-high |

- Project Value Benefit Score

  Project Benefit Score = Sum (Benefit Score x Weight)

  Table 5 – Project Benefit Criteria, Weight and Scoring Range for Brampton RZ

| Project Benefit | Weight | Scoring Range |
|---|---|---|
| Business Values | 30% | 1-low, 5-high |
| Paced and predictive asset rehabilitation and replacement | 25% | 1-low, 5-high |
| System performance | 20% | 1-low, 5-high |
| System capacity | 15% | 1-low, 5-high |
| Operational system agility | 5% | 1-low, 5-high |
| Employee Focus and Safety | 5% | 1-low, 5-high |

- Total Project Score

  Total Score = Risk Score + Benefit Score

The total project score is then multiplied by the project cost divided by the total budget, to normalize scores.

b) Exhibit 3, Tab 1, Schedule 1, Attachment 22 – 2018 Capital Spending Plan by Project Brampton RZ, contains the capital expenditure required in 2018. Certain system access investments include development projects and road widening works that are driven by customer and road authority schedules beyond the control of Alectra Utilities. For these certain system access investments, there are portions that may have commenced in or prior to 2017. Only the work forecasted in 2018 has been considered and budgeted in the attachment.

1. Feeder & Switchgear Installs: New Subdivisions
2. New General Service Customers
3. Developer Works & New Connections
4. Plant Relocations
5. Road Widenings

c) Exhibit 3, Tab 1, Schedule 1, Attachment 22 – 2018 Capital Spending Plan by Project Brampton RZ, contains the capital expenditure required in 2018. The system access investments included in response to part b) above are driven by customer and road authority schedules beyond the control of Alectra Utilities. For these certain system access

investments, there are portions that may have work carry into 2019 or later. Only the work to be expended in 2018 has been considered and budgeted in the attachment.

d) The DSP for the Brampton Rate Zone incorporated a 5 five year true-up for Pleasant TS in 2014 which was settled with Hydro One in 2015. As demand was expected to materialize as projected in 2014, there were no provisions for a Pleasant TS ten year true-up in the DSP. All other 2018 projects are consistent with projects in Hydro One Brampton DSP.

e) i) Please see Alectra Utilities response to G-SEC-5 c).
ii) Please see Alectra Utilities response to G-SEC-5 c).
iii) Please see Alectra Utilities response to G-SEC-5 c).

f) Alectra Utilities will use the predecessor utilities' Distribution System Plans ("DSP") in order to inform and influence the development of the consolidated Alectra DSP. The consolidated Alectra DSP will supersede the individual DSPs of the predecessor entities.

**BOMA-143**

**Reference(s): Exhibit 2, Tab 2, Schedule 10, pp 13**

**a) Is the proposed rate rider only in place for 2018, or does it extend beyond December 31, 2018, and, if so, for how long? Please show calculations that show the revenue generated by the rate rider each year it is in effect until rebasing, and how that amount is reconciled with the 2018 ICM driven capex that needs to be funded.**

**b) Please advise whether the amount of the rider would remain constant for the duration of its existence, or change from one year to the next.**

**Response:**

a) Please see Alectra Utilities response to BOMA -114 (a.

b) Please see Alectra Utilities response to BOMA -114 (b.

**BOMA-144**

**Reference(s): General**

**Is it Alectra's understanding that the Brampton division will continue under price cap IR for the next ten years, according to Board Guidelines, and that Alectra will be entitled to bring forward an ICM at any time during that period? Please discuss.**

**Response:**

Alectra Utilities confirms that the Brampton Rate Zone ("BRZ") will continue under Price Cap IR for the rebasing deferral period. Alectra Utilities further confirms that it will be eligible to file ICM applications during that period.

Please see Alectra Utilities' response to G-SEC-5 c).

**BOMA-145**

**Reference(s): Exhibit 2, Tab 2, Schedule 10, p2, Table 60**

**(a) Generally, the planned expenditures in 2018, 2019, and 2020 do not reflect a quantum increase from historical levels, eg. levels in 2015, 2016, 2017, and one would expect that, as Dr. Kaufman pointed out, in such circumstances, the price cap formula and growth would yield revenues sufficient to finance the capital expenditure program. In the circumstances, why is the ICM for 2018 justified?**

**(b) Please describe your interpretation of this passage at p6 of the "ACM Report": "Any incremental capital amounts approved for recovery must fit within the total eligible incremental capital amount (as defined in this ACM Report) and must clearly have a significant influence on the operation of the distributor; otherwise they should be dealt with at rebasing" (our emphasis).**

**What does Alectra interpret the phrase "must clearly have a significant influence on the operation of the distributor" to mean? What type of projects would not meet this test?**

**(c) Given that Alectra is allowed under the MAADs decision to defer rebasing for ten years, and to retain savings derived from the merger for that period to, inter alia, offset transaction costs, to what extent will Alectra use savings achieved to date to offset capex costs prior to seeking an ICM? To what extent does it intend to do so in the future?**

**(d) Please explain why the "ICM proposal" is an ICM, rather than as an ACM. Please explain fully.**

**(e) Does Alectra intend to ask for ICM modules for its Brampton division in each of the next nine years? Please explain fully.**

**Response:**

a) The Ontario Energy Board's Capital Module for ACM and ICM ("Capital Module") for the Brampton Rate Zone is included in Exhibit 3, Tab 1, Schedule 1, Attachment 18 – ICM Model Brampton RZ. Section 4.1.5 of the *Report of the Board – New Policy Options for the Funding of Capital Investments: The Advanced Capital Module*, issued September 18, 2014, states "*a capital budget will be deemed to be material, and as such reflect eligible projects, if it exceeds the Board-defined materiality threshold."* The Board-defined materiality threshold, which incorporates the price cap formula and growth, results in a materiality threshold of $30,955,867 for the Brampton RZ as identified in Exhibit 3, Tab 1, Schedule 1, Attachment 18, Tab 9. Threshold Test – Incremental Capital Module Brampton RZ. The 2018 capital

budget for the Brampton RZ exceeds the materiality threshold by $7,113,613. Alectra Utilities forecasted true up payment of $6,800,377 for the Brampton RZ is below the Board's maximum eligible incremental capital of $7,113,613.

b) Alectra Utilities is required by contractual payment terms guided by the Connection and Cost Recovery Agreement (CCRA) to true-up for Pleasant TS at pre-determined anniversary periods. Investments that have significant influence on the operation of the distributor would include material expenditures to meet mandatory obligations related to contractual, regulatory as well as prescribed codes, investment to ensure connection and system capacity are available to meet growth, investments to address sub-standard assets to facilitate operational effectiveness, system reliability, environmental stewardship and safety of employees and the general public.

c) Alectra Utilities is eligible to offset transaction costs with synergy savings during the rebasing deferral period. This is consistent with the OEB's *Rate-Making Associated with Distributor Consolidation*, dated March 26, 2015 (p.5). At page 5, the Report states, "*The purpose of the policy is to allow the net savings of a consolidation to accrue to a distributor's shareholder(s) for an extended period".* Further, at page 6 the Report states, *"The OEB believes that the requirement for the MAAD's application to include an earnings sharing mechanism ("ESM") will address ratepayer concerns that the accumulated savings could amount to a windfall for shareholders."*

d) Please see Alectra Utilities' response to G-SEC-3.

e) Alectra Utilities is eligible to file Incremental Capital Module ("ICM") applications for any of its rate zones that are on a Price Cap IR rate plan, during the rebasing deferral period. This is consistent with both the OEB's *Rate-Making Associated with Distributor Consolidation*, dated March 26, 2015 (p.9-10) and the *Handbook to Electricity Distributor and Transmitter Consolidations* released on January 19, 2016 (page 17).

**BOMA-146**

**Reference(s): Attachment 51; Alectra Utilities Customer Engagement Report, prepared by Innovative Research Group Inc., p15**

**The evidence contains a half page summary of "general comments" from customers in the Brampton rate zone.**

**Did Innovative carry out a consultation program with Brampton division ratepayers, comparable with the consultation with Enersource and PowerStream ratepayers? Please provide the results of the consultation. If there was no consultation, or very little consultation, please explain why.**

**Response:**

The Brampton RZ ICM investment proposal was informed by n=3,456 customer responses obtained through the online feedback portal.

Unlike the customer engagement in the Enersource and PowerStream rate zones – which included consultation on a DSP and multiple ICM projects – the project in consideration for the Brampton RZ was a Capital Cost Recovery Agreement ("CCRA") payment to Hydro One Networks Inc. Since this is a non-discretionary payment, with no optionality for customer consideration, a different approach for the Brampton RZ customers was executed.

Customer engagement feedback from the Brampton RZ is generally consistent with that of customers in both the Enersource and PowerStream rate zones (see Attachment 51, p15).