Exhibit 2A, Tab 1, Schedule 1

Alectra Utilities 2027-2031 Distribution System Plan

Appendix B01 – B14

October 2025

Table of Contents

Appendix B01 - Overhead Asset Renewal 1

I Overview 1

II Pole Renewal 6

2.1 Overview 6

2.2 Investment Description 10

2.3 Investment Drivers 13

2.4 Investment Need 13

2.5 Options Analysis 25

2.6 Summary of Net Benefits and Primary Risks 29

III Overhead Rebuild 30

3.1 Overview 30

3.2 Investment Description 31

3.3 Investment Drivers 34

3.4 Investment Need 35

3.5 Options Analysis 35

IV Voltage Conversion 37

4.1 Overview 37

4.2 Investment Description 39

4.3 Investment Drivers 45

4.4 Investment Need 46

4.5 Options Analysis 50

V Switch Renewal 52

5.1 Overview 52

5.2 Investment Description 52

5.3 Investment Drivers 54

5.4 Investment Need 55

5.5 Options Analysis 57

5.6 Summary of Net Benefits and Primary Risks 58

VI Investment Projects 60

Appendix B02 - Underground Asset Renewal 62

I Overview 62

II Cable and Accessories 67

2.1 Investment Description 67

2.2 Investment Drivers 74

2.3 Investment Need 75

2.4 Options Analysis 84

2.5 Summary of Cable and Cable Accessory Investment 86

III Switchgear 87

3.1 Investment Description 87

3.2 Investment Drivers 96

3.3 Investment Need 98

3.4 Options Analysis 101

3.5 Summary of Switchgear Investments 102

IV Civil Structures 103

4.1 Investment Description 103

4.2 Investment Drivers 104

4.3 Investment Need 104

4.4 Options Analysis 108

V Alectra-Initiated Underground Near-Term Projects 109
5.1 Investment Description 109
5.2 Investment Drivers 109
5.3 Investment Need 110
5.4 Option Analysis 110
5.5 Summary of Alectra Initiated Underground Near-Term Investments 110
VI Investment Timing & Pacing 111
6.1 Summary of Expenditures 111
6.2 Execution Approach 111
VI Investment Projects 112

Appendix B03 - Transformer Renewal 116
I Overview 116
II Investment Description 118
2.1 Summary of Investment Outcomes and Benefits 122
2.2 Summary of Expenditures 123
III Investment Drivers 125
IV Investment Need 126
4.1 Deteriorated Transformers (Public Safety and Environmental Contamination) 127
4.2 Prolonged Customer Interruption (Reliability Risk) 133
V Options Analysis 136
5.1 Execution Approach 139
VI Investment Projects 141

Appendix B04 - Substation Renewal 142
I Overview 142
II Investment Description 146
2.1 Renewal of Station Switchgear and Circuit Breakers ($31.5MM) 146
2.2 Protection, Control, and Telecommunication Systems ($10.5MM) 155
2.3 Power Transformer Tank and Radiator Reconditioning ($5.1MM) 157
2.4 Replacement of Trench Primary Metering Unit Instrument Transformers ($2.0MM) 158
2.5 Safety and Security ($6.4MM) 160
2.6 Replacement of Failed and Deteriorated Equipment ($11.4MM) 164
2.7 Summary of Investment Outcomes and Benefits 165
III Investment Drivers & Need 167
3.1 Purpose 167
3.2 Asset Details 169
IV Investment Timing & Pacing 179
4.1 Summary of Expenditures 179
4.2 Historical Expenditures (2020-2024) 179
4.3 Bridge Year and Forecast Expenditures (2025-2031) 179
4.4 Investment Pacing and Prioritization 180
V Options Analysis 181
5.1 Transformers 181
5.2 Station Switchgear 181
5.3 Circuit breakers 182
VI Investment Projects 184

Appendix B05 - Reactive Capital 185
I Overview 185

II Investment Description 187
2.1 Summary of Investment Outcomes and Benefits 191
III Investment Drivers & Need 193
3.1 Purpose 193
IV Investment Timing & Pacing 205
4.1 Historical Expenditures (2020-2024) 205
4.2 Bridge Year (2025-2026) and Future Expenditures (2027-2031) 206
V Options Analysis 208
VI Investment Projects 209

Appendix B06 – Network Metering 210
I Overview 210
II Outcomes and Measures 214
III Investment Drivers and Need 216
3.1 Mandated Service Obligations 216
IV Investment Plan 255
4.1 Historical Expenditures 255
4.2 Bridge Year Expenditures 256
4.3 Forecast Plan Expenditures 256
V Options Analysis 260
5.1 Alternative Assessment: Financial Considerations 265
5.2 Customer Engagement Insights 267
5.3 Plan Execution Risks and Mitigation 270
VI Investment Projects 272

Appendix B07 - Facilities Management 273
I Overview 273
II Investment Description 276
2.1 Planned Capital Investments 277
2.2 Reactive Capital Investments 280
2.3 Summary of Investment Benefits 281
III Investment Drivers and Need 282
IV Investment Timing & Pacing 287
4.1 Summary of Expenditures 287
4.2 Historical Expenditures (2020-2024) 287
4.3 Future Expenditures (2027-2031) 288
4.4 Execution Approach 288
V Options Analysis 289
5.1 Planned Replacement 289
5.2 Reactive (Asset Failure Emergency Replacements) 289
VI Investment Projects 290
VII Central Region Facilities Review Summary 291
7.1 3240 Mavis Road (Mississauga) 292
7.2 175 Sandalwood Parkway West (Brampton) 294
7.3 Analysis Background 296
7.4 Review and Assessment 297
7.5 Timeline 308
7.6 Costs and Savings: 309

Appendix B08 - Fleet Investments 312
I Overview 312
II Investment Description 316
2.1 Fleet Growth 318
2.2 Planned Fleet Renewal Investment by Vehicle Type. 320
2.3 Summary of Investment Outcomes and Benefits 324
III Investment Drivers and Need 325
3.1 Purpose for Planned Fleet Renewal & Growth 325
IV Investment Timing & Pacing 332
4.1 Summary of Expenditures 332
4.2 Historical Expenditures (2020-2024) 332
4.3 Bridge Year (2025-2026) and Forecast Expenditures (2027-2031) 332
4.4 Investment Pacing & Prioritization 333
4.5 Execution Approach 334
V Options Analysis 335
5.1 Fleet Renewal 335
5.2 Fleet Growth 336
VI Material Investment Projects 339

Appendix B09 - Information Technology Systems 340
I Overview 340
II Investment Description 343
2.1 IT Software 343
2.2 IT Hardware 358
2.3 IT Security 361
2.4 DER Supporting Technologies 364
2.5 Summary of Investment Outcomes and Benefits 366
III Investment Drivers & Needs 369
IV Investment Timing & Pacing 371
4.1 Summary of Expenditures 371
4.2 Historical Expenditures (2020-2024) 371
4.3 Bridge Expenditures (2025 to 2026) 375
V Options Analysis 382
5.1 IT Software 382
5.2 IT Hardware 384
5.3 IT Security 386
5.4 DER Supporting Technologies 388
VI Investment Projects 391

Appendix B10 - Customer Connections 392
I Overview 392
II Investment Description 394
2.1 Summary of Investment Outcomes and Benefits 401
III Investment Drivers & Need 402
3.1 Purpose 402
IV Investment Timing & Pacing 403
4.1 Summary of Expenditures 403
4.2 Historical Expenditures 403
4.3 Future Expenditures (2027-2031) 404
4.4 Investment Pacing and Prioritization 410

4.5 Execution Approach 411
V Options Analysis 412
VI Investment Projects 414

Appendix B11 - Road Authority & Transit Projects 416

Part A: Road Authority 418
I Overview 418
II Investment Description 422
2.1 Summary of Investment Outcomes and Benefits 425
III Investment Drivers & Need 426
3.1 Purpose 426
IV Investment Timing & Pacing 427
4.1 Summary of Expenditures 427
4.2 Historical Expenditures 428
4.3 Future Expenditures (2027-2031) 428
4.4 Investment Pacing and Prioritization 429
4.5 Execution Approach 430
V Options Analysis 432
VI Investment Projects 433

Part B: Transit Projects 434
I Overview 434
Transit Developments 434
II Investment Description 439
III Investment Drivers & Need 441
3.1 Purpose 441
IV Investment Timing & Pacing 444
4.1 Summary of Expenditures 444
4.2 Historical Expenditures 444
4.3 Future Expenditures (2027-2031) 445
4.4 Investment Pacing and Prioritization 446
4.5 Execution Approach 446
V Options Analysis 447
VI Investment Projects 449

Appendix B12 - Lines Capacity 450
I Overview 450
1.1 Summary of Planned Investments 453
II Investment Description 455
2.1 Greenfield Expansion 455
2.2 Intensification and Redevelopment 458
2.3 Backup Capability 460
2.4 Primary Supply to Municipal Stations 462
2.5 Summary of Investment Outcomes and Benefits 463
III Investment Drivers & Need 465
3.1 Purpose 465
IV Investment Timing & Pacing 472

4.1 Summary of Expenditures 472
4.2 Historical Expenditures (2020-2024) 472
4.3 Bridge Years (2025-2026) 472
4.4 Future Expenditures (2027-2031) 474
4.5 Investment Pacing & Prioritization 474
4.6 Execution Approach 476
V Options Analysis 477
5.1 Status Quo 477
5.2 Non- Wires Alternatives 477
5.3 Construct New Feeders 478
VI Investment Projects 479

Appendix B13 – Stations Capacity 481
I Overview 481
II Investment Description 487
2.1 Summary of Investment Outcomes and Benefits 489
III Investment Drivers & Need 490
3.1 Purpose 490
3.2 Stations Capacity Investment 497
3.3 CCRA Payments 561
3.4 Transmitter Related Upgrade 562
IV Investment Timing & Pacing 564
4.1 Summary of Expenditures 564
4.2 Historical Expenditures (2020-2024) 564
4.3 Bridge Year and Future Expenditures (2025-2031) 564
4.4 Investment Pacing and Prioritization 565
4.5 Execution Approach 565
V Options Analysis 566
5.1 Status Quo/ "Do Nothing" 566
5.2 Utilizing Non-Wire Alternatives 566
VI Investment Projects 568

Appendix B14 - Enabling Resiliency & Modernization 570
I Overview 570
II SCADA, Automation and System Control 573
2.1 Overview 573
2.2 Investment Description 575
2.3 Investment Drivers & Needs 586
2.4 Options Analysis 592
2.5 Investment Timing & Pacing 594
III Rear Lot Conversions 597
3.1 Overview 597
3.2 Investment Description 598
3.3 Investment Drivers & Needs 603
3.4 Options Analysis 609
3.5 Investment Timing & Pacing 611
IV Grid Modernization 614
4.1 Overview 614
4.2 Investment Description 616
4.3 Investment Drivers & Needs 620
4.4 Options Analysis 630
4.5 Investment Timing & Pacing 635

V Customer Service Technologies 637
5.1 Overview 637
5.2 Investment Description 638
5.3 Investment Drivers & Needs 643
5.4 Options Analysis 648
5.5 Investment Timing & Pacing 649
VI Investment Projects 652

Appendix B01 - Overhead Asset Renewal

I Overview

Alectra Utilities' Overhead Asset Renewal Program is a comprehensive, multi-year investment plan targeted at addressing the condition, functionality, and resilience of aging overhead distribution infrastructure. The program consists of four main segments: Pole Renewal (*Section II)*, Overhead Rebuild (*Section III)*, Voltage Conversion (*Section IV)*, and Switch Renewal (*Section V)*. Collectively, the investments in these segments aim to replace or remediate deteriorated and high-risk overhead assets that are increasingly susceptible to failure under adverse weather conditions. The program is driven by the need to ensure public and worker safety, maintain and improve system reliability, and modernize aging infrastructure. It represents a key component of Alectra Utilities' long-term asset management strategy, aligning capital investment with risk mitigation, compliance, and the growing demands for a climate-resilient and efficient electricity distribution network.

Over the 2027–2031 rate period, Alectra Utilities plans to invest a total of $396.3MM through the Overhead Asset Renewal Program. This represents a $203.2MM (105%) increase from the $193.1MM spent over the 2020-2024 period. Historical investments have been insufficient to keep pace with the deterioration of overhead assets. Based on analytics, asset age, asset condition and climatic risks, Alectra Utilities' forecast rate of overhead asset deterioration over the DSP period necessitates an increased investment to manage near-term asset degradation and ensure public and worker safety. Through the proposed investments, Alectra Utilities will reduce the number of deteriorated assets, harden the system to climate events, and increase the resiliency of the system to manage customer needs and asset failures.

Overhead assets targeted for renewal either have Health Index (HI) results of Very Poor or Poor, as identified through the Asset Condition Assessment (ACA) process, or belong to specific asset groups that have been identified as functionally obsolete or at high risk of failure. For additional details on Alectra Utilities' ACA process, refer to *Chapter 5.3.3 Asset Lifecycle Optimization Policies and Practices* as well as *Appendix E - Asset Condition Assessment Report*. A summary of the Overhead Asset Renewal Program capital investment mix is shown in Table B01 - 1.

Table B01 - 1 Overhead Asset Renewal Investment Mix Over the 2025-2031 Period

	Bridge		Forecast Spending					
Investment Type	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**Total (2027-2031)**
Pole Renewal	20.6	19.8	23.1	26.5	30.1	35.6	37.2	152.5
Overhead Rebuild	8.1	7.4	15.8	17.8	23.0	29.3	34.1	120.0
Voltage Conversion	4.3	2.3	12.5	8.5	25.1	18.7	24.0	88.8
Switch Renewal	4.7	6.7	6.8	6.9	7.0	7.1	7.2	35.0
Total ($MM)	**37.7**	**36.2**	**58.2**	**59.7**	**85.2**	**90.7**	**102.5**	**396.3**

The proposed pace of investment is based on condition assessment and failure risk and is intended to reduce the duration and impact of outages, enhance public and worker safety, system resilience, and long-term cost efficiency. As identified in *Appendix L - Historical Reliability Data (Section C)*, equipment failure was the leading cause of outages from 2020 to 2024, accounting for 44% of the total Customer Hours of Interruption (CHI). Overhead Line Hardware failures, which includes failure of poles, insulators, clamps, brackets, leads, cross-arms, and guying, were the second largest contributor to CHI. During the 2020 to 2024 period, Overhead Line Hardware caused, on average, 199 outages and 81,228 CHI per year.

The Pole Renewal segment is focused on replacing or reinforcing wood and concrete poles that are either fully deteriorated or structurally compromised, including those poles that are overloaded and vulnerable to extreme weather events. As explained in *Chapter 5.3.2 (Section 5.3.2.2 A.1.5)*, at the end of 2023, Alectra Utilities identified 10,277 fully deteriorated poles in need of replacement. This is an increase of approximately 4% compared to the 2018 ACA results. Alectra Utilities must accelerate the pace and scale of its Pole Renewal investments to prevent continued growth in its population of poles that are deteriorated and that pose safety and reliability risks. Poles are a critical component of the overhead distribution system, supporting not only multiple primary and secondary conductors, but also transformers, switches, telecommunications infrastructure, and other key equipment. As climate change drives more frequent and severe weather events, structurally compromised or overloaded poles are increasingly vulnerable to failure, making their timely remediation progressively more important to maintaining system integrity, public safety, and service continuity. Based on the climate study completed by Hatch

(*Appendix G – Climate Risk & Vulnerability Assessment*), there will be an increase in adverse weather events similar to the 2022 Derecho event which caused over 100 pole failures.

Under the Pole Renewal segment, Alectra Utilities plans to replace 5,256 poles over the 2027-2031 period. This target will only help address about half of the deteriorated poles and will result in a sizable reduction to the deteriorated population remaining on the system. For a detailed segment overview, refer to *Section II Pole Renewal*.

The Overhead Rebuild segment targets the proactive replacement of overhead distribution lines constructed from the 1960s through to the 1980s using #6 and 4/0 copper primary conductors. These primary conductors become brittle as they age, causing premature failure, especially during storms. Such failures result in significant safety risks to workers and the public, such as from energization of the ground near a fallen conductor. Additionally, conductor failures cause wide-spread outages. Over the DSP period, Alectra Utilities plans to replace 33.8KM of #6 and 56.1KM of 4/0 copper primary conductors with new materials. A detailed segment overview is provided in *Section III Overhead Rebuild*.

The Voltage Conversion segment involves upgrading the lower primary voltage 4.16kV and 8.32kV overhead distribution assets to the current standard voltages of 13.8kV and 27.6kV. The 4.16kV and 8.32kV systems are vintage infrastructure using aged materials based on out-of-date standards which do not meet modern safety requirements. These assets were built prior to the 1970s, to early 1990s, using wooden crossarms and pins to hold porcelain insulators, and #6 copper, 2/0 copper, 4/0 wire connected with quick sleeves. These materials are no longer used in standard construction. Risks associated with these materials include safety and reliability issues such as pole fires, pins sinking (which can cause pole fires), wire down events, and sleeve failures. The Voltage Conversion program aligns with system planning objectives to improve safety and system efficiency, enhance system resilience, and improve overall distribution system reliability.

Voltage Conversion investments allow for the elimination of station assets, which have been required to distribute power at the lower voltages and will become redundant once conversion is completed. Consequently, Alectra Utilities plans to decommission eight Municipal Substations (MS) over the DSP period. The capital investments will be prioritized in areas adjacent to the existing 13.8kV and 27.6kV infrastructure in Brampton, Mississauga, and Hamilton as this is a

cost-effective method for the execution of voltage conversion. These investments are expected to deliver long-term value to ratepayers by optimizing asset utilization and improving reliability. A detailed segment overview is provided in *Section IV Voltage Conversion*.

Lastly, the Switch Renewal segment targets the replacement of deteriorated or obsolete overhead Load Interrupter Switches (LIS) preventing asset failure and ensuring safe and effective operation of the devices when needed. Secondary drivers of the investment are safety, reliability, and functional obsolescence. The failure of overhead LIS has a significant negative impact on the distribution system. Without functional switches, Alectra Utilities' system control operators and field staff would not have the ability to isolate faults effectively, leading to longer outage durations and more wide-spread outages impacting more customers. This directly impacts the duration (SAIDI) and frequency (SAIFI) of power interruptions for customers. Failed switches hinder operational flexibility, making it difficult to reroute power during maintenance or emergencies. Defective switches pose serious safety risks to field crews, as clear points of isolation may not be available. Proactive replacement of these assets will help mitigate the risk of in-service failures that can lead to extended outages, larger affected customer areas, and increased emergency repair costs.

As identified in *Appendix L - Historical Reliability Data (Section C)*, on average overhead switch failures accounted for 56 outages and 29,997 CHI from 2020 to 2024. Overhead switches are a critical component of the overhead distribution system. As explained in *Chapter 5.3.3 (Section 5.3.3.2 A.5)*, at the end of 2023, Alectra Utilities identified 80 deteriorated LIS on its system that need replacement. Alectra Utilities plans to replace 51 devices per year. This pace of renewal is designed to address the 80 deteriorated switches and address functionally obsolete units (such as switches that upon failure have an extremely long restoration time due to their specific nature). Additionally, a portion of these replacements will involve replacing manual switches with new automated LIS at strategic locations. The automated devices will enhance distribution system performance, increase operational efficiencies, and enable future grid automation and self-healing capabilities. The Switch Renewal segment complements Alectra Utilities' broader need for enhanced grid resiliency and modernization, as described in *Appendix B14 - Enabling Resiliency & Modernization.* For a detailed segment overview, refer to *Section V Switch Renewal.*

Through the work planned in the Overhead Asset Renewal Program, Alectra Utilities will mitigate the failure risks associated with deteriorated overhead infrastructure. Alectra Utilities also plans

to replace specific failure-prone and obsolete assets such as porcelain insulators, first-generation polymeric insulators, and air-break switches. These failure-prone and obsolete assets create safety and reliability risks, which Alectra Utilities will mitigate through the planned investments. The listing of material projects planned over the 2027-2031 period is shown in *Section VI Investment Projects*.

Figure B01 - 2 summarizes the investments in the Overhead Asset Renewal Program from 2020-2031, including actual expenditures in the 2020-2024 historical period, 2025-2026 bridge year expenditures, and 2027-2031 forecasted capital expenditures.

Table B01 - 2 Overhead Asset Renewal Investment Expenditures, Drivers and Outcomes

	Historical Spending					Bridge		Forecast Spending				
Year	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
CAPEX ($MM)	32.8	39.8	38.7	44.3	37.5	37.7	36.2	58.2	59.7	85.2	90.7	102.5
Primary Driver	Failure Risk											
Secondary Driver	Reliability, Functional Obsolescence, Resilience to Adverse Weather, Safety											
Outcomes	Reliability, Safety, Customer Value, Efficiency											

For each segment below, this schedule will describe the proposed investments, the drivers and need for work, the proposed timing and pacing, and any alternatives considered by the utility.

II Pole Renewal

2.1 Overview

The Pole Renewal segment includes investments in the replacement and remediation of deteriorated wood and concrete poles that are in Poor or Very Poor condition, including overloaded poles which carry equipment, conductors and loads exceeding their capacity relative to weather conditions, thus posing an increased climate risk. The poles to be addressed through this segment are highly vulnerable to adverse weather conditions and prone to catastrophic failures under such events, posing significant public safety and reliability risks. At the end of 2023 Alectra Utilities had 10,277 deteriorated poles in Poor or Very Poor condition, which was an increase of approximately 4% compared to the 2018 ACA results, which shows an increase in the pace of deterioration and need to address these investments. A climate vulnerability assessment of the system identified an additional 25,534 poles which pose a risk. Predictive Analytics (*Chapter 5.3.3 Asset Lifecycle Optimization Policies and Practices)* determined that there would be positive value to customers if Alectra Utilities replaced up to 14,540 poles over the 2027-2031 timeframe. During the first phase of customer engagement, customers informed Alectra Utilities that outages stemming from major events was a source of concern.

Climatic studies support the increasing frequency and intensity of extreme weather events which pose growing risks to deteriorated infrastructure. In May 2022, a Derecho storm affected the majority of Alectra Utilities' service territory requiring over 100 poles to be replaced. Images of asset failures from this event can be seen in Figure B01 - 1 and Figure B01 - 2.

Figure B01 - 1 Downed Pole Line Sandalwood Parkway & McLaughlin Road, Brampton (May 2022)

Figure B01 - 2 Downed Overhead Lines on Tenth Line Road West, Mississauga May 2022

As a result of the Derecho event, entire pole lines were rebuilt, and it took 12.5 hours to restore power to 90% of affected customers.

Alectra Utilities established three alternative pacing strategies for the investment based on available resources and materials, and the demands and priorities of the complete capital portfolio. These strategies were presented to customers in the second phase of Customer Engagement (refer to *Exhibit 1, Tab 5, Schedule 2 Application-Specific Customer Engagement*) and customer feedback was considered in selecting the proposed investment strategy. Under this segment, Alectra Utilities proposes to replace 5,256 poles from 2027-2031. For comparison, from 2021-2024 Alectra Utilities replaced 3,259 poles under the same segment. Through the increased investment, Alectra Utilities plans to reduce the proportion of deteriorated assets and harden the system to climate events of increasing severity.

Achieving the proposed level of renewal is in alignment with customer preferences to avoid outages from climate events and improve system reliability and safety.

Pole Renewal investments also include plans to upgrade the attached pole line hardware for newer materials to improve overall system reliability and safety.[1] From 2020 to 2024, overhead line hardware failures caused 199 outages on average, contributing 81,228 CHI annually. The pole line hardware replacement includes replacing legacy porcelain insulators and first-generation polymeric insulators which are known to be prone to cracking and failure. When the insulators fail mechanically, they can cause powerlines to fall to the ground creating a severe public safety risk. When the insulators fail electrically, it can lead to flashover events and pole fires, causing widespread outages. Figure B01 - 3 depicts an example of an electrical insulator failure that caused a pole fire.

[1] New materials include higher pole class (stronger), composite insulators, fibre cross arms, and other material advancements depending on the age of construction.

Figure B01 - 3 Pole Fire Caused by Porcelain Insulators, Hamilton (July 2023)

A failure to address the large and growing population of deteriorated poles and overhead equipment poses an unacceptable safety risk to the public, utility workers and contractor crews who work in proximity to these assets. A single pole failure is a serious safety risk. However, when multiple poles fail (due to their condition and/or to adverse weather events, which are becoming increasingly frequent) this can cause a hazardous cascade of falling poles down a public street.

Deteriorated overhead infrastructure also poses a significant reliability risk for customers. As shown in Figure B01 - 4, overhead distribution line hardware failure is the second largest contributor to customer outage duration from defective equipment related outages. This is reflective of the large amount of overhead equipment in Alectra Utilities' distribution system, and the increasingly deteriorating condition of those assets. The planned expenditures are necessary to maintain system reliability and ensure a robust system that can withstand climate events of increasing frequency and intensity.

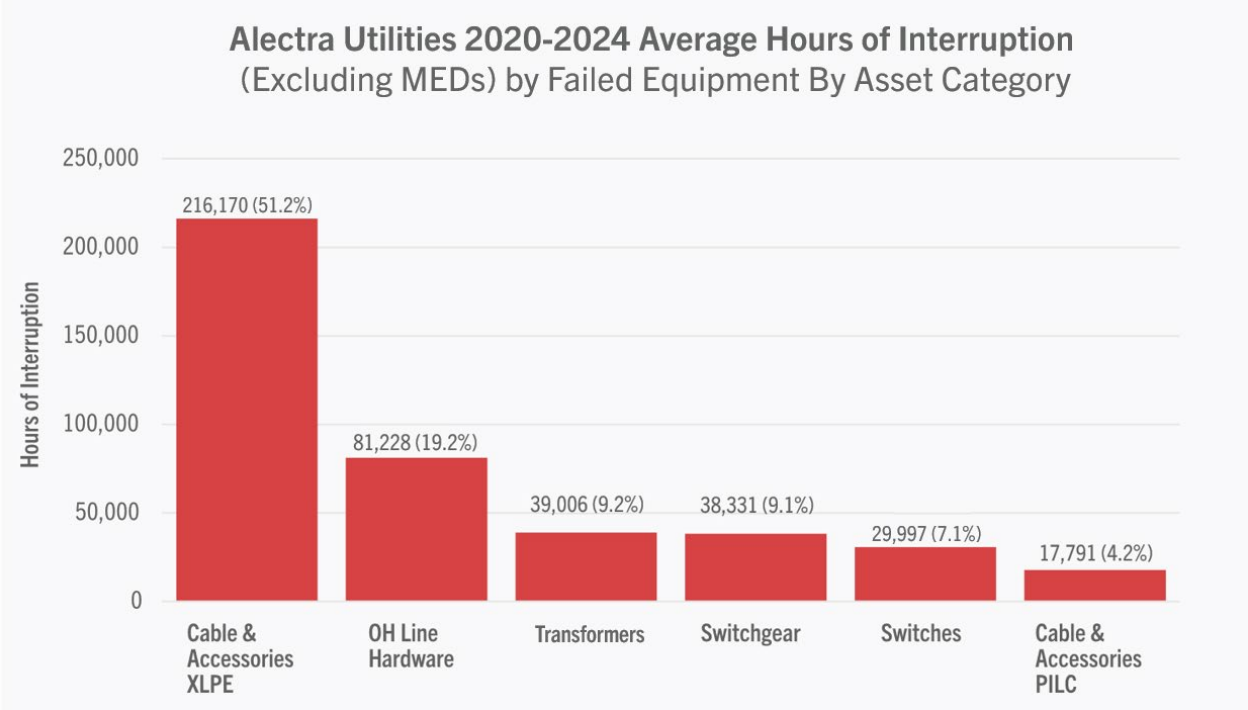


Figure B01 - 4 Failed Equipment – Average Customer Hours of Interruption (Excluding MEDs), Alectra Utilities' 5-Year Average (2020-2024)

2.2 Investment Description

This section summarizes the proposed investments comprising the Pole Renewal segment. The three main components of the proposed investments are:

- The replacement of deteriorated poles identified through the ACA as being in Poor or Very Poor condition
- The replacement and/or remediation of poles identified as being highly vulnerable to climate-related stresses based on their loading and location
- The replacement of pole line hardware, including certain porcelain insulators with known safety issues.

Table B01 - 3 shows the expenditures in this segment from 2020-2031, including actual historical investments from 2020-2024, 2025-2026 bridge years, and forecasted 2027-2031 capital expenditures.

Table B01 - 3 Pole Renewal Investment Summary

	Historical Spending					Bridge		Forecast Spending				
Year	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
CAPEX ($MM)	14.9	17.3	16.7	25.2	21.2	20.6	19.8	23.1	26.5	30.1	35.6	37.2
Primary Driver	Failure Risk											
Secondary Driver	Reliability, Safety, Resilience to Adverse Weather											
Outcomes	Improved Reliability, Improved Safety, Storm Resilience											

The specific drivers, needs, and options considered to address these assets are set out in *Section 2.3, Section 2.4, and Section 2.5*, respectively. The total cost of the Pole Renewal segment over the forecast DSP period from 2027 to 2031 is $152.5MM, or 38% of the total Overhead Asset Renewal Program expenditure. Pole Renewal forecast spending of $152.5MM represents a 60% (or $57.2MM) increase compared to actual Historical Spending from 2020 to 2024. Table B01 - 4 illustrates the percentage increase of pole costs (material only) per year from a 2020 baseline. By 2024, the pole cost had increased by 68.6% since 2020, which has contributed to an increase in spending in Pole Renewal projects.

Table B01 - 4 Percentage Increase of Pole Costs from 2020 Baseline

Year	2021	2022	2023	2024
Percent Increase	9.9%	23.4%	39.3%	68.6%

Over the 2027 to 2031 DSP period, Alectra Utilities plans to replace 5,256 deteriorated poles, starting with a target of 826 poles in 2027 and increasing the annual target by approximately 12% each year to reach 1,300 replacements by 2031. Out of the 5,256 poles that have been identified, 218 are high-risk overloaded poles due to location, loading and climate factors. These overloaded poles were identified using the methodology described in *Chapter 5.3.2 (Section 5.3.2.3. A)*.

As described in *Section 2.4*, Alectra Utilities determined that the proposed pace of the proactive Pole Renewal segment will address the backlog of assets and achieve an appropriate balance between mitigating public safety risks, ensuring reliability, being responsive to customer affordability concerns, and providing customer benefits. Copperleaf's Predictive Analytics was

leveraged to assess long-term asset risk and optimize investment pacing. These analytics support the planned investments in this segment by showing there is value to customers.

Additionally, Alectra Utilities' overhead distribution network contains a population of 19,086 poles with legacy porcelain insulators and 1,279 first-generation polymeric insulators.[2] The design of these insulators has led to safety issues for Alectra Utilities' crews and reliability issues for the overhead distribution system. Alectra Utilities will replace a subset of these insulators over the DSP period with new polymeric materials.

Table B01 - 5 summarizes the outcomes and benefits of the Pole Renewal segment.

Table B01 - 5 Summary of Pole Renewal Investment Outcomes and Benefits

Outcome	Investment Benefits and Objectives
Customer Value	• Remediating deteriorated poles and insulators improves customer safety and reliability by reducing the potential for catastrophic failures of the overhead system in storm events. • The Pole Renewal segment reduces the length of prolonged outages by improving system resilience in storm events.
Reliability	• Remediating deteriorated poles will help maintain system and feeder-level reliability. • Replacing deteriorated and functionally obsolete assets with assets constructed to present day standards will enhance reliability. • Pole Renewal investments will improve the overhead system resilience to storms by minimizing the impact of storm damage.
Safety	• Safety improvements through the construction of new, standardized equipment that aligns to current operational practices. For instance, the risks of catastrophic failure associated with degrading poles (i.e. pole line collapse) will be mitigated. • Pole Renewal will improve safety by mitigating catastrophic pole failures in storm events. • Replacing porcelain and first-generation polymeric insulators will reduce the safety risks (i.e. pole fires) caused by their failure.

[2] Referred to as "non K-line" insulators.

2.3 Investment Drivers

Alectra Utilities' Pole Renewal investments are primarily driven by the need to address deteriorated poles. Secondary (but no less important) drivers include reliability, safety, and resilience to adverse weather conditions.

The primary and secondary drivers are further defined and summarized in Table B01 - 6.

Table B01 - 6 Pole Renewal Investment Drivers

Investment Driver	Reasoning & Investment Benefits
Primary Driver: Failure Risk	The primary driver for these investments is the elevated risk of failure due to the wood and concrete poles and insulators being deteriorated to the point of being in Poor or Very Poor condition. Additionally, failure of poles due to climate poses a significant risk.
Secondary Driver: Safety	Remediating deteriorated poles will help reduce the significant public and worker safety risk posed by these assets. Falling poles present obstacle risks to public rights of way and create potential proximity to energized equipment. Porcelain insulators can result in hazardous wood pole fires. These events can cause pole failures, potentially putting the public and crews in contact with equipment that may fall, including in extreme cases, energized conductors falling to the ground.
Secondary Driver: Reliability	Improved reliability due to the reduced frequency and duration of outages is an expected outcome of the Pole Renewal segment.
Secondary Driver: Resilience to Adverse Weather Conditions	Pole Renewal segment investments will make Alectra Utilities' distribution system more resilient against adverse weather conditions.

2.4 Investment Need

This section describes the need to invest in replacing deteriorated poles and related assets (e.g. deteriorated porcelain and first-generation polymeric insulators) in Alectra Utilities' distribution system.

The planned Pole Renewal investment addresses multiple needs including the significant volume of deteriorated poles on Alectra Utilities' distribution system, compliance with current CSA standards, and improved resiliency to adverse weather conditions. Ultimately, these investments are needed to maintain the safety and reliability of the overhead distribution system.

2.4.1 Volume of Deteriorated Poles on Alectra Utilities' Distribution System

Alectra Utilities' wood and concrete poles are a critical component of the utility's distribution system. Alectra Utilities' overhead distribution system (as of 2023) includes 105,262 wood poles and 29,110 concrete poles for a total of 134,372 poles. Alectra Utilities relies on these poles to support many distribution components such as conductors, transformers, switches, streetlights, and telecommunication attachments. Healthy poles also help ensure the safety of the distribution system, since they provide physical separation between the ground level and energized conductors.

Alectra Utilities must assess and monitor the condition of its pole population to ensure that its poles remain in a safe and serviceable condition, while meeting applicable standards and requirements for safety and reliability. Alectra Utilities does this through annual pole inspection and testing initiatives.

As described in *Chapter 5.3.3 (Section 5.3.3.3)*, Alectra Utilities performs regular inspections and testing to assess the condition of assets in the field. Wood poles with an in-service life of over 15 years are tested using a residual pole strength test. This non-destructive testing method evaluates the remaining structural integrity of the asset by assessing the internal decay of wood. This test is designed to estimate the remaining wood fibre strength as a percentage and is a key indicator of a wood pole's condition. In addition to the non-destructive testing of residual pole strength, Alectra Utilities performs visual field inspections of wood poles and concrete poles. The inspection process assesses various aspects of a pole's condition. Key degradation indicators for wood poles include:

- Remaining pole strength
- Rot and feathering at the top of the pole
- Shell and ground line rot
- Pole defects, including horizontal cracks or electrical burns

Key degradation indicators for concrete poles include:

- Rusting/corrosion of the re-bars
- Cracking
- Concrete spalling
- Mechanical damage

The information from non-destructive pole testing (applicable to wood poles) and visual inspections (applicable to both wood and concrete poles) is weighted to produce the overall HI score for each asset. Alectra Utilities' pole inspection and testing programs are critical for gathering the necessary information to determine pole condition and the resulting HI score.

Figure B01 - 5 and Figure B01 - 6 illustrate the condition of the entire population of wood and concrete poles in Alectra Utilities' distribution system. In total, there were 10,277 deteriorated poles at the end of 2023.

Figure B01 - 5 shows there are 9,691 wood poles (9% of the wood poles in Alectra Utilities' service territory) that are in Poor or Very Poor condition. These poles have deteriorated to the point where their structural integrity is significantly compromised due to age, decay, weathering, insect damage, or mechanical stress. These poles often fail residual strength testing and represent a direct risk to public and worker safety, particularly under load or during adverse weather conditions.

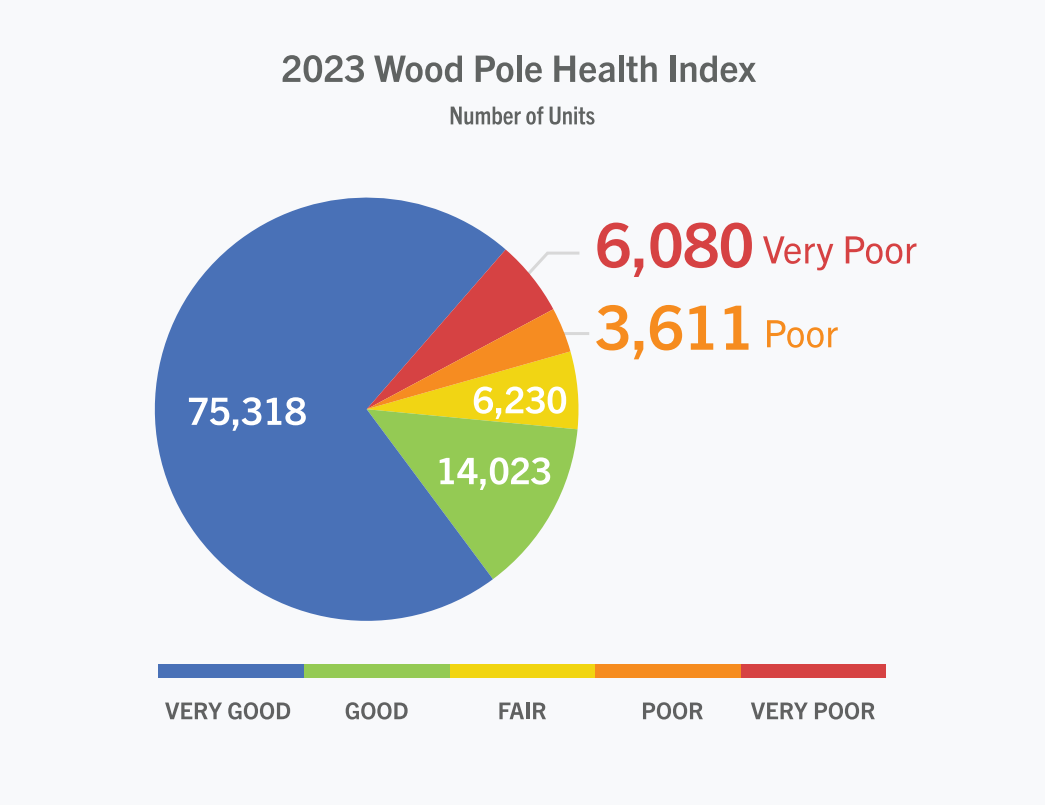


Figure B01 - 5 Wood Pole Health Index Demographics

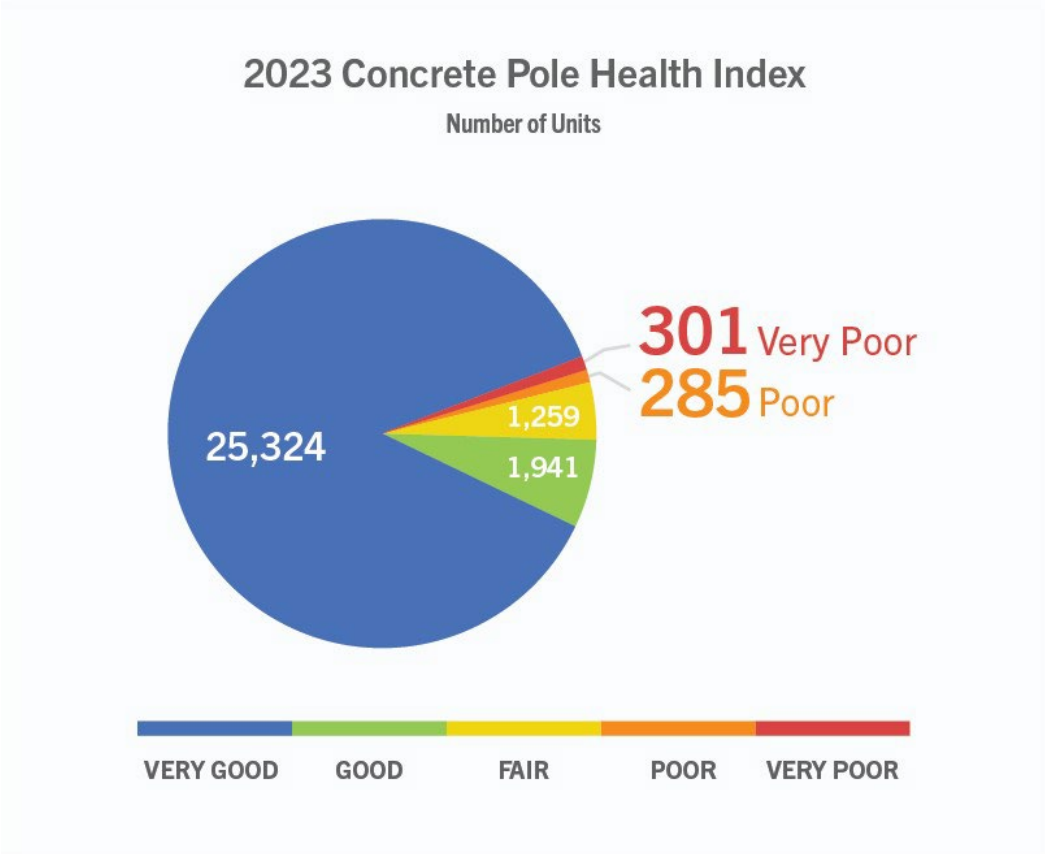


Figure B01 - 6 Concrete Pole Health Index Demographics

Figure B01 - 6 shows that 586 concrete poles (2% of the concrete poles in Alectra Utilities' service territory) are in Poor or Very Poor condition. These poles show signs of significant structural degradation, including spalling, cracking, exposed or corroded rebar, and damage from environmental stressors such as freeze-thaw cycles or impact. Some concrete poles in Poor condition may still support some structural load but require monitoring or reinforcement, while those in Very Poor condition are at high risk of failure and are prioritized for replacement to prevent safety hazards and service interruptions. This is not the case for wood poles in Poor condition because the organic nature of wood has different properties than concrete.

Figure B01 - 7 depicts a 4% increase in the volume of deteriorated poles from 2018 to the end of 2023, an increase from 9,839 to 10,277. Further investment is required to stop the growth in the proportion of the pole population that is in deteriorated condition.

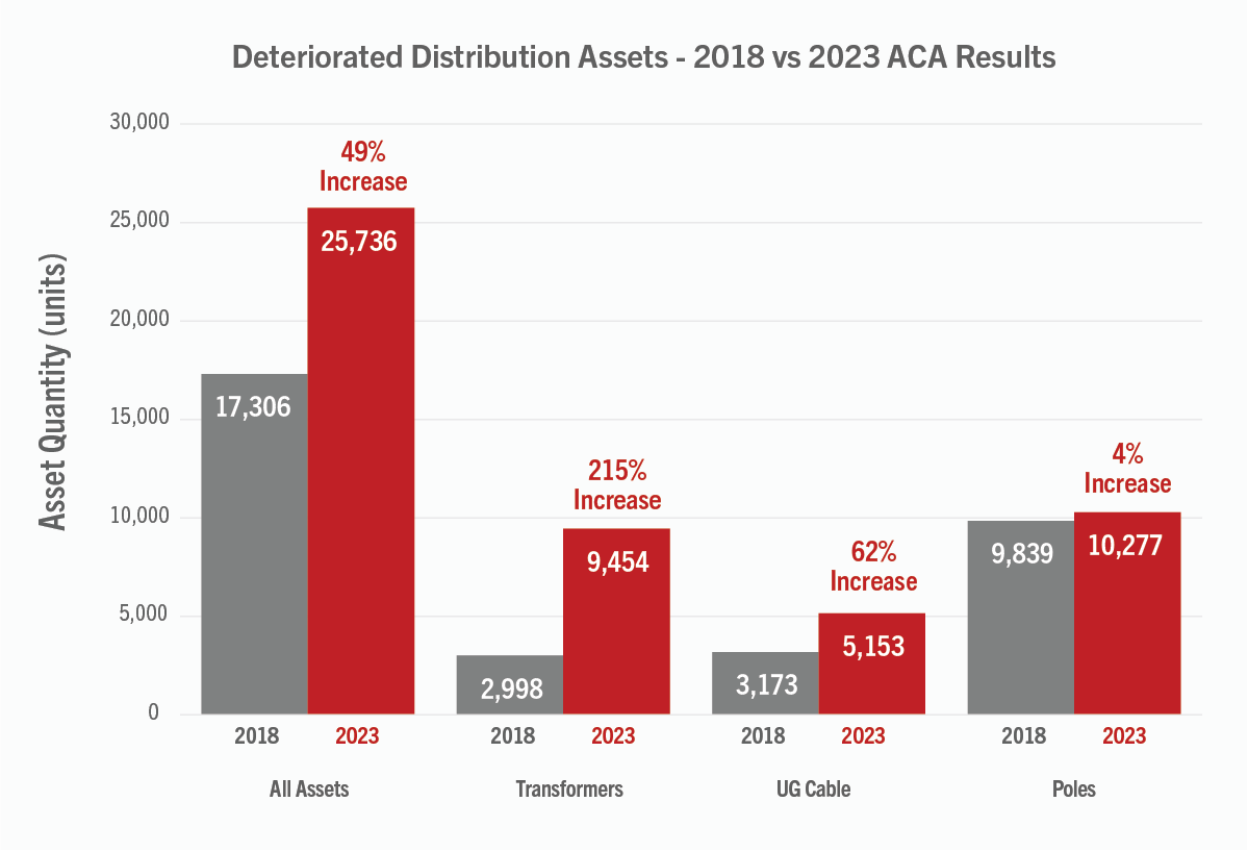
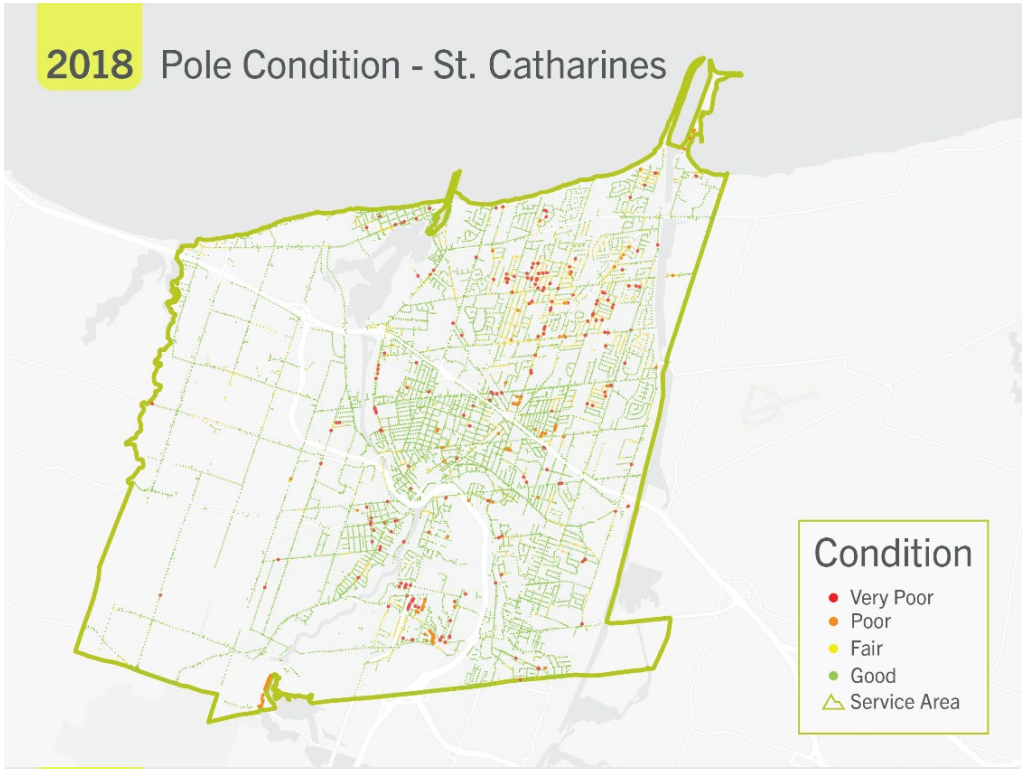


Figure B01 - 7 Trending Analysis of Deteriorated Distribution Assets

For example, Figure B01 - 8 displays the increase in the population of deteriorated poles in St. Catharines from 2018 to 2023. Despite investment being made to renew deteriorated poles every year, the population of deteriorated poles continues to outpace current levels of investment.



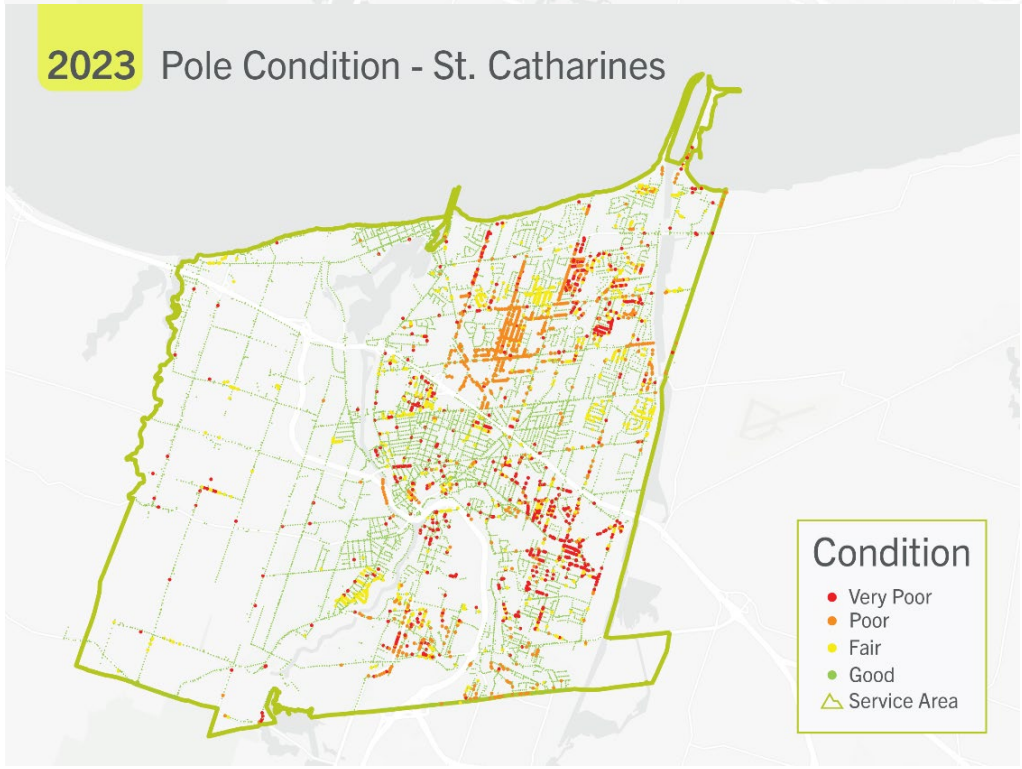


Figure B01 - 8 West (St. Catharines) – Pole Health Index Comparison (2018 vs. 2023)

2.4.2 Compliance with External Standards

Alectra Utilities adopted industry standards from the CSA in its overhead construction in compliance with Ontario Regulation 22/04, namely CSA Standard C22.3 No. 1-10.[3] Clause 8.3.1.3 of these standard states:

> *"When the strength of a wood pole structure has deteriorated to 60% of the required design capacity, the structure shall be reinforced or replaced"*.

This standard sets out requirements for maintaining the structural integrity and safety of distribution infrastructure, including poles. The majority of the wood poles identified for renewal under the investment have a remaining fiber strength of less than 60%. Without the planned Pole Renewal investment, the utility may face increased risk of safety hazard from severely deteriorated poles.

In 2023, CSA introduced new requirements for pole loading calculations based on updated factors around wind pressure and specific weather conditions for the area where the pole is installed. These changes came into effect as part of the revised CSA C22.3 No.1-15 Overhead Systems under the Canadian Electrical Code. The new requirements are intended to be a more accurate reflection of how poles will perform in real-world situations with increasing severity of weather events.

This change directly affects how Alectra Utilities determines whether a pole's class, a measure indicating its strength and size, is adequate to support attached equipment and withstand environmental loads. The adoption of wind pressure and weather loading analysis improves system safety and resilience.

The change in the standard has decreased Alectra Utilities' ability to re-use existing infrastructure. For example, there are several pole line installations prior to the standard change could support up to four distribution circuits. These installations no longer meet CSA non-linear requirements and either need additional structural reinforcement (i.e. guying) or in most cases need to be replaced with higher strength poles if additional circuits need to be added. In all cases, Alectra Utilities is required to ensure its assets meet design standards, including when an additional circuit

[3] "Overhead Systems", CSA C22.3 No. 1-10, Canadian Standards Association.

is needed. This typically generates additional costs in the cases where the new, more rigorous standards apply.

The replacement or reinforcement of these assets ensure that they are more resilient and able to withstand severe weather events. Figure B01 - 9 highlights a location where on May 21, 2022, 24-year-old poles failed when a Derecho passed through the service territory.

Figure B01 - 9 Weston Road, North of Highway 7, Vaughan (May 2022)

During the May 2022 Derecho, Alectra Utilities recorded over 100 pole failures. Most of these poles were in Good or Very Good condition, with an average age of 27 years, approximately half of their expected service life. Post-event analysis revealed that while these poles met the legacy CSA standards based on linear analysis methodology at the time of their installation, these poles would not meet today's CSA C22.3 No. 1-15 loading requirements. When reassessed using the current CSA standard methodology, it was determined that the failed poles needed to be one to two classes stronger. This highlights a significant vulnerability in legacy pole installations. Even structurally sound poles may be underbuilt by today's standards, increasing the risk of failure during extreme weather events.

To comply with updated CSA standards and improve storm resilience, Alectra Utilities may need to replace poles when undertaking other asset renewals, such as switch replacements. The structural capacity of poles may be insufficient to support new equipment under the revised CSA C22.3 No.1-15 non-linear loading requirements. Alectra Utilities will need to replace or reinforce these structures to ensure reliability and compliance with the standard.

To identify poles that are high-risk due to climate trends, Alectra Utilities used specialized pole loading software to evaluate typical pole construction combinations across each distinct climate region. This evaluation factored in pole height, class, the number of primary conductors, as well as the presence of single-phase or three-phase transformers and load-interrupting switches. Any configuration that failed the loading capacity criteria was used as a threshold to systematically flag in-service poles with similar characteristics, as verified by pole records in Alectra Utilities' GIS.

The evaluation identified 29,092 climate-vulnerable poles of which 3,558 overlapped with deteriorated poles meaning that 25,534 are net-new risks. Of that 29,092 population, 4,387 poles were flagged as high-risk, structurally-overloaded poles, as they do not meet pole loading criteria and lack sufficient strength to withstand their specific climate loading scenarios. These climate-vulnerable high-risk poles will be systematically addressed in accordance with the pole prioritization factors outlined in Figure 5.3.3 – 12 *in Chapter 5.3.3 Asset Lifecycle Optimization Policies and Practices*. There are 218 high-risk climate poles that are also deteriorated which will be replaced within the 2027-2031 period.

Figure B01 - 10 and Figure B01 - 11 illustrate the location of the identified 29,092 climate-vulnerable poles within Mississauga, Brampton, and St. Catharines. According to the climate adaptation study (refer to *Appendix G - Climate Risk and Vulnerability Assessment*) these regions carry the highest risk among the Alectra Utilities territories for damaging wind gusts.

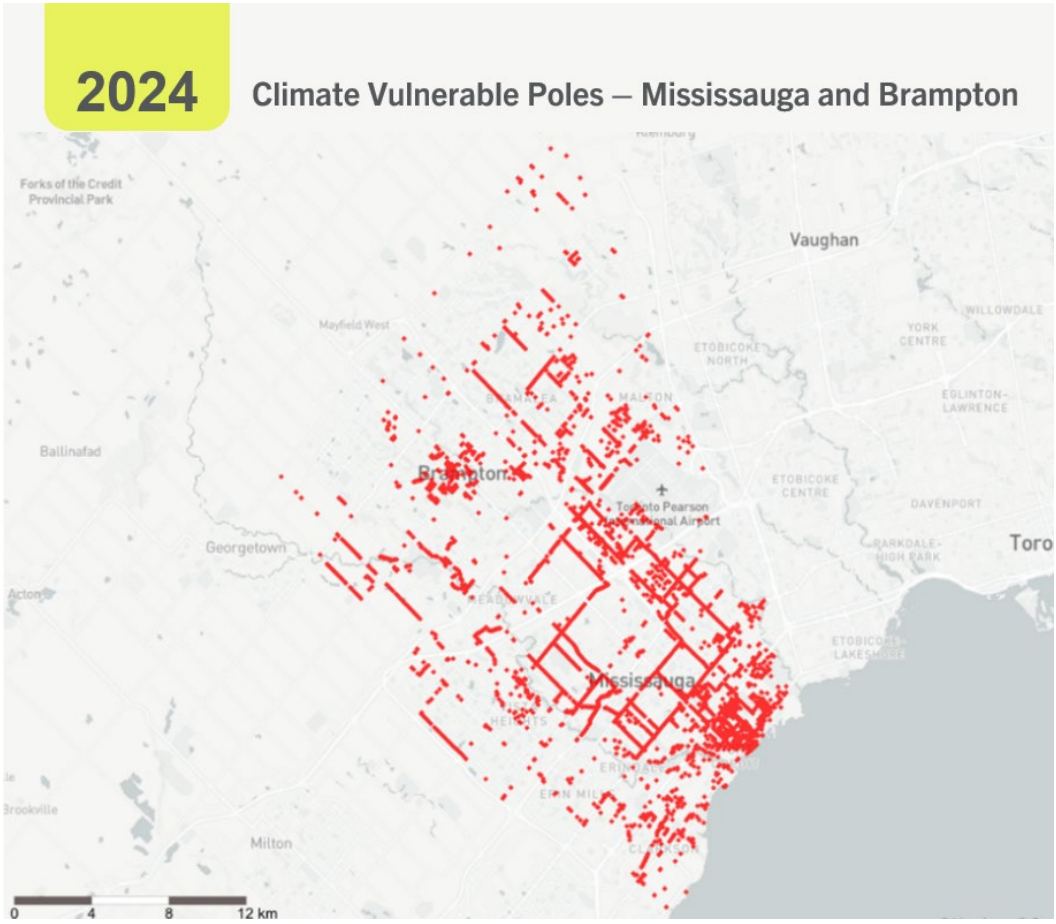


Figure B01 - 10 Climate Vulnerable Poles in Mississauga and Brampton

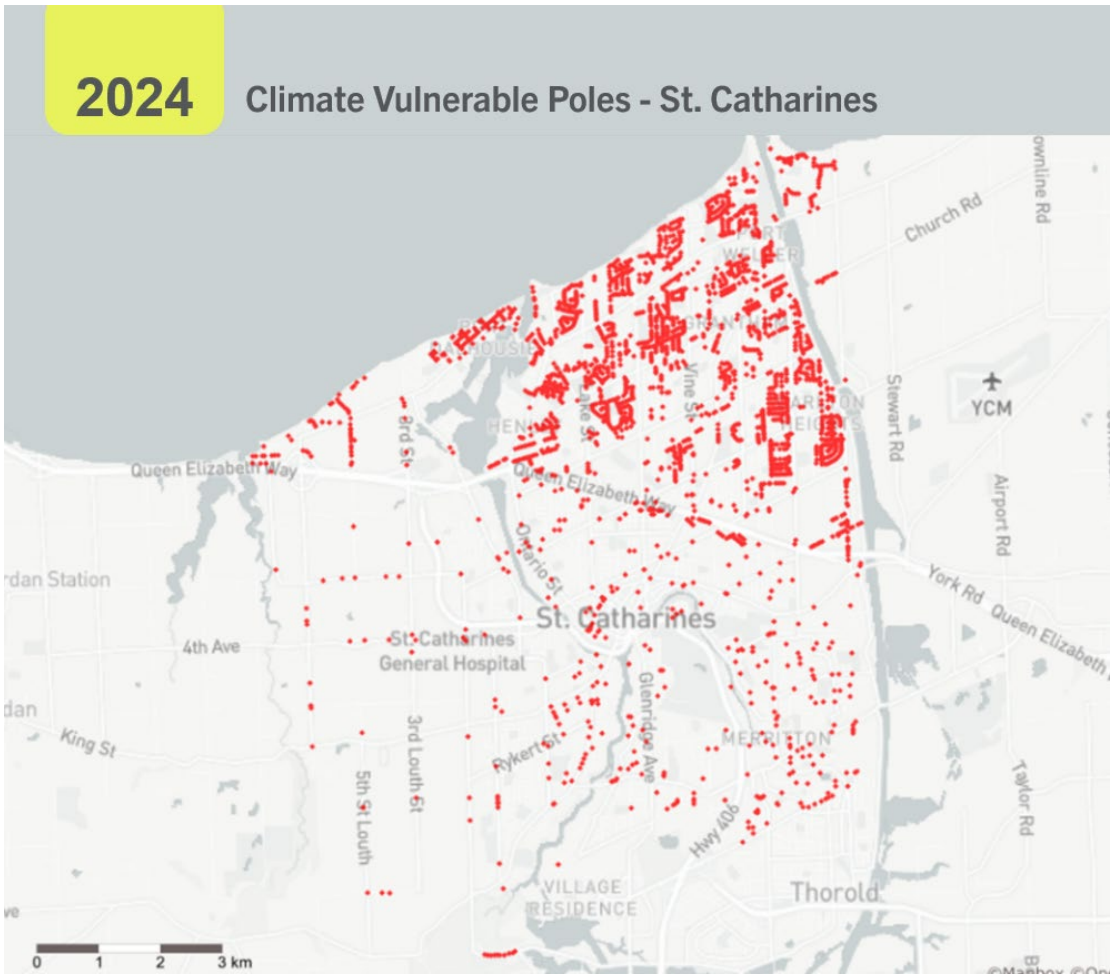


Figure B01 - 11 Climate Vulnerable Poles in St. Catharines

The climate adaptation study was also used to guide further detailed pole loading analysis to develop targeted projects aimed at investing in areas and overhead assets identified as increasingly vulnerable to climate change. Alectra Utilities will continue to monitor updates to the Intergovernmental Panel on Climate Change scenarios [4] and adjust the climate models accordingly to ensure that the selected strategies remain robust and effective.

2.4.3 Legacy Porcelain and First-Generation Polymeric Insulators

Legacy porcelain and first-generation polymeric insulators have displayed a susceptibility to the accumulation of contaminants. This has caused a reduction in their insulating properties which

[4] https://www.ipcc.ch/

promotes tracking leading to flashover events. Flashovers have resulted in pole fires and have caused reliability and safety risks to field crews and Alectra Utilities' customers. Figure B01 - 12 and Figure B01 - 13 illustrate the loss of pole structure and pole failures caused by tracking insulators and resulting pole fires.

Figure B01 - 12 Wood Pole Fire Resulting from Tracking Insulators

Figure B01 - 13 Pole Failure Resulting from Tracking Insulators

2.5 Options Analysis

This section describes the alternatives that Alectra Utilities considered for the pace of Pole Renewal investments. Alectra Utilities has not considered alternatives to the planned volumes of insulator and overloaded poles replacements, as it considers that work to be non-discretionary.

As described in *Chapter 5.3.3 Asset Lifecycle Optimization Policies and Practices*, Alectra Utilities leverages Predictive Analytics software to develop a multiyear asset replacement strategy, refer to *Chapter 5.3.3 (Section 5.3.3.2 A.1)*. Alectra Utilities focused its assessment on three alternative pacing strategies as follows:

Option 1: Pole Renewal Program - Accelerated Pace

- Starting with 960 poles/year in 2027, ramping up to 1,555 by 2031. This pacing approach would replace 6,265 poles in total.

Table B01 - 7 Pole Renewal Program - Accelerated Pace

	Bridge		Forecast Period					
Year	2025	2026	2027	2028	2029	2030	2031	Total (2027-2031)
Option 1: Accelerated Pacing	746	826	960	1,100	1,250	1,400	1,555	6,265

Option 2: Pole Renewal Program – Moderate Pace (Selected Option)

- Starting with 826 poles/year in 2027, ramping up to 1,300 by 2031. This pacing approach would replace 5,256 poles in total.

Table B01 - 8 Pole Renewal Program – Moderate Pace

	Bridge		Forecast Period					
Year	2025	2026	2027	2028	2029	2030	2031	Total (2027-2031)
Option 2: Moderate Pacing	746	746	826	925	1,025	1,180	1,300	5,256

Option 3: Pole Renewal Program – Reduced Pace

- Starting with 746 poles/year in 2027, ramping up to 1,250 by 2031. This pacing approach would replace 4,832 poles in total.

Table B01 - 9 Pole Renewal Program – Reduced Pace

	Bridge		Forecast Period					
Year	2025	2026	2027	2028	2029	2030	2031	Total (2027-2031)
Option 3: Reduced Pacing	746	746	746	746	985	1,105	1,250	4,832

Figure B01 - 14 provides a visual illustration of each option that shows the ramp up curve for the three pacing options.

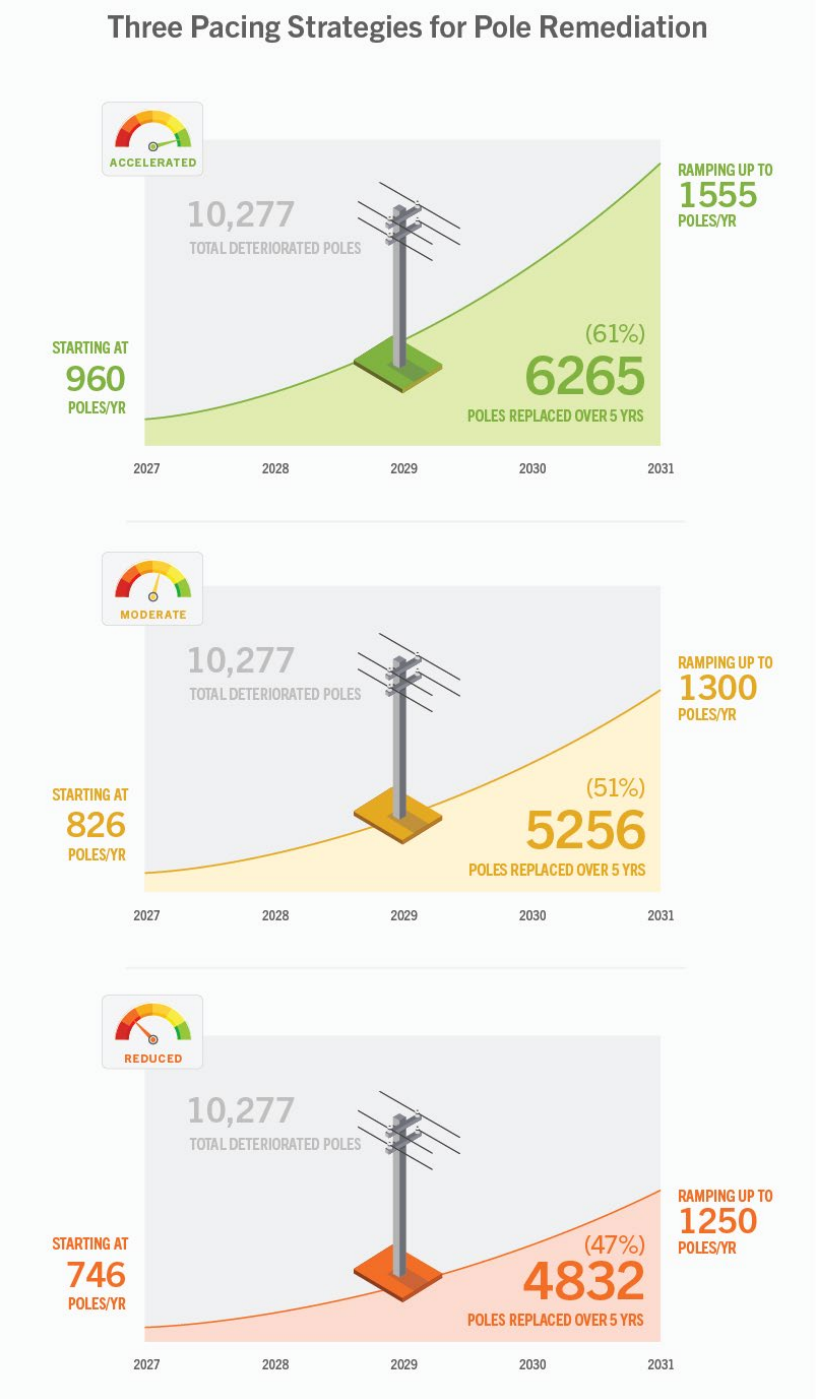


Figure B01 - 14 Pole Renewal Pacing Strategies

Due to natural degradation of materials, the pool of deteriorated poles will continue to grow over the DSP period. The Pole Renewal segment must not only address the existing population of deteriorated assets but also account for the ongoing rate of deterioration to prevent future accumulation. This requires a sustained, proactive replacement and maintenance strategy. Table B01 - 10 sets out the three strategies, associated costs and the estimated number of deteriorated poles renewed at the end of the 2031.

Table B01 - 10 Pacing Options for Pole Renewal, DSP Forecast 2027-2031

Pacing Options	Poles Renewed over DSP Period	Pole Renewal Plan Cost ($MM)
Option 1: Accelerated Pace	6,265	182.2
Option 2: Moderate Pace	5,256	151.1
Option 3: Reduced Pace	4,832	141.8

Alectra Utilities determined that Option 2: Moderate Pace strikes the best balance between mitigating public safety risks, reliability concerns, resource constraints, and annual cost and customer affordability. This approach results in the renewal of 5,256 wood and concrete poles over the 2027 - 2031 period through Pole Renewal segment.

The Accelerated Pace has a greater impact on mitigating pole failure risk. However, the high volume of work required by this plan would require redirecting funding from other areas to fund the accelerated Pole Renewal budget or require customers to pay more. Alectra Utilities believes the accelerated pace would not be prudent from the overall execution standpoint of its total capital plan.

Option 3: Reduced Pace mitigates a portion of the public safety risks within the current planning period. Among the three strategies, the reduced pacing option leaves the highest backlog of deteriorated poles at the end of 2027 - 2031 period. Option 3 is viable from a resource constraint point of view, as it mitigates some risks and lowers the overall program spending in the current planning period. However, the reduced pacing approach does not align with customer preferences for a more storm resilient system and will lead to higher spending and a more aggressive system renewal plan beyond 2031.

Insulator replacements are targeted at replacing legacy porcelain and first-generation polymer insulators from the distribution system. Alectra Utilities has planned to continue replacing these

assets to avoid insulator failure and the risks related to pole fires associated with these insulator types. Alectra Utilities plans to commence insulator replacements in 2029. The forecasted capital spending is below the threshold of materiality.

Given the relatively small cost of replacing the identified insulators, and the significant benefit that will result, Alectra Utilities has not considered any option other than the proposed replacement pace. Replacing insulators is a proportional response to the failure risk.

2.6 Summary of Net Benefits and Primary Risks

The Pole Renewal segment centers on replacing or reinforcing deteriorated wood and concrete poles, a critical measure to bolster safety and reliability in the distribution network. By addressing poles that are in Poor or Very Poor condition, often exacerbated by adverse weather events, the investment enhances public and worker safety while mitigating the risk of cascading failures. This proactive approach ensures improved system resilience and a reduction in the potential for large-scale outages. Similarly, replacement of legacy porcelain and first-generation polymeric insulators helps mitigate outages that pose a risk to public and worker safety, ultimately improving reliability of service to customers.

III Overhead Rebuild

3.1 Overview

The Overhead Rebuild segment consists of the following categories:

- #6 copper Wire Replacement
- Overhead Conductor Upgrades
- Alectra Initiated Overhead Near-Term Projects
- Joint Use

#6 Copper Wire Replacement: These investments mitigate safety risk associated with deteriorated poles and aging #6 copper primary lines. These smaller gauge primary conductors become brittle over time, increasing the likelihood of premature failure. Such failures result in significant safety risks for the public and workers. In some cases, broken conductors can ignite fires and cause damage to nearby infrastructure (refer to Figure B01 - 15 which shows a broken live conductor that falls to the ground igniting the grass).

Figure B01 - 15 Broken Overhead Conductor in Hamilton, 2020

Overhead Conductor Upgrades: These investments include renewal of associated pole line hardware, which in some rare instances will necessitate a complete pole line rebuild. Projects within this investment category are prioritized based on the condition of the assets. Projects include the renewal of conductors which are exhibiting signs of degradation or repeated connector failure. In high wind conditions, conductors have slapped together causing outages, and areas where legacy construction contains tight clearances allowing animal contacts or arcing leading to outages.

Alectra Initiated Overhead Near-Term Projects: These projects are required to support smaller system investments (less than $500,000) in overhead-related activities to resolve issues that are not reactive in nature but require swift intervention due to safety risks, reliability impact and regulatory compliance. Examples include aerial trespass, issues with equipment on private property, localized upgrades to address safety issues related to clearances, component condition, and legacy installations not suitable for current practices and joint use needs.

Joint Use: These investments include projects associated with Joint Use tenants.

Through the work planned in the Overhead Rebuilds segment, Alectra Utilities will mitigate failure risk associated with deteriorated overhead infrastructure. Overhead assets targeted for renewal either have HI results of Very Poor or Poor, as identified by the ACA process, or belong to specific asset groups that have been identified as being functionally obsolete or at high risk of failure.[5] Alectra Utilities proposes an increase in investment compared to historical funding levels to manage the increased risk these assets have due to continued deterioration and the risk of worsening climate events. Without the funding, many of these situations will result in outages, cause safety risks (falling wires) and increase reactive spending which reduces the available funding for planned work.

3.2 Investment Description

This section summarizes the proposed investments contained within the Overhead Rebuilds segment. The specific drivers, need, and options considered to address these assets are set out in *Section 3.3, Section 3.4, and Section 3.5* respectively.

[5] For additional details on Alectra Utilities asset condition assessment processes, refer to Chapter 5.3.3 Asset Lifecycle Optimization Policies and Practices as well as the *Appendix E - Asset Condition Assessment Report*

There are 13 projects related to overhead conductors, specifically #6 copper, installed beginning in the 1960s and through to the 1980s, which have a higher than average failure rate and have been identified as a public safety risk by the ESA. The ESA has previously urged Alectra Utilities to manage the risks associated with #6 copper conductors. All these assets are in Very Poor condition and are undersized relative to load growth. This results in a high probability of these conductors falling to the ground which poses a significant safety risk to the public.

Over the 2027-2031 period, the Overhead Conductor Upgrades segment targets specific assets or parts thereof, that comprise the Overhead System. Investment in this category involves renewal of legacy assets, built to legacy standards, that have a history of causing reliability issues. Without intervention, these assets will fail, resulting in outages, reactive spending, and risk of damage to surrounding infrastructure due to the failure introducing high fault current into the system.

These conductors will be replaced with standardized aluminum conductors and supporting equipment that are appropriately sized to relevant load demands.

Joint Use investments require Alectra Utilities to permit various entities such as communications companies and municipal street lighting to attach their equipment to Alectra Utilities' poles. When Alectra Utilities' poles are replaced or relocated, the joint use tenants are notified that their equipment needs to be transferred to the new poles, and once transferred, Alectra Utilities removes the old poles. The transfer process can have a lengthy lag time for joint use parties to relocate their plant to the new poles. The lag can be several months long.

Overhead Rebuilds also include Alectra Utilities initiated projects, which are all below the materiality threshold. However, each project is designed to proactively address a specific urgent need stemming from asset failures, instead of addressing the need reactively. An example of this is repeated animal contact outages within a certain neighbourhood. In this scenario, Alectra Utilities will attend each individual outage location, as they occur, to resolve and restore power. This is inefficient as it necessitates multiple trips to the same area ultimately not resolving the systemic issue that exists in the neighbourhood. An Alectra Utilities initiated project would install animal guards within the neighbourhood, permanently resolving the issue.

Overhead Rebuilds also include projects which involve undergrounding an overhead distribution circuit, or other storm resilience work. The underground infrastructure is shielded from extreme

weather events which materially improves system resiliency. The storm resilience work includes 'tree-wire' which protects the overhead conductor from tree contacts, reducing outages to customers.

Table B01 - 11 shows the expenditures in this segment from 2020-2031, including actual historical investments from 2020-2024, 2025-2026 bridge years, and forecasted 2027-2031 capital expenditures.

Table B01 - 11 Overhead Rebuild Investment Expenditures, Drivers and Outcomes

	Historical Spending					Bridge		Forecast Spending				
Year	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
CAPEX ($MM)	7.1	10.8	9.4	6.7	3.5	8.1	7.4	15.8	17.8	23.0	29.3	34.1
Primary Driver	Failure Risk											
Secondary Driver	Reliability, Safety, Resilience to Adverse Weather, Legal, Compliance											
Outcomes	Improved Reliability, Improved Safety, Storm Resilience											

Table B01 - 12 summarizes the outcomes and benefits of Alectra Utilities' Overhead Rebuild investments.

Table B01 - 12 Summary of Overhead Rebuild Investment Outcomes and Benefits

Outcome	Investment Benefits and Objectives
Reliability	• System and feeder-level reliability will be improved through the replacement of #6 copper wires. • Reliability will be enhanced as deteriorated and functionally obsolete assets are replaced with assets constructed to present day standards.
Safety	• Safety improvements through the construction of new, standardized assets that align to current operational practices.
Storm Resilience	• Conductor upgrades will include spacers and tree wire that will harden the system to high winds and storm related events.

3.3 Investment Drivers

There are multiple drivers for the Overhead Rebuild investments. Drivers for most of the sub-category's stem from the replacement of assets that are prone to failure, where the outcome provides enhanced storm resilience and improved customer reliability. Accordingly, the primary driver of these investments is failure risk. Secondary (but no less important) drivers are safety, reliability, resilience to adverse weather conditions, and industry standards.

The primary and secondary drivers of the investment are further defined and summarized in Table B01 - 13.

Table B01 - 13 Overhead Rebuild Investment Drivers

Investment Driver	Reasoning & Investment Benefits
Primary Driver: Failure Risk	The primary driver for these investments is the elevated risk of failure affecting public and worker safety, due to the deterioration of the identified conductors.
Secondary Driver: Safety	Remediating deteriorated assets or temporary conditions (e.g. braced pole or non-standard framing) will help reduce the significant public and worker safety risk posed by these assets. Replacement of conductors prone to failure which would fall within the public domain will reduce the risk to public and worker safety.
Secondary Driver: Reliability	Replacement of conductors prone to failure is expected to improve reliability.
Secondary Driver: Resilience to Adverse Weather	Customers supplied by circuits that are partially overhead would see increased reliability and storm resilience if the remaining portions of the circuit were undergrounded.
Secondary Driver: Legal	Aerial trespass or assets on private property without easement must be addressed.
Secondary Driver: Compliance	Transfers are required to be completed such that authorities do not withhold approvals that will cause difficulties with other projects required by Developers, customers or other Road Authorities.

3.4 Investment Need

The Overhead Rebuild segment has a diverse group of needs based on each sub-category. Alectra Utilities makes capital investments to address urgent issues related to overhead infrastructure throughout the year. A variety of these projects are managed year-over-year through the Alectra Utilities Overhead Near-Term investments. These just-in-time investments mitigate risk of larger scale issues and higher costs under a combination of reactive and planned work. Some are relatively straightforward, such as when a pole has cracked at ground level, but like for like replacement is not possible because framing the wires as-is does not meet minimal clearances and poses a significant risk to staff. Others are more complicated and involve assets installed on private property without easement which must be relocated at the request of the landowner.

Under the #6 Copper Wire Replacement, the identified #6 conductors have been flagged based on several parameters including but not limited to: outages, condition, cost/benefit of deployment to impact, and public exposure. If Alectra Utilities allowed these assets to remain in service, they would continue to pose a risk to the public due to the potential of failing and falling within the public domain.

Regarding Joint Use investments, Alectra Utilities, as the pole owner, is required to ensure that the original pole is removed. If this does not occur, the municipalities, as permit authorities, may withhold Municipal Consent approval or Road Occupancy Permits for Alectra Utilities' current and future work.

3.5 Options Analysis

Alectra Utilities has considered two investment options:

- Option 1: Status Quo / Do Nothing / Run to Failure
- Option 2: Remediate Issue

After evaluating each option, Alectra Utilities proposes funding of investments as selected by optimization based on the value it provides to customers. Additionally, the proposed investments were included in customer engagement, where Overhead Renewal received significant endorsement.

The “do-nothing” or status quo approach is not a reasonable option because Alectra Utilities cannot continuously defer investment in these smaller sub-categories relative to the benefits they provide customers in terms of reliability, safety, storm resilience and compliance.

IV Voltage Conversion

4.1 Overview

Over the 2027-2031 period, Alectra Utilities plans to replace certain deteriorated 4.16kV and 8.32kV distribution assets (poles, transformers, conductors) with modern, higher-voltage equipment as well as decommission associated municipal substation assets. The lower-voltage assets that will be replaced through Voltage Conversion investments are among the oldest in the distribution system and must be renewed. By decommissioning these assets and converting the system to higher-voltage equipment that meets present-day safety and performance standards, Alectra Utilities can mitigate failure and safety risks, improve system resilience and gain efficiencies.

The Voltage Conversion investment transitions legacy distribution and substation equipment operating on outdated 4.16kV and 8.32kV systems to modern, standardized voltage levels (13.8kV or 27.6kV). This conversion is intended to improve overall system reliability, enhance safety by reducing the risk of equipment failure, and increase operational efficiencies through better backup and restoration capabilities. Lower primary voltages were utilized in the 1950s and are found in pockets within the distribution system. The lower primary voltages are mainly surrounded by current standard 13.8kV and 27.6kV primary voltage levels. Feeders operating with a specific voltage can only be backed up from tie-points of the same voltage, thereby limiting effective and timely system restoration.

The Voltage Conversion investment involves decommissioning the lower primary voltage 4.16kV and 8.32kV sub-station assets and utilizing the higher primary voltage that feeds these substations as the distribution voltage to deliver power to customers. The voltage conversion process leverages existing distribution assets that meet the current codes and standards of the new voltage level. During Voltage Conversion projects, the distribution assets that will be replaced consist primarily of:

- Poles that do not meet the height and strength requirement
- Overhead switches and insulators that are not rated for use at the new voltage
- Distribution transformers that cannot operate at the new voltage
- Obsolete overhead conductors

By addressing these deteriorated substation and distribution assets upgrading them to current voltage systems will allow Alectra Utilities to improve safety, system resilience, and efficiency of the distribution system (refer to *Chapter 5.3.2 (Section 5.3.2.2 A.2)* for further details).

Deteriorated station assets pose a significant failure risk. Station assets are managed proactively as they deteriorate and are not operated on a run-to-failure basis due to the criticality and consequence of failure. Removing these station assets from the system provides additional benefits resulting from voltage conversion investments. In addition to station assets, deteriorated distribution assets on the existing lower-voltage infrastructure pose safety risks. Lower primary voltages are predominantly overhead construction. When overhead equipment fails there are consequential impacts on safety risks due to downed powerlines, pole fires and other factors.

From a functional perspective, lower primary voltages can pose significant safety risks. For example, protective equipment on the lower primary voltages, in some cases, might not recognize a wire down, resulting in a live conductor within the public's reach.

By eliminating lower primary voltage levels and utilizing the primary voltage of a substation in the distribution of electricity, system resilience is improved by allowing for more back-up tie-points that facilitate system restoration and planning.

The locations of the proposed Voltage Conversion investments include:

- Alectra West Voltage Conversion, including feeders in Stoney Creek & Hamilton Mountain locations
- Alectra Central North Voltage Conversion, including conversion of feeders in Brampton
- Alectra Central South Voltage Conversion, including conversion of feeders in the Truscott/Lewisham Dr. area

Alectra Utilities' Voltage Conversion investments have increased compared to spending over the historical period for several reasons. Some of the targeted assets are aged to the point of obsolescence and consequently have a growing scarcity of available replacement parts. These assets are not supported by the manufacturer, fail to meet current standards, or are being operated at maximum capacity with restricted backup capabilities. A proactive investment approach will create cost efficiencies by avoiding otherwise necessary operations and

maintenance expenditures on certain Municipal Stations (MS), and avoiding reactive costs triggered by asset failures.

The planned Voltage Conversion investments seek to mitigate safety risks and the ongoing maintenance challenges associated with infrastructure that needs intervention due to deteriorating condition and functional obsolescence. The discussion below provides a data-driven picture of historical spending trends, forecasted capital investments, and technical criteria that underlie the proposed asset replacement strategy. Together, these details support the decision to pursue a full conversion strategy rather than reactive, like-for-like renewals, ensuring that the system remains robust and capable of meeting current and future demands while addressing the concerns associated with Alectra Utilities' deteriorated assets.

4.2 Investment Description

During the 2027-2031 period, Alectra Utilities plans to convert deteriorated substation and distribution assets operating at the lower system primary voltages of 4.16kV and 8.32kV to the modern standardized 13.8kV or 27.6kV primary voltage class.[6] Table B01 - 14 below summarizes expenditures in this segment from 2020-2031, including actual historical investments from 2020-2024, 2025-2026 bridge years, and forecasted 2027-2031 capital expenditures.

Table B01 - 14 Voltage Conversion Investment Expenditures, Drivers and Outcomes

	Historical Spending					Bridge		Forecast Spending				
Year	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
CAPEX ($MM)	9.3	10.2	9.3	8.6	7.7	4.3	2.3	12.5	8.5	25.1	18.7	24.0
Primary Driver	Failure Risk											
Secondary Driver	Functional Obsolescence, Reliability											
Outcomes	Reliability, Safety, Efficiency, Other Benefits											

[6] The substation assets addressed in the Voltage Conversion investments are in Poor or Very Poor condition or are functionally obsolete. Overhead assets encountered during the upgrade process will be reused if they are in good condition and can be used on the current primary voltages, otherwise they will be replaced.

Figure B01 - 16 shows examples of indoor and outdoor type municipal substations that are being eliminated as part of the voltage conversion.

Figure B01 - 16 Indoor and Outdoor 4.16kV and 8.32kV Municipal Stations

Through the Voltage Conversion investment, Alectra Utilities plans to decommission eight substations completely (five as part of voltage conversion projects, and three remaining stations that can be decommissioned following the completion of MS-12 in Brampton) and begin conversion of four more substations that have deteriorated and pose significant failure and safety risks due to lower primary voltages. Moreover, distribution assets will be upgraded to operate on the current primary voltages and reconfigured to provide system reliability and resiliency. The reconfiguration will provide looped/switchable configurations.[7] Re-configuring the distribution system in an area can substantially reduce reliability risks to customers and improve system resilience, as future outages can be further limited to smaller groups of customers, and restoration procedures can be executed within a shorter period. System resiliency provides operational benefits by allowing operators to have more options to shift loads to maintain optimal operation of the distribution system during system peaks. Figure B01 - 17 illustrates the pre-conversion and post-conversion conditions where clearances from trees were improved by installing taller poles with modern hardware.

The negative impacts of lower primary voltage equipment affect pockets of Alectra Utilities' customers. Most of the utility's customers are served from feeders that operate at the 13.8kV and

[7] Radial configuration is a historic design method for feeder lines. While initially less expensive to build, the radial configuration has limited backup provisions restricting the utility's ability to restore power during a planned or a contingency event, resulting in longer outages to customers.

the 27.6kV primary distribution voltage levels. However, over 103,000 customers are served from feeders operating at the 4.16kV and 8.32kV primary voltage levels. These areas include 17 substations in Hamilton, three substations in Brampton, 25 stations in Mississauga and 16 stations in Barrie. These stations were installed in the 1950s, their condition has deteriorated, and there is scarcity of available spare parts. There is also a higher probability of unanticipated outages caused by equipment failure due to the deterioration. Further, some parts of the distribution system within the 4.16kV and the 8.32kV voltage levels are being operated at maximum capacity with restricted backup capabilities in the event of unplanned outages.

Figure B01 - 17 Pre-Conversion and Post -Conversion of 4.16kV Area

The projects planned for the 2027-2031 period will replace lower-voltage assets in four communities: Brampton, Mississauga, Hamilton and Stoney Creek. Over the DSP period, Alectra Utilities will have eliminated all 4.16kV in Brampton and Stoney Creek.

Figure B01 - 18 and Figure B01 - 19 depict the lower-voltage systems in Hamilton and Brampton showing the pockets of 4.16kV and 8.32kV surrounded by 13.8kV or 27.6kV.

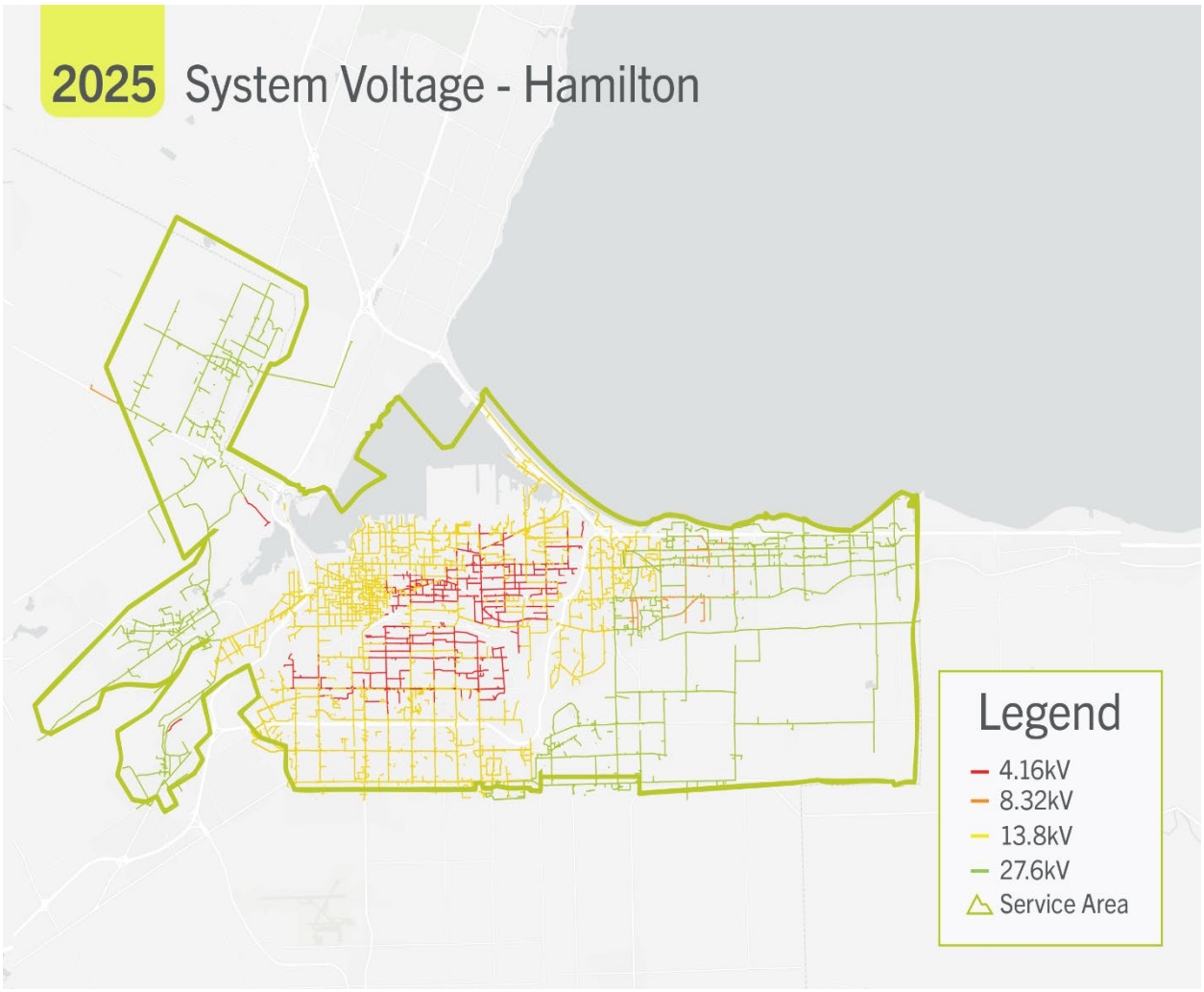


Figure B01 - 18 System Voltage Map – Hamilton

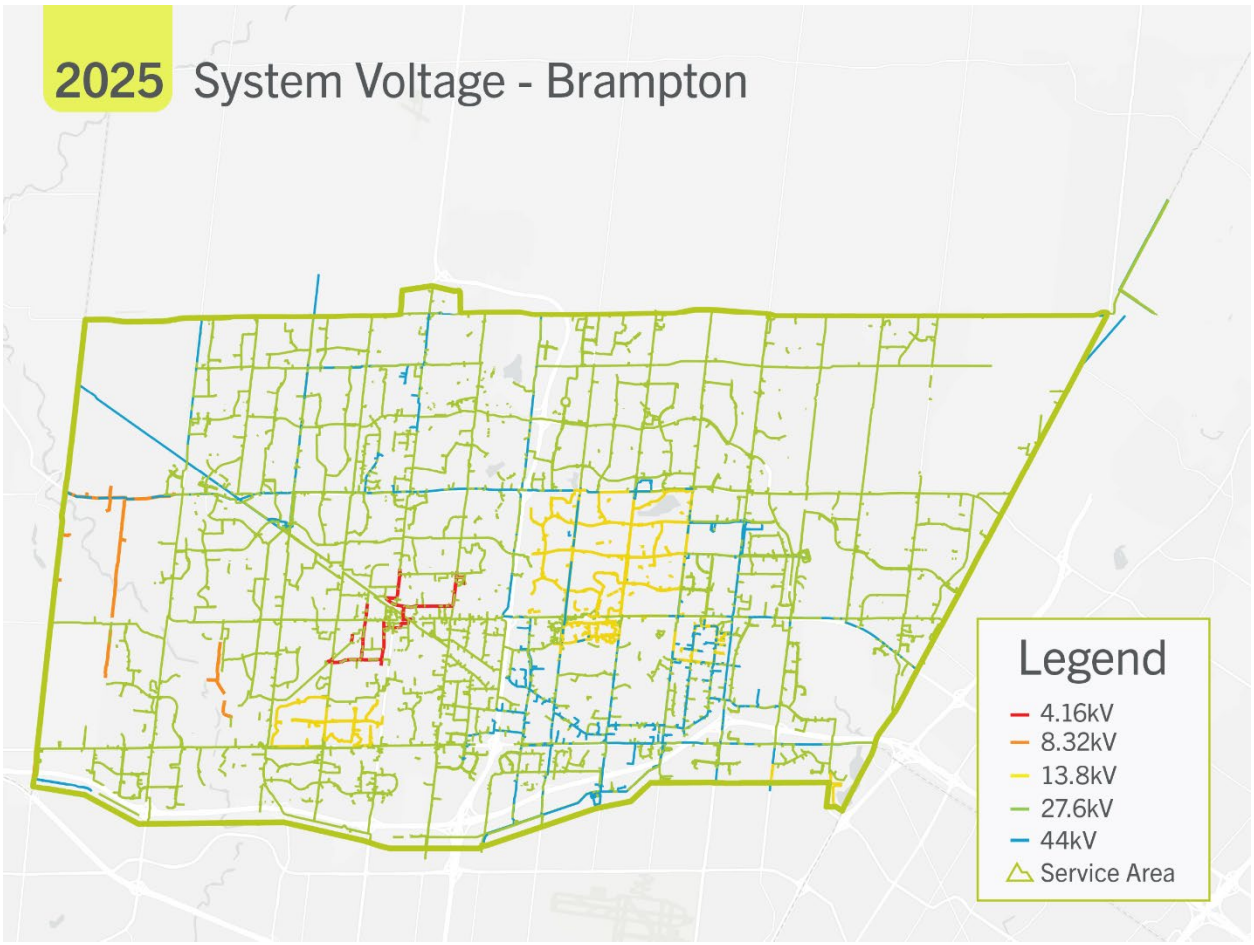


Figure B01 - 19 System Voltage Map - Brampton

In addition to improving reliability, these investments will mitigate safety risks and create efficiencies. Replacing deteriorated lower-voltage assets improves safety since modern assets adhere to current safety codes. Moreover, in the case of wire-down scenarios, current standard voltages enable protective equipment to recognize the event of wire down and remove the voltage from the lines. In some scenarios, protective equipment on legacy voltages might not recognize the wire-down event, resulting in an energized conductor endangering public safety and property.

Additionally, modern voltages can distribute more power to more customers requiring less station capital investments to meet new customer connections. Moreover, higher voltages reduce line losses, thus providing perpetual conservation.

Table B01 - 15 summarizes the outcomes and benefits associated with Voltage Conversion investments.

Table B01 - 15 Voltage Conversion Investment Outcomes and Benefits

Outcome	Investment Benefits and Objectives
Reliability	• Reliability will be enhanced for customers transferred from lower primary voltages of 4.16kV or 8.32kV feeders to the standard 13.8kV or 27.6kV feeder design, due to the enhanced tie points and contingency capabilities that these feeders offer when compared to the radial design of the legacy feeders. • Additional feeder ties built at 13.8kV feeders provide for flexible load transfers and resiliency (4.16kV areas are removed allowing continuous 13.8kV voltage level, thus providing increased feeder ties) • Replacing non-functional switches with working switching points will enhance outage restoration procedures, thereby further minimizing customer impacts during an outage event. • Removal of wooden cross arms and pins eliminates the risk of pole fires.
Safety	• Safety improvements will be realized through the installation of new, standardized equipment that aligns with current operational practices. • Through the installation of Supervisory Control and Data Acquisition (SCADA) enabled switches, the safety risks associated with manual load-break switch operation can also be avoided. • Safety improvements through the removal of porcelain insulators and switches which are prone to contamination and failure. • Reducing the risks of having energized wire-down events in case of conductor failure.
Efficiency	• These investments will provide financial and operational benefits by decommissioning the lower-voltage substations, eliminating the maintenance and inspection of the decommissioned sub-stations assets. • The addition of new switching points on existing feeders will optimize the restoration procedures by which crew workers in the field and/or power system controllers in the control room are able to operate switching devices to perform sectionalization, isolation and restoration procedures. • Higher voltages can accommodate more customers and feeders can go longer distances. • Lower line losses due to conversion to higher voltage class.
Other Benefits	• Logistic benefits related to reducing parts needed in inventory when eliminating lower voltage class equipment from the system.

4.3 Investment Drivers

The purpose of the planned Voltage Conversion investments is to create long-term value for Alectra Utilities and its customers by replacing deteriorated 4.16kV and 8.32kV distribution assets with modern, higher-voltage equipment. Alectra Utilities has determined that, at minimum, $24.7MM of the Voltage Conversion investments are required to resolve urgent distribution system issues. These issues stem from Poor and Very Poor condition assets such as poles, cables and transformers that are within the scope area, but have had their replacement deferred to align with the timing of the Voltage Conversion project. An additional $14.4MM of assets in the Fair condition category are within the scope areas, and present further risk. The cost estimates above are assuming that no reactive failures occur to these assets prior to the planned work which, could double the cost of the replacement. Halting Voltage Conversion would result in the loss of any additional benefits such as:

- Reduction in OPEX costs (from eliminated station maintenance)
- Increased reliability from feeder ties at 13.8kV for both 4.16kV customers and customers already on 13.8kV feeders
- Increased reliability from feeder ties at 27.6kV for both 8.32kV customers and customers already on 27.6kV feeders
- Automation (reduction in outage duration) for legacy 4.16kV and 8.32kV customers and some 13.8kV and 27.6kV customers
- Reduction in reactive costs triggered by asset failure
- Reduction in line losses

In addition, converting to higher voltage distribution allows Alectra Utilities to decommission some older stations that would otherwise need to be renewed and maintained. Like-for-like renewal of lower-voltage assets would increase stations capital requirements during the first three years of the 2027-2031 period by approximately $19.6MM because of a need to replace assets like power transformers, reclosers, relays, breakers and switchgear that are in Poor condition.

Alectra Utilities' planned Voltage Conversion investments have been aligned to ensure that, in most cases, any non-deteriorated assets can be reused when conversion occurs. For example, in the Alectra West Operating Area, practices call for the installation of dual voltage transformers. These transformers can be reused when the higher 13.8kV voltage feeders are installed.

Similarly, taller poles are installed to accommodate future installation of more circuits at a higher ground clearance.

The primary and secondary drivers are further defined and summarized in Table B01 - 16.

Table B01 - 16 Voltage Conversion Investment Drivers

Investment Driver	Reasoning & Investment Benefits
Primary Driver: Failure Risk	• Deteriorated station assets pose a significant failure risk. Station assets are managed proactively as they deteriorate and are not operated on a run-to-failure basis due to the criticality and consequence of failure. • Historic distribution infrastructure associated with low-voltage feeders is functionally obsolete. These older, lower-voltage systems use smaller-diameter wood poles that are weaker than modern wood or concrete poles. These poles are ultimately more susceptible to failure during severe weather events. • The use of wood cross arms and pins instead of modern armless construction increases likelihood of pole fires, and wire downs. • The use of porcelain insulators on switches is prone to failure in contrast to modern polymer insulators and switches.
Secondary Driver: Reliability	• In conjunction with the primary driver of Failure Risk, Alectra Utilities expects that reliability will improve from performing voltage conversion projects and other overhead asset renewal investments. In particular, the voltage conversion of 4.16kV and 8.32kV feeders is expected to enhance the security of supply, not only due to the robust substations that supply the 27.6kV feeders, but also due to the enhanced contingency and availability of tie points at this voltage level.
Secondary Driver: Function Obsolescence	• The station assets associated with the low voltage are functionally obsolete. This equipment is not supported by manufacturers, meaning that parts must be re-used from other older assets, which poses operational issues if the equipment must be taken out of service for extended periods of time to custom fit replacement parts.

4.4 Investment Need

4.4.1 Overview of Targeted Assets

Assets in the Voltage Conversion investment fall into two categories:

- Substation Assets (discussed in *Section 4.4.2*)[8]

[8] Alectra Utilities has other investments in stations renewal; however, the stations mentioned in this narrative do not overlap the other stations renewal investment.

- Distribution Assets (discussed in *Section 4.4.3*)

The priority projects for Voltage Conversion are the substation assets, failure of a critical component, such as a switchgear bus, can cause a major outage for an extended timeframe, impacting many customers. Furthermore, due to system design and construction in the 1950s, feeder redundancy is minimal, and loss of a station would result in stranded load and increased cost as generators would be required to provide customers power until the assets can be replaced. This can take between 48-120 hours depending on a variety of constraints. Alectra Utilities has an extensive maintenance program in place to manage substation assets, which has allowed facilities to operate past their typical useful lives. However, no amount of maintenance can overcome obsolescence. This is most pronounced in the circuit breaker category, where the majority of breakers for stations identified for conversion in this DSP period have been identified as obsolete.

The following is a list of the different service areas and assets targeted for Voltage Conversion in this DSP period with details of their age-related maintenance issues and reasons for their inclusion in the program:

Stoney Creek Area

- Deerhurst Station: Two of three feeders have been decommissioned due to reclosers being non-functional. Loads have been permanently transferred to the last remaining feeder in anticipation of the future conversion.
- Dewitt Station: The station transformer is in Poor condition and has had a history of failures. The reclosers at this location failed in 2024.
- Galbraith Station: Switchgear and breakers are in Poor condition. The station transformer required repairs recently.

Hamilton Mountain Area

- Eastmount Station: The switchgear breakers are obsolete and in Poor condition. The protection systems have recurring issues with the electromechanical relays. Operational issues also exist with overhead rear lot infrastructure on some feeders.

- Elmwood Station: Breakers are obsolete and in Poor condition. Recurring issues with electromechanical relays. Several pole hardware issues due to wood cross arms and pins.

Brampton Area

- MS12 Station: The switchgear breakers are obsolete and in Poor condition. The voltage conversion of MS12 enables the final decommissioning of three adjacent stations that have already had their distribution feeders converted: MS-1, MS-2 and MS-8.

Mississauga

- Bromsgrove Station: The T1 power transformer is in Poor condition. Operational issues with rear lot construction on some feeders. Some feeders have direct buried cables which are known to be more problematic than cables in duct.
- Park Royal Station: The power transformer has exceeded its typical useful life. Operational issues also exist with overhead rear lot infrastructure on some feeders.
- Parkwest Station: The T2 Power transformer is in Poor condition. Operational issues with rear lot construction on some feeders. Some feeders have direct buried cables which are known to be more problematic than cables in duct.

Voltage Conversion of a station occurs over multiple years (or phases) based on the number of feeders and geographical service area. Alectra Utilities and its predecessor utilities have been actively engaged in voltage conversion projects.

4.4.2 Substation Assets

For many of the substation equipment categories included in the Voltage Conversion projects, the equipment is:

- No longer supported by the manufacturer
- Difficult to source parts for or must be custom made
- Difficult or costly to maintain
- Functionally and operationally obsolete (e.g. safety restrictions on operation circuit breakers)

- Unable to meet current safety standards (e.g. switchgear that are not arc resistant)
- Unable to meet current performance standards
- A source of environmental risk (e.g. lacking spill containment or contain hazardous substances)
- Otherwise lacking modern monitoring capabilities

Alectra Utilities harvests serviceable assets during voltage conversion to benefit customers by re-using assets already within the system. Harvesting strengthens the reliability and operability of the remaining station assets by having a supply of available power transformers or circuit breakers for redeployment in the event of an unplanned failure in other compatible stations. Power transformers are a long-lead and higher capital cost item and harvesting these units as spares creates efficiencies and reduce costs.

Harvesting serviceable assets ultimately avoids costs to buy new power-class transformers. Instead of making significant renewal expenditures, Alectra Utilities can maintain the Poor and Very Poor station assets because the conversion of stations creates additional spares for the remaining lower-voltage stations. While Alectra Utilities strives to maximize the value of harvested assets, such assets are nonetheless vintage equipment that have been in service for a considerable period of time. This equipment will not have the same functional lifespan as new equipment. Accordingly, Alectra Utilities will ultimately see diminishing returns from this practice.

4.4.3 Distribution Assets

Since there is a large population of distribution assets, the condition of these assets tends to be diverse. While the overall condition shows the average, this can be a case of diverse populations masking the impact of deteriorated assets. If the Voltage Conversion projects were not to proceed, significant renewal investments would still be required to renew these deteriorated assets as part of the Overhead Renewal investment. Even if the assets in the worst condition were replaced, the rest of the system would continue to deteriorate and continue to pose reliability risk and eventually need to be replaced.

Some lower-voltage feeder assets already share poles with the higher-voltage circuits that will be used for conversion. Accordingly, Alectra Utilities has placed less weight on the condition of distribution assets when prioritizing voltage conversion project areas.

4.5 Options Analysis

Alectra Utilities prioritizes and paces Voltage Conversion projects based on need, value and risk. The overall priority of a project is determined by taking into consideration the following factors:

- Asset condition
- Asset age
- System configuration and capacity
- Co-ordination with other capital and maintenance work programs
- Criticality and customer impact

Alectra Utilities uses Copperleaf C55, a multi-variable capital investment optimization tool, to optimize projects based on value and risk across the entire capital investment portfolio for the DSP period. For more information on the process, refer to *Chapter 5.3.1 Asset Management Process Overview*. The projects identified in this program are optimized based on the available funding and the values and risk in the given year.

Alectra Utilities has considered different options for each of the major asset classes being addressed in this investment. The following subsections provide further information on the different options that were considered.

Alectra Utilities did not consider status/quo (or no conversion scope) nor selective approach alternatives. If Alectra Utilities was to renew the deteriorated lower-voltage assets without converting to a higher voltage, it would likely lose the opportunity to economically transition to higher voltage equipment for many years. Alternatively, if Alectra Utilities took a selective approach where conversion scope would only be completed during certain targeted rebuilds, more risk would be introduced to customers. Stations are normally backed up by one or more stations in the same geographical area. Similarly, feeders themselves are also backed up by other feeders in the surrounding geographical area. Removing any feeder as part of a rebuild could create gaps in the resiliency of the network and increase the risk and exposure to the remaining customers to prolonged outages. Neither of these approaches would be prudent. The scope must be completed in a planned manner to minimize risk and maximize benefit.

Accordingly, Alectra Utilities considered three pacing options which were presented to customers as part of the Overhead & Transformer Renewal customer engagement question.

- Reduced Pace: Only focusing on four stations, fully converting one
- Moderate Pace: Focusing on seven stations, fully converting two
- Accelerated Pace: Focusing on 11 areas, fully converting three stations (and some local pockets)

Following the strong customer support for Overhead Renewal investments during Customer Engagement Phase 2 (refer to *Exhibit 1, Tab 5, Schedule 2 Application-Specific Customer Engagement*), Alectra Utilities considered a modified approach to the Accelerated Pace, which has ultimately been selected as the preferred alternative:

- Final Forecast Pace (Selected Option): Focusing on 11 areas (nine stations), comprised of fully converting five stations, beginning conversion for four other stations and two spot conversions (voltage conversions of a single neighbourhood) for areas supplied by distribution step-down transformers.

The Final Forecast Pace alternative aligns with the accelerated pace in terms of the same areas being addressed. However, the timing of projects is shifted to enable more of the planned Voltage Conversions to be completed within the DSP period, while delaying the start of other more expensive voltage conversion projects to begin later in the DSP period. This shift allows Alectra Utilities to focus on fewer stations being converted concurrently and realizing the benefits of those stations being decommissioned sooner.

The five stations planned to be fully converted are MS-12 in Brampton (which will complete all 4.16kV conversion work in the city), Elmwood, Dewitt, Deerhurst and Galbraith, which will complete all voltage conversion in the Stoney Creek area of Hamilton and remove all 8.32kV. In addition, Eastmount MS in Hamilton, Bromsgrove MS, Park Royal MS and Parkwest MS in Mississauga will begin conversion during this DSP period. As part of the MS-12 conversion in Brampton, the remaining MS-1, MS-2 and MS-8 stations will be decommissioned.

V Switch Renewal

5.1 Overview

Alectra Utilities' Switch Renewal segment addresses deteriorated overhead switches identified to be in Poor and Very Poor condition. Overhead switches are crucial to the operation of the distribution system, especially during the isolation of faults and the restoration of customers after an outage. While Alectra Utilities' switch investments will focus primarily on manual switches, they will also include the replacement of early automated devices if the asset condition merits replacement. Figure B01 - 20 shows an automated switch installed in 1994 that failed due to a faulty contact.

Figure B01 - 20 Failed Automated Switch, Mississauga (Dec 2023)

5.2 Investment Description

This section summarizes the proposed investments to address deteriorated switches in Alectra Utilities' overhead distribution system. The specific drivers, need, and options considered to address these assets are set out in *Section 5.3, Section 5.4 and Section 5.5*, respectively.

Overhead switches are a distributor's main method of switching loads for system operation and to restore power to customers after an outage. Switches are the basic tool by which Alectra Utilities can sectionalize and isolate parts of the distribution system when needed.

Alectra Utilities plans to replace deteriorated overhead switches (those that are in Poor or Very Poor condition) in its overhead distribution system at a moderate pace over the term of the 2027-2031 period. Table B01 - 20 summarizes the proposed overhead switch replacement expenditures from 2020-2031, including actual historical expenditures from 2020-2024, 2025-2026 as bridge years and forecasted 2027-2031 capital expenditures.

Table B01 - 17 Overhead Switches Investment Expenditures, Drivers and Outcomes

	Historical Spending					Bridge		Forecast Spending				
Year	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
CAPEX ($MM)	1.5	1.5	3.3	3.8	5.1	4.7	6.7	6.8	6.9	7.0	7.1	7.2
Primary Driver	Failure Risk											
Secondary Driver	Reliability, Functional Obsolescence, Safety											
Outcomes	Reliability, Safety, Customer Value, Efficiency											

In addition to the deteriorated switches, this investment will target switches that are not fit for operation, either because they are functionally obsolete, no longer operable, or otherwise incapable of interrupting the load current (which is the primary function of a switch). In some cases, the new switches will be capable of remote operation and automation, which will have the benefit of reducing outage times for customers. Alectra Utilities may replace overhead switches with automated high-speed circuit reclosures, depending on the location of the overhead switch in relation to normal system open points. Switch locations with high operating counts will also be considered for automation to improve switching response time and reduce the requirement to dispatch a crew to operate a switch. Normal system open points are identified pursuant to control room processes and are positioned to balance the loading on feeder circuits. This approach enables load transfer from one circuit to the alternate circuit at the normal open point if one circuit experiences loss of power. Automation of switches at these normal open points will reduce service restoration response time and minimize the requirement to dispatch a crew to operate the switch at the open point. This contributes to the system's overall resilience. Table B01 - 18

summarizes the outcomes and benefits of the investments planned to address deteriorated switches.

Table B01 - 18 Summary of Overhead Switches Investment Outcomes and Benefits

Outcome	Investment Benefits and Objectives
Efficiency	• Renewing deteriorated overhead switches with automated and remotely operated switches provides Alectra Utilities with the ability to expeditiously restore service, transfer supply and enable isolation from the Control Room, reducing the need for crews to operate switches and permit crews to focus on fault identification and repair.
Customer Value	• Improved reliability because of the renewal of deteriorated and functionally obsolete assets. • Replacing non-functional switches with operational switching points will enhance outage restoration procedures, thereby further minimizing customer impacts during an outage.
Reliability	• System and feeder-level reliability will be improved through the replacement of deteriorated switches. • Reliability will be enhanced as deteriorated and functionally obsolete assets are replaced with assets constructed to present-day standards.
Safety	• Safety improvements through the construction of new, standardized equipment that aligns with current operational practices. For instance, the risks of catastrophic failure associated with any failed switches (e.g. flashovers) will be mitigated. • Alectra Utilities will avoid the safety risks of manually operated switch failure through the installation of remotely controlled switches. • The safety risks associated with legacy air-brake switches, which cannot be operated under load (i.e. non-load-break switches) will also be eliminated as these switches are removed from the system.

5.3 Investment Drivers

The planned replacement of deteriorated switches is driven by the need to address the risk that these assets will fail. Accordingly, the primary driver of these investments is failure risk. Secondary (but no less important) drivers are reliability, safety, and functional obsolescence. The primary and secondary drivers are further defined and summarized in Table B01 - 19.

Table B01 - 19 Overhead Switches Investment Drivers

Investment Driver	Reasoning & Investment Benefits
Primary Driver: Failure Risk	The primary driver for these investments is the elevated risk of failure affecting worker safety due to deteriorated switches, as well as the elevated risk of failure associated with specific switch assets that are not fit to operate.
Secondary Driver: Safety	Replacing deteriorated or unfit switches mitigates worker safety risks posed by those assets. When switches cannot be relied on to operate properly, it can be harder to de-energize parts of the distribution system. Also, deteriorated switches introduce flashover risks that pose a safety risk to crews that must operate them.
Secondary Driver: Reliability	Replacing deteriorated switches will improve the reliability of the overhead distribution system, as it will allow the utility to sectionalize the system and restore power to customers more efficiently. The replacement of legacy switches with modern standard assets, including those that allow remote and automated operation, will further enhance reliability.
Secondary Driver: Functional Obsolescence	Obsolete asset types, such as non-load-break air-break switches, will be replaced through these investments. Replacement of these assets is expected to improve reliability.

5.4 Investment Need

As shown in Figure B01 - 21, based on the latest ACA, there are 80 deteriorated switches (those in Poor and Very Poor condition) in the distribution system. These switches pose elevated safety and reliability risks. The continued operation of the distribution system with these deteriorated devices exposes Alectra Utilities' customers to prolonged outages and creates operational constraints. Alectra Utilities must address the population of deteriorated switches at an appropriate pace to maintain safe and reliable operation of the grid. Failure to replace these assets would result in increased safety risks and decreased reliability due to the significant role these switches play in feeder sectionalizing and load transfers on the distribution grid.

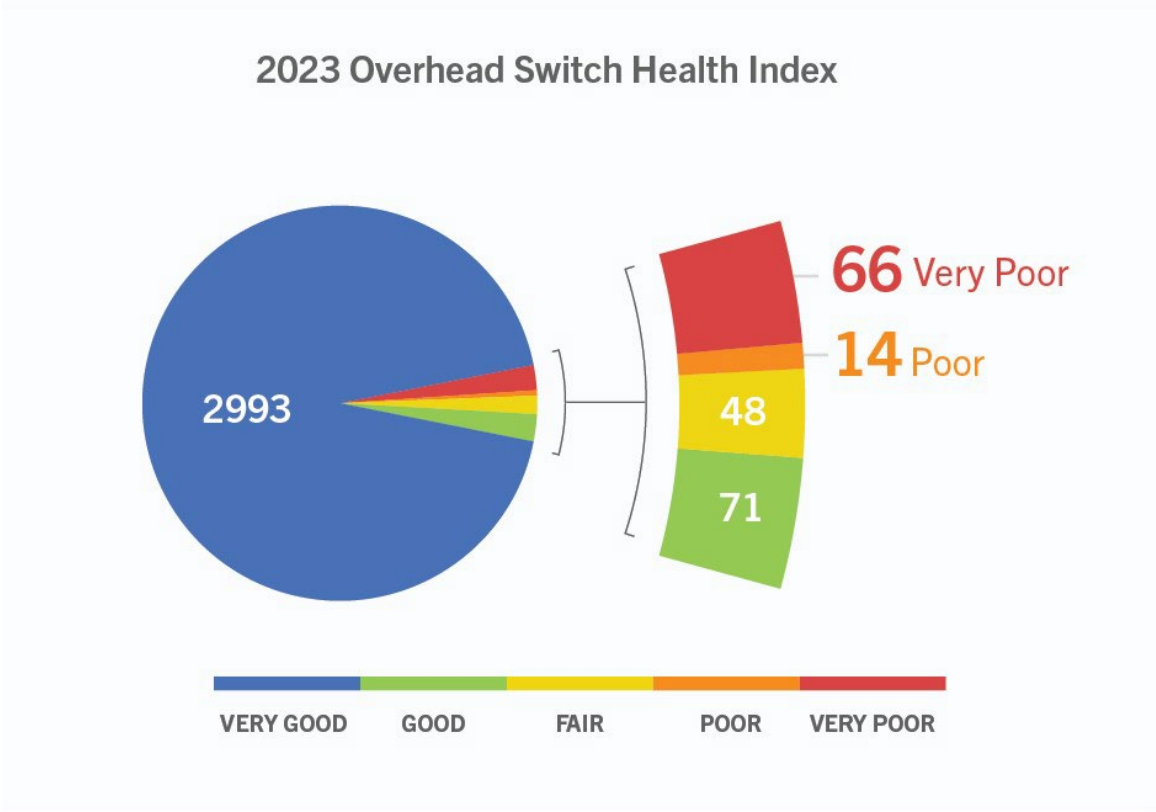


Figure B01 - 21 2023 Overhead Switches Health Index Distribution

Alectra Utilities has a switch maintenance initiative as part of its asset life cycle optimization (refer to *Chapter 5.3.3 Asset Lifecycle Optimization Policies and Practices*). The initiative allows switches to operate as intended in a safe and reliable manner to achieve their expected useful life. The upgraded automated switches will provide Alectra Utilities system operators with remote fault detection and isolation capabilities, faster switching, and power restoration with enhanced operational flexibility. These upgrades are aligned with customer preferences for faster power restoration and greater system resiliency, specifically during severe weather events and large-scale outages. For example, the newly procured 44kV automated switches include ice-breaking capability. This technology improves safe and reliable operation during ice storms, which support public and worker safety while maintaining service continuity.

The targeted replacement program complements the broader need for enhanced grid resiliency and modernization described in *Appendix B14 - Enabling Resiliency & Modernization.* This program includes a dedicated funding stream for the deployment of automated switches across

the distribution grid. While the Enabling Resiliency & Modernization program focuses on the need to expand automation to enhance fault response, operational flexibility, and outage restoration in priority areas, the Switch Renewal investment specifically targets the replacement of deteriorated or functionally inadequate switches that are impeding safe and reliable operations today. By integrating automation into these replacements where justified, the two programs work in tandem to modernize the grid efficiently, optimize capital deployment, and deliver improved outcomes for customers.

5.5 Options Analysis

Alectra Utilities utilized Copperleaf's C55 Asset Aware and Predictive Analytics tools to determine the optimal timing and pacing of asset replacement based on the asset condition assessment data, the impacts to reliability, safety, and financial risks associated with the failure of the asset. Details on the predictive analytics process can be found in *Chapter 5.3.3 Asset Lifecycle Optimization Policies and Practices*. The result of the Copperleaf C55 optimization was a yearly replacement rate of 51 switches per year. This target pace would effectively manage system risk, based on the asset condition, criticality, and probability of failure.

Alectra Utilities considered three pacing options that address the deteriorating switches:

- Option 1: Renewal of deteriorated assets at the accelerated pace 68 units per year
- Option 2: Renewal of deteriorated assets at a moderate pace 51 units per year (Selected Option)
- Option 3: Renewal of deteriorated assets at a reduced pace 35 units per year

Costing for each option is detailed in Table B01 - 20.

Table B01 - 20 Overhead Switch Renewal Pacing Options

Option	Switches Remediated Per Year Long Term Projection	Total Switch Renewal Plan Cost (2027-2031) ($MM)
Option 1: Accelerated Pace	68	46.5
Option 2: Moderate Pace	51	35.0
Option 3: Reduced Pace	35	23.0

Due to the critical nature of switches for safe restoration, isolation, and operation of the system, and customers' preference for faster power restoration, Alectra Utilities decided to follow Option

2: Moderate Pace. This pace strikes the optimal balance between managing risk and maintaining affordability for customers. It ensures that the resources are allocated where they deliver the most value on maintaining system reliability, improving outage response times, and enabling load transfers during contingencies.

From 2020 to 2024, Alectra Utilities replaced on average 30 deteriorated switches per year. Since 2022 the number of switch failures has increased. Additionally, the number of major corrective maintenance items is increasing as demonstrated in Table B01 - 21. The increase in failures and increase in major corrective maintenance issues are signs that the assets are deteriorating faster than the current pace of renewal.

Table B01 - 21 Overhead Switch Renewal (2020-2023)

Year	Overhead Switch Deficiencies		
	Major and Moderate	Minor	Total
2020	2	5	7
2021	8	10	18
2022	24	34	58
2023	43	49	92

The Accelerated Pace would replace 68 deteriorated switches per year over five years. While this approach best mitigates switch failure risk and ensures the system is more resilient against storm events, it costs more.

The Reduced Pace of 35 deteriorated switch replacements per year is still above the historic actual pace of 30 units per year. This level of investment reduces the overall benefit to reliability of having a modernized grid, as many of the switch renewal candidates would not be replaced with automated devices. Automated devices have a direct impact on SAIDI, and with enough penetration allow for advanced protection schemes, as outlined in *Appendix B14 - Enabling Resiliency & Modernization*, which would also assist in reducing SAIFI.

5.6 Summary of Net Benefits and Primary Risks

The Switch Renewal program emphasizes the replacement of deteriorated and functionally obsolete overhead switches, which are vital for effective system sectionalization and rapid fault isolation during outages. Upgrading these switches, particularly with the integration of remote

operation and automation capabilities, not only accelerates restoration times but also directly improves customer service by minimizing outage durations. The net benefits include enhanced safety by reducing the dangers associated with manual operations, improved reliability through more efficient and modern switching functions, and overall gains in operational efficiency and cost management over time.

The pacing of these investments must balance risk mitigation with costs. An overly aggressive replacement schedule could significantly increase capital costs and potentially divert resources from other necessary projects. Conversely, too slow a pace will leave vulnerable equipment in service for longer than is optimal, increasing outage frequency and the risk of equipment failure. Additionally, as the utility shifts to more advanced technology, without proper funding in communication infrastructure and backend systems, there is a risk of unforeseen integration challenges that could impact the promised improvements in efficiency and reliability.

VI Investment Projects

The material Overhead Asset Renewal Program investments from 2027 to 2031 are included in Table B01 - 22.

Table B01 - 22 Material Projects and Initiatives

Project Code	Project Name	CAPEX ($MM)
Multiple	Pole Renewal	151.1
Multiple	Switch Renewal	35.0
150354	Voltage Conversion - Eastmount MS, Hamilton	21.7
150355	Voltage Conversion - Elmwood MS, Hamilton	18.1
Multiple	Overhead Asset Renewal-Alectra Initiated Distribution System Projects	17.4
152837	Voltage Conversion - (AREA11) - Bromsgrove/Park Royal/Parkwest MS at Truscott/Lewisham Dr, Mississauga	14.0
150317	Voltage Conversion - Deerhurst MS, Hamilton	12.7
150321	Voltage Conversion - Galbraith MS, Hamilton	9.4
Multiple	Installation of Tree wire conductor and Wildlife Mitigation products	7.9
101832	Joint Use Pole Removal - Alectra East	5.9
151952	Overhead Conductor #6 Replacement Feeders PA-F3, PA-F5, PA-F6	5.6
151947	Overhead Conductor #6 Replacement Feeder MK-11	5.0
152489	Climate Adaptation - Rymal Road, Hamilton - 3612X and 3621X Overhead line undergrounding	4.2
150356	Voltage Conversion - (AREA11) - Bromsgrove/Park Royal/Parkwest MS at Constable Rd and Seagull Dr, Mississauga	3.9
151161	Joint Use Pole Removal - Alectra West	3.9
151470	Joint Use Pole Removal - Central South	3.8
151942	Overhead Conductor #6 Replacement Feeder MK-1	3.5
150377	Voltage Conversion and Rear Lot - Montgomery Dr, Hamilton	3.2
152783	New Build - Lake/Winona CN Rail Overhead Relocate, Hamilton	2.9
151936	Overhead conductor #6 Replacement Feeder MK-2	2.9
151956	Overhead Conductor #6 Replacement Feeder WL-11	2.8
151946	Overhead Conductor #6 Replacement Feeder MK-9	2.5
152985	Hamilton O/H Conductor upgrade - Stirton M86	2.4
152982	Hamilton O/H Conductor upgrade - Birmingham M8	2.2

Project Code	Project Name	CAPEX ($MM)
151944	Overhead Conductor #6 Replacement Feeder MK-3	2.2
150320	Voltage Conversion - Dewitt MS, Hamilton	2.2
151139	Voltage Conversion - MS-12 Hansen Rd, Brampton	2.0
151539	Joint Use Pole Removal - Alectra Central North	1.9
152981	Hamilton O/H Conductor upgrade - Birmingham M7	1.8
152241	Overhead #6 Replacement Feeder OT-5	1.6
151951	Overhead Conductor #6 Replacement Feeders OT-3, CP-2	1.5
151945	Overhead Conductor #6 Replacement Feeder MK-5	1.3
152993	Upgrade egress riser poles, hardware and lightning arresters - West	1.3
152950	Hamilton O/H Conductor Upgrade - Newton M5 (251X)	1.3
152958	Hamilton O/H Conductor upgrade - Mohawk M81 (0812X)	1.2
151955	Overhead Conductor #6 Replacement Feeder WT-1	1.1

1

Appendix B02 - Underground Asset Renewal

I Overview

Underground cables are Alectra Utilities' most deteriorated asset type, and a significant cause of outages in its distribution system. Currently, nearly half of Alectra Utilities' controllable outages stem from deteriorated equipment directly jeopardizing both service reliability and safety. Over the 2027-2031 period, the company must continue to invest in renewing these assets to mitigate safety and failure risks, and to improve customer reliability. This multi-year initiative targets the replacement and rehabilitation of key asset categories that have reached a deteriorated state.

The core objectives of this program are to:

- Replace failing components before their condition worsens
- Improve reliability levels
- Enhance overall safety for both customers and field crews

Alectra Utilities' investment plan follows an upwards trajectory necessitated by the window of opportunity for cable injection closing at the end of 2029. After this point, the only renewal option for deteriorated underground cable will be replacement, causing a significant increase in the cable renewal budget which cannot be avoided. The main categories of assets/investments that will be renewed, whether by replacement or otherwise, through Underground Asset Renewal over the 2027-2031 period are:

- **Cable and Cable Accessories:** Cable and cable components that are near their end-of-life and eligible for rehabilitation through injection, or in Poor or Very Poor condition and in need of replacement
- **Switchgear:** Switchgear that are near their end-of-life and leaking, or in Poor or Very Poor condition
- **Civil Structures:** Deteriorating structures that pose both a public and/or worker safety risk
- **Alectra-Initiated Underground Near-Term Projects:** Projects required to address underground assets that must be resolved quickly to avoid prolonged outages or an imminent risk.

Table B02 - 1 Underground Asset Renewal Investment Expenditures, Drivers and Outcomes

	Historical Spending					Bridge		Forecast Spending				
Year	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
CAPEX ($MM)	61.5	55.6	46.9	68.9	75.9	69.8	75.1	80.0	91.0	91.0	153.0	152.1
Primary Driver	Failure Risk											
Secondary Driver	Reliability, Functional Obsolescence, Safety											
Outcomes	Improved Reliability, Improved Efficiency and Improved Safety											

Table B02 - 1 highlights the underground asset renewal investment expenditures, drivers and outcomes. The objective of Alectra Utilities' planned Underground Asset Renewal investments is to reduce failure risk, which ultimately leads to improved reliability. Specifically, Alectra Utilities will be targeting areas where customers are having multiple sustained outages. At present, defective equipment accounts for 44% of outages in Alectra Utilities' system (MEDs and scheduled outages removed). Underground assets contribute significantly to the reliability of Alectra Utilities' system (refer to *Appendix L - Historical Reliability Data* for historical reliability performance). Deteriorated underground cables are the leading cause of equipment-related outages in the distribution system. Figure B02 - 1 illustrates the causes of outages that are due to failing equipment. Cable and cable accessory (XLPE and PILC) failures account for 41% of all equipment-related outages. Failing switchgear account for a further 4% of all equipment-related outages.

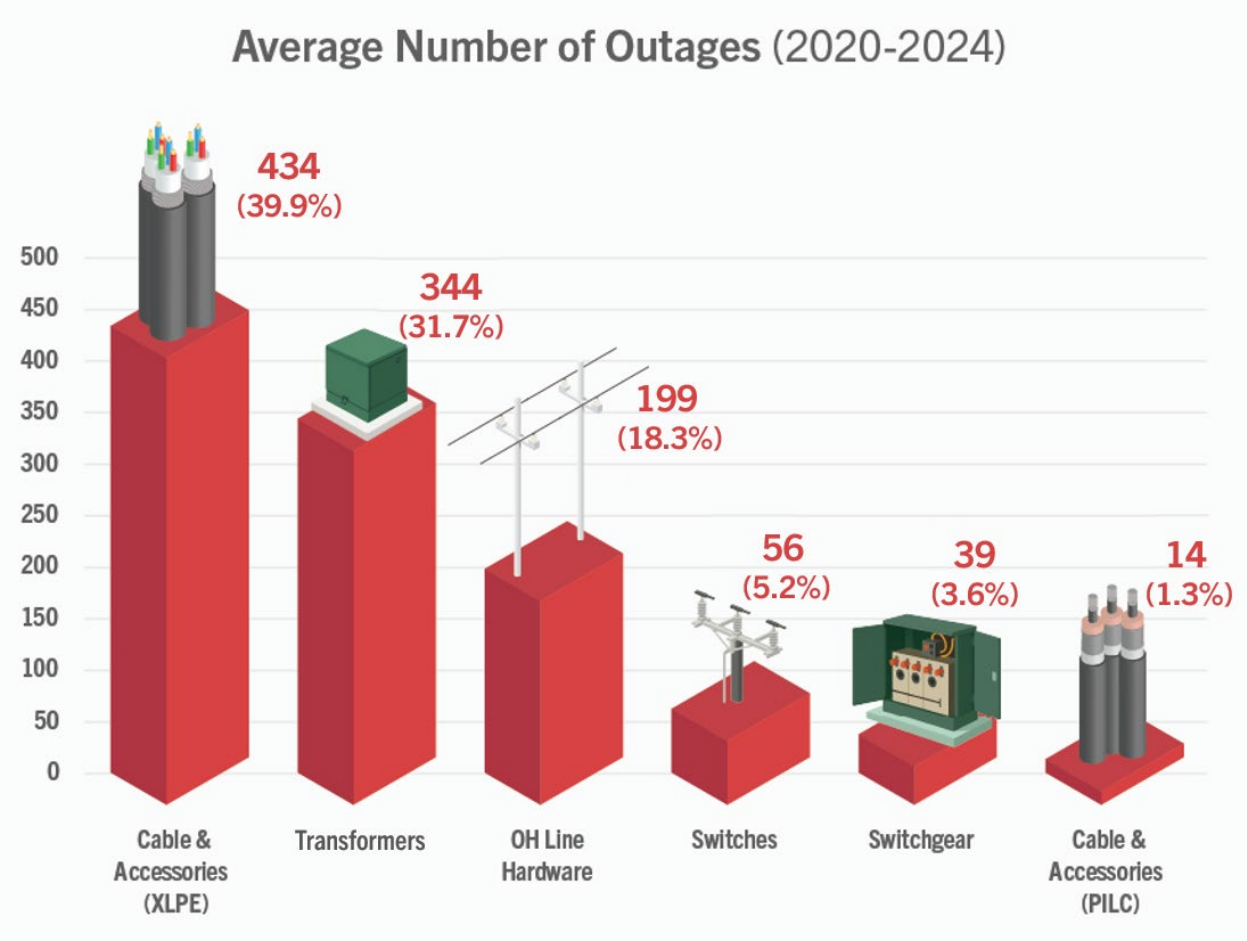


Figure B02 - 1 Outages Due to Defective Equipment, Alectra Utilities 5-Year Average (2020-2024)

Deteriorated underground cables are the largest contributor to Customer Hours of Interruption (CHI) due to Failed Equipment. Figure B02 - 2 presents the breakdown of CHI for all outages due to Failed Equipment and illustrates that underground cable and cable accessory (XLPE and PILC) failures account for 55% of all equipment-related outages. Failing switchgear account for a further 9% of all equipment-related outages.

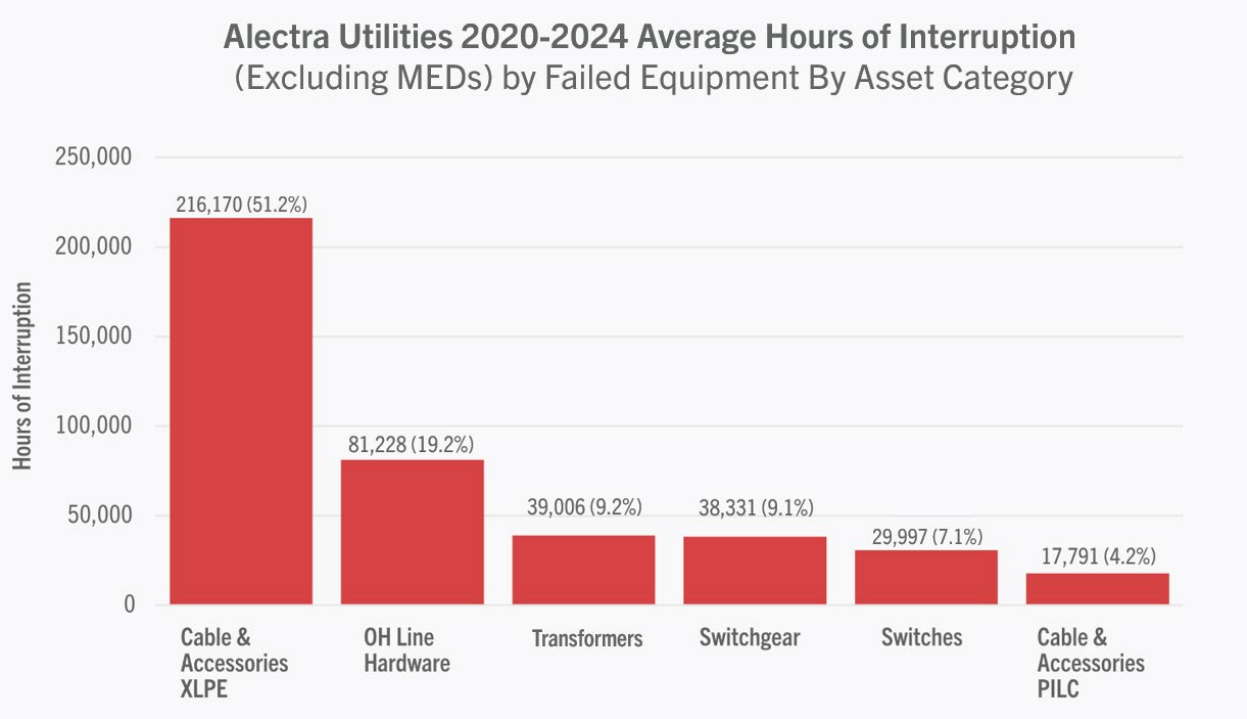


Figure B02 - 2 Customer Hours of Interruption Due to Defective Equipment, Alectra Utilities 5-Year Average (2020-2024)

The proposed Underground Asset Renewal investments will address both the Cable and Switchgear asset groups, with a focus on mitigating outages due to failing direct-buried Cross-Linked Polyethylene (XLPE) cable.[9] Cables that have been stressed by previous faults will continue to degrade at increasing rates. While prior investments in XLPE renewal have extended the lifespan of some XLPE cables and mitigated key risk areas, the amount of XLPE cables in Poor and Very Poor condition continues to increase, as shown in Figure B02 - 3. Continued investment is required to manage this growing volume of deteriorated cables. While the program also includes a modest investment to replace Paper Insulated Lead Covered (PILC) cables, Alectra Utilities anticipates that this will become an area requiring increasing investment over the medium term.

[9] The majority (97.5%) of underground conductors in Alectra Utilities' system is encased in Cross-Linked Polyethylene or Tree-resistant Cross-Linked Polyethylene (collectively, "XLPE"). Some sections of the system use older Paper Insulated Lead-Covered or "PILC" cable, in which wrapped paper is used to insulate the cable and molten lead used to cover splices in the cable.

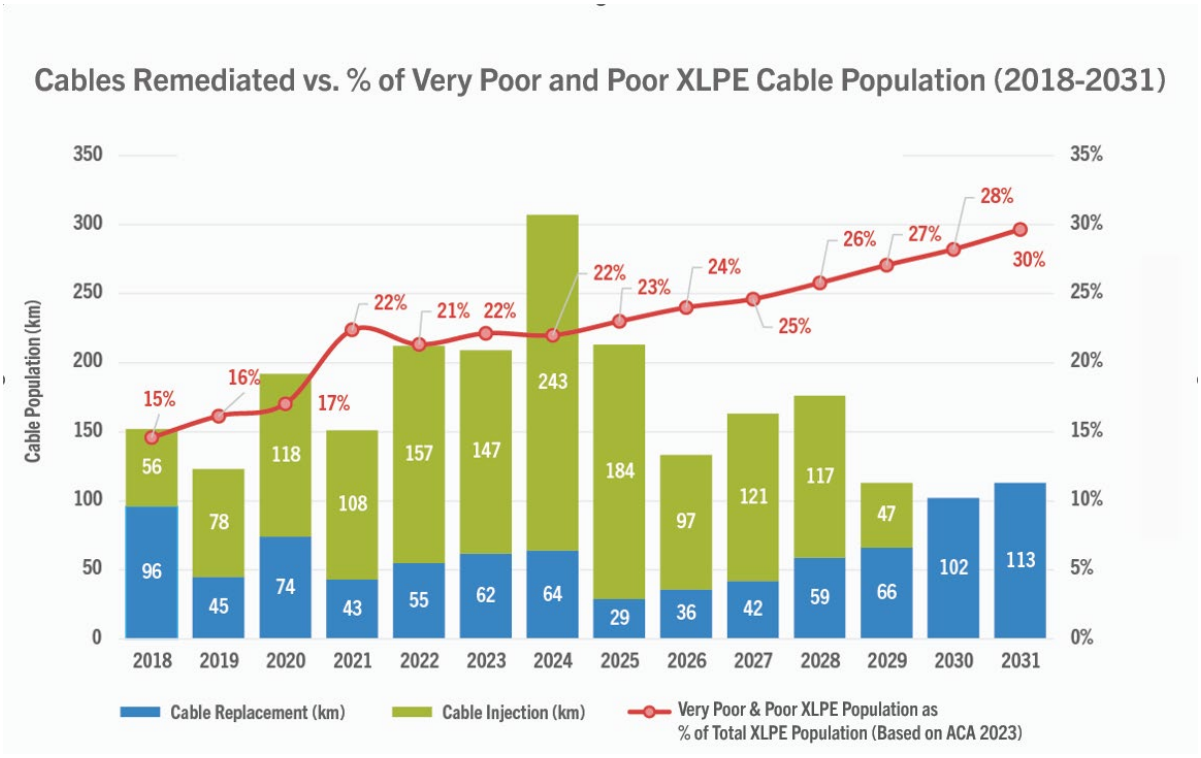


Figure B02 - 3 Cables Remediated vs. % of Very Poor and Poor XLPE Cable Population (2018 to 2031)

The proposed Underground Asset Renewal investments will address reliability, public and worker safety risks due to risk of failure of 25kV air-insulated and oil-insulated switchgear, and the renewal of civil structures (primarily chamber lid sections). There is an urgent need to address these reliability and safety issues during the 2027-2031 period.

The remainder of this evidence is organized around the four asset groups that will be addressed by the proposed investments:

- **Cables and Cable Accessories** (discussed in *Section II*)
- **Switchgear** (discussed in *Section III*)
- **Civil Structures** (discussed in *Section IV*)
- **Alectra Initiated Underground Near-Term Projects** (discussed in *Section V*)

For each asset group, Alectra Utilities describes the proposed investments, the drivers and need for the work, and an Options Analysis of any alternatives considered by the utility.

II Cable and Accessories

2.1 Investment Description

This section summarizes the proposed investments to address deteriorating cable and cable accessories in Alectra Utilities' underground system. The specific drivers, needs, and options considered to address these assets are set out in *Section 2.2, Section 2.3, and Section 2.4*, respectively.

2.1.1 XLPE Cables

Alectra Utilities' service area currently contains an extensive network of underground cables totalling approximately 23,694 linear kilometers, which are continuing to degrade. Almost all these cables are XLPE (either the first generation XLPE cable, or the subsequent tree-resistant XLPE cable).

Cable manufacturers introduced the first-generation XLPE cable into the market in the late 1960s. These cables have inherent problems due to the nature of the manufacturing processes, which led to impurities within the insulation material developing into electrical 'trees' over time. The impurities are responsible for the increase in cable failures that Alectra Utilities and the electrical utility industry has been experiencing with cables from this period.

The method of addressing XLPE cable failures is limited by the cable installation method. Decades ago, utilities were commonly in the practice of burying cables directly in the ground. Over time, the construction standard shifted to installing cables in protective conduits, but much of the system still consists of "direct-buried" cables. When cable-in-conduit fails, it can typically be entirely removed and replaced with brand-new cable with relative ease. In contrast, direct-buried cables can only be repaired by excavating the cables and splicing in a new segment of cable for replacement. This approach is fundamentally reactive and introduces further complications, since the splice installation may itself become a future failure point. Moreover, it does not solve the underlying issue, since the older, direct-buried cables remain installed and are increasingly likely to fail again.

Figure B02 - 4 illustrates several challenges with direct buried XLPE cable installations. First, the image shows XLPE cables intertwined and in very close proximity, which causes cascading failures. For situations where bundled cables are causing cascading failures, Alectra Utilities

must address this cascading failure risk by replacing direct-buried cable with cable segments in protective conduits.

Figure B02 - 4 Typical Congested Direct Buried Cable Trench (XLPE cables at the bottom)

The degradation of these assets is directly impacting customers. Examples include more frequent, longer outages in the York Hill and Hilda neighbourhood in Vaughan, Batson Drive in Aurora, and Sir John's Homestead in Mississauga. In all these examples, customers experienced increasing cable faults over a short period of from 1 to 3 months. Most recently, the Hawthorne Lane neighbourhood in Aurora provides an example of an area that escalated catastrophically. In October 2023, this area had three cable failures, which escalated into an additional four cable failures by June 2024. While that particular event affected a relatively small number of customers, those customers nonetheless experienced service reliability well below Alectra Utilities' system average. Customers served by the failed cables experienced eight outages in nine months. Four of these outages ranged from 10 to 17 hours.

Another example of repeated disruption experienced by customers due to deteriorated underground XLPE cable was along Valleywood Drive in a commercial/industrial part of Markham. This project was originally optimized for execution in 2032, landing outside the timeline of this DSP. Customers in this area experienced five cable faults from 2018 to 2023, amounting to approximately one cable failure per year. However, between July 2024 and September 2024 this

area experienced seven cable failures (approximately 2 per month). In one of the most recent failures, it left customers without power for up to 41 hours. Despite efforts to address the aging infrastructure with single cable segment replacements in earlier years, customers continued to experience service disruptions that resulted in extended restoration times and heightened concerns over the service reliability in the area. The underground XLPE cables in this area were replaced in 2024. These examples illustrate a trend that will continue in other neighbourhoods and potentially increase if the underlying deterioration of underground assets is not addressed.

During the 2027-2031 period, Alectra Utilities plans to increase its spending to rejuvenate or replace XLPE cables and related accessories. As the injection window closes, Alectra Utilities will move away from cable rejuvenation after 2029 and will then only perform cable replacements starting in 2030. As discussed in *Section 2.1.2*, there is a significant increase each year in the amount of cables ineligible for cable injection. This necessary change in approach contributes to the significant increase in investment required in 2030 and 2031. As shown in Figure B02 - 1 and Figure B02 - 2 above, these assets are the single largest equipment-related cause of outages in Alectra Utilities' distribution system. Failing direct-buried cables are causing an increasing number of outages, and when these cables fail, it can take a significant amount of time to restore service.

In addition to the significant volume of cables currently in Very Poor condition, Alectra Utilities must plan and be prepared to address the segment of the cable population that will deteriorate in the coming years. As illustrated in Figure B02 - 5, there is a direct correlation between the age and condition of an XLPE cable.[10]

[10] Health Index for cables are based cable type (including installation) and cable age. For example, Non-Tree Retardant XLPE direct buried cable has a different failure curve then Tree Retardant XLPE cable in a conduit.

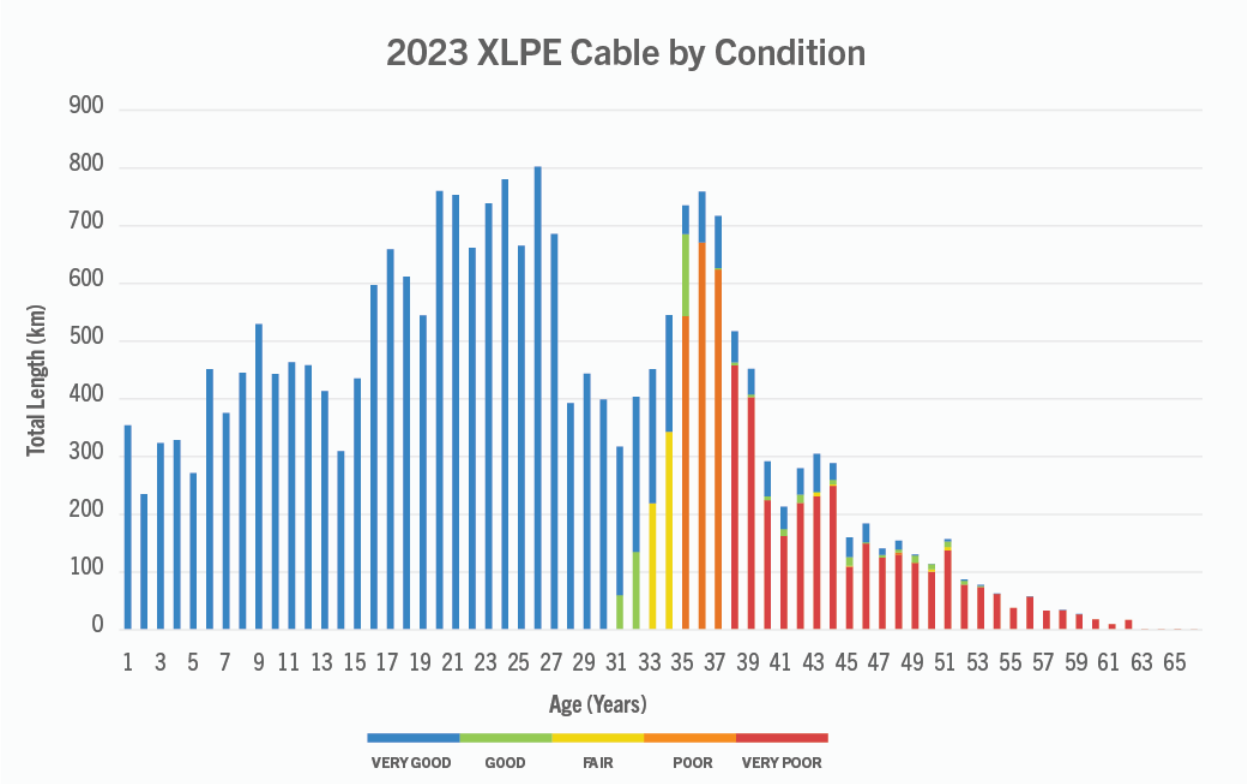


Figure B02 - 5 XLPE Cable by Condition and Age.

2.1.2 Cable Rejuvenation and Cable Replacement

Alectra Utilities plans to address deteriorating cables through a combination of two remediation strategies: cable rejuvenation and cable replacement. For each project, Alectra Utilities will use the option that delivers the best value for customers.[11]

Over the 2027 to 2029 period, Alectra Utilities will primarily focus on cable rejuvenation, injecting a significant portion of cables (at a lower cost) while replacing cables in poor reliability areas. In 2030 and 2031, the company plans to transition to a sustained pace of cable replacement. This staged approach will provide customers better reliability by extending cable life and tackling deteriorated cable assets while also balancing cost affordability.

[11] A detailed explanation of the options Alectra Utilities considered when developing these investments is set out below in section 2.4.

Option 1: Cable Rejuvenation

Cable rejuvenation is a cost-effective method that can extend the service life of XLPE cables by up to 20 years though fluid injection into the core of a direct buried cable. The fluid combines with the existing insulation, increasing the strength of the insulation, and slowing down the rate of further degradation. This approach allows cable life to be extended economically, provided that the cable is eligible to receive this treatment. A cable is only eligible for rejuvenation through injection if the cable construction allows for the liquid to be received, and if its physical condition meets the injection eligibility criteria.[12]

While a rejuvenated cable will eventually need to be replaced, in the interim, this method avoids the need to excavate and replace the entire cable, which is more costly and significantly more disruptive to customers and neighbourhoods. Cable rejuvenation is essentially a tool to extend the life of a cable nearing its end-of-life to defer its near-term renewal into the long-term, reducing the immediate capital need. Figure B02 - 6 illustrates the cable injection process.

Figure B02 - 6 Underground Cable Rehabilitation by Cable Injection in field

[12] Some condition factors include: type of cable (strand filled or solid core cable are not eligible for injection), the location of splices and proximity to each other, the number of splices within the cable segment, neutral corrosion, the location of cable (e.g. under a boulevard, under a sidewalk, under a roadway, under a driveway), and the actual field conditions (i.e. the ability to excavate and civil work cost required to replace the cable).

Alectra Utilities prioritizes rejuvenation over replacement where possible, since the cost of cable replacement is up to six times greater than the cost of injection on a per kilometer basis. However, not all cables are good candidates for rejuvenation. Alectra Utilities has carefully established condition-based criteria for selecting appropriate candidates for cable rejuvenation. This is based on over 10 years of experience with cable injection.

As the population of cables deteriorates, Alectra Utilities increasingly loses the opportunity to rejuvenate the assets. Alectra Utilities is proposing an increase in cable injection spending until 2029. Analyzing the post-injection data over the last five years, the utility has experienced a year-over-year increase in the number of cables that cannot be injected. As illustrated by Figure B02 - 7, the data consistently indicates a significant increase in the proportion of cables that are ineligible for injection. The pool of viable candidates for injection is rapidly diminishing, making it unlikely that candidates will be available by 2030.

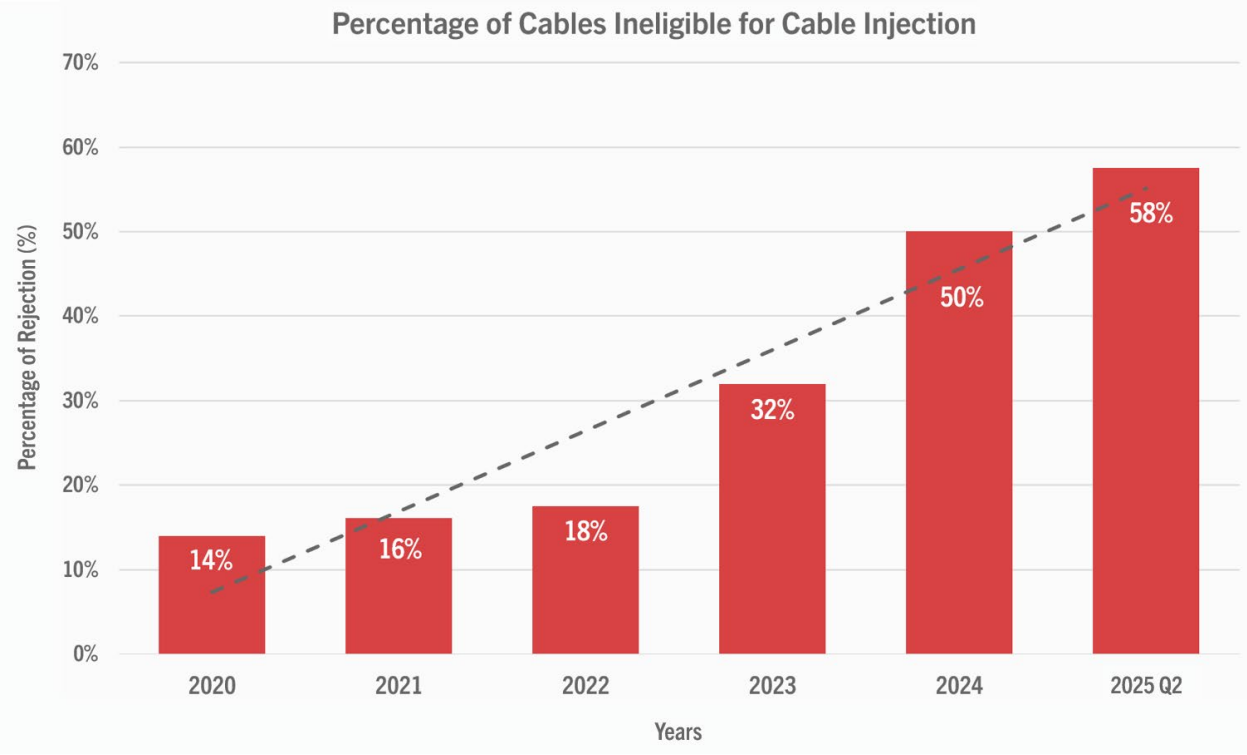


Figure B02 - 7 Underground Cable Rehabilitation by Cable Injection (2020 – 2025 Q2)

Option 2: Cable Replacement in Conduit

In areas where the only prudent choice is to replace the cable, Alectra Utilities will replace direct-buried cable, as shown in Figure B02 - 8, with the new generation of XLPE cable, which will deliver superior reliability over its lifetime relative to the older standards of cable. The cable will also be installed in conduit which is a superior method of installation for long term reliability as compared to direct-buried cable. The conduit provides protection from mechanical and corrosive damage and will make future replacement much more efficient and less costly.

Figure B02 - 8 Underground Cable Replacement

During an underground system rebuild project, Alectra Utilities reviews the layout of the distribution system to optimize the layout and routing of the cable to minimize replacement costs. During cable replacement, Alectra Utilities also reviews the associated condition of other assets including, but not limited to, switchgears and transformers. For switchgears, the decision to replace while a rebuild of the cable infrastructure is underway is based on the condition of the switchgear. For transformers, it is based on two factors: the transformer's condition, and

electrification. Like many other utilities, Alectra Utilities has adopted 100kVA as the standard single-phase pad-mount transformer size going forward[13], refer to *Chapter 5.3.3 (Section 5.3.3.2.A.1)* for details. This supports a significant level of electrification over legacy transformation standards.

Alectra Utilities will also begin to install secondary civil infrastructure along with the primary cables, within the public right-of-way (i.e. up to the customer's property line). Secondary cables and ducts are the assets that directly serve individual customers. This change responds to increasing congestion in municipal road allowances as telecommunications companies add fibre-optic facilities in the same corridors, reducing the available space for Alectra Utilities' assets and driving up future construction costs. To secure corridor capacity and avoid higher future costs to customers, Alectra Utilities will transition to this concurrent installation approach starting in 2027.

Table B02 - 2 summarizes the outcomes and benefits of the proposed cable and cable accessory investments.

Table B02 - 2 Cable and Accessories Investments Outcomes and Benefits

Outcome	Investment Benefits and Objectives
Reliability	• Replacing or rejuvenating degraded underground cables will reduce the risk of future outages to customers. • New XLPE cables are manufactured to the latest specifications and do not have the inherent historical flaws of the older generation cable.
Efficiency	• Replacing a direct-buried cable with cables in conduit creates future efficiencies. When the cable needs to be replaced, the entire cable segment from device to device can be replaced, rather than the costly process of locating the fault and excavating a pit to install a splice in the cable.

2.2 Investment Drivers

The primary driver of the proposed investments in underground cable and cable accessories is to address the significant risk of failure associated with these assets. The outcome of this driver is to reverse the growing impact on reliability caused by failing cables.

[13] The term 'Standard' is being used in the context that it is the recommended size the majority of the time, not that it is exclusively the only size available.

The drivers for this investment are further defined and summarized in Table B02 - 3.

Table B02 - 3 Cable and Accessories Investment Drivers

Investment Driver	Reasoning & Investment Benefits
Driver: Failure Risk	The primary driver for these investments is the elevated risk of failure, leading to poorer reliability for Alectra Utilities' customers. The increased risk of failure is primarily driven by the deterioration of the insulation material and associated equipment, and premature failure associated with the cable accessories. Alectra Utilities expects that the reliability of the underground distribution system will improve as a result of the planned cable and cable accessory renewal investments.
Reliability	Replacing or rejuvenating degraded underground cables will reduce the risk of future outages to customers. The replacement of XLPE direct-buried cables with new cables in conduits introduces significant reliability benefits. The new XLPE cables are manufactured to the latest specifications and do not have the inherent historical flaws of the older generation cable.

2.3 Investment Need

This section provides further details on the impact that XLPE cable and cable accessories are having on Alectra Utilities' underground distribution system, as well as the condition of the assets to be replaced. Table B02 - 4 highlights the proposed cable and cable accessories-related investment expenditures, drivers and outcomes.

Table B02 - 4 Cable and Cable Accessories Investment Expenditures, Drivers and Outcomes

	Historical Spending					Bridge		Forecast Spending				
Year	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
CAPEX ($MM)	46.9	39.0	32.9	55.0	60.6	52.1	57.2	61.6	71.8	66.4	120.8	116.9
Primary Driver	Failure Risk											
Secondary Driver	Reliability											
Outcomes	Improved Reliability and Improved Efficiency											

Material costs for cabling have impacted historical spending, as the cost of materials has outpaced inflation. Alectra Utilities has seen a cumulative three quarters increase in the average cost of cables in aggregate over the period from 2020 to 2024. Material cost changes over the historical spending period are summarized below in Table B02 - 5. These rising material costs will impact the budget related to replacing these cable assets.

Table B02 - 5 Cumulative Annual % Increases in Cable Material Costs from 2020 Baseline

Year	2021	2022	2023	2024
Percent Increase	16.7%	47.6%	37.4%	77.9%

2.3.1 Increasing Deteriorated XLPE Cable Population

Despite increasing investment in remediating cables, the population of deteriorating cable assets continues to grow. Figure B02 - 9, Figure B02 - 10 and Figure B02 - 11 pictorially compare the HI results geographically in Central South (Mississauga), East (Markham), and East (Vaughan) operating areas, respectively.

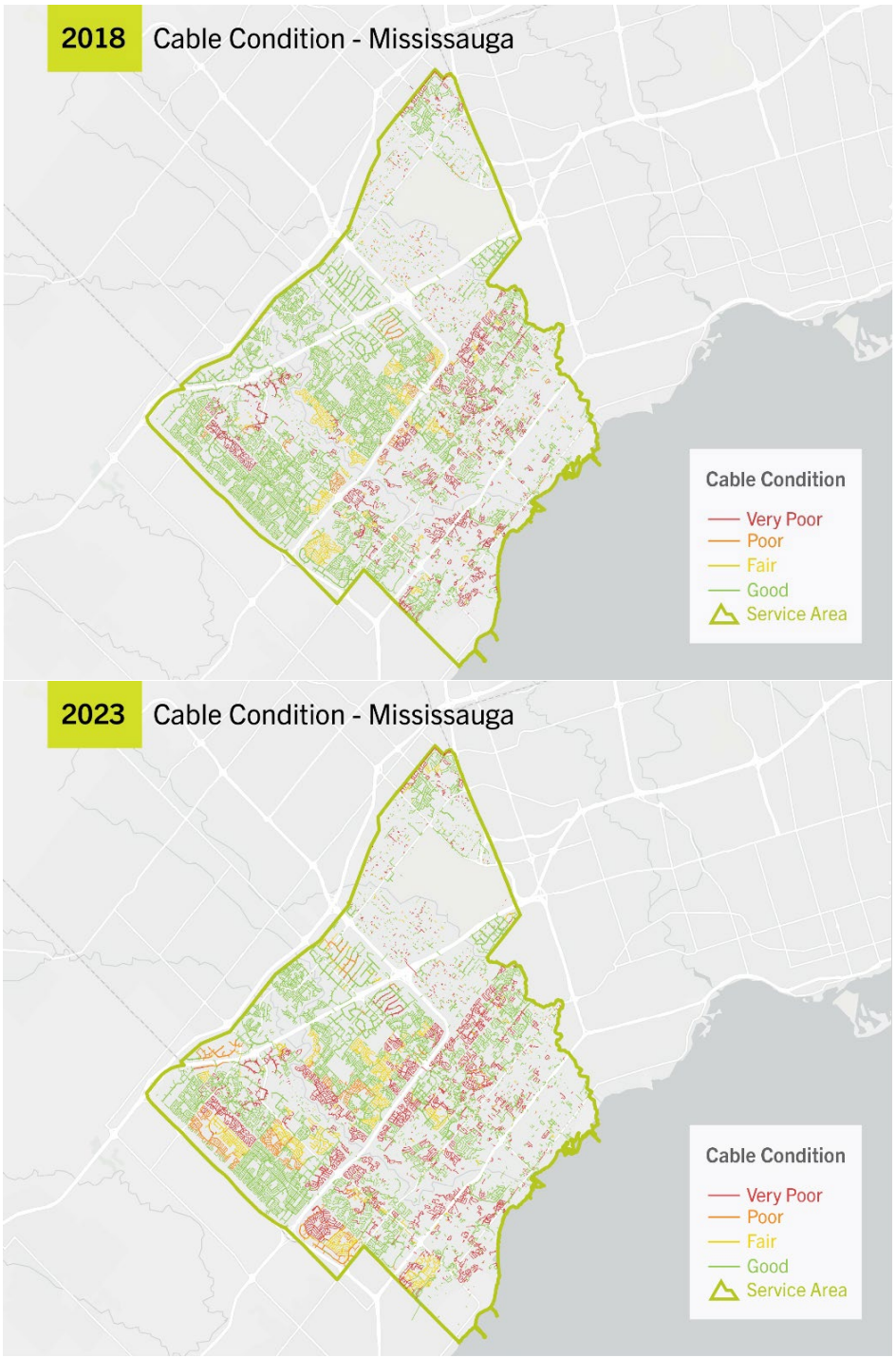
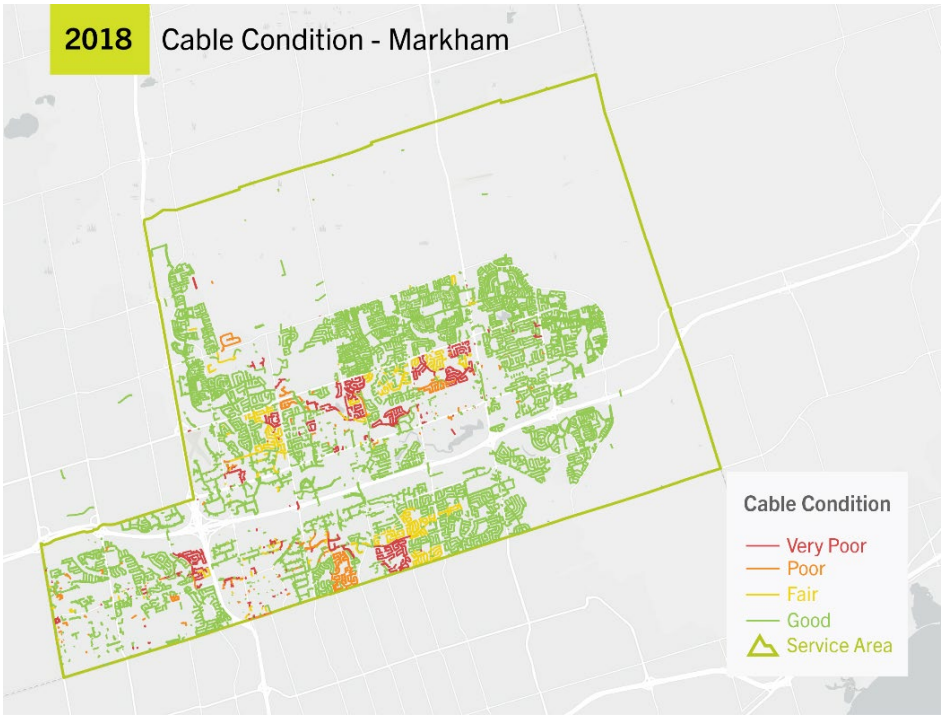


Figure B02 - 9 Mississauga – XLPE Cable Health Index Comparison (2018 vs. 2023)



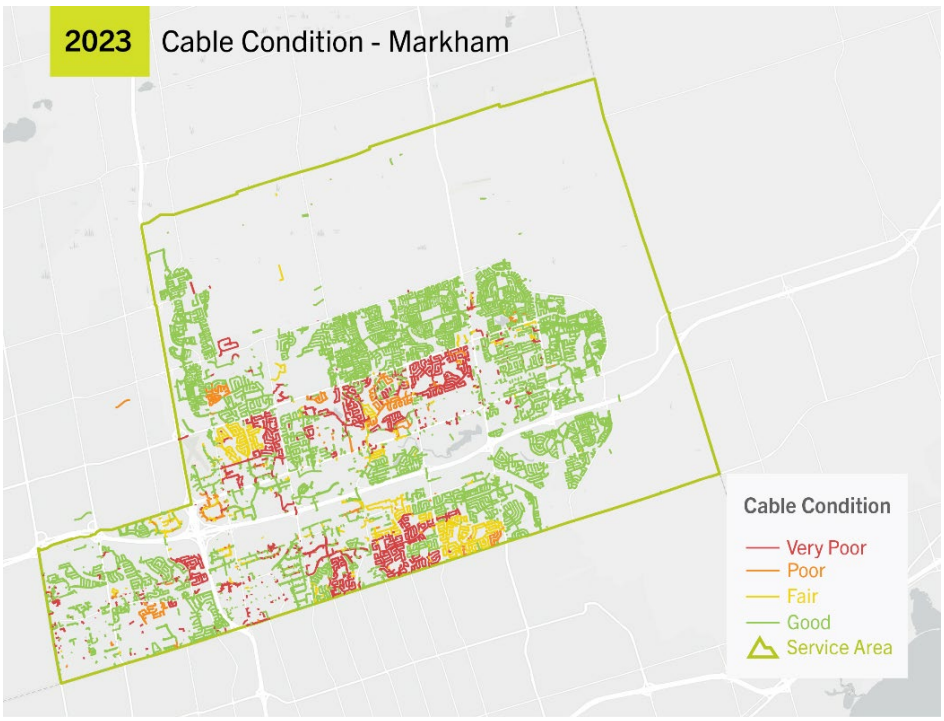
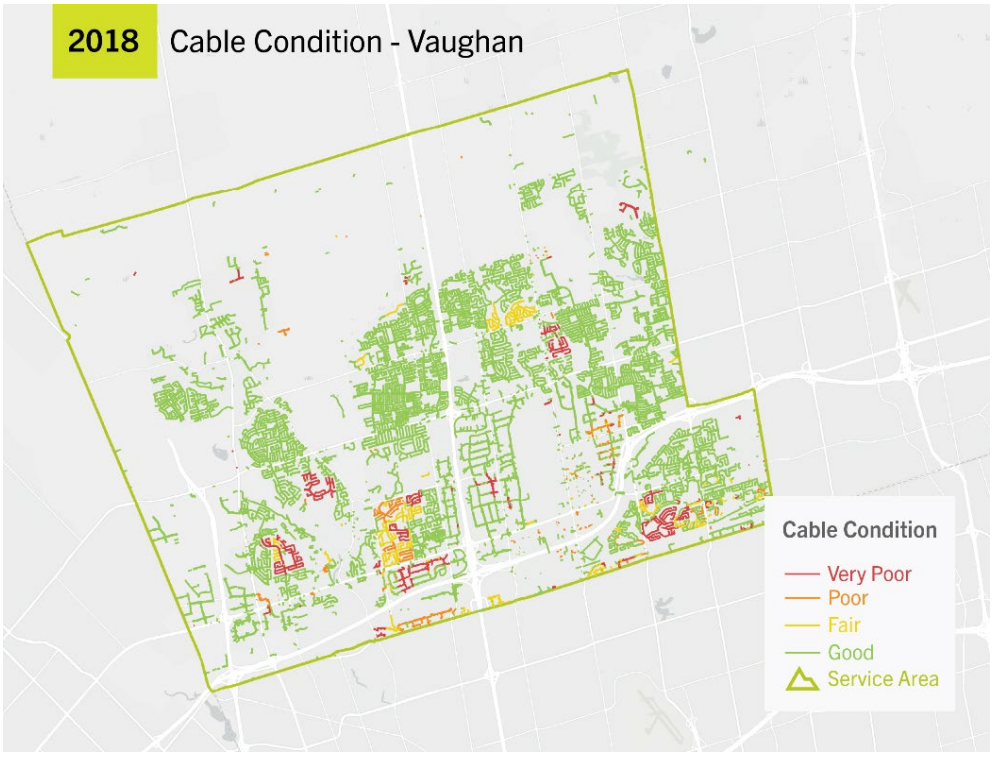


Figure B02 - 10 Markham – XLPE Cable Health Index Comparison (2018 vs. 2023)



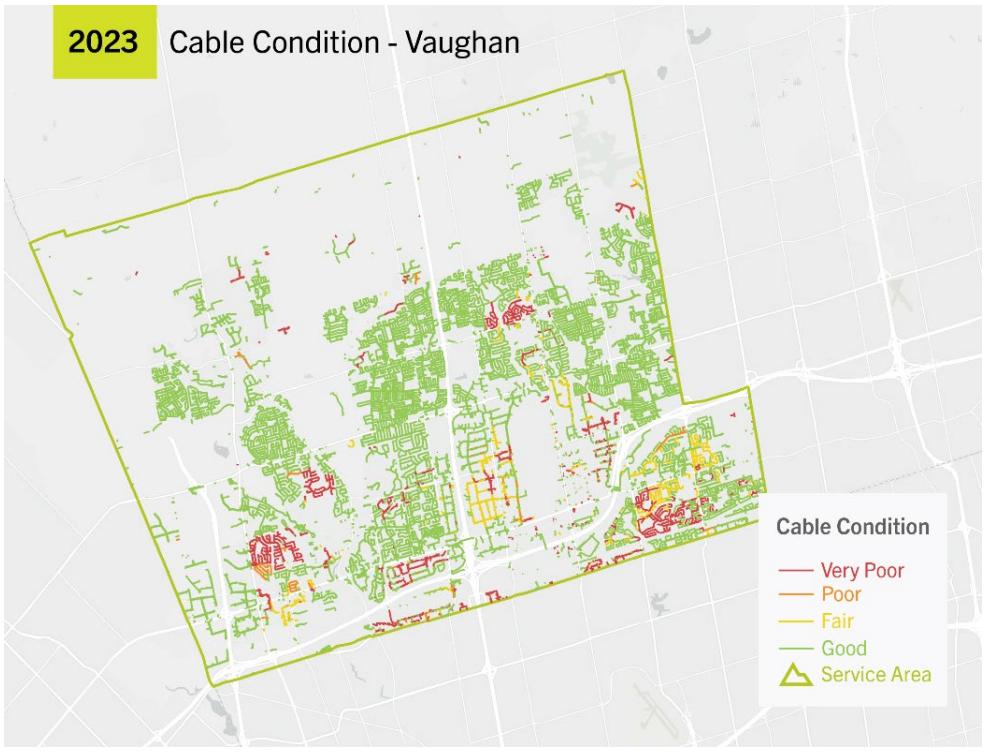


Figure B02 - 11 Vaughan – XLPE Cable Health Index Comparison (2018 vs. 2023)

The above maps comparing 2018 and 2023 highlight the growing risk of failures in aging underground XLPE cables. Cable faults are also increasing in complexity, with faults occurring in areas that are difficult for crews to expedite repairs. For example, cable faults in middle of driveway which requires additional co-ordination and restoration of the driveway once the cable is repaired.

Since 2018, the proportion of Poor and Very Poor cables is exceeding the pace at which targeted investments have been able to address cable failures. A comparison of 2018 vs 2023 deteriorated XLPE cable populations is shown in Figure B02 - 12.

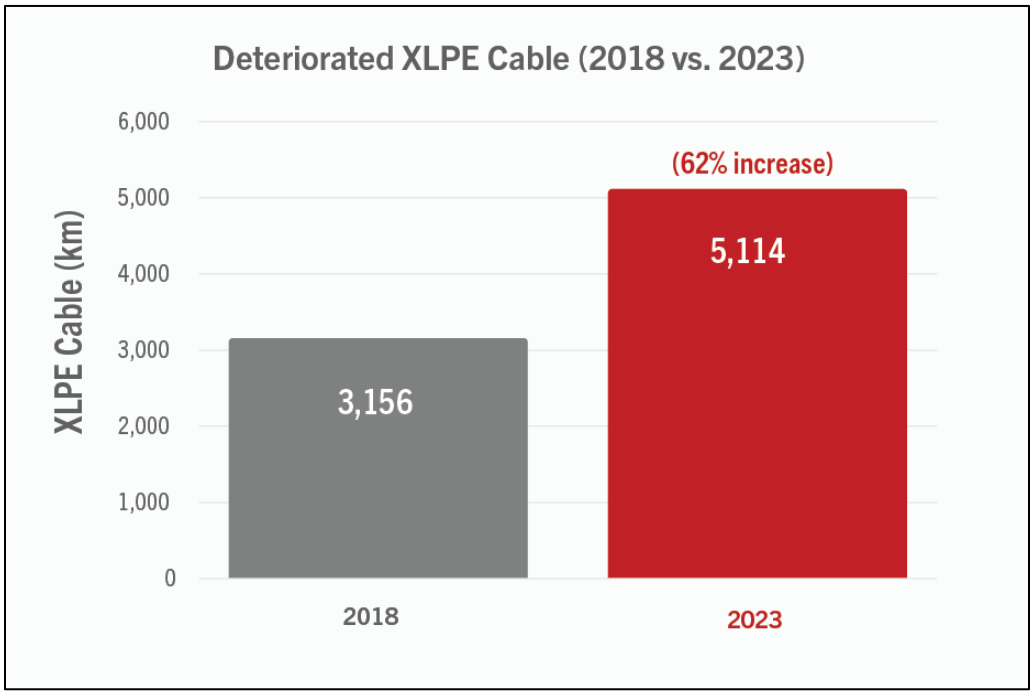


Figure B02 - 12 XLPE Cable Health Index Comparison (2018 vs. 2023)

Alectra Utilities has identified that a sustained and increasing investment is required to prevent this population of deteriorated cables from becoming too large as to hit a tipping point where reactive spending outpaces renewal spending. Should this occur, Alectra Utilities would be spending more in reactive costs and getting less cable replaced than with proactive spending. Additionally, rather than preventing customers from experiencing outages through proactive renewal investments, reactive spending implies that customers would have already experienced reliability impacts before the investments are made. Lastly, as failures occur, the cable is stressed

leading to additional failures if the cables or accessories are left in service, resulting in an increase in reactive costs to repair deteriorated segments of cable.

Figure B02 - 13 below highlights the fact that, with the OEB's approval through two ICM applications, in conjunction with targeted investments, Alectra Utilities was able to reduce the number of cable outages from 2018 levels despite the increased deterioration. This demonstrates that cable remediation projects have had a net positive impact. Alectra Utilities needs to continue to invest in cables to mitigate significant reliability risks to customers.

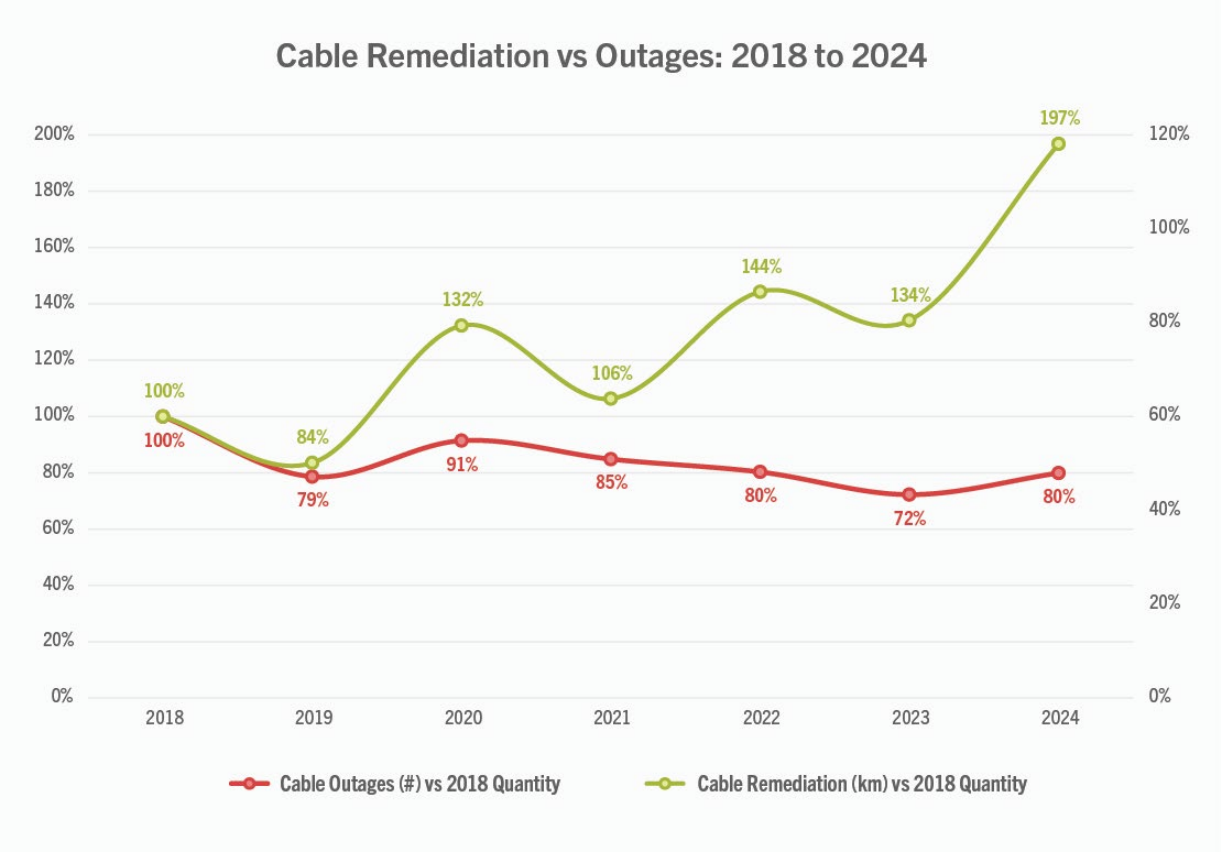


Figure B02 - 13 Cable Remediation Quantity vs. Outages, in Percentage (2018 to 2024)

2.3.2 Asset Description by Area

This section describes the assets in each area shown in Figure B02 - 14 including the strategies that Alectra Utilities utilizes to address failing and deteriorating cable in each area.

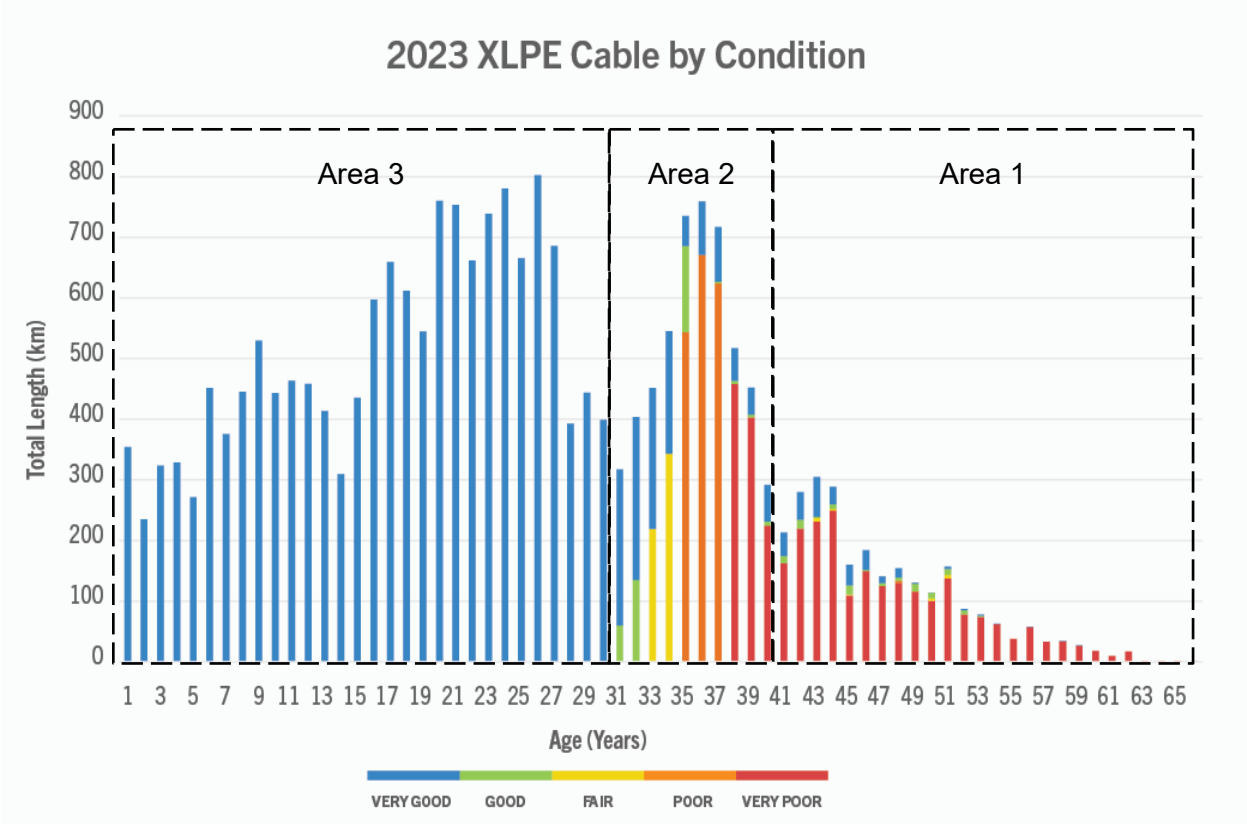


Figure B02 - 14 XLPE Cable by Condition and Age

Area 1 – First Generation XLPE Cables

Area 1 consists of first generation XLPE cables and totals approximately 2,423KM of cable. Due to the technology and capability of the manufacturing processes available at the time, impurities were able to enter the insulating medium. As such, these cables possess a far greater susceptibility to water and electrical "treeing," which will ultimately result in partial discharge and eventual failure of the cable. The majority of these cables are also direct-buried (i.e. not installed in conduits), which is an aggravating condition to the rate of degradation of the cables. Unlike failed cables-in-conduit, which can typically be removed and replaced with new cable segments, failed direct-buried cables can only be excavated and repaired via cable splicing in a reactive situation. As noted above, the installed splice may also introduce a future failure point.

These cables have also been in-service longest and have therefore seen more faults, had more failures, and consequently, more repairs than younger cable. These cables do not

tend to be materially improved by the rejuvenation process. In addition, the cost of rejuvenation (injection) increases based on the number of splices that need to be replaced. This limits the cost effectiveness of injection to the point where the better value is to replace the cable. Cable accessories in this area are also of first-generation construction and would be replaced along with the cable.[14]

Area 2 – Injection Candidates

The cables in Area 2 are predominantly first generation XLPE, the majority of which are direct buried, totaling approximately 5,159KM of cable. Based on their younger age and fewer lifetime repairs (splices), some of these cables are candidates for rejuvenation.

Not all of the cables in Area 2 can be rejuvenated, either due to the conductor used in the cables or the number of repairs that a specific cable has incurred over its lifetime.[15] There have been cases where cables identified under Area 2 that were planned for cable injection were discovered to be of the strand-filled XLPE cable type, thereby precluding them from being candidates for rejuvenation. This further reduces the expected population of injectable candidates once pre-design inspections have been conducted.

Alectra Utilities will endeavour to maximize the quantity of injectable cables in this segment to reduce the magnitude of cable replacement. By deferring replacement costs for cables in Area 2 to later years, it allows Alectra Utilities to focus its cable replacement investments on older segments in Area 1, rather than dealing with cable replacements in both Area 1 and Area 2 concurrently. Cable accessories in Area 2 are mixed. Some accessories are similar to Area 1, while others are of newer design, which have eliminated the deficiencies of the earlier versions.[16]

[14] For example, elbows on the 27.6kV system are “non-vented,” which have led to a partial vacuum flashover when operated. Splices are heat shrink or first-generation cold shrink. Terminations may be hand taped (not manufactured) which degrade faster than a cold shrink body.
[15] Solid conductor style cables cannot be injected. Similarly cables that are strand filled cannot be injected. These were used by Alectra Utilities legacy utilities however, the data currently available makes it extremely difficult to determine to what extent this reduces the amount of injectable candidates.
[16] Splices, elbows, and in some cases, terminations would have to be replaced during the injection process as the fluid cannot flow through the legacy devices.

Area 3 – Cables Not in Consideration for Investment

Cables in Area 3 are in Very Good condition and are not being considered for investment in this DSP. This area accounts for the remaining approximately 15,524KM of XLPE cable. However, Alectra Utilities notes that many of the cables in this area are "strand-filled" and therefore not eligible for rejuvenation. When these cables begin to deteriorate, Alectra Utilities will have no option but to replace them. However, since most of these cables are in conduit, the replacement will be less expensive than for older cables. A secondary benefit includes the installation of newer generation strand filled cable which is expected to have a longer operating life than earlier generation cable.

2.4 Options Analysis

Alectra Utilities creates discrete projects for dealing with cable remediation projects. Candidate neighbourhoods are identified based on the Asset Analytics Platform, combining condition data and failure history to make a business case in Copperleaf C55. C55 then optimizes considering all constraints to select the mix of projects that will provide the most value. As part of its Customer Engagement, Alectra Utilities set constraints on the portfolio of candidate projects to provide a lower bound and upper bound that the utility believes are feasible and achievable. Within these bounds, a moderate pace was derived based on optimization from Copperleaf C55 (refer to *Chapter 5.3.1 Asset Management Process Overview* for further detail on project optimization).

The upper bound, draft plan and lower bound form the basis for the three pacing strategies communicated to customers as part of Customer Engagement:

- Option 1: Accelerated pace (Remediate 807.1KM of cable)
- Option 2: Moderate pace (Remediate 665.7KM of cable) (Selected Option)
- Option 3: Reduced pace (Remediate 495.9KM of cable)

The expenditures proposed in the DSP reflect Option 2: Investing at the Moderate pace.

Alectra Utilities must address the cables in Area 1 and Area 2 now to be prepared for the wave of cables in Area 3 shown in Figure B02 - 14. If Alectra Utilities does not address Areas 1 and 2 now, then it will be challenging to manage the larger volume of assets in Area 3.

Table B02 - 6 Pacing Options For XLPE Cable Remediation

Option	XLPE Cable Remediated Over DSP 2027-2031 (KM)	Cable Renewal Plan Cost of DSP 2027-2031 ($MM)
Option 1: Accelerated pace	807.1	526.5
Option 2: Moderate pace	665.7	437.5
Option 3: Reduced pace	495.9	319.4

Option 1: Accelerated Pace (Remediate 807.1KM)

Option 1 would address 807.1KM of cables in Areas 1 and 2 from Figure B02 - 14 by 2031, with 41.5% of the cables being remediated with cable rejuvenation and 58.5% of cables being replaced. Table B02 - 6 illustrates that total spending that is associated with Option 1 over the DSP period would amount to $526.5MM. Long term sustainment based on asset condition assessment suggests that moving forward with the accelerated pacing of underground renewal would provide the highest value to customers over the next 20 years in terms of avoided outages. However, Alectra Utilities considered customers priorities to maintain rates when considering these investments and therefore recommended the Moderate pacing plan.

Option 2: Moderate Pace (Remediate 665.7KM) (Selected Option)

Option 2 addresses 665.7KM of cables in Areas 1 & 2 from Figure B02 - 14 by 2031, with 42.7% of the cables being remediated with cable rejuvenation and 57.3% of cables being replaced. Table B02-6 illustrates that total spending associated with Option 2 over the DSP period would amount to $437.5MM. The long-term impact of proceeding with this plan, relative to Option 1, is that the reduced investment exposes customers to an increased risk of outages. The selected pacing attempts to balance the need for investment in cable remediation, while respecting customer preferences regarding cost.

Option 3: Reduced pace (Remediate 495.9KM)

Option 3 addresses 495.9KM of cables in Areas 1 & 2 from Figure B02 - 14 by 2031, with 36.6% of the cables being remediated with cable rejuvenation and 63.4% of cables being replaced. Table B02 - 6 illustrates that total spending that is associated with Option 3 over the DSP period would amount to $319.4MM. The pacing of this option, relative to Options 1 and 2, further

exposes customers to worsening cable related outages. While customers did voice their preference for keeping rates lower, there were also clear indications that reliability is important, particularly to commercial and large use customers. This pace provides the least rate impact but was ultimately rejected by Alectra Utilities due to the long-term cost/benefit of addressing cable replacements with a measured pace.

2.5 Summary of Cable and Cable Accessory Investment

Alectra Utilities has determined it will pace expenditures for cable and cable accessories at the moderate pacing level shown in Option 2. This aligns generally with the results from Customer Engagement. At this rate, the majority of the investment in Underground Asset Renewal will be direct investment in cables residing in Area 1 and 2, accounting for 77.2% of the forecasted spend from 2027-2031 for all Underground Renewal.

The proposed investments do not address other categories of cables that are negatively affecting customer reliability, but to a lesser extent. Alectra Utilities' lower-voltage secondary distribution and service cables are another source of some reliability issues. The investments included as part of the cable replacement projects account for providing some secondary conduit in road allowance, but do not include full secondary replacements.

Similarly, a portion of Alectra Utilities' feeders use PILC cables that, while generally in good condition, are not immune to failure. While work must be done to address these assets, typically on a reactive basis, Alectra Utilities believes proactive replacement can only be deferred for so long to allow for focus on the more pressing issues associated with the XLPE cables and cable accessories proposed by the Underground Asset Renewal investments.

III Switchgear

3.1 Investment Description

This section summarizes the proposed investments to address deteriorating switchgear in Alectra Utilities' underground system. The specific drivers, need, and options considered to address these assets are set out in *Section 3.2*, *Section 3.3*, and *Section 3.4*, respectively.

3.1.1 Underground Switchgear in Alectra Utilities' Distribution System

Pad-mounted switchgear are a critical component of the underground distribution system. Underground distribution systems are based on large "trunk" feeder cables that are connected to smaller distribution cables that directly serve customers and neighbourhoods. The system relies on pad-mounted switchgear to connect local distribution circuits to the main feeder cable systems, and to interconnect multiple trunk feeder circuits. A single switchgear can impact as many as 5,000 customers.[17]

Alectra Utilities continues to identify a significant need for investment in replacement of pad-mounted switchgear. Over the last number of years, it has become evident that among the various types of pad-mounted switchgear, the largest contributor to reliability and safety risk to Alectra Utilities customers can be prioritized as provided in Figure B02 - 15.

[17] Switchgear serves several other important functions in the underground distribution system. They are used to isolate sections of the system for maintenance, safety and other reasons. They allow Alectra Utilities to "sectionalize" the system, provide fusing for lateral connections, and to reconfigure cable loops for maintenance, restoration and other operating requirements.

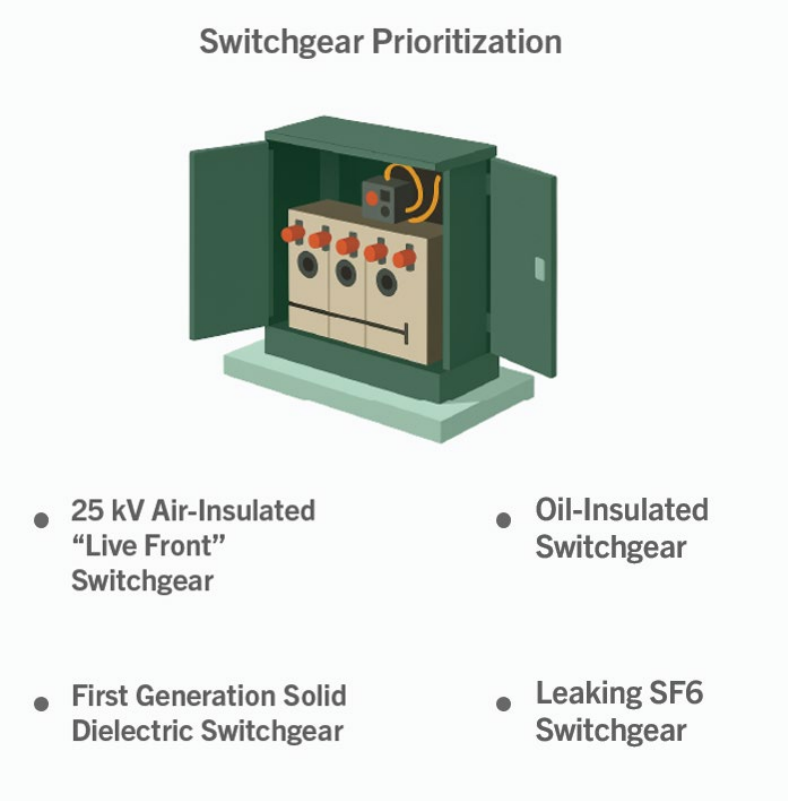


Figure B02 - 15 Alectra Utilities Switchgear Prioritization

In the sections below, Alectra Utilities provides more details on each of the switchgear categories listed above, and why they contribute to decreasing reliability of service for customers.

3.1.1.1 Air-Insulated "Live-Front" Switchgear

Air-insulated switchgears utilize insulators and air as the means to insulate live components from ground. These units have been failing earlier than expected, due to a combination of usage and environmental factors.

The reported useful life of a pad-mounted switchgear is 20-45 years with a typical useful life of 30 years when operating within a normal continuous rated operating voltage of 25kV.[18] Air-insulated switchgears use porcelain insulators and air to insulate live components from ground. These air-insulated switchgears have been failing prematurely due to the operating requirements of Alectra Utilities' underground distribution system. The air insulated switchgear units were manufactured

[18] Kinectrics Inc., "Asset Depreciation Study for Use by Electricity Distributors" (EB-2010-0178), July 8, 2010.

to specification for normal continuous rated operating voltage of 25kV and tested to operate as high as 28kV to ensure operation at 27.6kV distribution voltage. These tests consider an operational voltage of 28kV, but they do not consider the long-term lifecycle impacts of operating the asset at higher voltages in external environments with the presence of moisture and contamination. However, as noted above, where these units have been installed on Alectra Utilities' 27.6kV underground distribution system (which has a maximum range of 29.3kV), they have experienced failures at service ages as low as 11 years.[19]

Environmental factors in southern Ontario have also led to earlier failure of these switchgears. While these units function relatively well when their environment remains dry, the southern Ontario environment presents many challenges that cause units to fail. High humidity, condensation from changing temperatures and water in the below grade foundations when mixed with dirt and road dust contribute to the formation of conductive paths on the insulating components. Over time this ultimately reduces the insulating properties and leads to flashover and failure of the switchgear.

These switchgears use a "live front" design, in which energized components are exposed and accessible when the access doors are opened for inspection, maintenance or operation. This design means that crews must take additional safety precautions when working with this equipment. In addition, the increasing failure rate of these switchgear means that workers may be at higher risk of being exposed to an arc flash. The planned replacement units would remove this risk. Figure B02 - 16 below displays an air-insulated gear which was found smoking and failed.

[19] The units were purchased at 25 kV as this was a standard American voltage and was all that the manufacturer offered. The maximum rating of 28 kV was above the 27.6 kV operational rating.

Figure B02 - 16 Failing Air Insulated Switchgear, Mississauga

Figure B02 - 17 and Figure B02 - 18 provide images of common component failures on air switchgear. These units experienced a manufacturer defect with the stored energy spring mechanism used to operate the load breaking switch positions. While replacement parts are provided from the manufacturer, this added nuisance poses an incremental risk and can nonetheless affect the safe operation of the units. Some of the in-service units have been retrofitted with new spring units, however, these springs continue to fail and need replacement.

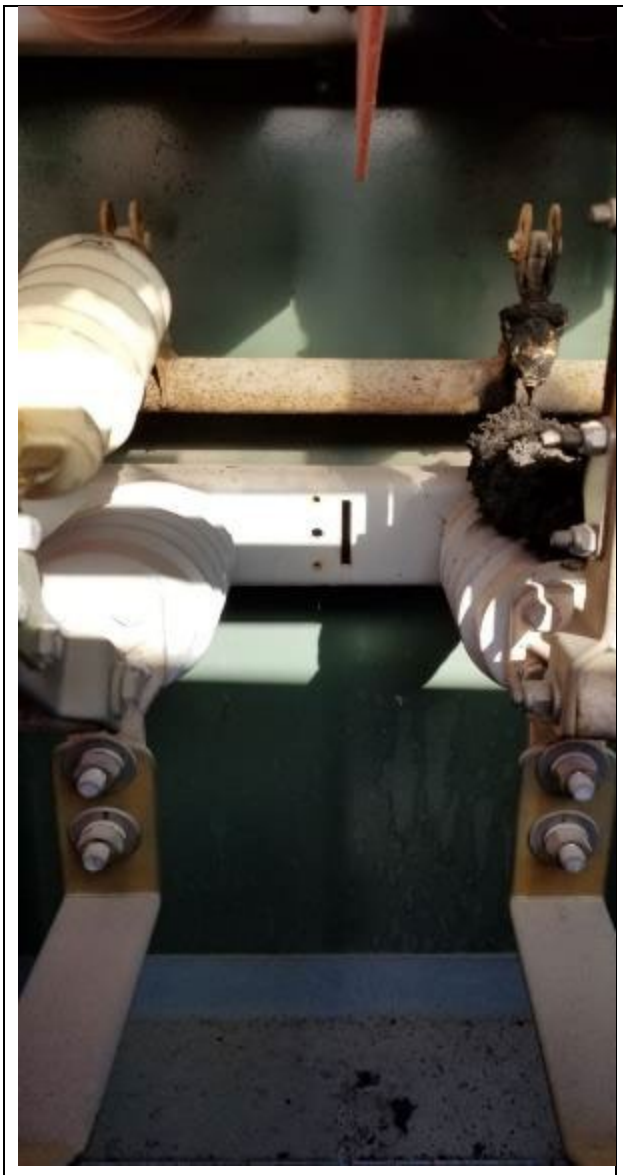


Figure B02 - 17 Failed Insulator on Air Switchgear

Figure B02 - 18 Failed Switch Mechanism

Alectra Utilities and its predecessor utilities have previously attempted to mitigate air-insulated switchgear failures through regular inspection and dry ice cleaning of insulating components. While dry ice cleaning is effective over the short term, the problem remains persistent and the cost to perform dry ice cleaning is significant when considered over time.

There are currently 1,419 air gears in service throughout Alectra Utilities. Out of this population, 451 units are operating on 27.6kV, above their nameplate voltage. The majority of failed switchgear are from these deteriorated units. It is necessary to replace these units in Very Poor and Poor condition throughout the 27.6kV underground distribution system. Alectra Utilities expects that this investment will reduce the number and duration of outages and eventually allow for a reduction in O&M costs due to a lower amount of dry ice cleaning.

Alectra Utilities plans to replace its 25kV air-insulated switchgear with solid dielectric or SF6 switchgear rated for the correct operating voltage. This approach will achieve several benefits, including:

- Reducing incidences of failures due to flashover
- Improved reliability
- Better long-term value, as the replacement units have an expected useful life of 50 years
- Reduced maintenance and spare inventory costs

3.1.1.2 Oil-Insulated Switchgear

Alectra Utilities also has a significant population of oil-insulated switchgear in its underground distribution system. As the name suggests, these units are filled with mineral oil, which operates as the switchgear's insulating medium – a typical oil-filled switchgear unit contains over 1,500 litres of oil.

When these units fail, the oil within them can ignite and cause a fire, creating a public and worker safety risk. Figure B02 - 19 shows the result of a typical failure of an oil-filled switchgear. As shown, many of these units are installed in public places and adjacent to customers' homes. Although the switchgears' oil tanks are sealed, any contamination of the oil (which occurs over time) will lead to failure.

In addition to the public and worker safety risks posed by potential oil ignition and fire, oil leaks and environmental cleanup may be required (as was the case in the incident shown in Figure B02 - 19). Further to the importance of mitigating environmental risks, oil leaks add to the cost of replacement and increase the time to restore power as the site needs to be remediated first.

Figure B02 - 19 Failed Oil-Filled Switchgear

The regulations under the Ontario *Environmental Protection Act*, require Alectra Utilities to report spills of oil into the environment. In those instances, Alectra Utilities is required to make immediate arrangements for remediation of the site where the oil leak occurred. The regulations under the *Canadian Environmental Protection Act* require Alectra Utilities to report any spills involving more than one gram of PCB contaminating the environment. Under this scenario, Alectra Utilities is required to carry out full environmental remediation of the site where the oil leak occurred. Alectra Utilities also verifies whether any of these units may contain polychlorinated biphenyls (PCBs) when returned to stores from the field.

To maintain a high level of environmental stewardship and ensure compliance with regulatory and environmental regulations, Alectra Utilities is required to urgently address situations where oil filled switchgear have been found to be leaking or containing PCB oil. To avoid expensive and hazardous environmental contamination and the need for subsequent remediation, Alectra Utilities has implemented a coordinated, paced and predictive replacement of known oil-filled

switchgear. Leaking units with PCB concentrations above 2 ppm will be prioritized over units that are leaking but have PCB concentrations of less than 2 ppm.

3.1.1.3 First Generation Solid Dielectric Switchgear

While solid dielectric switchgear are relatively new, Alectra Utilities has identified issues with several manufacturers' first-generation versions of these switchgear. While now corrected, Alectra Utilities has seen premature failures from several manufacturers, and this is expected to continue, since the defect impacts the long-term life expectancy of the units. Figure B02 - 20 (showing the bus location) and Figure B02 - 21 (showing the damaged bus) display one of the issues Alectra Utilities faces, where the cable bus used within the switchgear prematurely fails. Over the DSP period, Alectra Utilities will replace some of these units.

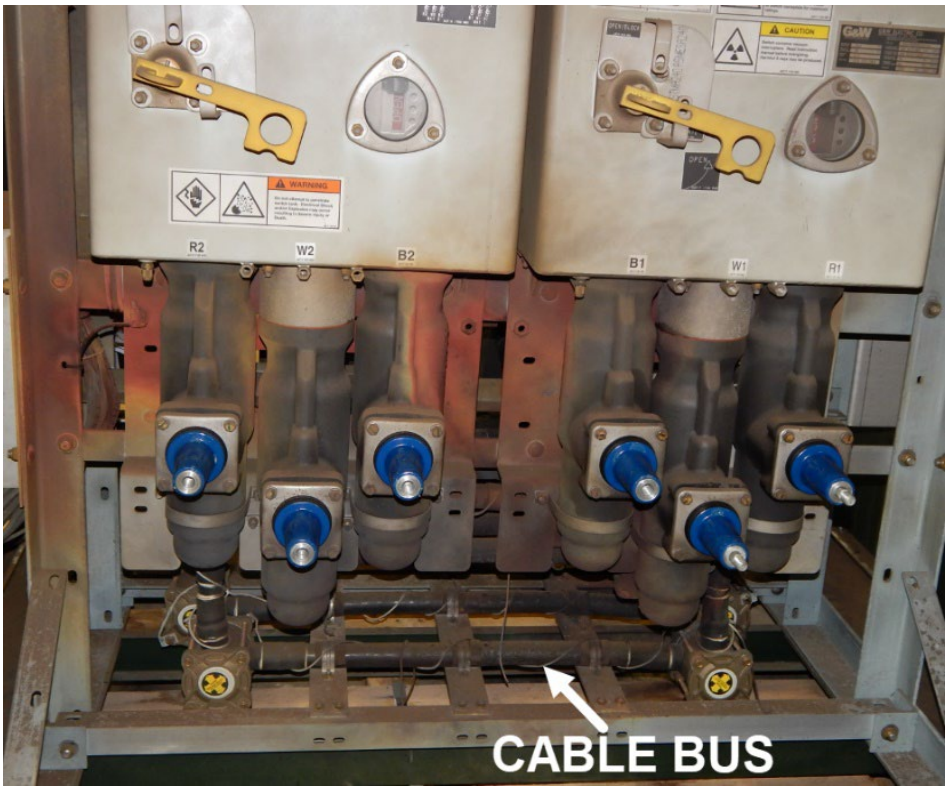


Figure B02 - 20 Failed Solid Dielectric Switchgear, Mississauga

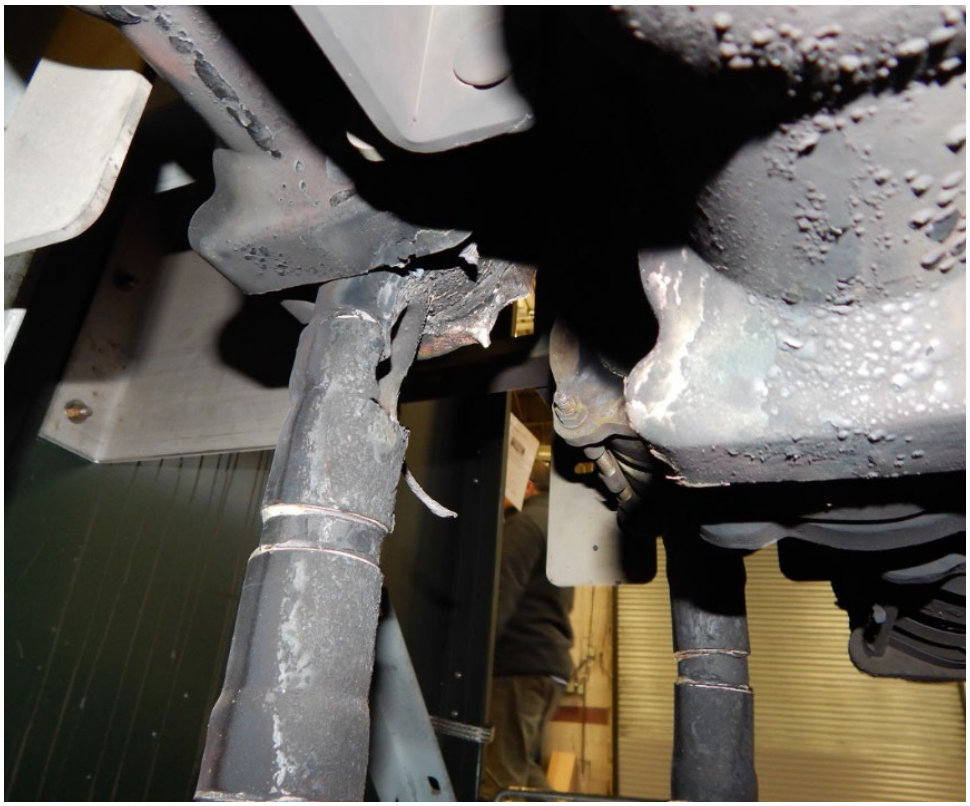


Figure B02 - 21 Failed Solid Dielectric Switchgear, Mississauga

3.1.1.4 Leaking SF6 Switchgear

Alectra Utilities has noticed that since 2023 there has been an increase in units discovered to be leaking SF6 gas. In many cases, repairing the leak involves the unit needing to be replaced, triggering a capital expense. Additionally, when units leak SF6 gas and the level drops below a certain threshold, the unit will no longer be operable, impacting system operation. An issue of increasing concern is that there is no ability to confirm operability until staff arrive onsite. Alectra Utilities has encountered situations where outage time was increased because staff arrived and could not safely operate a switch, as the SF6 gas was too low. In addition, Alectra Utilities is mandated to report SF6 leaks to the Ministry of Environment, if over the thresholds for total CO2 equivalent emissions.

3.1.2 Planned Investments

The switchgear units described above are a significant issue for Alectra Utilities and must be replaced proactively during the term of the DSP. The planned investments will replace 56 units

per year to 2029, then ramp up in 2030 and 2031 to 88 units per year, for a total of 344 switchgear replacement over 5 years, with a total cost of $57.1MM during the DSP period. For 2030 and 2031 the pace of switchgear renewal is planned to increase to add further automation to switchgear within the system to mitigate cable outage duration.

Table B02 - 7 summarizes the outcomes and benefits of the Switchgear Investments.

Table B02 - 7 Switchgear Investments Outcomes and Benefits

Outcome	Investment Benefits and Objectives
Reliability	• The increased level of switchgear replacement will address customer outage levels associated with switchgear failures. • Certain replacement switchgear will be SCADA-enabled and/or fully automated, which allows for isolation, sectionalizing and restoration activities to take place in a substantially expedited manner.
Efficiency	• The new dielectric or SF6 pad-mounted switchgear that will be installed as part of this investment do not require CO_2-cleaning maintenance practices.
Safety	• Replacement of legacy air-insulated pad-mounted switchgear with new dielectric switchgears introduce several safety benefits for field crews, as these new switchgears are self-contained and have minimal maintenance costs. • If the new switchgears are SCADA-enabled, they can be controlled directly from the control room and remove direct personnel operating the devices.
Environment	• In the case of oil-filled pad mounted and vault-mounted switchgear, catastrophic failure of these assets can result in a rupture, creating environmental impacts from leaking oil.

3.2 Investment Drivers

The primary driver of the proposed investments in switchgear is to address the significant risk of failure associated with these assets. Secondary (but no less important) drivers are addressing the reliability impact these assets are having on customers, the functional obsolescence of legacy switchgear, and public and worker safety due to the failure risks posed by legacy switchgear.

The primary and secondary drivers are further defined and summarized in Table B02 - 8.

Table B02 - 8 Switchgear Investment Drivers

Investment Driver	Reasoning & Investment Benefits
Primary Driver: Failure Risk	The primary driver for these investments is the elevated risk of failure, affecting public and worker safety and leading to poorer reliability for Alectra Utilities' customers. The increased risk of failure is primarily driven by the elevated frequency of failure associated with specific legacy switchgear.
Secondary Driver: Reliability	Alectra Utilities expects that the reliability of the underground distribution system will improve as a result of the planned switchgear investments.
Secondary Driver: Functional Obsolescence	Obsolete asset types, such as porcelain insulators and non-load-break air-break switchgear, will also be replaced through these efforts. Replacement of these assets is expected to improve reliability and reduce rehabilitation and maintenance costs associated with maintaining these legacy assets.
Secondary Driver: Safety	By replacing legacy switchgear assets, the arc flash exposure risks currently facing workers will be mitigated, as will the workers and public safety risk posed by failure of oil-filled switchgear. Remote operation capability introduced by some replacement switchgear will remove the safety risk of live operations at the equipment.
Secondary Driver: Environment	By replacing oil-filled switchgear assets in poor condition, Alectra Utilities will mitigate the environmental risk posed by these legacy switchgear assets.

3.3 Investment Need

This section provides further detail of the impact that legacy switchgear is having on Alectra Utilities' underground distribution system, as well as the condition of the assets to be replaced.

Table B02 - 9 Switchgear Investment Expenditures, Drivers and Outcomes

	Historical Spending					Bridge		Forecast Spending				
Year	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
CAPEX ($MM)	5.5	5.4	6.2	6.8	9.1	8.7	8.6	8.7	8.8	11.7	13.8	14.1
Primary Driver	Failure Risk											
Secondary Driver	Reliability, Functional Obsolescence, Safety and Environmental risks											
Outcomes	Better Reliability, Expedient Fault Finding and Restoration, Safety and Environmental Risk Mitigation											

Historical spending has been impacted by rising material costs related to many assets, including switchgear. Alectra Utilities has seen a cumulative 35.9% increase in the cost of switchgear over the period from 2020 to 2024. Material cost changes over the Historical spending period are summarized below in Table B02 - 10. Upward price pressures will continue to impact the budget related to replacing these assets.

Table B02 - 10 Cumulative Annual % Increases in Switchgear Costs from 2020 Baseline

	2021	2022	2023	2024
Percent Change	-1.4%	9.6%	16.4%	35.9%

3.3.1 Reliability Impacts of Legacy Switchgear

Switchgear are a critical component to Alectra Utilities' underground distribution system. A single switchgear failure can impact as many as 5,000 customers. In reference to distribution assets, switchgear failures have the second highest outage duration per event. This highlights how critical these assets are. Failing to proactively replace switchgear assets would lead to increasing failures resulting in a large negative impact on reliability.

If the switchgear identified in the proposed investments are not addressed during the term of the DSP, Alectra Utilities expects that the reliability of the underground system will worsen. Delaying

these necessary investments risks creating a substantial backlog of replacements, requiring considerable investment and resources to correct, if even possible at that time.

3.3.2 Switchgear Population Condition

The Health Index (HI) values produced by Alectra Utilities' 2023 Asset Condition Assessment (ACA) pinpoint specific forms of degradation in distribution assets. As shown in Figure B02 - 22, 9.6% of Alectra Utilities' switchgear population is in Very Poor or Poor condition, with the majority 78% in Very Good condition (refer to *Chapter 5.3.3 Asset Lifecycle Optimization Policies and Practices* or *Appendix E - Asset Condition Assessment Report* for further information).

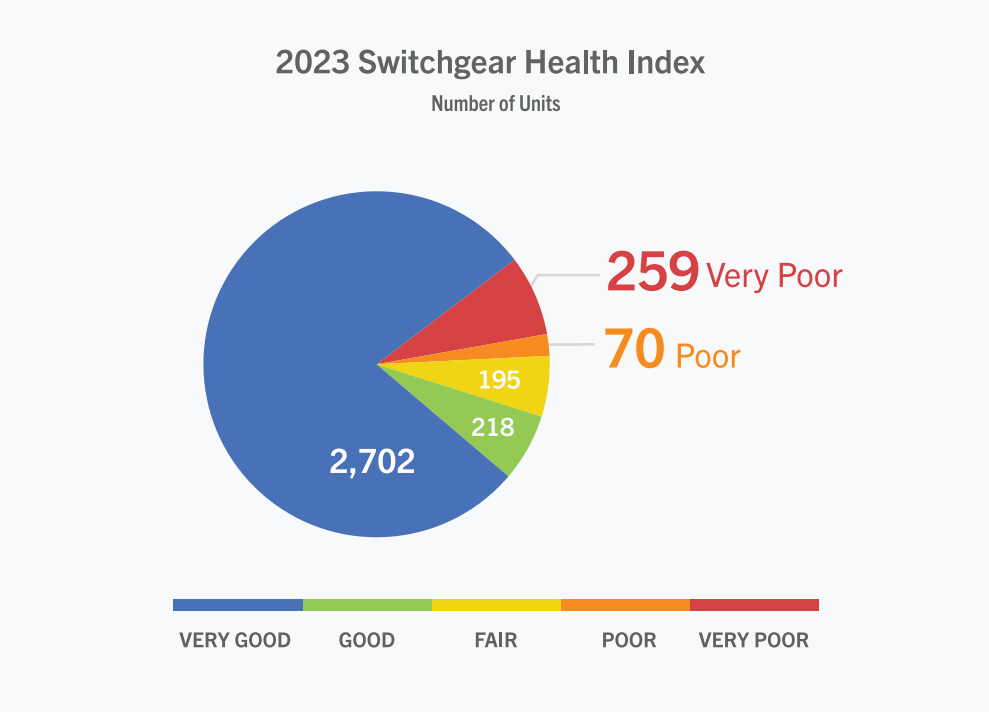


Figure B02 - 22 Switchgear Condition

There are 329 Very Poor and Poor units, with additional units in Fair condition continuing to degrade over time. These numbers, as mentioned above, do not include other issues Alectra Utilities is experiencing (e.g. first-generation solid dielectric and SF6 leaking switchgear).

3.3.3 Replacement Switchgear

Units replaced on the 27.6 kV system will be replaced with new solid dielectric units, or units insulated with sulfur hexafluoride (SF_6). Alectra Utilities plans to install solid dielectric switchgear where possible instead of SF_6 insulated units. Solid dielectric insulation does not pose safety and environmental risks while SF_6 gas, when leaked into the atmosphere in large quantities will contribute to global warming and if leaked in enclosed space will displace oxygen, creating a safety risk. SF_6 units will still be required due to fault rating limitations of solid dielectric switchgear. This is because the solid dielectric insulating material available on the market today is of a lower fault rating then SF_6. Based on the system fault level, Alectra Utilities will install devices rated accordingly. This is explained further in *Chapter 5.3.3 Asset Lifecycle Optimization Policies and Practices*.

In certain cases, SCADA connectivity will be added to newer switchgear as part of these investments. These investments will enable them to be remotely controlled from the control room or alternatively can be integrated into a Distribution Automation (DA) scheme. Figure B02 - 23 provides an image of one the many versions of an automation cabinet for pad mounted switchgear. These automation-ready switchgear introduce several benefits, including the ability to rapidly perform isolation, sectionalizing, and restoration during emergency situations. These types of operations can be completed in as little as 1 to 15 minutes under a DA scheme when compared to the process of manual switching, which can take 1 to 4 hours to perform. Additionally, these automated units provide telemetry that can help more readily identify cable faults and provide current readings, which can support both Alectra Utilities' ability to restore power, manage load and optimize asset management.

Figure B02 - 23 Automation Cabinet on Switchgear

3.4 Options Analysis

As listed in *Chapter 5.3.3 Asset Lifecycle Optimization Policies and Practices,* Alectra Utilities utilizes Copperleaf C55 Predictive Analytics for multiyear asset replacement planning. Specifically for switchgear, the result of this process sets the baseline for how many units Alectra Utilities should be replacing over the next 40 years based on the condition of its assets and the value to customers of proactive replacement. That analysis concluded that over the five-year DSP period, Alectra Utilities should replace 344 switchgear, or 56 units per year from 2027-2029, increasing to 88 units in the last two years of the rate period. Alectra Utilities considered three pacing strategies for switchgear renewal as described below and detailed in Table B02 - 11. All three pacing strategies were provided to customers as a part of Alectra Utilities' Phase 2 Customer Engagement. Based on the results of Customer Engagement, no changes were made to the proposed pacing strategies.

Alectra Utilities considered three pacing options that address the deteriorating switchgear:

- Option 1: Renewal of deteriorated assets at the accelerated pace 110 units per year
- Option 2: Renewal of deteriorated assets at a moderate pace 81 units per year
- Option 3: Renewal of deteriorated assets at a reduced pace 69 units per year (Selected Option)

Costing for each option is detailed in Table B02 - 11.

Table B02 - 11 Investment Options and Pacing for Switchgear

Option	Avg. Quantity Per Year	Investment Cost ($MM)
Option 1: Accelerated pace	110	85.2
Option 2: Moderate pace	81	62.7
Option 3: Reduced pace	69	54.3

3.5 Summary of Switchgear Investments

The focus of these switchgear investments will be on reducing the number of air-insulated and oil-filled switchgear. This will reduce the number of outages and interruption duration related to failures and drastically reduce the population of oil-filled switchgear. As mentioned in *Section 5.3.3*, Alectra Utilities plans to adopt the reduced pace of investment in switchgear. This pacing strikes a balance between reducing risk by targeting particularly troublesome switchgear types and managing spend for these assets over the near term. Total investment over this DSP period for switchgear renewal is $57.1MM [20], which accounts for approximately 10% of overall Underground Renewal spending.

[20] This value includes a discrete project outside of this Switchgear Program for $2.8 MM.

IV Civil Structures

4.1 Investment Description

This section summarizes the proposed investments to address deteriorating civil infrastructure in Alectra Utilities' underground system. The specific drivers, need, and options considered to address these assets are set out in *Section 4.2, Section 4.3, and Section 4.4*, respectively.

Through these investments, Alectra Utilities plans to systematically and proactively replace vault lids of the worst-rated civil chambers to avoid potentially serious accidents. Legacy manhole and vault lids will be replaced with new lids that are capable of withstanding the heavy loading conditions present at street level. Each location will need to be treated differently as there is no single standardized solution that can be implemented. In certain cases, the vault or manhole will need to be redesigned.

Failure to address these issues has a significant potential safety risk to the general public since weak lids can collapse resulting in damage to vehicles passing over the manholes or vaults.

Depending on the vintage of the structure, there will be a variety of structural/condition factors to consider when replacing these civil chamber covers and vault lids. Older chambers would have been poured in place by utility workers without inclusion of rebar as it was not standard at the time. In certain cases, the chambers are so large that steel frames were used to support the lids. Some of the chambers also have scrap material that was mixed with the concrete such as broken plates, glass bottles and other garbage material. In some instances, the lids are not rated for the vehicular traffic that drives over them. These legacy installations do not meet current design standards in comparison to modern pre-cast structures which use rebar and have lids rated for vehicular traffic. Taken together, these examples demonstrate the case-by-case nature of civil structure investments.

Table B02 - 12 summarizes the outcomes and benefits of civil infrastructure Underground Asset Renewal investments.

Table B02 - 12 Civil Structures Summary

Outcome	Investment Benefits and Objectives
Safety	Replacement of vault lids and manhole covers is expected to mitigate serious safety risks to customers, as some of the existing lids do not possess the necessary criteria to withstand current loads/weights at the surface/street level.

4.2 Investment Drivers

The primary driver of the proposed investments is to address the significant risk of failure associated with the identified civil structures.

These drivers are further defined and summarized in Table B02 - 13.

Table B02 - 13 Civil Structures Investment Drivers

Investment Driver	Reasoning & Investment Benefits
Primary Driver: Failure Risk	The primary driver for these investments is the elevated risk of failure, affecting public and worker safety. The increased risk of failure is primarily driven by specific deteriorating underground infrastructure.
Secondary Driver: Safety	By replacing these civil structures, this helps lower the risk of failure to these assets which could affect public and worker safety, as they are in areas of heavy traffic.
Secondary Driver: Reliability	Avoiding outages due to falling debris that could damage equipment within the civil structures.

4.3 Investment Need

Alectra Utilities has a number of civil structures that require replacement based on historical inspection and assessment. Early structures were not precast and were instead poured in place. These early structures have no rebar for support, or in some cases have rail ties used as the supporting steel. Figure B02 - 24, Figure B02 - 25, and Figure B02 - 26 show these larger steel beams and with the loss of concrete the rusting that is taking place. Once the beams rust, structural support is lost. Figure B02 - 27 highlights one of the other inherent risks with lid degradation. Equipment placed in the below grade chamber, as is common in certain operational areas, is now susceptible to damage from debris, such as falling concrete, which can damage equipment causing it to require replacement, or even result in an outage due to failure. Without

investment to replace these assets they pose a risk not only to reliability but also to the safety of the public since these are public-facing assets that are walked on or driven over.

In June 2024, the Electrical Safety Authority issued a bulletin informing electric utilities of their legal obligation under *Ontario Regulation 22/04* and Society of Cable Telecommunications Engineers Standard 77 2023 in regard to subsurface chambers and covers meeting structural loads.[21] This was released after the Government of Ontario released a similar 'Alert' after a fatality occurred because of inadequate structural loading by a utility service cover. Based on available data, Alectra Utilities is aware that several chambers are showing signs of structural stress, and some chamber lids are not rated for the locations at which they are installed. Both these issues are a risk to the public that need to be addressed as quickly as possible. Alectra Utilities will be focusing on those with the highest risk first.

[21] DB-02-24-v1 - Subsurface Chamber and Box Covers

Figure B02 - 24 Lid Degradation: Steel Supporting Rusting

Figure B02 - 25 Lid Degradation: Steel Support Rusting

Figure B02 - 26 Lid Degradation: Cement Crumbling

Figure B02 - 27 Debris Falling on Equipment

4.4 Options Analysis

Table B02 - 14 Civil Structures Investment Expenditures, Drivers and Outcomes

	Historical Spending					Bridge		Forecast Spending				
Year	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
CAPEX ($MM)	1.1	1.1	1.7	1.5	1.9	2.4	2.3	2.3	2.6	4.9	10.0	12.6
Primary Driver	Failure Risk											
Secondary Driver	Reliability, Safety											
Outcomes	Better Reliability, Easier Fault Finding, Easier Restoration, Safety											

As presented in Table B02 - 14, Alectra Utilities plans to invest approximately $32.4MM in Civil Structures over the DSP period, constituting 5.7% of the forecast expenditures on Underground Asset Renewal. While civil structures last much longer than both cable and switchgear, they still degrade and are prone to failures.

For civil infrastructure, Alectra Utilities considered two intervention strategies:

- Replacement of the entire civil structure
- Replacement of the vault / manhole lids

Replacing the entire civil structure would result in a highly complex, lengthy and costly project for Alectra Utilities, as some vaults and manholes will be located within the roadway and not within the off-road boulevard allowance. Relocating all the infrastructure (cables, junctions) is very difficult in comparison to localized rehabilitation.

Replacing only the lids that are in poor condition along heavily travelled routes is the most cost-effective solution compared to complete replacement, unless the underlying civil structure is compromised. This option targets the most commonly affected part of the civil structure deemed to be deteriorated and retains the existing footprint so that additional costs of relocating assets can be avoided.

Since the risk to the public is substantial, and the ESA has formally flagged this as an issue utilities need to manage, it is not a matter of if, but when these investments need to be made.

V Alectra-Initiated Underground Near-Term Projects

5.1 Investment Description

Alectra-Initiated Underground Near-Term projects refer to the collection of projects that are identified during a planning year that are not captured under reactive remediation yet still require some urgency to complete, with the primary driver being related to an underground asset. Such work is required every year, is urgent, and is non-discretionary. These projects require some design work to be carried out to successfully address the issue. Due to the unpredictable nature of these types of projects, spending rates in this category tend to be driven based on historical trends, as presented in Table B02 - 15.

The work related to these projects varies widely, from the need to urgently replace a faulted cable segment, to the replacement of vault covers damaged by snow removal equipment, to relocating assets on private property. The specific project scopes tend to vary from year to year and region to region, but generally the projects require timely intervention and represent a smaller scope and budget amount (<$500,000) than a typical renewal project.

Table B02 - 15 Alectra Initiated Underground Near-Term Projects Investment Expenditures, Drivers and Outcomes

	Historical Spending					Bridge		Forecast Spending				
Year	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
CAPEX ($MM)	8.0	10.1	6.1	5.6	4.3	6.6	7.0	7.4	7.7	8.0	8.4	8.5
Primary Driver	Failure risk, Compliance											
Secondary Driver	Reliability, Safety											
Outcomes	Resolution of customer/joint use issues, improved reliability, safer working conditions											

5.2 Investment Drivers

The drivers of Alectra-Initiated Underground Near-Term projects varies with the type of project scope realized within the budget year.

5.3 Investment Need

Alectra Utilities makes these non-discretionary capital investments to address urgent issues related to underground infrastructure throughout the year. A variety of project types are managed year-over-year by this investment that would otherwise risk a larger scale issue without these timely investments.

5.4 Option Analysis

Alectra-Initiated Underground Near-Term investments do not follow the same categorization as other assets within the Underground Asset Renewal portfolio and therefore do not align with a pacing option. Instead, Alectra Utilities bases the forecasted spending needs on historical spending trends and through this has derived a single option to fund these required investments. Alectra Utilities is projecting to spend $40.0M over the DSP period towards Alectra-Initiated Underground Near-Term projects, which represents 7.1% of the total Underground Asset Renewal portfolio. Table B02 - 16 below summarizes the timing of these investments.

Table B02 - 16 Alectra-Initiated Underground Near-Term Projects Investment Expenditures, Drivers and Outcomes

	Historical Spending					Bridge		Forecast Spending				
Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
CAPEX ($MM)	8.0	10.1	6.1	5.6	4.3	6.6	7.0	7.4	7.7	8.0	8.4	8.5

5.5 Summary of Alectra Initiated Underground Near-Term Investments

Investments towards Alectra-Initiated Underground Near-Term projects are based on historical trending in this category, and the funding requested through this DSP is in anticipation of a continued need to manage these recurring needs as they arise.

VI Investment Timing & Pacing

6.1 Summary of Expenditures

Table B02 - 17 provides the year-over-year breakdown of underground asset renewal investments, including the historical period from 2020-2024, the bridge years from 2025-2026, and the DSP period from 2027-2031.

Table B02 - 17 Historical & Proposed Investment Spending

	Historical Spending					Bridge		Forecast Spending				
Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
CAPEX ($MM)	61.5	55.6	46.9	68.9	75.9	69.8	75.1	80.0	91.0	91.0	153.0	152.1

The basis for historic expenditures and proposed forecast expenditures is set out for each asset group in the sections above.

6.2 Execution Approach

Alectra Utilities will leverage internal and external contractors to complete the design and installation of the new underground infrastructure to be installed within the system. The utility has retained external contractors as well as engineer contractors or consultants working at different work sites throughout the year under a multi-year Master Service Agreements. Regular progress meetings are held to ensure technical and operational issues are resolved promptly.

The execution phase will follow Alectra Utilities' internal project management methodology which provides specific guidelines, procedures, work instructions, and industry best practices that allow the project work to be performed in an economically efficient, cost effective, and safe manner.

While the planned investments target the three groups of assets described in this document, Alectra Utilities will replace other assets that are in Poor or Very Poor (deteriorated) condition as part of Underground Asset Renewal projects. For example, if the main goal of a project is to replace direct-buried XLPE cable that is in deteriorated condition, and that cable connects to a transformer that is also in deteriorated condition, Alectra Utilities may replace that transformer as part of the project if doing so is more cost-efficient than replacing the transformer through another subsequent project.

VII Investment Projects

The material investments from 2027 to 2031 that form the Underground Asset Renewal investments are included in Table B02 - 18.

Table B02 - 18 Material Projects and Initiatives

Project Code	Project Name	CAPEX ($MM)
Multiple	Switchgear Renewal	54.3
151556	Cable and Transformer Replacement - (HAM) - Hollybush - Parkside - Dundas - Spring Creek	45.0
Multiple	Cable Replacement Project – Uninjectable Cables	44.0
Multiple	Underground Asset Renewal-Alectra Initiated Distribution System Projects	32.0
Multiple	Vault Cover Renewal	29.8
152841	Cable Replacement Project - (M27) Hwy 7, Mc Cowan Rd ,16th Ave, Main St Unionville)	28.3
151339	Cable Replacement Project - (BA19) - Letitia - Anne - Edgehill - Ferndale, Barrie	24.6
151301	Cable and Transformer Replacement Project - (HAM) - Rymal - Mud - Upper Centennial - Upper Red Hill Valley	17.3
152781	Cable Replacement Project - (A05) - Wellington St W, Bathurst St, Henderson Dr, Yonge St	17.1
152665	Cable Replacement Projects - (M15) Fincham Avenue of Markham	15.7
152383	Cable Injection - (AREA 39) - Erin Mills Pkwy & Thomas St, Mississauga	15.3
151325	Cable Replacement Project - (M31) - 14th - Old Kennedy - Steeles - Warden, Markham	14.6
151081	Cable and Transformer Replacement Project - (SCH) Courtleigh Rd	13.6
152774	Cable Replacement Project - (V15) - Centre St, Keele St, Steeles Ave W, Dufferin St (Vaughan)	10.3
151559	Cable and Transformer Replacement - (HAM) - Upper Wentworth - Lincoln M. Alexander - Upper Ottawa - Stonechurch	9.1
151879	Cable and Transformer Replacement - (HAM) - Upper Sherman - Stone Church - Nebo – Rymal	8.7
151882	Cable Replacement Project - (G3) - Main - Bovaird - Kennedy - Queen, Brampton	8.3
152801	Cable Replacement Project - (V36) - Vaughan (Steeles Ave W, Weston Rd, Hwy 7, Pine Valley Dr)	8.1
152454	Cable and duct replacement - Golf Club Dr, Hamilton	7.7

Project Code	Project Name	CAPEX ($MM)
151285	Cable Replacement Project - (G2) - Sandalwood Pky E and Conestoga Dr Brampton	7.7
152789	Cable Replacement (Rear Lot) Project - (AREA23) - Forestwood Dr-Stainton Dr, Mississauga	7.0
152785	Cable Replacement Project - (AREA26) - Rathburn Rd E/Rockwood Rd. Mississauga	6.9
151297	Cable and Transformer Replacement Project - (HAM) - Govenors - Old Ancaster	5.7
152502	Cable Replacement Projects - (M15) Sir Constantine Dr & Parkway area of Markham	5.5
152666	Cable Injection Project - (M15) Church Street area, Markham	5.3
151335	Cable Replacement Project - (BA14) - Tiffin and Hwy 400, Barrie	4.9
151276	Cable Injection Project - (SCH) - Vansickle	4.7
152786	Cable Replacement Project - (AREA28) - Rathburn Rd E/Chalfield Ln and Meadows Blvd, Mississauga	4.5
151332	Cable Replacement Project - (BA20) - Bayfield and Simcoe, Barrie	4.3
151299	Cable and Transformer Replacement Project - (HAM) - Millen - Barton – Fruitland	4.2
151298	Cable Injection Project - (HAM) - Govenors - Old Ancaster	4.1
151336	Cable Replacement Project - (BA22) - Sunnidale and Anne, Barrie	4.1
151404	Cable Replacement (Rear Lot) Project - (AREA21) - Miss. Valley & Daralea Hts/Molly Ave, Mississauga	4.1
151468	Cable Replacement Project - (V51) - Langstaff - Kipling - Hwy 7 - Hwy 27 – Phase 2, Vaughan	3.6
151315	Cable Injection Project - (G5) - County Crt Blvd and Hartford Trail, Brampton	3.5
150138	Cable Replacement Project – (BA23-BA24) - Cook St and Steel St, Barrie	3.5
151424	Cable Replacement (Rear Lot) Project - (AREA21) - Miss. Valley & Bloor, Mississauga	3.5
151306	Cable Injection Project - (HAM) - Upper Wentworth - Lincoln M. Alexander - Upper Ottawa - Stone Church	3.5
151467	Cable Replacement Project - (V17) - Langstaff - Keele - Rutherford - Dufferin, Vaughan	3.1
151310	Cable Injection Project - (E4) - Moffat Ave/Torrance Woods/Lockwood Rd, Brampton	2.9
151293	Cable and Transformer Replacement Project - (SCH) - Lakeshore - Stanley - Parnell – Chancery	2.9

Project Code	Project Name	CAPEX ($MM)
151466	Cable Replacement Project - (V24) - Langstaff - Jane - Rutherford - Keele, Vaughan	2.9
152392	Install 27.6kV Dead-front Solid Dielectric Switchgear @ Vault 1879 (Conestoga Drive, north of Sandalwood Pkwy), Brampton	2.8
151521	Cable Replacement Project - (A05) - Bathurst - Wellington - Yonge - Henderson, Aurora	2.8
151393	GUELPH - Transite Underground Duct Replacement	2.7
151323	Cable Injection Project - (L2) - Mountainash Rd/Mountainberry Rd, Brampton	2.5
151319	Cable Injection Project - (L3) - Chrysler Dr/Corporation Dr, Brampton	2.4
151333	Cable Replacement Project - (BA9) - Little - Fairview - Harvie - Ferndale, Barrie	2.3
152743	Cable Injection - (M09) - 16th Ave, Reesor Rd, Hwy 7, Ninth Line - Markham	2.3
151330	Cable Replacement Project - (A01) - Henderson - Yonge - Bloomington - Bathurst, Aurora	2.2
151363	Cable Injection Project - (M25) - 14th - McCowan - Steeles - Old Kennedy, Markham	2.1
151176	Cable Replacement Project - (AREA45) - Argentia Rd & Campobello Rd/Kinsmen Gate, Mississauga	1.9
152830	Cable Replace-(Barrie 417-F3) St Vincent St,Kempenfelt Dr,Berczy St	1.9
152812	PILC Cable Replacement Project - (HAM) - Beach and Ottawa Feeders	1.7
151386	Cable and Transformer Replacement - (278) - 31 Greengate Rd Subdivision, Guelph	1.6
152697	Cable Replacement Project - (71F2 in Area 27) - Rathburn Rd. E. & Willowbank Trail	1.6
151373	Cable and Transformer Replacement - (923) - 301 - 539 Scottsdale Drive Subdivision, Guelph	1.6
151275	Cable Injection Project - (SCH) - QEW - Highway 406 - Martindale Road	1.6
151144	Cable and Transformer Replacement - (AREA30) - Rathburn Rd. W, Mississauga	1.6
151304	Cable Injection Project - (HAM) - Stone Church - Garth - Lincoln M. Alexander	1.5
152746	Cable Injection Project - (M14) - Hwy 7, Box Grove Bypass, 14th Ave, Markham Rd	1.4
151385	Cable and Transformer Replacement - (892) - 74 - 176 Janefield Ave Subdivision, Guelph	1.3
151320	Cable Injection Project - (I5) - Steelwell Rd/Hedgedale Rd, Brampton	1.2
151888	Cable and Transformer Replacement - (906) - 39 - 131 Dovercliffe Dr, Guelph	1.2

Project Code	Project Name	CAPEX ($MM)
151887	Cable and Transformer Replacement - (96) - 700 Paisley Rd, Guelph	1.2
151322	Cable Injection Project - (N4) - Deerhhurst Dr, Brampton	1.1

1

Appendix B03 - Transformer Renewal

I Overview

The Transformer Renewal investment program addresses transformers that pose safety, environmental, and reliability risks through planned replacement. Safety and environmental risks are associated with deteriorated transformers, which are categorized with a Poor" or Very "Poor Health Index (HI) in the Asset Condition Assessment (ACA) due to severe corrosion and/or active oil leaks. Reliability risks are associated with units that pose a high risk of prolonged service interruption due to inaccessibility, lack of redundancy, or functional obsolescence (e.g. non-standard legacy configurations or transformers that are undersized).

Since the 2018 ACA, Alectra Utilities has made investments in improving asset health data, including enhancements to the Geographical Information System (GIS) and the collection of more detailed condition factors. These advancements have led to increased visibility into the health of the transformer population, uncovering previously unrecognized units with safety, environmental, and/or reliability risks. The improved visibility necessitated a realignment of investment pacing to address these risks on a planned basis. In the 2023 ACA, there are 9,454 deteriorated transformers (i.e. categorized with a Poor or Very Poor HI in the ACA). Transformers in the Poor and Very Poor HI categories exhibit major deterioration, posing risks to public safety and environmental contamination. During the 2027-2031 period, half of the identified deteriorated transformers are targeted for planned replacement, striking a balance between risk reduction, cost, and resource availability.

Alectra Utilities plans to replace at-risk transformers at a moderate pace over the DSP period. This investment plan is underpinned by the ACA and Copperleaf C55 Asset Aware (Predictive Analytics detailed in *Chapter 5.3.3 (5.3.3.6 A)*) which generated the quantity of distribution transformer replacements over the 2027-2031 period. Table B03 - 1 summarizes the transformer replacement expenditures from 2020-2031, including actual expenditures from 2020-2024, and forecast expenditures for the 2025-2026 bridge years, and 2027-2031 forecast period. The increase in transformer replacement expenditure can be attributed to rising unit costs (discussed in *Section 2.2.1*) and greater visibility into the health of the transformer population, which has revealed a significant increase in the number of deteriorated transformers. The primary strategy is therefore shifting towards planned replacement, as relying on a run-to-failure approach is no

longer considered prudent in light of the current level of at-risk transformers. Reactive capital expenditures related to equipment failure are detailed in *Appendix B05 – Reactive Capital*. By aligning past expenditure trends with forward-looking risk assessments and regulatory requirements, Alectra Utilities aims to enhance system reliability, ensure public safety, and promote environmental stewardship while managing costs effectively over the DSP period.

Table B03 - 1 Transformer Renewal Investment Expenditures, Drivers and Outcomes

	Historical Spending					Bridge		Forecast Spending				
Year	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
CAPEX ($MM)	5.8	6.9	6.7	8.6	12.3	12.0	11.4	16.7	20.6	22.5	29.8	30.5
Primary Driver	Failure Risk											
Secondary Driver	Reliability, Public Safety, Environmental Risk											
Outcomes	Customer Value, Reliability, Safety, Environment											

II Investment Description

Through the Transformer Renewal investment program, Alectra Utilities plans to replace at-risk overhead and underground transformers (e.g. pole-mounted, pad mounted, vault transformers, and submersible transformers) with new transformers that conform to present day standards. The transformers to be replaced are either deteriorated (i.e. categorized with a Poor or Very Poor HI posing safety or environmental risks), or pose a high risk of a prolonged outage due to functional obsolescence, inaccessibility, or lack of redundancy. The Transformer Renewal investment program follows a planned replacement strategy. The reactive capital replacement strategy to address immediate system risks are detailed in *Appendix B05 - Reactive Capital*.

Table B03 - 2 shows that Alectra Utilities has 128,362 distribution transformers in service which are vital to the provisioning of electrical supply to Alectra Utilities' customers. Depending on the customers and type of load, Alectra Utilities' distribution transformers may be single-phase or three-phase, and range from 50kVA in capacity (i.e. supplying a few residential customers) up to 3,000kVA (i.e. supplying industrial, large commercial or multi-unit/high-rise residential customers).

Table B03 - 2 Breakdown of Distribution Transformer Types

Transformer Type	Total Quantity
Pad Mounted Transformer	83,885
Pole Mounted Transformer	31,807
Vault and Submersible Type Transformer	12,670

While transformers have historically operated under a run-to-failure strategy due to their relatively low impact on public safety, the environment, and customer reliability (as discussed in *Chapter 5.3.3 Asset Lifecycle Optimization Policies and Practices*), Alectra Utilities' ACA has identified an increased number of deteriorated transformers. The elevated risk associated with the current level of at-risk transformers underscores the need to shift to a planned replacement strategy. Maintaining a run-to-failure strategy with the increased level of deteriorated transformers heightens the risk of public safety incidents and severe oil leaks requiring costly environmental remediation. Alectra Utilities will pursue planned transformer replacement according to the criteria listed below:

- **Deteriorated Transformers (Public Safety and Environmental Risk)**

Transformers may be scheduled for planned replacement when they exhibit safety hazards (e.g. a corroded or damaged enclosure that may expose the public to energized components) or pose a risk of environmental contamination (e.g. leaking oil). Transformers in the Poor and Very Poor HI categories are considered deteriorated.

Figure B03 – 1 displays a pad mounted transformer with a severe oil leak and an overhead transformer exhibiting major corrosion. These examples show the types of conditions that can lead to catastrophic failure if deteriorated transformers are not addressed through a planned replacement program. Furthermore, Alectra Utilities' planned approach to leaking transformers is aligned with the Ministry of the Environment, Conservation and Parks, which requires the utility to enact a replacement plan to address the leak regardless of severity.

Figure B03 – 1 Leaking Pad Mounted Transformer and Corroded Overhead Transformer

- **Prolonged Customer Interruption (Reliability Risk)**

Transformers may be scheduled for planned replacement when they are legacy assets that are functionally obsolete and no longer aligned with current standards. Such transformers are also more likely to be overloaded, given the increase in loads since their installation. The new transformers to be used for replacement will be sized appropriately

in relation to customer demand at the relevant locations, which will prevent accelerated degradation of transformers due to overloading conditions. Vault style transformers installed under older construction standards also fall into this category, as many were installed in enclosures, that at the time were acceptable, but no longer meet CSA requirements. Many of these installations use obsolete (now unsafe) practices for protection, and do not provide safe working conditions. Figure B03 – 2 and Figure B03 - 3 highlight instances of obsolete and unsafe working conditions in vault mounted installations. Figure B03 – 2 shows power fuses hanging along the same wall as the transformers. Operation of these devices in the room is a safety concern and poses a risk of failing and damaging the transformers. Figure B03 - 3 shows load break switching compartments inside a vault room. This is an atypical practice that in many cases forces switching to be performed outside of the room. This equipment is not flood-proof (i.e. excess water reaching the secondary connection would lead to failure of the equipment), and is also live front, meaning failure exposes staff to greater risk.

Figure B03 – 2 Obsolete Power Fuses on Vault Wall with Transformers

Figure B03 - 3 Obsolete Load Break Switches in Vault Room with Transformers

In addition, transformers may be scheduled for planned replacement when they are legacy assets for which spares, or backup are unavailable, or that are installed in hard-to-reach locations such as underground chambers, below-grade vaults, basements, and low-ceiling areas. When such transformers fail, there is a greater risk of extended outages. Also, emergency power supply is required which impacts restoration costs. In addition, specialized equipment, which is not always readily available, may be required for removal and installation of the assets located in these spaces. Figure B03 - 4 highlights the tight spacing some of these locations have.

Figure B03 - 4 Submersible (Classified as Vault) Transformer in Below Grade Installation

Planned replacement of transformers posing a reliability risk avoids lengthy or widespread customer outages (e.g. apartment buildings) and provides an opportunity to reconfigure an alternative supply, or relocate these assets to more accessible locations.

2.1 Summary of Investment Outcomes and Benefits

Table B03 - 3 summarizes the outcomes and benefits associated with Alectra Utilities' proposed Transformer Renewal investments.

Table B03 - 3 Investment Outcomes and Benefits

Outcome	Investment Benefits and Objectives
Customer Value	Deliver customer value by replacing at-risk transformers through a planned replacement program, which will minimize disruptions to customers (this will also avoid prolonged outages associated with emergency reactive replacement of a failed transformer).
Reliability	Ensure the reliable performance of Alectra Utilities' distribution system by replacing hazardous, obsolescent, inaccessible, or overloaded distribution transformers, which will contribute toward system-wide and feeder-level reliability by: • minimizing outage duration • minimizing unplanned outages

Outcome	Investment Benefits and Objectives
	• reducing probability of untimely failure due to overloaded assets • removing the risk of corrosion (new units are stainless steel)
Safety	The replacement of hazardous deteriorated transformers will minimize safety risks to the public (e.g. exposure of energized equipment to potential public access due to transformer enclosures that have been structurally compromised).
Environment	Deteriorated transformers can lead to environmental impacts and costs due to oil spill. The replacement of deteriorated and leaking transformers will avoid environmental contamination risks.

2.2 Summary of Expenditures

Table B03 - 4 outlines the Transformer Renewal investment spending across three distinct periods: the historical period from 2020 to 2024, bridge years 2025 to 2026, and the forecast period from 2027 to 2031. The increase in expenditure during the forecast period is largely driven by the improvements to transformer health condition data, which has resulted in the identification of a greater number of at-risk transformers in need of planned replacement. In addition, rising unit costs, as discussed in *Section 2.2.1*, further contribute to a necessary increase in program costs to mitigate safety, environmental, and reliability risks.

Table B03 - 4 Historical and Proposed Investment Spending

	Historical Spending					Bridge		Forecast Spending				
Year	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
CAPEX ($MM)	5.8	6.9	6.7	8.6	12.3	12.0	11.4	16.7	20.6	22.5	29.8	30.5

2.2.1 Historical Expenditures (2020-2024)

During the 2020–2024 period, actual Transformer Renewal program expenditures totalled $40.3MM. This period reflects the initial costs associated with transformer renewal and marks the onset of significant cost escalations. Four non-discretionary factors have contributed to the rising unit costs in transformer renewal. The first, occurring noticeably in 2023, was material cost inflation, stemming from post-COVID-19 pandemic supply chain disruptions, higher labour costs, and overall increase in production costs. Second, overlapping the same period, was completion of the ongoing harmonization of transformer specifications to one Alectra Utilities specification,

which included transitioning to stainless-steel enclosures. Third, harmonization also included meeting increased transformer efficiencies required by *Ontario Regulation 509/18*, which increased transformer cost. Fourth, in late 2023, the harmonization efforts further expanded to include residential transformers standardized at 100kVA. The increase from 50kVA to 100kVA was required to allow for the raising customer power usage. The cost to increase from a 50kVA transformer to a 100kVA transformer represents a 14% increase in asset cost and doubles the capacity available to customers. Table B03 – 5 illustrates the percentage increase of transformer cost (material only) per year from a 2020 baseline. By 2024, the transformer cost had increased by 103.12% since 2020.

Table B03 – 5 Percentage Increase of Costs from 2020 Baseline

Year	2021	2022	2023	2024
Percent Increase	12.68%	67.24%	101.46%	103.12%

2.2.2 Bridge Expenditures (2025-2026)

During the 2025-2026 period, Alectra Utilities allocated $23.4MM for transformer renewal. Investments in these two years are levelized and focused on maintaining expenditure that is consistent with the end of the historical expenditure period before ramping up in 2027.

2.2.3 Future Expenditures (2027-2031)

Forecast expenditures for the period 2027 to 2031 are approximately $120.1MM[22]. This period of increased investment is due to the planned replacement of transformers that are deteriorated (i.e. posing safety or environmental risk) or pose a significant customer interruption risk, as detailed in *Section IV*.

[22] This includes discrete projects of $7.2 MM in addition to the Transformer Renewal Program spend.

III Investment Drivers

The primary and secondary drivers of the Transformer Renewal program are described in Table B03 - 6. Both drivers are discussed in more detail in *Section 4.1* and *Section 4.2*.

Table B03 - 6 Investment Drivers

Investment Driver	Reasoning and Investment Benefits
Primary Driver: Failure Risk	The primary driver for these investments is the elevated risk of failure, posing risk to safety and the environment and leading to poorer reliability for Alectra Utilities' customers.
Secondary Driver: Public Safety	By replacing deteriorated transformers (i.e. categorized as Poor or Very Poor in the ACA) through a planned replacement program, Alectra Utilities will mitigate public and employee safety risks (e.g. corroded enclosure resulting in exposed energized components).
Secondary Driver: Environmental Contamination	By replacing deteriorated transformers (i.e. categorized as Poor or Very Poor in the ACA) through a planned replacement program, Alectra Utilities will mitigate the risk of oil and PCB contamination and avoid environmental remediation costs associated with loss of oil containment.
Secondary Driver: Reliability Impact	By replacing at-risk distribution transformers through a planned replacement program, Alectra Utilities will mitigate the risk of prolonged outages associated with functional obsolescence, inadequate redundancy, and difficulty of access, which lead to reduced reliability for Alectra Utilities' customers.

IV Investment Need

This section describes the need to invest in replacing at-risk transformers in Alectra Utilities' distribution system. During the DSP period, the Transformer Renewal program is designed to replace transformers exhibiting the following conditions using a planned replacement strategy:

- **Safety Risk** – A deteriorated transformer (i.e. categorized as Poor or Very Poor in the ACA) with significant rust or corrosion that damages transformer enclosure and potentially exposes the public to energized equipment.
- **Environmental Risk** – A deteriorated transformer (i.e. categorized as Poor or Very Poor in the ACA) with leaking oil posing an environmental contamination risk. Units that contain Polychlorinated Biphenyl (PCB) are also targeted for planned replacement to avoid leaking PCBs into the environment.
- **Customer Interruption Risk** – Transformers that are functionally obsolete (e.g. consistent and significant overloading of the transformer and delta transformers) and transformers without adequate redundancy or that are located in difficult to access spaces leading to prolonged restoration.

A planned approach to transformer replacement reduces exposure to safety, environmental, and reliability risks that cannot be effectively managed on a run-to-failure strategy. Reactive capital expenditures related to equipment failure are detailed in *Appendix B05 - Reactive Capital.* Replacing transformers that exhibit any of the above conditions using a planned replacement strategy ultimately reduces costs for Alectra Utilities and for customers in two ways:

- **Reduced Environmental Stewardship and Remediation Costs:** Environmental remediation costs increase over time as leaking transformers remain in service. From 2021 to 2024, the average environmental remediation cost due to leaking oil was $50,000 per site.
- **Cost-Efficiency of Planned Replacement:** Compared to planned replacement, emergency response to the failure of transformers that lack adequate redundancy, or are difficult to access would increase logistical costs, require increased labour hours, and drive unplanned rental costs for specialized equipment. Furthermore, costs to reactively replace units that fall outside of normal working hours (i.e.

overtime labour/premium contractor costs) are higher than planned replacements when completed during normal working hours.

4.1 Deteriorated Transformers (Public Safety and Environmental Contamination)

Alectra Utilities inspects its distribution transformers every three years in compliance with the established inspection requirement of the Ontario Energy Board.[23] The conditions of the transformers captured during these inspections are factored into the ACA process to identify safety and environmental risks and to calculate the transformer HI.

Through the ACA process, Alectra Utilities identified a total of 9,454 transformer units in the Very Poor (6,847 units) and Poor (2,607 units) HI categories as illustrated in Figure B03 - 5. All transformers in the Very Poor and Poor HI categories exhibit varying degrees of deterioration, including leaking oil and corrosion, posing risks to public safety and environmental contamination. During the 2027-2031 period, approximately half of the identified deteriorated transformers are targeted for planned replacement.

[23] Distribution System Code "Appendix C – Minimum Inspection Requirements."

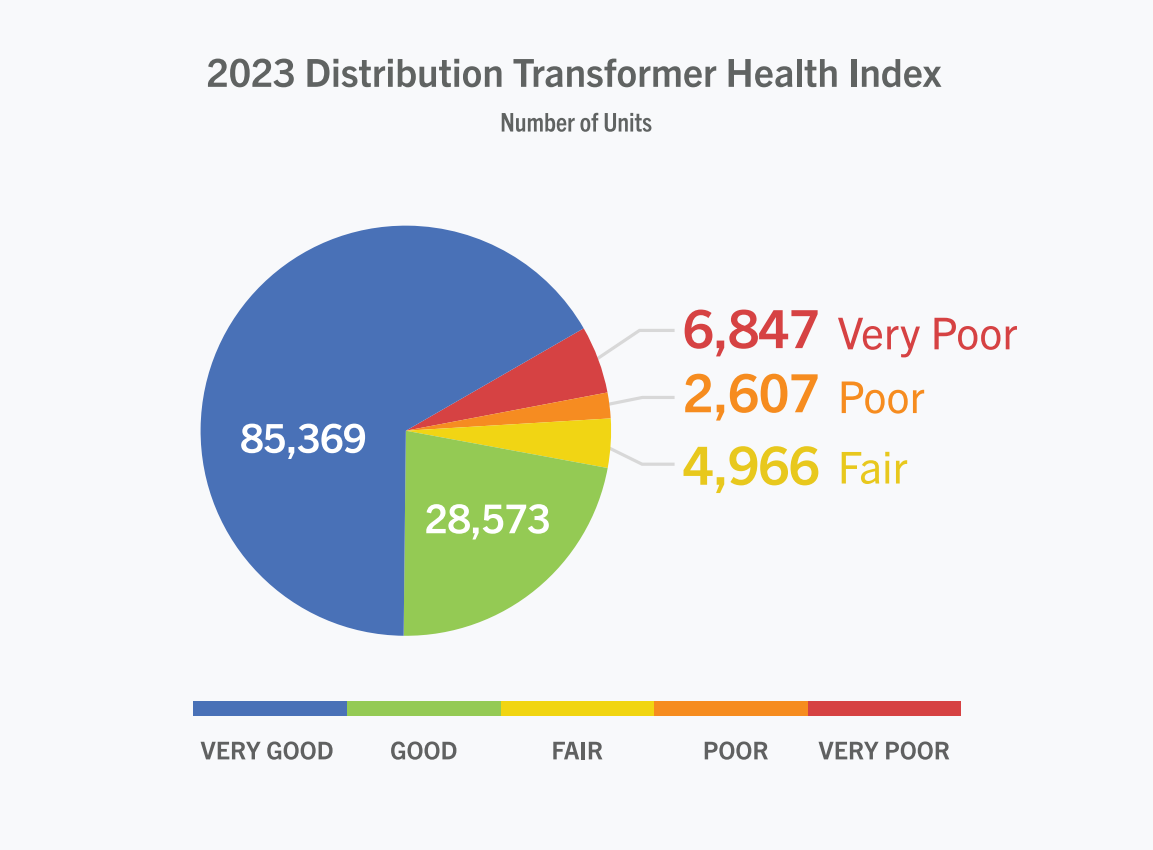


Figure B03 - 5 Distribution Transformer Condition Demographics

Excessive rust and corrosion can result in holes forming within the transformer enclosure, which can expose live connections creating a potential public safety risk. Furthermore, when comparing 2018 vs. 2023, the number of deteriorated transformers has increased by 215%, as shown in Figure B03 - 6. The increase in the number of deteriorated transformers compared to the 2018 ACA is primarily due to advancements in the GIS and the collection of more granular asset condition data. These improvements to inspection of the assets have contributed to higher quality health condition data, revealing that there is a greater need to invest in renewing the utility's transformers than was identified in the prior period. With improved information regarding the assets, Alectra Utilities was able to re-align the investment pacing within this asset class to address safety, environmental, and reliability risks.

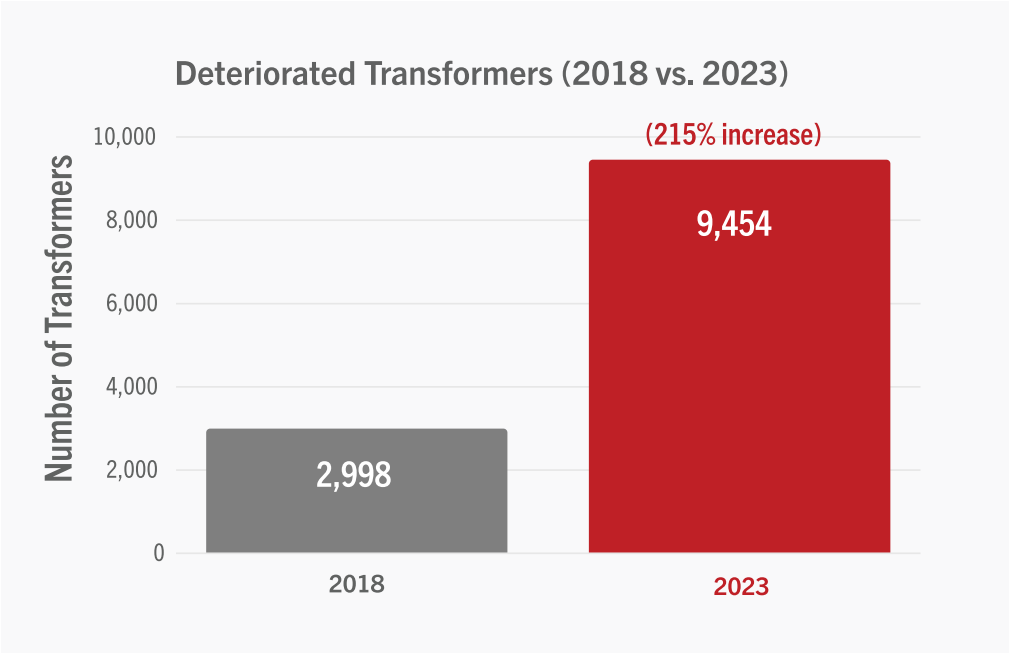


Figure B03 - 6 Distribution Transformer Health Index Comparison (2018 vs. 2023)

To illustrate another example of this increase, Figure B03 - 7 and Figure B03 - 8 compare the HI results geographically in Alectra East (York Planning Zone including Vaughan, Markham, Richmond Hill, and Aurora) and Alectra Central North (Brampton) operating areas.

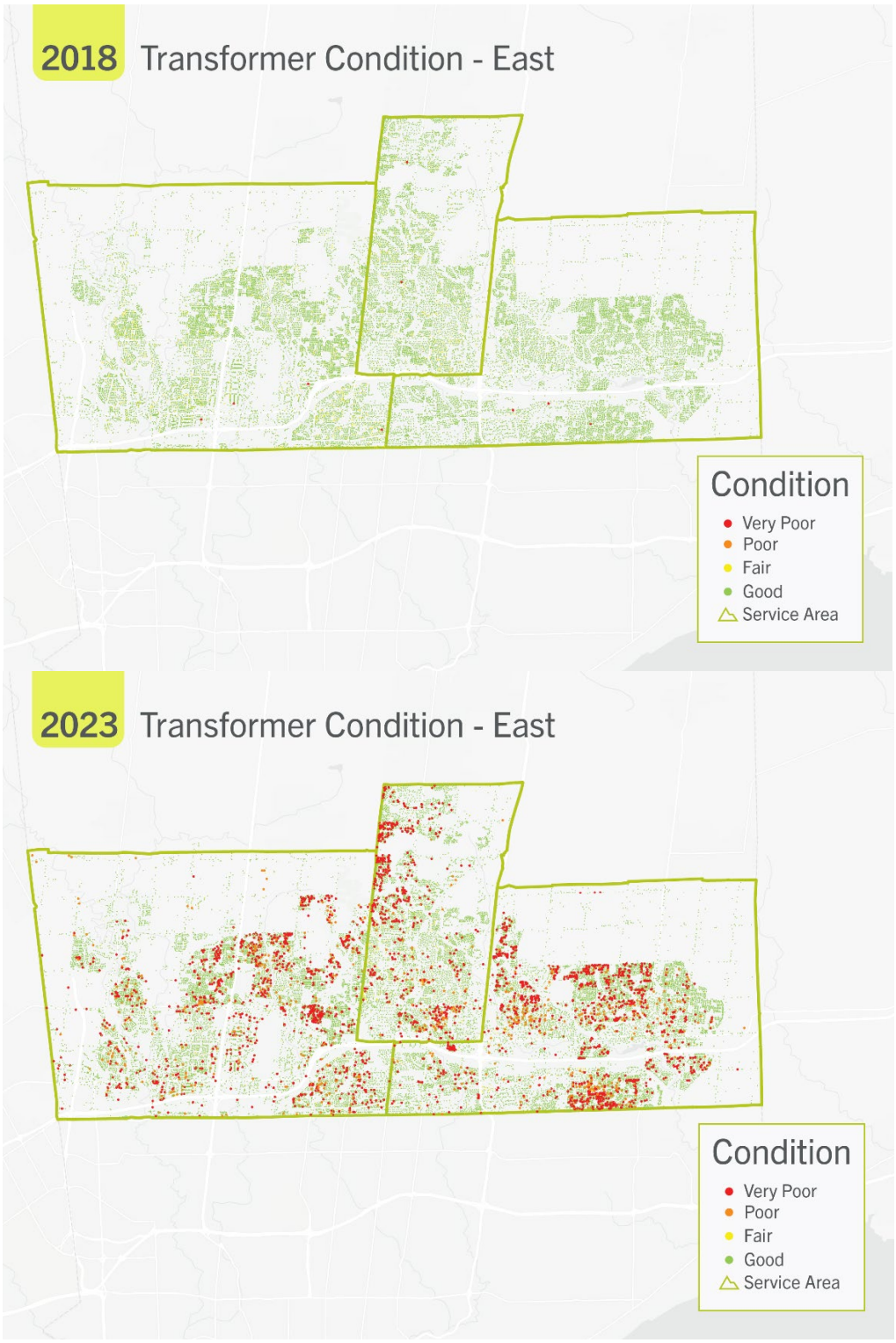


Figure B03 - 7 East – Distribution Transformer Health Index Comparison (2018 vs. 2023)

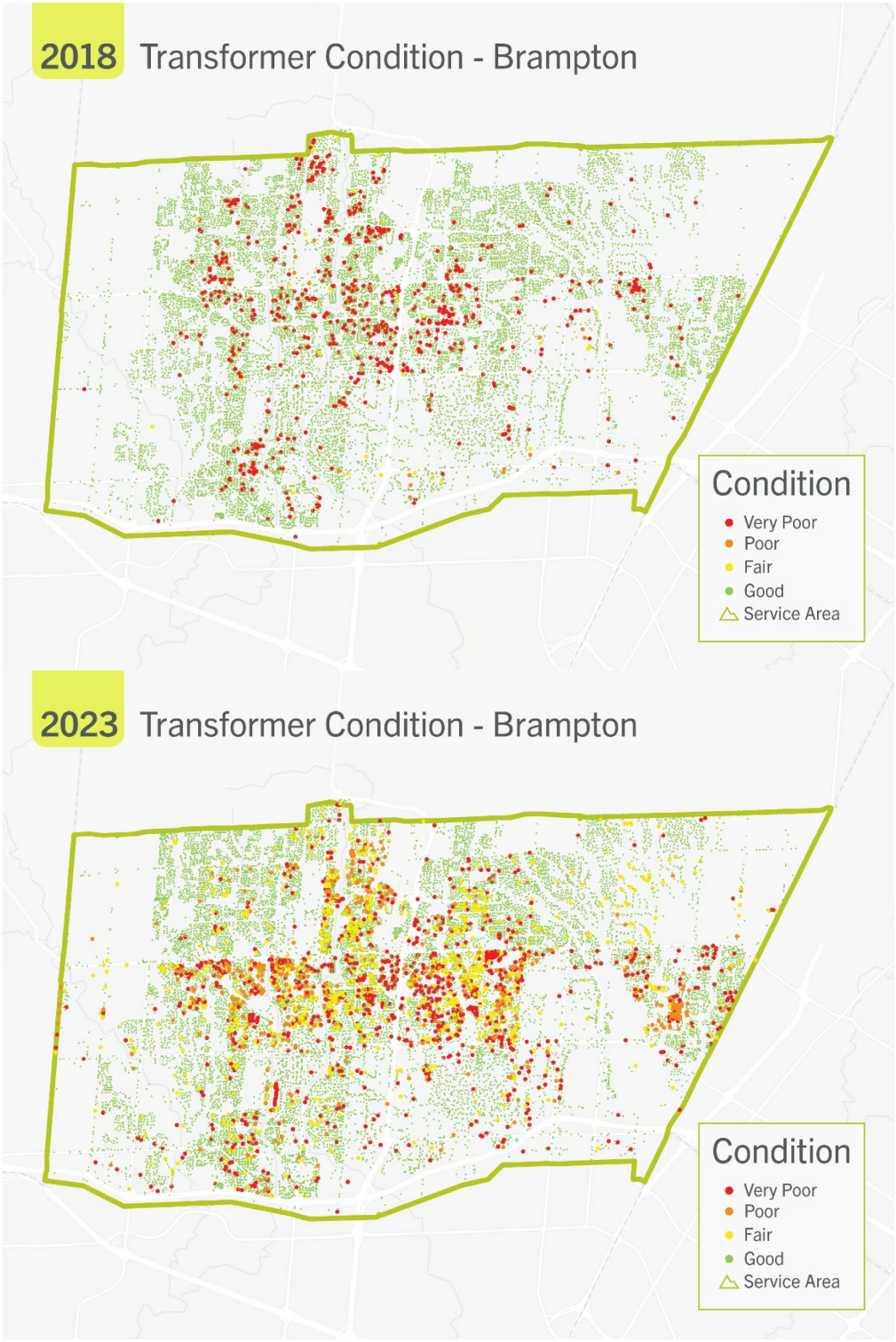


Figure B03 - 8 Brampton – Distribution Transformer Health Index Comparison (2018 vs. 2023)

Alectra Utilities must comply with environmental legislation which governs the management of oil spills occurring from Alectra Utilities' in-service oil-filled assets, including transformers. This environmental legislation includes *Ontario Regulation 675/98* enacted under the *Environmental Protection Act,* RSO 1990, E. 19, and the PCB Regulations (SOR/2008-273), enacted under the *Canadian Environmental Protection Act, 1999.*

Under the PCB Regulations, Alectra Utilities is also required to report any spills involving more than one gram of PCB into the environment. In this scenario, Alectra Utilities is required to carry out full environmental remediation of the site where the transformer oil leak occurred.

Under *O. Reg. 675/98*, Alectra Utilities is also required to report all oil spills of 100 litres or more into the environment. If spills of 100 litres or more occur from Alectra Utilities' transformers, Alectra Utilities is required to report and make immediate arrangements for remediation of the site where the transformer oil leak occurred. From 2021-2024, Alectra Utilities had a total of 1,234 spills, and on average ~90% were due to equipment failure.

Alectra Utilities generally addresses transformers with oil leaks through different capital programs. Leaking transformers posing immediate safety, environmental, and regulatory risks are managed reactively. In these cases, the severity of the leak demands an urgent response to prevent rapid environmental contamination and to safeguard public safety. For example, a transformer oil leak that has migrated off the foundation poses a high risk of environmental contamination, potentially resulting in significant remediation costs and operational disruptions. By addressing these types of leaks reactively, Alectra Utilities can quickly mobilize emergency responses, contain the damage, and restore compliance with environmental regulations without waiting for a scheduled capital replacement cycle. Oil leaks with lower severity, while not presenting an immediate catastrophic risk, still require planned intervention to prevent further deterioration. Addressing these assets on a planned basis before they escalate into major issues has several benefits, including minimizing the cumulative impact of small leaks which, over time, can lead to increased environmental exposure and higher long-term remediation costs.

In response to the increased number of deteriorated transformers, Alectra Utilities is shifting to a planned replacement strategy. This shift enables Alectra Utilities to realize inherent benefits, including more predictable capital expenditures and the integration of these replacements into the utilities' broader asset management strategy. This shift also enhances system reliability by

avoiding unscheduled outages and ensures that all at-risk transformers are managed in a way that minimizes risks and supports sustainable, long-term operational planning.

4.2 Prolonged Customer Interruption (Reliability Risk)

Reliability risks are associated with units that pose a high risk of prolonged service interruption due to inaccessibility, lack of redundancy, or functional obsolescence (e.g. non-standard legacy configurations or transformers that are undersized). The impact of a prolonged transformer failure on customers has increased, as customers rely more heavily on electricity for transportation, heating, and remote work.

4.2.1 Functionally Obsolete, Over-loaded Transformers & Delta Transformers

Overloaded transformers are functionally obsolete since these units are undersized for the customer demand they serve. Operating under an overloaded state accelerates the deterioration of the transformer's insulation, ultimately leading to failure. Additionally, Alectra Utilities has harmonized on 100kVA being the standard kVA size for residential transformers. This allows for increased power usage driven by EVs and electrification.

Delta transformers are transformers that have the windings connected in a triangle (or delta) configuration. These types of transformers lack a neutral wire and therefore pose a safety and reliability risk. Delta transformers are considered functionally obsolete and represent another asset type that Alectra Utilities must address during the upcoming rate period. In 2023, the ESA directed all utilities in the province with these units in service to resolve the associated safety concerns. Required actions can range from relatively simple fixes, such as removing a ground strap, to more complex interventions, including complete overhead rebuilds in affected areas. As this directive is tied to public safety, and non-discretionary, Alectra Utilities is obligated to comply and ensure that all delta transformer units meet ESA requirements.

4.2.2 Lack of Redundancy and Poor Accessibility

Transformers that have inadequate redundancy pose the risk of extended outages because of the lack of backup supply or spare inventory. A major benefit of planned replacement in these situations (as opposed to running these units until failure) is to provide looped supply in the event the customers are supplied radially. Managing this risk on a planned basis provides Alectra

Utilities with the time and opportunity to design new cable routes and reconfigure the network, creating multiple supply paths. By supplying power from two sources, a backup source of power is available in the event of a transformer failure along the loop. This enhances the reliability for customers as the failed transformer can be removed from the loop and power can be restored to nearby customers whose transformer was unaffected.

Transformers located in environments with poor accessibility, such as below-grade installations, basements, underground chambers, or cramped vault rooms, pose unique challenges that extend beyond the typical degradation of the asset itself. In these cases, the inherent difficulty of reaching the unit not only delays routine maintenance but also hampers rapid reactive replacement efforts when failure occurs. For instance, if a transformer installed in a confined vault room fails, the logistical challenges of mobilizing specialized equipment, coordinating emergency access, and executing the work during non-standard hours can lead to prolonged outages and elevated restoration costs. Moreover, many of these vault installations no longer meet current CSA specifications, making them less safe for both the workforce and public. Due to these factors, a planned replacement strategy is implemented for transformers in these specific situations to mitigate risks and service impacts.

In addition, the decision to replace transformers in such hard-to-access locations is driven by the broader impact on network reliability. These assets often lack redundancy. When a unit fails in an inaccessible area, there is typically no immediate backup or parallel supply to minimize disruption. By replacing and relocating these transformers to more accessible sites (such as moving a vault installation to a pad mounted configuration) through a planned replacement program, Alectra Utilities not only reduces the inherent risk of extended outages but also enhances operational efficiency in the long run. This approach ensures that planned capital investments address both immediate safety and environmental concerns while aligning with Alectra Utilities' overall strategy to maintain high reliability standards and minimize customer impact. When transformers in these vault rooms fail catastrophically it leads to lengthy outages, and increased costs due to generators being required to power the building. While customers are supplied by generators, the long-term solution must be designed, materials procured, resources assigned, and finally the permanent service installed on a rush basis. In many cases, these expedited replacement projects do not allow sufficient time to conduct comprehensive design evaluations or to secure the best materials and resources, which can lead to suboptimal

performance or premature failure of the new installations. By replacing and relocating these transformers through a planned replacement program, Alectra Utilities can mitigate risks of unplanned, lengthy outages.

V Options Analysis

This section describes the alternatives that Alectra Utilities considered for the pace of Transformer Renewal investments.

Alectra Utilities leveraged Copperleaf C55 Technologies Predictive Analytics software to develop a multiyear asset replacement strategy (refer to *Chapter 5.3.3 (5.3.3.6 A)*). The software generated the quantity of distribution transformer replacements over the 2027-2031 period. As provided in *Chapter 5.3.3 Asset Lifecycle Optimization Policies and Practices*, Alectra Utilities developed three pacing options for Transformer Renewal: Accelerated, Moderate and Reduced.

Each of the three options addresses transformers during the DSP period that: are currently in Very Poor or Poor condition; contain PCBs; are functionally obsolete (e.g. delta transformers); lack adequate redundancy or are difficult to access. While each option will mitigate public safety, environmental, and reliability risks, the Accelerated option will have the greatest impact since it addresses the largest number of units (followed by the Moderate option, and finally the Reduced option).

Option 1: Transformer Renewal Program – Accelerated Pacing

Starting with 844 transformers per year in 2027, ramping up to 1,348 transformers per year by 2031 (as shown in Table B03 - 7), this pacing approach would replace 5,442 transformers in total, which represents 58% of the 9,454 deteriorated transformers.

Table B03 - 7 Accelerated Pacing

	Bridge		Forecast Period					
	2025	2026	2027	2028	2029	2030	2031	Total (2027-2031)
Option 1: Accelerated Pacing	590	700	844	964	1,083	1,203	1,348	**5,442**

Option 2: Transformer Renewal Program – Moderate Pacing (Selected Option)

Starting with 680 transformers per year in 2027, ramping up to 1,201 transformers per year by 2031 (as shown in Table B03 - 8), this pacing approach would replace 4,771 transformers in total, which represents approximately 50% of the 9,454 deteriorated transformers.

Table B03 - 8 Moderate Pacing

	Bridge		Forecast Period					
	2025	2026	2027	2028	2029	2030	2031	Total (2027-2031)
Option 2: Moderate Pacing	590	590	680	844	964	1,082	1,201	**4,771**

Option 3: Transformer Renewal Program – Reduced Pacing

Starting with 590 transformers per year in 2027, ramping up to 1,109 transformers per year by 2031 (as shown in Table B03 - 9), this pacing approach would replace 4,222 transformers in total, which represents 45% of the 9,454 deteriorated transformers.

Table B03 - 9 Reduced Pacing

	Bridge		Forecast Period					
	2025	2026	2027	2028	2029	2030	2031	Total (2027-2031)
Option 3: Reduced Pacing	590	590	590	700	844	979	1,109	**4,222**

Figure B03 - 9 illustrates the ramp up curve for the three pacing options.

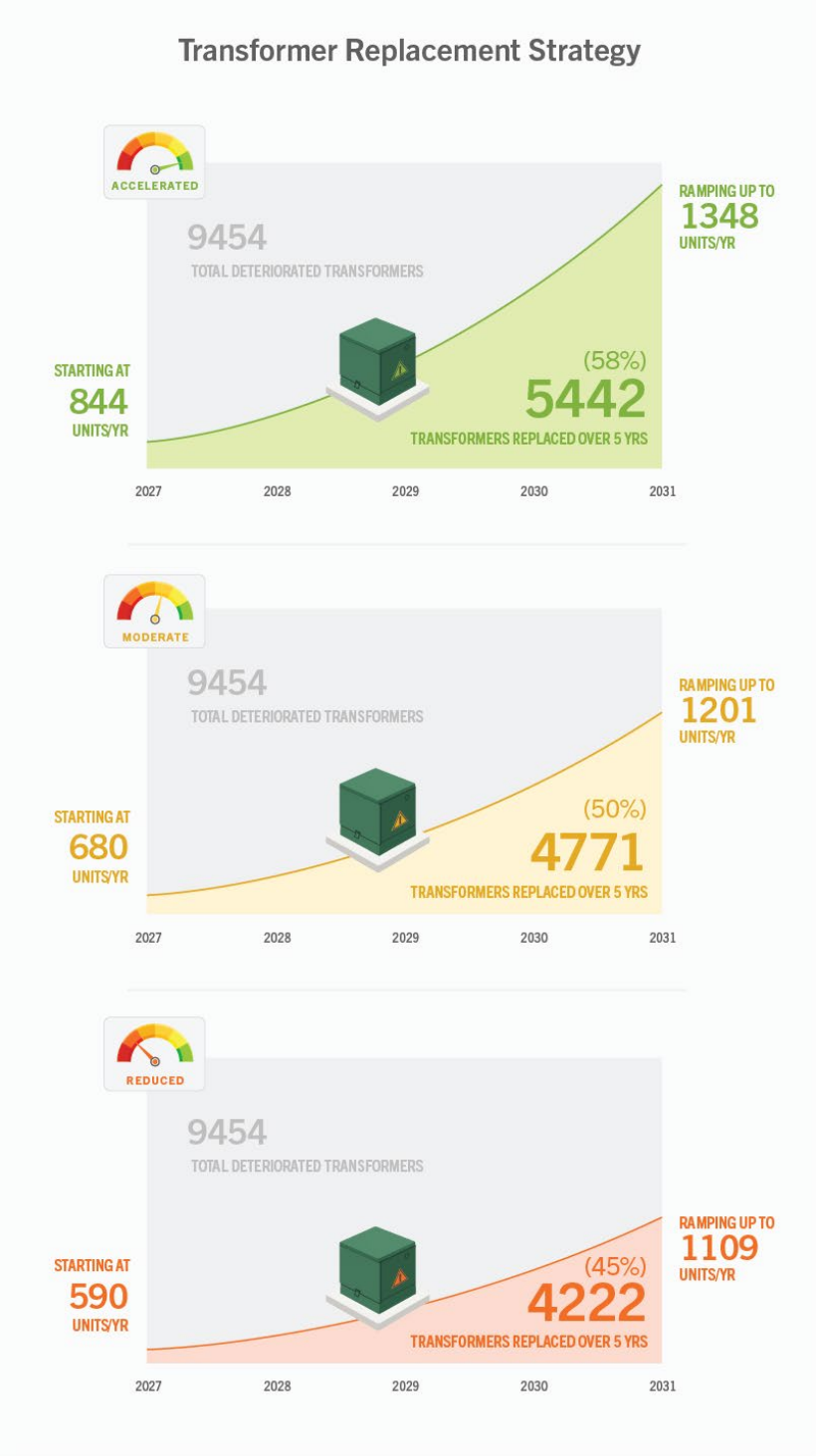


Figure B03 - 9 Transformer Replacement Strategies

Option 2 (Moderate Pacing) was selected through the budget optimization process. This option was presented to customers in the second phase of Customer Engagement. The Accelerated and Reduced pacing options were provided as alternatives. The results of the second phase of Customer Engagement supported the moderate level of investment so no changes were made to the proposed spending.

The Moderate Pacing option addresses approximately half of the deteriorated transformers identified in the ACA. This was considered appropriate given the need to balance DSP investment priorities across the system and practical execution constraints related to supply chain and available resources. The remaining deteriorated transformer population will be managed under a run-to-failure strategy during this DSP period. While this population exhibits comparable risk characteristics, this approach is supported by established asset sustainment practices (detailed in *Chapter 5.3.3 Asset Lifecycle Optimization Policies and Practices*) and reactive strategy (detailed in *Appendix B05 - Reactive Capital*), which will allow Alectra Utilities to appropriately manage safety, environmental, and reliability risks.

The quantities from the three investment options, and their associated costs, are shown in Table B03 - 10.

Table B03 - 10 Pacing Options for Transformer Renewal

Option	Total Quantity	Total Transformer Replacement Plan Cost ($MM)
Option 1: Accelerated Pace	5,442	134.2
Option 2: Moderate Pace	4,771	112.9
Option 3: Reduced Pace	4,222	98.3

5.1 Execution Approach

Alectra Utilities prioritizes transformers for replacement based on environmental, safety, and reliability risks as illustrated in *Figure 5.3.3 – 6* in *Chapter 5.3.3*. Refer to *Chapter 5.3.3 (5.3.3.3 A.1)* for further details on transformer replacement practices. Alectra Utilities will leverage internal staff and external contractors to complete the design of new transformers. The design process also includes coordination with other ongoing projects (e.g. rear lot conversion, road widening, voltage conversion, etc.), where a transformer may be scheduled for replacement as part of a larger project scope. The Project Delivery Group allocates the work to internal staff and external

contractors, if needed, and schedules the transformer replacements to be executed within the planned year. Alectra Utilities conducts regular progress meetings with internal staff and external contractors to ensure technical and operational issues are resolved promptly.

Additionally, to support the increased level of transformer replacements during the 2027-2031 period, Alectra Utilities will leverage established contracts with manufacturers to procure larger volumes of material. These contracts include pricing that is not typically available for smaller customers. Furthermore, long-term material projections were provided to all manufacturers (including transformers) to support reduced lead times in the future.

VI Investment Projects

The material investments from 2027 to 2031 that form the Transformer Renewal investments are included in Table B03 - 11.

Table B03 - 11 Material Investments

Project Code	Project Name	CAPEX ($MM)
Multiple	Transformer Renewal	112.9
151905	Transformer Room Renewal - Swansea Apts (T305), Hamilton	1.8
151906	Transformer Room Renewal - Bentley Place (T553), Hamilton	1.6
151907	Transformer Room Renewal - Greenhill Apts (T194), Hamilton	1.5

Appendix B04 - Substation Renewal

I Overview

Alectra Utilities' substations (or stations) transform electricity from a higher transmission or sub-transmission voltage to distribution voltages supplying distribution grids. Alectra Utilities has 14 Transformer Stations (TSs) that are supplied from the transmission grid at 230kV or 115kV, and 149 Municipal Stations (MSs) that are supplied from the low-voltage side of TSs at 44kV, 13.8kV or 27.6kV. Alectra Utilities' extensive network of TSs and MSs contain essential equipment that is deteriorating. This is evidenced by a 41% increase in average annual corrective, preventative, and emergency maintenance work during the 2020 to 2024 historical period as compared with the previous five-year period. Through this Substation Renewal Program, Alectra Utilities proposes to replace deteriorated and legacy station assets (i.e. station power transformers, circuit breakers, switchgear, switches, and associated equipment) based on condition, with new, standardized equipment in alignment with Alectra Utilities' needs and requirements, including capacity needs to meet forecasted future demands.

The primary driver of replacements under this investment category is the need to mitigate failure risks. The results from Alectra Utilities' 2023 Asset Condition Assessment (ACA) models were an important input for the investment planning process (refer to *Chapter 5.3.2 (Section 5.3.2.2 A)* for ACA study results). Inputs for the ACA models are based on ongoing monitoring and inspections, including visual observations, equipment testing, dissolved gas analysis, oil quality testing, and transformer load monitoring.

Asset condition in the ACA is assessed by computing Health Indices based on collected condition factors. Health indices are expressed as a percentage and are classified into one of the five categories described in Figure B04 - 1.

Health Index Categorization

Category	Criteria	Range
Very Good	Assets with no signs of deterioration.	HI ≥ 85%
Good	Assets in solid working condition with minimal signs of deterioration.	70% ≤ HI < 85%
Fair	Assets functional but showing clear signs of deterioration.	50% ≤ HI < 70%
Poor	Assets exhibiting significant degradation requiring attention.	25% ≤ HI < 50%
Very Poor	Assets showing major degradation or critical condition demanding urgent intervention.	HI < 25%

Figure B04 - 1 Health Index Categorization

Figure B04 - 2 illustrates the 2023 Health Index distribution by condition category for major station assets. This assessment, and all subsequent discussions, are based on Alectra Utilities' station asset inventory as of 2023.

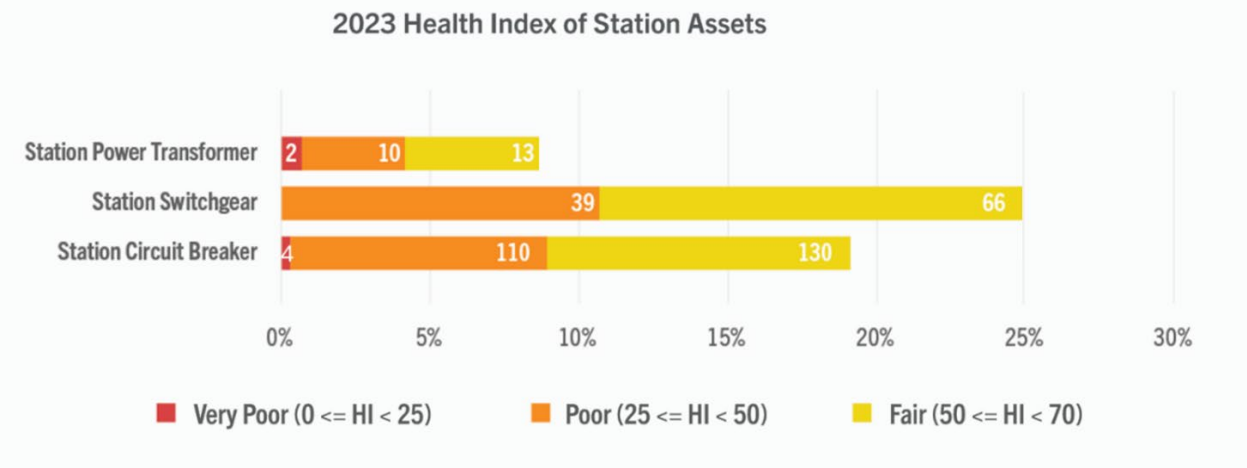


Figure B04 - 2 Health Index for Major Station Assets

Assets flagged as requiring attention are those identified in the Very Poor or the Poor condition category. This Health Index categorization highlights that about 4% of the power transformers, 11% of the station switchgear, and 9% of the circuit breakers are in Very Poor or Poor condition.

Secondary drivers for this program include functional obsolescence (i.e. assets without manufacturer support or spare parts availability), safety hazards (e.g. risk of flashover due to outdated switchgear design), and environmental risks (e.g. transformer oil leaking into sensitive areas such as parklands or waterways). While all of these are important considerations, condition is the primary driver for replacement (refer to *Chapter 5.3.3 (Section 5.3.3.2 B)* and *Section III* below for a discussion of investment drivers and asset failure mechanisms).

Alectra Utilities subject matter experts (SMEs) identified deteriorating assets to establish priorities and recommended pacing for replacement or other remedial actions. In doing so, Substation Renewal Investments were identified and business cases developed based on both risk and impact of failure, including those related to safety, the environment, magnitude and duration of load interrupted, and repair costs. Substation Renewal Investments in the portfolio are described in more detail in *Section II*.

Not proceeding with Substation Renewal Investments at the recommended pace would present an increasing risk of equipment failure. Equipment failures in Substation assets can lead to prolonged outages that impact thousands of customers, pose safety hazards to Alectra Utilities' personnel, and raise environmental concerns, such as potential oil spills from failing transformers. Replacing equipment that fails unexpectedly is also more costly than replacing the same equipment under planned, controlled conditions. Given these risks, a proactive renewal of the utility's station assets with modern, standardized, and safer equipment is needed. These investments are essential for protecting public safety, maintaining customer value, and sustaining overall system resilience.

Table B04 - 1 provides a summary of the Historical, Bridge, and Forecast spends, as well as primary and secondary drivers and key outcomes.

Table B04 - 1 Substation Renewal Investment Expenditures, Drivers and Outcomes

	Historical Spending					Bridge		Forecast Spending				
Year	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
CAPEX ($MM)	16.1	9.9	8.4	9.0	9.3	5.3	4.8	7.5	9.8	14.0	15.8	19.8
Primary Driver	Failure Risk											
Secondary Driver	Functional Obsolescence, Safety, Environmental Risk											
Outcomes	Safety, Reliability, Efficiency, Customer Value, Environment											

Spending during these periods is discussed in further detail below in *Section IV*.

II Investment Description

Over the 2027-2031 period, Substation Renewal Investments generally fall into the following categories depicted in Figure B04 - 3.

Figure B04 - 3 Substation Renewal Investment Categories

Investment descriptions and drivers for each of these categories are contained in the sub-sections that follow.

2.1 Renewal of Station Switchgear and Circuit Breakers

An area of particular concern at Alectra Utilities is the deteriorating condition of a significant number of station switchgear lineups and circuit breakers. The 2023 ACA identified several of these assets as being in the Poor or Very Poor condition category (refer to *Chapter 5.3.2 (Section 5.3.2.2 A.2.2) and Chapter 5.3.2 (Section 5.3.2.2 A.2.3) for details, and Section 3.2 below*). Future investments are required to replace these deteriorating assets to reduce the risk of failure, and

consequent adverse impact on reliability. While condition is the main driver, replacement of these assets will also address safety risks that are present due to the condition of these assets. Furthermore, due to the age of these assets, many are obsolete because they are no longer manufactured, no longer supported by the manufacturer, and/or spare parts are not readily available. This impedes Alectra Utilities' ability to effectively maintain these assets in the optimal operating condition necessary to sustain a safe, reliable system.

An important benefit to replacing deteriorated switchgear is that safety and operational features will be brought to modern standards. The older design of the switchgear targeted for replacement does not effectively protect against safety hazards arising from potentially catastrophic failures. As an example, legacy, non-arc-resistant switchgear will be replaced with modern, arc-resistant models, which greatly reduce the possibility of a catastrophic failure and consequent reliability and safety risks. Some existing switchgear utilize asbestos in their circuit breaker arc-snuffing mechanisms, presenting a further safety hazard to field staff. Alectra Utilities has managed these risks by implementing operational practices to protect staff. For example, at some stations, live switching is not permitted to avoid the risk of catastrophic failure that can result in explosion, fire, and risk to personnel during live switching. However, this introduces complexity and inefficiency into operating practices. For example, an entire bus must be taken out of service in order to maintain a single breaker or cell within the switchgear lineup. Moreover, the system is placed in a higher level of risk during the bus outage. Therefore, this is not a viable, sustainable long-term solution.

Figure B04 - 4, Figure B04 - 5 and Figure B04 - 6 show the extent of the damage that can result from the catastrophic failure of an Alectra Utilities' station switchgear that is not arc resistant.

Figure B04 - 4 Failed Station Switchgear Circuit Breaker

Figure B04 - 5 Blistered Ceiling Caused by Heat from Switchgear Fault

Figure B04 - 6 Blast Damage to Wall Caused by Switchgear Fault

The new switchgear will employ vacuum breakers, which are both safer and more environmentally friendly because they do not contain oil or sulphur hexafluoride (SF_6), which is a potent greenhouse gas. The new switchgear will also be designed to be arc-proof, which reduces the risk of catastrophic failure and consequent adverse impacts on reliability and safety, and allows for breaker racking while the bus is energized, thereby reducing operational complexity and costs. Other significant operational and safety improvements include optical sensors that rapidly trip the upstream breaker in the event of an arc flash to significantly reduce the energy delivered, and remote racking mechanisms will allow staff to disconnect the breakers from the switchgear at a safe distance when performing switching or maintenance activities.

In addition to replacing deteriorated switchgear and breakers, these investments will include replacing deteriorated protection relays and control systems with modern, microprocessor-based platforms. These upgrades will provide better protection for station assets, improved protection

co-ordination with downstream protective devices on the distribution system and provide data for analyzing system faults and equipment failures. In addition, the microprocessor-based equipment would replace aged, deteriorating control and monitoring equipment, resulting in more reliable flows of data to the Supervisory Control and Data Acquisition (SCADA) system. Upgrading the protection and control systems will also support grid modernization initiatives, as the microprocessor-based equipment will provide more real-time system information as well as facilitate the future development of automatic switching and self-healing schemes.

- Over the 2027-2031 period, Alectra Utilities will replace fourteen 13.8kV switchgear lineups, containing a total of 65 circuit breakers. In addition, 3 sets of fused switches and 2 vacuum reclosers will be replaced with circuit breakers. Investments will also be made to install 8 Medium-Voltage Interrupters to implement primary-side power transformer protection at four Stations in Hamilton that presently do not have such protection. Eleven of these projects meet the materiality threshold of $1MM and are described in more detail below. Estimated costs are summarized in Table B04 - 5. The outcomes of these proposed investments will avoid outage impacts due to failing station assets, and the renewal of protection and control schemes will also support the utility's grid modernization initiative.

2.1.1 Station Switchgear Replacement - Maingate MS27 LV1 & LV2 ($4.0MM)

This investment will replace the 13.8kV LV1 and LV2 switchgear, associated circuit breakers, protection and control systems, other ancillary equipment, and end-of-life egress cables at Maingate MS27 in Mississauga. Maingate MS was placed into service in 1982, and the equipment to be replaced is in deteriorated condition. With the ongoing expansion of the downtown Mississauga core, it is imperative that Maingate MS operates reliably since it provides backup to City Centre North MS, another critical station.

Many of the assets to be replaced are also obsolete, meaning that they are no longer manufactured nor supported by the manufacturer, and spare parts are not readily available. These circuit breakers utilize vintage technology to provide short-circuit protection against faults. The outcome of these investments will be to reduce failure risk at this station and will bring the station up to current standards for safety and operability.

2.1.2 Station Switchgear Replacement: Rogers MS30 LV1 & LV2 ($4.0MM)

This investment will replace the 13.8kV LV1 and LV2 switchgear, associated protection and control systems, other ancillary equipment, and end-of-life underground feeder egress cables at Rogers MS30 in Mississauga. Rogers MS was placed into service in 1982, and the equipment to be replaced is in deteriorated condition. This station serves load in the Square One commercial area and provides backup to other Stations in the area. With the continued expansion of the Mississauga downtown core, it is essential that Rogers MS be sustained in optimal operating condition, otherwise reliability in this heavily populated area could be adversely impacted.

Many of the assets to be replaced are also obsolete, as they are no longer manufactured nor supported by the manufacturer, and spare parts are difficult to obtain. The circuit breakers at this location utilize vintage technology to provide short-circuit protection against faults. This investment will reduce failure risk at this station while bringing the station up to current standards for safety and operability.

2.1.3 Station Switchgear Replacement: Woodlands MS13 LV1 & LV2 ($3.6MM)

This investment will replace the 13.8kV LV1 and LV2 switchgear, associated circuit breakers, protection and control systems, other ancillary equipment, and end-of-life underground feeder egress cables at Woodlands MS13 in Mississauga. Woodlands MS was placed into service in 1976, and the equipment to be replaced is in deteriorated condition. With the ongoing growth in Mississauga, Woodlands MS is a critical station and provides backup to Stillmeadow MS. Therefore, maintaining the operability and reliability of the switchgear at Woodlands MS is essential.

Many of the assets to be replaced are also obsolete, as they are no longer manufactured nor supported by the manufacturer, and spare parts are not readily available. These circuit breakers utilize vintage technology to provide short-circuit protection against faults. The outcome will be to reduce failure risk at this station while bringing the station up to current standards for safety and operability.

2.1.4 Station Switchgear Replacement: New Dixie MS45 LV1 & LV2 ($3.5MM)

This investment will replace the 13.8kV LV1 and LV2 switchgear, associated circuit breakers, protection and control systems, and other ancillary equipment at New Dixie MS45 in Mississauga.

New Dixie MS was placed into service in 1990 and the equipment to be replaced is in deteriorated condition. New Dixie MS is a critical supply point in Mississauga and also provides backup to Rockwood MS, another critical station. Therefore, it is essential to ensure there is a reliable supply from this location.

Many of the assets to be replaced are also obsolete, as they are no longer supported by the manufacturer, and spare parts are not readily available. Circuit breakers in this switchgear utilize vintage technology to provide short-circuit protection against faults. The outcome will be to reduce failure risk at this station while bringing the station up to current standards for safety and operability.

2.1.5 Station Switchgear Replacement: Bloor MS38 LV1 & LV2 ($3.5MM)

This investment will replace the 13.8kV LV1 and LV2 switchgear, associated protection and control systems, and other ancillary equipment at Bloor MS38 in Mississauga. Bloor MS was placed in service in 1971, and the equipment to be replaced is in deteriorated condition. With the ongoing expansion of the downtown core, it is imperative that Bloor MS is reliable since it also provides backup to other stations in the area.

Many of the assets to be replaced are also obsolete, as they are no longer manufactured nor supported by the manufacturer, and spare parts are not readily available. Circuit breakers utilize vintage technology to provide short-circuit protection against faults. The outcome will be to reduce failure risk at this station while bringing the station up to current standards for safety and operability.

2.1.6 Station Switchgear Replacement: Hamilton MS71 LV1 ($2.6MM)

This investment will replace the 13.8kV LV1 switchgear, associated circuit breakers, protection and control systems, other ancillary equipment, and end-of life underground feeder egress cables at Hamilton MS71 in Mississauga. Hamilton MS was placed into service in 1982, and the equipment to be replaced is in deteriorated condition. With the ongoing growth in the Mississauga area, Hamilton MS serves significant load and provides backup for Rockwood MS and Bloor MS.

Many of the assets to be replaced are also obsolete, as they are no longer manufactured nor supported by the manufacturer, and spare parts are difficult to obtain. The circuit breakers at this location utilize vintage technology to provide short-circuit protection against faults. This

investment will reduce failure risk at this station while bringing the station up to current standards for safety and operability.

2.1.7 Station Switchgear Replacement: John MS39 ($2.6MM)

This investment will replace the 13.8kV LV1 switchgear, associated protection and control systems, other ancillary equipment, and end-of-life underground feeder egress cables at John MS39 in Mississauga. John MS was placed into service in 1980, and the equipment to be replaced is in deteriorated condition. This station supplies the critical downtown Mississauga area and provides backup to other stations in the downtown core.

Many of the assets to be replaced are also obsolete, as they are no longer manufactured nor supported by the manufacturer, and spare parts are difficult to obtain. The circuit breakers at this location utilize vintage technology to provide short-circuit protection against faults. This investment will reduce failure risk at this station while bringing the station up to current standards for safety and operability.

2.1.8 Station Switchgear Replacement: Aurora MS2 ($2.5MM)

This investment will replace the 15kV switchgear, associated circuit breakers, protection and control systems, other ancillary equipment, and end-of-life underground feeder egress cables at Aurora MS2. The Aurora MS2 was placed into service in 1979, and the equipment to be replaced is in deteriorated condition. The existing switchgear is non-arc-resistant, and moreover these assets are obsolete because they are no longer manufactured nor are they supported by the manufacturer, and spare parts are not readily available. Furthermore, the non-arc-resistant switchgear has been identified as a safety risk and poses operational challenges as live switching is not permitted at this location.

The scope of work will include replacing the existing 15kV switchgear with a new 15kV metal-clad switchgear lineup with arc-resistant construction that meets industry standard and houses new circuit breakers and protection equipment. The outcome will be to reduce failure risk at this station while bringing the station up to current standards for safety and operability.

2.1.9 Primary Breaker and Transformer Protection Upgrade - Brampton MS21 ($1.9MM)

This investment will replace the existing 44kV S&C Alduti-Rupter fused switches at Brampton MS21 with circuit breakers, implement a power transformer differential protection scheme, and improve animal mitigation measures. This station was placed into service in 1974 and serves an area with significant commercial and industrial load. The existing primary transformer protection and switching capability is provided by two Alduti-Rupter switches, which are in deteriorated condition. This equipment is no longer supported by the manufacturer and parts are difficult to come by. Replacing this equipment with modern circuit breakers and adding microprocessor-based relays would reduce the risk of failure at this location, improve operability, and provide improved transformer protection. Moreover, this station has experienced outages due to animal contact in the past; installing animal contact mitigation measures will further improve the reliability of this critical station.

2.1.10 Primary Breaker and Transformer Protection Upgrade - Brampton MS19 ($1.7MM)

This investment will replace the two existing vintage 44kV Joslyn vacuum reclosers at Brampton MS19 with two modern circuit breakers, implement a transformer differential protection scheme and online transformer monitoring. The outcome will be to (a) improve detection of transformer internal faults before a catastrophic failure thereby preventing collateral damage, (b) improve protection coordination at the station and facilitate remote primary breaker operation from the control room, (c) improve supply reliability at this station, while reducing maintenance costs, and (d) bring the station up to current standards for safety and operability.

Although installed in 2014, these vacuum reclosers have a history of failure, including failing to open under fault conditions, an inability to operate either remotely or locally, and one catastrophic failure. Moreover, they do not support the provision of an optimal transformer protection scheme. Protection for the two 16.7 MVA transformers is provided by outdoor drop-out 250E, SMD 2C, 46kV fuses, which do not provide the required capability to rapidly detect faults and isolate equipment to prevent damage. This station has also experienced a number of faults in the past and is therefore at risk for experiencing a fault that develops into a catastrophic incident resulting in significant asset damage, with consequent adverse impact to customer supply. This investment will replace deteriorated assets, improve protection schemes, enhance the remote operability of the station, and reduce the risk of asset failure.

2.1.11 Station Switchgear Replacement – City Centre South MS61 LV1 ($1.8MM)

This investment is to replace the 13.8kV LV1 switchgear, associated circuit breakers, protection and control systems, other ancillary equipment, and end-of-life feeder egress cables at City Centre South MS61 in Mississauga. The City Centre South MS61 LV1 switchgear and circuit breaker inspection results have identified these assets as having poor overall performance and are in deteriorated condition. Furthermore, the manufacturer has provided a written notice advising that these circuit breakers are in the obsolete phase of their life cycle noting that production of this breaker ended more than 30 years ago, and spare parts are not readily available. Since the switchgear is not arc-rated, an arc can cause explosive failure of the existing switchgear which could seriously injure personnel and damage property in its proximity, and result in a widespread and prolonged outage to customers. Also, the circuit breaker arc chutes contain asbestos which is a known cause of lung disease. These arc chutes will be eliminated with the replacement of the switchgear. The safety risks are currently mitigated with operating restrictions and asbestos-handling procedures, but this is not a sustainable longer-term solution.

The outcome will be to reduce failure risk at this station while reducing maintenance costs and will bring the station up to current standards for safety and operability. Any usable breaker components will be harvested to provide needed spares for other stations that have similar types of equipment, thereby serving to maintain the operability of these stations until they can be upgraded. These outcomes align with Alectra Utilities' focus on decreasing the outage impacts due to deteriorating station assets. City Centre South MS was placed into service in 1983, and is a critical station located centrally adjacent to Square One shopping mall in Mississauga. This station supplies a large number of customers and is in an important commercial sector of Mississauga. In addition, this station provides backup to City Centre North MS and other stations in the city core. Accordingly, this station is a critical asset, and it is imperative that it be sustained in an optimal working condition.

2.2 Protection, Control, and Telecommunication Systems ($10.5MM)

Over the DSP period, Alectra Utilities plans to replace end-of-life protection, control, and telecommunications systems to reduce the risk of failure of these assets and maintain these systems in optimal working condition. Protection, control, and telecommunication systems are critical for effective grid operation and reliability, so it is essential that these assets be replaced

before they fail. Failure of these assets could result in customer outages, less effective system protection, and/or a loss of the ability to remotely monitor and control station or distribution assets. Investment decisions are made on the basis of asset condition and performance. In addition to reducing failure risk by replacing end-of-life assets, these investments will allow Alectra Utilities to implement more effective protection, control, and telecommunication schemes for the benefit of its customers.

Protection and control equipment at substations consists of relays, communication switches, controllers and computing platforms. Several substations at Alectra Utilities contain electromechanical, solid-state, or early-generation microprocessor-based relays that are at or beyond their useful life. In some cases, the existing devices are no longer supported by the original manufacturers and there is limited availability of spare parts to perform repairs to these assets. Should these legacy relays fail, customer outages could result, and repair or replacement at that stage would be challenging. Electromechanical and solid-state relays do not provide fault recording or control capability and are not programmable, so their functionality is limited. In some cases, it is no longer possible to communicate with older microprocessor-based relays, as their communication interfaces have become obsolete. Failures of power supplies have also occurred with these relays. Replacing these end-of-life assets yields benefits by reducing the possibility of asset failure and consequent risk to the distribution system that would arise from a non-functional protection scheme.

Electromechanical and solid-state relays also require periodic recalibration and have a limited range of functionality compared to modern protection and control systems. Modern protection and control components are predominately microprocessor-based digital devices that do not have mechanical or moving parts, and, therefore, do not require periodic re-calibration and are less likely to experience failure. When compared to electromechanical or solid-state relays, microprocessor-based relays provide increased functionality and flexibility in terms of protection co-ordination and monitoring and control capability. Replacing end-of-life electromechanical and solid-state protection equipment with microprocessor-based systems results in improved protection co-ordination between substation circuit breakers and downstream protective devices such as reclosers and fuses. This provides better protection for system assets but also results in better reliability, as outages can be more contained to the problem area. In addition, improved protection co-ordination results in fewer momentary outages, which are, at best, a nuisance to

customers with sensitive electronic equipment or those industrial customers whose entire production processes could be disrupted by momentary outages. Microprocessor-based relays provide valuable fault and event record information for effective post event analysis, including fault levels and current and voltage waveforms, which allows for improved analysis of fault events. Information from these systems, such as fault current information, can also be provided to System Controllers via the SCADA system, allowing them to make more informed decisions in response to fault or outage events. Microprocessor-based systems also provide cybersecurity benefits compared to electromechanical and solid-state devices.

Alectra Utilities will also invest in renewing end-of-life telecommunication network equipment. Alectra telecommunications networks perform a critical function by enabling the flow of data from substation and distribution equipment to the SCADA system, thereby supporting remote monitoring and control of this equipment from centralized control rooms. In the future, Alectra Utilities telecommunication networks will also support the flow of AMI 2.0 data from field collectors to the AMI head-end and other operational systems, thereby supporting essential billing and operational functions. Robust, reliable telecommunications networks, therefore, are essential for day-to-day grid operations as well as to enable Distribution Automation and Grid Modernization initiatives. Replacing end-of-life telecommunications equipment, such as Remote Terminal Units (RTUs), switch controllers, and communication base stations are essential to prevent equipment failure and maintain telecommunication networks in optimal operating condition.

During the 2027-2031 period, Alectra Utilities will invest $10.5MM to renew protection, control, and telecommunication systems. These investments are prioritized based on asset condition, asset criticality, remaining useful life, and required functionality. These investments can be categorized as follows:

- Replacement of protection and control systems at 15 MSs across Alectra, and the replacement of feeder protection relays at Vista switchgear located at several Central South MSs ($5.0MM)
- Replacement of end-of-life telecommunications equipment ($5.5MM)

2.3 Power Transformer Tank and Radiator Reconditioning ($5.1MM)

This investment will recondition power transformer tanks and radiators to address corrosion and oil leaks, which can occur as transformers age. Tank or radiator corrosion and leaks could lead

to premature transformer failure and oil spills that could potentially harm the environment. Since power transformers are critical assets, it is essential that these risks be mitigated before a transformer failure, or a major oil spill occurs. The decision to recondition transformer tanks and radiators is based on data collected from site inspections. It should be noted that reconditioning transformers is substantially more cost-effective than replacing units that exhibit the deteriorated conditions observed. The timing and prioritization of specific assets to be addressed is dependent upon the severity of the corrosion or leaks, as well as the relative significance of the specific transformer. These investments will address 23 power transformers across Alectra Utilities' service territory. The outcome of these investments will be to reduce the risk of asset failure, reduce the risk of environmental contamination in compliance with the Ontario *Environmental Protection Act*, and maintain a reliable power supply to Alectra Utilities' customers.

2.4 Replacement of Trench Primary Metering Unit Instrument Transformers ($2.0MM)

This investment replaces existing Alectra Utilities-owned high-voltage (230kV and 115kV) Trench oil-filled primary metering unit instrument transformers (PMU ITs) with SF_6 gas-insulated or clean-air technology instrument transformers that do not contain oil. This investment is a continuation of previous work whereby 230kV combined-unit PMU ITs at Alectra Utilities stations have been replaced. Oil-filled units experience issues with oil levels, oil level imbalance, and overheating, which can lead to catastrophic failure. These units are contained in a porcelain housing and lack pressure relief or monitoring capability. Overpressure events have led to three catastrophic failures where the porcelain body shattered, and projectiles caused damage to adjacent assets as well as posing a significant safety risk. The oil that was released also caused damage to adjacent equipment due to its heat and presented an environmental hazard. Cleanup and replacement activities after these catastrophic failures incurred significant costs. With the completion of this investment, all oil-filled Alectra-Utilities-owned PMU ITs will have been replaced. Figure B04 - 7 shows the PMU IT at Jim Yarrow TS that failed explosively on August 8, 2022. Shrapnel from the explosion can be seen in the foreground of the photo. Shrapnel did cause damage to the radiator of one of the power transformers. Fortunately, no one was in the switchyard at the time of the event, and safety impacts, such as a critical injury, did not occur.

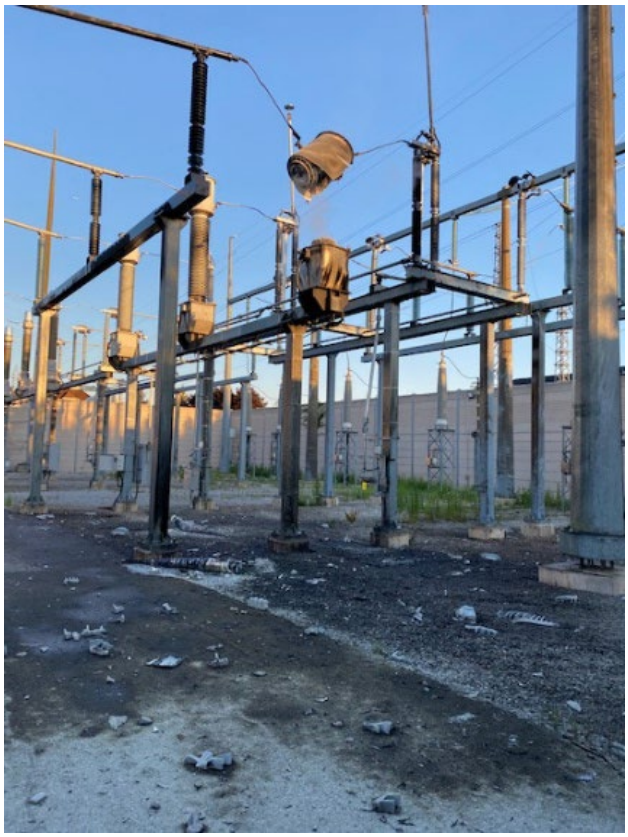


Figure B04 - 7 Failed PMU IT

Due to the significant risks associated with the existing units, Alectra Utilities replaced twenty-four 230kV combined current transformer/voltage transformer (CT/VT) PMU ITs in its Transformer Stations in 2022 and 2023. Until all these units were replaced, operating restrictions were put in place to protect personnel from potential catastrophic failures. The replacement units are SF_6 gas-insulated, contained in a polymer housing, and incorporate pressure relief and real-time monitoring capability. These investments, therefore, greatly reduce the risk of catastrophic failure.

The next phase of the project is to replace 6 remaining units at Alectra Utilities VTS3 in Vaughan, and 12 units owned by Alectra Utilities at Hydro One TSs in Hamilton. The replacement units will be similar to the ones deployed in the previous phase and will be either SF_6 gas-insulated or utilize clean air technology. The six units at VTS3 are 230kV stand-alone Current Transformers and Voltage Transformer units, and each pair will be replaced with a single, combined CT/VT unit. The assets in Hydro One TSs are 115kV combined CT/VT PMU ITs, and their replacement will be co-ordinated with planned Hydro One upgrades at these locations. Over the 2027-2031

period, the total investment will be $2MM. The result of these investments will be improvements to safety and reliability due to a greatly reduced risk of asset failure.

2.5 Safety and Security ($6.4MM)

Safety & Security investments mitigate identified safety and security risks at Alectra Utilities' stations. During the 2027-2031 period, the utility plans to address specific risks through these investments:

1. Station Buildings and Facilities renewals
2. Physical security reinforcement at Stations
3. Installation of Oil containment systems

2.5.1 Stations Buildings and Facilities Renewals ($3.4MM)

In addition to the electrical assets located at Alectra Utilities Stations, there are structures such as buildings and facilities that must be maintained in good working condition to protect electrical equipment, preserve safety of Alectra Utilities personnel and the general public, and enhance physical security of Stations. Such structures include roofs, windows, walls, brickwork, doors, gates, fences, foundations, driveways, plumbing and drainage, and HVAC systems. Investments are planned to replace or upgrade deteriorated components before they fail to reduce risks to safety and physical security and protect electrical apparatus. For example, water ingress due to leaking roofs could create hazards to electrical equipment, while loose roof shingles could present safety risks to personnel and the general public. Broken gates or windows could result in physical security risks. HVAC systems must be maintained in good working condition for the safety of personnel and to protect sensitive electronic equipment. Deficiencies are identified through monthly station inspections and periodic building/facility condition assessments, and corrective or replacement work is planned and prioritized accordingly. During the 2027-2031 period, Alectra Utilities will invest $3.4MM in this category.

2.5.2 Physical Security Reinforcement at Transformer Stations and Municipal Stations ($0.7MM)

As stations are critical components of Alectra Utilities' distribution system, it is necessary not only to maintain station assets in optimal working condition, but also to maintain the physical security

of stations to protect against unauthorized intrusion. [redacted] Moreover, Alectra Utilities incurs costs to repair or replace stolen or damaged assets, including [redacted] Unauthorized intrusions can also present safety risks, as damaged equipment or compromised grounding systems can manifest as safety hazards to members of the general public, as well as Alectra Utilities' personnel. The intruders themselves also run the risk of coming into contact with live equipment, with potentially dire consequences.

Unauthorized intrusions also occur where [redacted] Damage to station property or the building can also occur.

[redacted]

[redacted] Over the 2027-2031 period, Alectra Utilities will invest $0.7MM to [redacted]

2.5.3 Oil Containment Systems ($2.3MM)

Alectra Utilities has a number of MSs that do not have oil containment systems. When the stations were put in service, there was no requirement to install oil containment systems. However, without oil spill containment systems, leaks from the power transformers can result in severe environmental damage to the immediate station site, as well as to adjacent private or public properties. The risk is heightened when a station is located close to parklands or waterways. An oil containment system provides a means of collecting transformer oil should there be a high-volume leak or spill, thereby reducing the risk of contaminating neighbouring properties as well as environmentally sensitive areas, such as waterways or parks. Moreover, cleaning up a major oil spill is costly. Implementation of these systems minimizes these risks and ensures that these stations are aligned with the recommendations specified in IEEE Std. 980-2013 (IEEE Guide for Containment and Control of Oil Spills in Substations) and also comply with the Ontario *Environmental Protection Act*. Having an oil containment system in place also demonstrates

proactive risk management to insurance providers and signals a commitment to safety and environmental protection.

To mitigate the risk posed by stations not having oil containment, over the past several years Alectra Utilities installed Sorbweb oil containment systems at several MSs. The Sorbweb oil containment system is a gravity-based system using geosynthetic materials which trap oil in the event of spills and leaks. The system incorporates a three-layer architecture, including a synthetic impermeable liner, an absorbent/adsorbent filter layer, and a retention layer containing oil-absorbing fabric that seals on contact with hydrocarbons. This design does not require any sumps or oil water separators and therefore eliminates the need for any regular maintenance activities. Figure B04 - 8 shows an image of the installation of the Sorbweb material at an Alectra Utilities' municipal station.

Figure B04 - 8 Sorbweb Installation

The main driver of Alectra Utilities' planned investment in oil containment is public safety through environmental stewardship. By protecting customers from oil spills into water systems or onto their property, Alectra Utilities is protecting its neighbours and customers from property damage and potential health issues. During the 2027-2031 period, Alectra Utilities plans to implement modern oil containment systems, such as the Sorbweb system, to address transformers in Mississauga and Barrie that presently do not have oil containment capability. Priorities have been selected based on stations located in the proximity of creeks or parklands. Over the 2027-2031 period, a total of $1.6MM will be invested in this category in Mississauga to install oil containment systems at 5 MSs. In East North (Barrie), a total of $0.7MM will be invested to address 3 MSs. These investments will result in greatly reduced environmental risk, reduced possibility of significant cleanup costs, and improved compliance with standards and regulations.

2.6 Replacement of Failed and Deteriorated Equipment ($11.4MM)

Reactive capital investments are driven primarily by failure of station, protection and control, and telecommunication assets, thereby requiring replacement of the failed asset to maintain the normal operating status of the system or station and the overall grid. Deterioration of the health of an asset may also become apparent through routine inspections, testing, transformer oil sampling, or via online asset monitoring tools. In some cases, the health of the asset is poor enough to warrant immediate replacement to prevent failure and the consequent disruption to service. Examples of assets that can fail are power transformers, switchgear, circuit breakers, power cables, high-voltage bushings, voltage and current transformers, bus structures and switches, and protection and control (P&C) and telecommunication components. Since these are complex assets and systems, components of these assets may also fail and require replacement. For example, failures may occur in a transformer cooling system that requires replacement or upgrade of the cooling components. Failure of major stations assets can have a significant adverse impact on station operation and the reliability of supply to customers. Failures of protection, control, or telecommunication assets present risks to the grid due to ineffective protection or a loss of control and monitoring capability, all of which have an adverse impact on grid operation. Therefore, it is imperative that failures or imminent failures of these assets be immediately addressed. Replacement of these parts often require considerable costs consisting of procurement of parts or equipment, contractor charges, and internal labor costs. Investments in this category are also utilized to ensure that sufficient spare equipment and parts are on hand

to ensure that asset failures can be promptly addressed, thereby reducing equipment downtime and potential risks to the grid.

Through the execution of this investment, Alectra Utilities' station, protection and control, and telecommunication assets will continue to perform in a reliable and safe manner, with mitigated failure risks and associated grid, customer, safety and environmental impacts.

For the 2027-2031 period, total investments in this investment category are $9.9MM for stations and $1.5MM for P&C and telecommunications assets.

2.7 Summary of Investment Outcomes and Benefits

Table B04 - 2 summarizes the outcomes and benefits associated with the Substation Renewal investment.

Table B04 - 2 Investment Outcomes and Benefits

Outcome	Investment Benefits and Objectives
Safety	• Help ensure public and crew safety by replacing station assets that pose significant safety risks in the event of failure, including the replacement of legacy non-arc proof switchgear units that may give rise to catastrophic flashovers and safety hazards with new arc-proof switchgear.
Reliability	• Help ensure the reliable performance of Alectra Utilities' critical station infrastructure and overall distribution system by: ○ Replacing deteriorated and functionally obsolescent station, protection and control, and telecommunications equipment, which, if not replaced, may impact a high number of residential and commercial customers in the event of failure; and ○ Increasing operational flexibility in terms of inter-station load transfer capabilities to maintain continuity of supply during scheduled or unscheduled outages.
Customer Value	• Deliver customer value by addressing assets in need of replacement on a planned basis to minimize service disruptions, including by avoiding potentially prolonged outages due to the unavailability of spare parts and installing new standardized switchgear that will operate more rapidly to reduce overall impact on customers.

Outcome	Investment Benefits and Objectives
Environment	• Investments in station assets are required to mitigate the risk of failure of power transformers, which contain large volumes of mineral insulating oils used as both an insulating and cooling medium. The consequences of substation power transformer failure may be significant, as they can lead directly to the catastrophic failure of protected equipment, which in turn can lead to customer interruptions, health and safety consequences, and adverse environmental impacts due to loss of oil containment and potentially fire.
Efficiency	• Support efficient control room operations and decision-making by replacing legacy switchgear that have limited automation and event-recording capabilities with new, standardized units that contain high-speed relays and provide enhanced event-recording, automation, control and field intelligence. • Reduce maintenance requirements relating to station circuit breakers because of the installation of new, standardized vacuum breakers that have fewer moving parts and that are more robust in terms of current interruption capabilities and structural durability through repeated switching operations.

1

III Investment Drivers & Need

3.1 Purpose

The Substation Renewal Investment Portfolio is primarily driven by the failure risk of station equipment (due to their deteriorated conditions), with secondary drivers including obsolescence and safety and environmental risks. Given the critical importance of TS and MS infrastructure to the transformation and delivery of electricity across Alectra Utilities' service territory, it is paramount for the utility to identify and plan Substation Renewal Investments in a proactive and timely manner. The fact that station asset failures can impact up to 10,000 (or more) customers for several hours means that an asset lifecycle approach relying on run-to-failure and reactive replacement is not appropriate to achieve customer outcomes.

The planned investments are based on asset condition information that Alectra Utilities gathers and tracks through ongoing monitoring and inspections (including visual observations, equipment testing, dissolved gas analysis (DGA), oil quality testing, and transformer load monitoring). These findings provide the basis for assessments through Asset Condition Assessment models as a key input for subject matter expert evaluation of investment needs and alternatives. Details regarding the key characteristics and conditions of station power transformers, circuit breakers, and switchgear are provided in *Chapter 5.3.2 (Section 5.3.2.2 A.2)* of this submission.

In addition to condition deterioration and failure risk, Stations Renewal investments are also needed to address safety risks and the functional obsolescence of certain assets. The older design of certain station equipment, which are already subject to elevated failure risks due to their age and condition, does not adequately protect against safety hazards arising from potentially catastrophic failures. As an example, legacy, non-arc-resistant switchgear will be replaced with modern, arc-resistant models, which include arc chutes to greatly minimize the safety impacts associated with a catastrophic flashover event. These new switchgear also employ vacuum breakers, which are both safer and more protective of the environment in that they do not contain oil or SF_6 which is a potent greenhouse gas. Other safety features include optical sensors that rapidly trip the upstream breaker in the event of an arc flash to significantly reduce the energy delivered, and solid-state trip devices to improve the safety margin for breaker operation compared to traditional thermal-magnetic protection. Additional features of the new equipment include remote racking capability to enable staff to rack out the breakers at a safe distance when

performing maintenance activities and a control delay function to effectively delay the operation of the breaker on energizing or de-energizing, so that crews have adequate time to move to a safe distance before the circuit breaker contacts are closed.

This investment will also replace assets that are functionally obsolete and difficult or impossible to maintain given the lack of available parts. Some equipment is no longer manufactured or supported by vendors on the market. In the event of failure, spare parts for such legacy equipment are scarce or unavailable, leading to extended outages during complex and difficult reactive repairs.

Table B04 - 3 lists the primary and secondary drivers of Substation Renewal Investments:

Table B04 - 3 Investment Drivers

Investment Driver	Reasoning & Investment Benefits
Primary Driver: Failure Risk	This program is primarily driven by the risk of failure of the station assets, and targets assets identified as being in the poorest condition according to ACA and HI results.
Secondary Driver: Functional Obsolescence	Identified station assets (particularly switchgear and circuit breakers) are technically and functionally obsolete. They need to be replaced through proactive and planned renewal to reduce the impact of prolonged outages (i.e. due to unavailability of spare parts for equipment that is no longer supported or manufactured by vendors) and ensure alignment of critical station assets with Alectra Utilities' system and customer demands.
Secondary Driver: Safety	The design of certain older station assets could create significant safety risks. Alectra Utilities needs to replace non-arc-flash-resistant switchgear with new, standardized units that protect workers against the potentially catastrophic impact of flashover events as well as other features to ensure that work is executed at station sites in a safe manner. Transformer ruptures resulting from catastrophic failure can result in fires and public safety risk.
Secondary Driver: Environmental	Spill containment for older transformers may not meet modern-day standards. Loss of oil containment could result in environmental contamination and high cleanup costs.
Secondary Driver: Physical Security	Unauthorized access onto station premises can result in theft and damage to equipment, thereby presenting operational and safety risks in addition to the cost to repair or replace damaged equipment.

3.2 Asset Details

As discussed above, asset condition data is a key input for identifying and prioritizing replacement candidates as part of the Stations Renewal Investment Portfolio. To this extent, this section describes the salient characteristics and condition demographics of key station equipment (i.e. power transformers, switchgear, and circuit breakers), which underpin Alectra Utilities' ACA analysis and determination of needs and solutions for this investment.

3.2.1 Station Power Transformers

The investments in station power transformers during the 2027-2031 period are primarily to recondition transformer tanks and radiators across Alectra Utilities' service territory to address corrosion and oil leaks. These investments will avoid further deterioration of transformer tanks which could lead to premature failure and large oil spills. The decision whether to replace or recondition a transformer is determined by the type and the extent of work required. Reconditioning is considered when the transformer can be returned to an acceptable operating condition by addressing external components. Transformers are typically replaced when there are internal issues that cannot be rectified.

Selection of transformers for this reconditioning work is based on the results of monthly station inspections and Asset Condition Assessments (ACA). The 2023 ACA Health Index distribution of Alectra Utilities' fleet of power transformers is described in *Chapter 5.3.2 (Section 5.3.2.2 A.2.1)*. Twelve units (about 4% of the total population) are shown to be in Poor or Very Poor condition, while thirteen are in Fair condition. Transformers identified as being in Very Poor or Poor condition are assessed further to determine appropriate action and to determine whether it might be possible to take remedial action to correct or mitigate the issue and maintain the asset in acceptable working condition. However, if such action is not viable, then a decision is made to replace the transformer. In the case of the aforementioned twelve power transformers, all were identified using DGA analysis, which revealed that their insulating oil contained high concentrations of certain gases. Nine of the twelve units were made by the same vendor, are of similar design and vintage, and have historically shown relatively high gas concentrations. Since the gas levels have not changed appreciatively over time, Alectra Utilities has decided to continue to monitor these units with frequent oil sampling and DGA analysis. Should gas concentrations increase, then further actions will be taken. It was decided to adopt a similar course of action with

the other three units, one of which is at a MS that is scheduled to be decommissioned in two years. Consequently, during the 2027-2031 period, no power transformer replacements are planned. The main station power transformer issues and impacts are depicted in Figure B04 - 9 below.

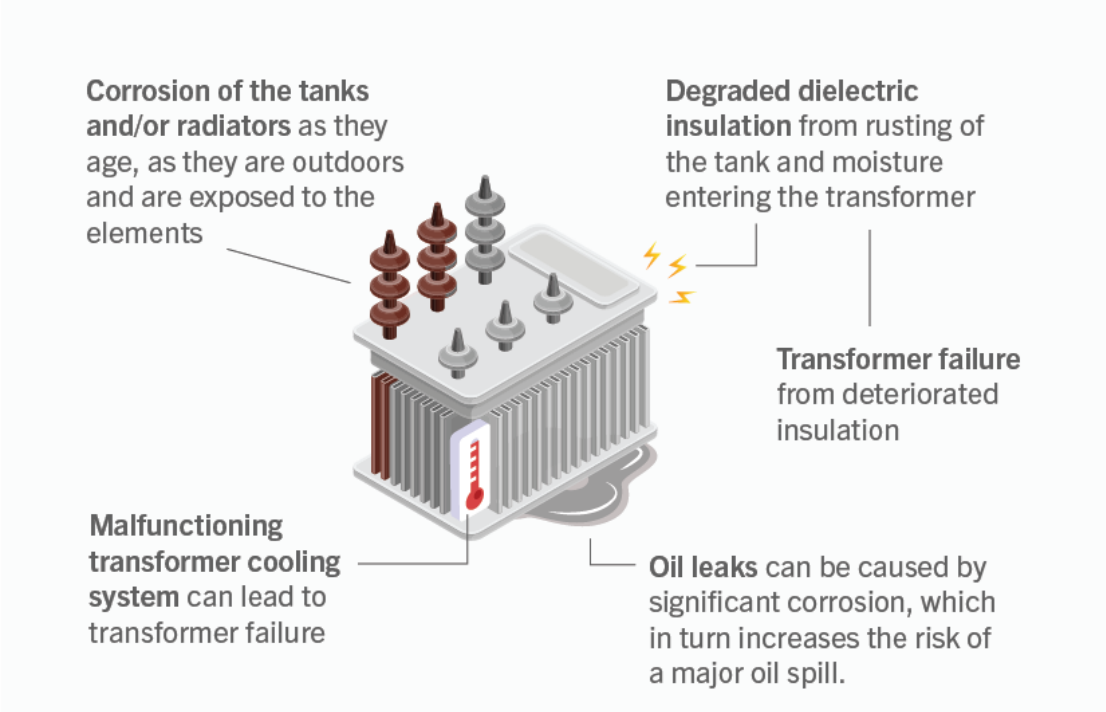


Figure B04 - 9 Station Power Transformer Issues and Impacts

Transformer failures can be catastrophic, resulting in explosions and fire, with subsequent damage to other connected assets. The consequences of a station power transformer failure are significant, as it can lead to widespread customer interruptions, introduce health and safety risks, and create adverse environmental impacts. Moreover, the cost to replace a failed unit would be significant, and the reliability of the system would be at risk until the failed unit could be replaced. Maintaining transformers in optimal working condition is, therefore, imperative, and this extends to ensuring that the tanks and radiators remain in optimal condition.

Alectra Utilities has a fleet of 289 power transformers, including 27 spare units. These are comprised of 31 TS transformers, three of which are spares, and 258 MS transformers that include 24 spares. The age distribution of these assets is described in detail in *Chapter 5.3.2 (Section 5.3.2.2 A.2.1)* of this submission. Forty-nine power transformers were beyond their TUL of 45

years. By the end of the 2027-2031 period, 26 units are expected to exceed their expected End of Useful Life of 60 years, assuming that no power transformers are replaced reactively. All units at or exceeding their useful life are smaller-scale MS power transformers. All larger-scale TS power transformers are within their TUL. Observations of useful life for power transformers is presented for high-level information purposes only; investments are planned based on condition. Alectra Utilities will closely monitor the condition of its aging transformers to determine timing for replacement (currently planned beyond 2031), as well as to identify whether specific maintenance practices are required to maintain these assets in optimal operating condition.

3.2.2 Station Switchgear

The investments in stations switchgear during the 2027-2031 period are to replace deteriorated assets and those that may pose failure risks. Station switchgear includes breakers, disconnect switches, or fuse gear, current transformers (CTs), potential transformers (PTs), and occasionally some or all of the following: metering, protective relays, internal DC and AC power, battery charger(s), and AC station service transformation. The driver for switchgear replacement is condition, primarily that of the enclosed circuit breakers. Safety considerations associated with the switchgear are a secondary driver and improved safety features are a benefit of the replacement.

Detailed information on the 2023 ACA Health Index distribution of Alectra Utilities' fleet of switchgear units is presented in *Chapter 5.3.2 (Section 5.3.2.2 A.2.3)* of this submission. 39 units (about 11% of the installed population) are shown to be in the Poor condition category, while 66 are in the Fair condition category. The switchgear population identified as being in Poor condition were examined against a number of criteria to determine the appropriate course of action. The review considered criteria such as station decommissioning schedules associated with voltage conversion projects, capacity and operational constraints, peak loading levels, type of customers supplied, potential stranded load conditions, distribution system load transfer capabilities, availability of spare components, technical obsolescence, safety and environmental concerns, and available budget/resources. Based on this review, nine station switchgear replacements have been identified in the 2027-2031 period. Replacement of associated circuit breakers, protection and control systems, and other ancillary equipment is included in the replacement of station switchgear. In some cases, underground feeder egress cables will also be replaced if they

are in deteriorated condition. Alectra Utilities will continue to monitor switchgear in the Poor category to determine timing for potential future replacement beyond 2031, as well as any additional maintenance that may be required in the interim to maintain the switchgear in an acceptable operating condition. Alectra Utilities will also manage constraints associated with non-arc-flash rated switchgear remaining in service through the application of modified operating practices to ensure the safety of field personnel.

Condition and age demographics of Alectra Utilities' fleet of station switchgear are shown in *Chapter 5.3.2 (Section 5.3.2.3 B.2.3)* and depicted in Figure B04 - 10.

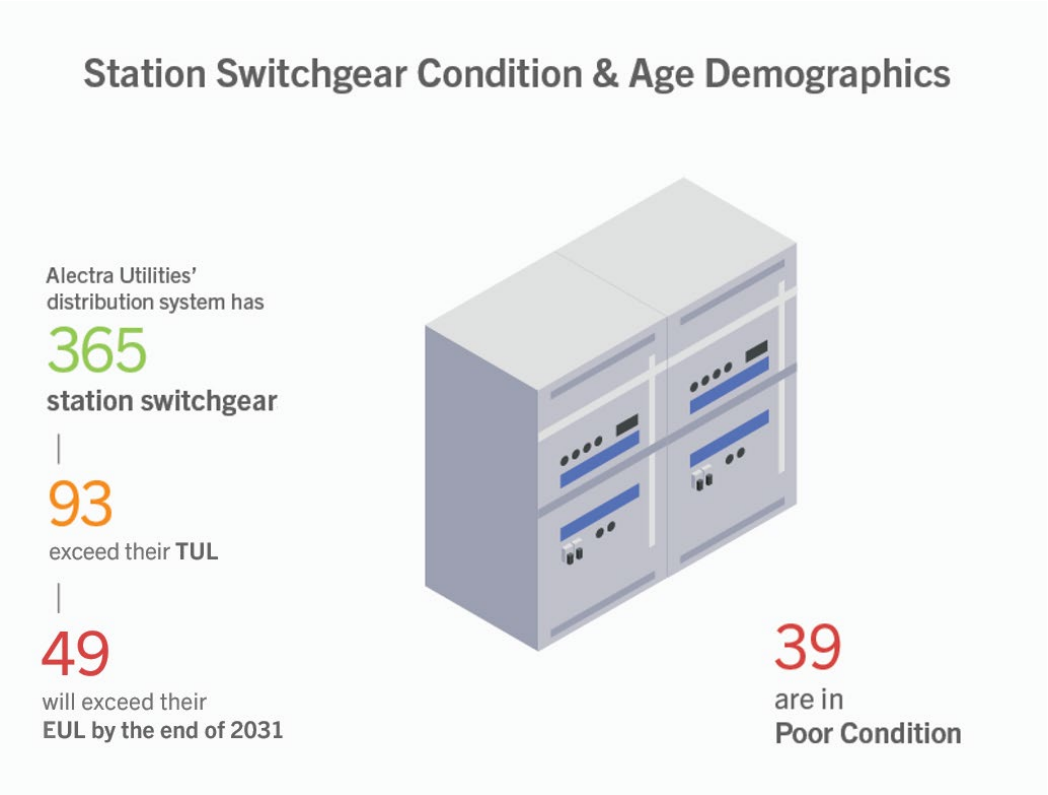


Figure B04 - 10 Station Switchgear Condition and Age Demographics

The utility's distribution system has 365 station switchgear. 93 of these are beyond their TUL of 40 years. 49 switchgear will exceed their EUL by the end of the 2031, if none are replaced. Observations of useful life for these assets is presented for high level information purposes only. The HI model for switchgear does not include an age component since more specific condition data was available for condition assessments. However, switchgear of an older vintage may not meet the current safety and operational standards of modern switchgear assemblies. Once vintage switchgear is ultimately replaced, the advantages of updated switchgear will be realized.

Legacy station switchgear assemblies are not arc rated and typically incorporate older relaying platforms, which have limited automation and event recording capabilities. Maintenance operations, such as the racking in and out of circuit breakers configured within non-arc-rated switchgear, are potentially dangerous. When performing such tasks, proper personal protection equipment (PPE) and an arc-flash boundary must be established and followed. While proper PPE will protect maintenance personnel from the hazards of arc flash to a certain degree, material safety risks remain. For instance, such PPE is designed to prevent burns to the body that could cause death but provides little protection from the force of flying debris when an arc flash occurs.

3.2.3 Station Circuit Breakers

The investments in circuit breakers during the 2027-2031 period are driven by condition and the costs associated with most are tied to switchgear replacement.

Station circuit breakers can make, carry, and interrupt electrical currents under normal and abnormal conditions. Circuit breakers are required to operate infrequently. However, when an electrical fault occurs, breakers must operate reliably and with adequate speed to minimize damage impact. Circuit breaker designs have evolved over time, and many different varieties are currently in use at Alectra Utilities' stations. New switchgear will be equipped with vacuum circuit breakers. The utility typically installs vacuum breakers indoors in metal-clad switchgear for all new installations. Current medium-voltage vacuum breakers require low mechanical drive energy, have high endurance, can fully interrupt rated short-circuit currents up to 100 times, and operate reliably for over 30,000 or more switching operations, thereby making them an appropriate choice for replacement.

Circuit breakers can be stand-alone units (for example, in a station yard) but can also be enclosed in a switchgear assembly in medium-voltage, indoor applications. Enclosed circuit breaker

replacements typically drive the replacement of non-arc-flash-resistant switchgear. The replacement of non-arc-flash-resistant switchgear also drives the replacement of the circuit breakers and protection and control relays that they house. In addition, the risk associated with "obsolete" circuit breakers is being mitigated to a certain extent by retaining components from old units that have been removed from service so that they can be used as spare parts.

The 2023 ACA Health Index results were examined against a number of criteria to determine the course of action for those circuit breakers identified in the asset condition assessment. The review considered criteria such as station decommissioning schedules associated with voltage conversion projects, capacity constraints, peak loading levels, type of customers supplied, potential stranded load conditions, distribution system load transfer capabilities, availability of circuit breakers and components, technical obsolescence, environmental concerns, and available budget.

The fleet consists of 1,277 installed circuit breakers at its stations, 236 of which are associated with Transformer Stations. 114 of these assets are in the Poor or Very Poor condition category (about 9% of the installed population). 64 circuit breakers have been identified for replacement in the 2027-2031 period, in addition to the replacement of 11 medium-voltage interrupters. These assets are all located at MSs. The MS circuit breakers are to be replaced along with their associated switchgear and protections. Obsolete circuit breakers that have been removed from service will be harvested for parts to help to mitigate risks associated with those obsolete circuit breakers that continue to remain in service.

The condition and age distribution of circuit breakers on the Alectra Utilities system are described in detail in *Chapter 5.3.2 (Section 5.3.2.2 A.2.2)* and depicted in Figure B04 - 11.

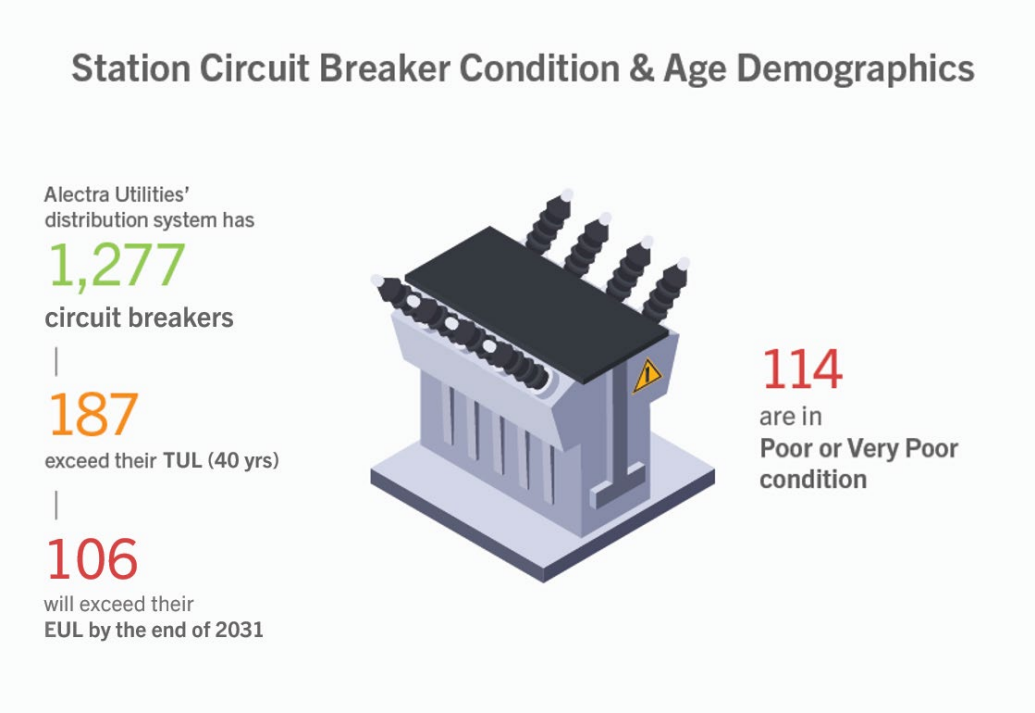


Figure B04 - 11 Station Circuit Breaker Condition and Age Demographics

187 circuit breakers were beyond their TUL of 40 years. 106 will exceed their EUL by the end of 2031, if none are replaced. Observations of useful life for circuit breakers is presented for high level information purposes only. Health Index models for circuit breakers do not include an age component since more specific condition data was available for condition assessments. However, the age of these assets is pertinent, as circuit breakers of an older vintage have design and construction characteristics that make their operation sub-optimal when compared to equipment of more recent vintage.

Certain vintage circuit breakers are a concern, as they have become slow to operate, resulting in longer fault duration times and increased energy dissipation due to arc faults that can affect the integrity of equipment, and pose a safety hazard to operations personnel. This asset degradation is a result of the effects of multiple breaker operations over the life of the asset. There are also safety concerns related to the general nature of switchgear materials and housing design. Electrical short circuits and faults are extremely dangerous, and potentially fatal to personnel. Arc flash occurs when phase conductors are shorted, and ionization of the air occurs. When this happens, the arc faults produce large amounts of heat in radiated form, which can severely burn

the skin and set clothing on fire. Also, during an arc flash hot plasma and molten metal is blasted from the fault location outward in a radial direction at such high speeds that impact can be deadly.

Exposure to arcing faults poses the risks depicted in Figure B04 - 12.

Figure B04 - 12 Risks of Exposure to Arcing Faults

3.2.4 Protection, Control, and Telecommunications Systems

The investments in protection, control, and telecommunications systems during the 2027-2031 period are to replace deteriorated assets and those that may pose failure risks due to being at end-of-life.

Protection and control system equipment consists of relays, RTUs, communication switches, controllers, and computing platforms typically installed in a series of panels or in the low-voltage compartments of switchgear cells. Protection and control components can also be found in control cabinets of outdoor switchgear and transformers.

The primary function of a protection and control system is to provide monitoring and protection of station equipment and to initiate circuit breaker trip and close functions. This function is extremely important because it protects equipment from being damaged by high electrical currents that flow through electrical equipment during fault conditions. Protection systems operate to clear the fault by opening circuit breakers or other protective devices to cease the flow of fault current before equipment sustains damage. Protection relays consist of three types, electromechanical, solid state, and microprocessor based. Details about these three relay types can be found in *Chapter 5.3.3 (Section 5.3.3.3 B.4)*.

Health Indices are not calculated for protection and control equipment. Protection and control assets in poor or deteriorating condition are identified by a history of failure or by increased maintenance or repair requirements. Criticality and the impact resulting from a failure are considered in prioritizing replacements.

Alectra Utilities has 1,638 installed station protection relays, comprised of all three of the aforementioned types. Among all relay types, 457 exceed TUL and 153 exceed EUL. Age demographics for protection and control relays are shown in *Chapter 5.3.2 (Section 5.3.2.2 A.2.4)*.

Protection and control system investments at 15 MSs are scheduled for the 2027-2031 period.

Alectra Utilities will invest in renewing end-of-life telecommunication network assets during the 2027-2031 period. The telecommunications networks perform a critical function by enabling the remote monitoring and control of station and distribution equipment from centralized control rooms, thereby allowing for more efficient switching operations and speedier fault isolation and customer restoration during unplanned outage events. Alectra Utilities' telecommunication

networks will also support the flow of AMI 2.0 data from field collectors to the AMI head-end and other operational systems, thereby supporting essential billing and operational functions. Robust, reliable telecommunications networks are essential for day-to-day grid operations as well as to support Distribution Automation and Grid Modernization initiatives (refer to *Appendix B14 – Enabling Resiliency & Modernization* for more details). These telecommunications networks consist of both wireline (such as fibre-optic systems) as well as wireless media, which primarily include Worldwide Interoperability for Microwave Access (WiMAX), Licensed 900 MHZ Network (LN900 MHZ), and microwave systems. Assets that are at end-of-life present a heightened risk of failure, which would jeopardize the ability to remotely monitor and control the grid. Some assets, such as on the East Synchronous Optical Networking (SONET) fibre-optic network and some WiMAX base stations, are obsolete in that they are no longer supported by the manufacturer, and spares are not readily available. Therefore, investments will be made during the 2027-2031 period to replace end-of-life and obsolete telecommunications equipment, such as RTUs, multiplexers, radios and transmitters, and communication base stations. These investments are essential to prevent equipment failure and maintain telecommunication networks in optimal operating condition.

IV Investment Timing & Pacing

4.1 Summary of Expenditures

Table B04 - 4 provides the year-over-year breakdown for Stations Renewal Program capital expenditures, including the Historical period from 2020 to 2024, the Bridge years in 2025-2026, and the Forecast period from 2027 to 2031.

Table B04 - 4 Historical & Proposed Investment Spending

	Historical Spending					Bridge		Forecast Spending				
Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
CAPEX ($MM)	16.1	9.9	8.4	9.0	9.3	5.3	4.8	7.5	9.8	14.0	15.8	19.8

4.2 Historical Expenditures (2020-2024)

Historical expenditures between 2020 and 2024 total $52.7MM and focused on the replacement of substation assets, including power transformers, station switchgear, and circuit breakers. Two spare power transformers were also procured during this period.

Chapter 5.4.1 (Section 5.4.1.2) describes how investments were prioritized during the Historical period.

4.3 Bridge Year and Forecast Expenditures (2025-2031)

Over the two-year Bridge period in 2025 and 2026, planned expenditures total $10.1MM. Forecast expenditure from 2027 through 2031 is $66.9MM. These expenditures continue the replacement and reconditioning of major station assets, including power transformers, station switchgear, circuit breaker assets, and primary metering units, at an increasing pace during the Forecast period. *Chapter 5.4.1 (Section 5.4.1.3)* outlines how increasing expenditures are strategically necessary during the 2027-2031 period to address renewal of deteriorated infrastructure to maintain reliability and safety. It is imperative that renewal work proceed to mitigate the risk of equipment failure and associated adverse customer impacts and costs. Alectra Utilities has experienced increased costs associated with extending the life of assets, indicating that assets are reaching the end of their useful life. This is evidenced by a 41% increase in average annual corrective, preventative, and emergency maintenance work during the 2020 to

2024 Historical period as compared with the previous five-year period. The increasing expenditures planned during the 2027 to 2031 period are required to address renewal driven by deteriorated asset condition and worsening reliability customers would experience from failed equipment. Investments are also being made to install oil containment systems, [redacted] and replace failed or deteriorated equipment.

4.4 Investment Pacing and Prioritization

Alectra Utilities leverages the asset condition information provided by its ACA models to generate asset health indices for individual station components. The HI results of the ACA are reviewed with subject matter experts in multiple departments to identify those assets most warranting follow-up activities, to ascertain whether a business case should be developed, and if cross-functional drivers are involved. Business cases are prepared and submitted through Alectra Utilities' Copperleaf C55 optimization application where each business case is evaluated based on a multivariable value framework. Business cases are optimized and investments providing the highest value are advanced while the timing of investments providing lower value may be adjusted or deferred. For more detailed information regarding this process, refer to *Chapter 5.3.1 Asset Management Process Overview*.

V Options Analysis

Alectra Utilities has considered the following options to manage the deteriorating and functionally obsolete station assets within its service area. These include the following:

5.1 Transformers

Option 1. Replace all transformers exceeding TUL or deemed to be in Very Poor or Poor condition as identified by the 2023 ACA.

Option 2. Do nothing.

Option 3. Conduct an in-depth review with SMEs. Consider factors described in this appendix to determine suitable remedial actions and their scheduling.

The 2023 ACA identified 12 transformers in Very Poor or Poor condition and 49 transformers that exceed their TUL. The cost to replace all units that exceed their TUL and the 12 units in Very Poor or Poor condition is high and is therefore not recommended. This option was rejected. The decision to replace an asset is driven by condition and not by age.

The do-nothing option was also rejected as the failure risk and impact to customers was deemed to be too significant.

The preferred solution is Option 3. Using a combination of increased condition monitoring and maintenance will provide continued service life in the near term. In addition to addressing transformers that have been identified in the Very Poor or the Poor condition category, Alectra Utilities will perform transformer tank and radiator reconditioning on several units to address corrosion and oil leaks before the operation of these transformers is seriously compromised.

5.2 Station Switchgear

Option 1. Replace all switchgear exceeding TUL or deemed to be in Very Poor or Poor condition as identified by the 2023 ACA.

Option 2. Do nothing.

Option 3. Conduct an in-depth review with SMEs. Consider factors described in this appendix to determine suitable remedial actions and their scheduling.

Option 4. Utilize the outcome of the review described in Option 3, but with a slower pace of replacement to reduce the investment outlay during the 2027-2031 period.

The 2023 ACA identified 39 station switchgear in Poor condition and none in Very Poor condition and 93 station switchgear that exceed their TUL. Option 1, to replace all switchgear in deteriorated condition and that have exceeded their TUL, was rejected as the decision to replace an asset is driven by condition and not by age. This would also be a very costly option.

The do-nothing option was also rejected as the failure risk was deemed to be too high.

Solutions based on Options 3 and 4, with Option 4 being a slower pace of switchgear replacement, were put forward for optimization. The results of the optimization process were the inclusion of 14 individual switchgear lineup replacements within the 2027-2031 period.

In the meantime, focused condition monitoring and maintenance activities will continue, and Alectra Utilities' staff will continue to observe appropriate safety and operating protocols for non-arc-resistant switchgear.

5.3 Circuit breakers

Option 1. Replace all circuit breakers exceeding TUL or deemed to be in Very Poor or Poor condition as identified by the 2023 ACA.

Option 2. Replace only those circuit breakers associated with the switchgear replacements referenced in 5.2 above.

Option 3. Conduct an in-depth review with SMEs. Consider factors described in this appendix to determine suitable remedial actions and their scheduling.

The 2023 ACA identified 4 circuit breakers in Very Poor condition and 110 in Poor condition and 187 circuit breakers that exceed their TUL. The cost to replace all units that exceed their TUL and the 114 units that are in Very Poor or Poor is high and would place pressure on available resources. Therefore, Option 1 was rejected. The decision to replace an asset is driven by condition and not by age.

Option 2 was also rejected, as beyond the 14 switchgear replacements described in 5.2 above there are deteriorated assets that need to be addressed. Not addressing these assets would incur too high a failure risk.

The preferred solution is Option 3. The results of the optimization process were the inclusion of 5 new circuit breaker installations and 8 Medium-Voltage Interrupter installations. These investments are in addition to the 65 breakers are being replaced as part of switchgear renewal investments.

In the meantime, focused condition monitoring and maintenance activities will continue. Risk will further be mitigated by retaining components from replaced breakers as spare parts.

VI Investment Projects

The material investments from 2027-2031 that form the Substation Renewal Investments are included in Table B04 - 5.

Table B04 - 5 Material Projects and Initiatives

Project Code	Project Name	CAPEX ($MM)
Multiple	Capital Reactive Equipment Replacement*	9.6
151100	Station Switchgear Replacement - Rogers MS30 LV1 & LV2	4.0
151102	Station Switchgear Replacement - Maingate MS27 LV1 & LV2	4.0
151097	Station Switchgear Replacement - Woodlands MS13 LV1 & LV2	3.6
150323	Station Switchgear Replacement - Bloor MS38 LV1 & LV2	3.5
151101	Station Switchgear Replacement - New Dixie MS45 LV1 & LV2	3.5
150715	MS Transformers Refurbishment Multi-Year Program - West	2.9
150700	Station Switchgear Replacement - Hamilton MS71 LV1	2.6
150701	Station Switchgear Replacement - John MS39 LV1	2.6
151548	Station Switchgear Replacement - Aurora MS2	2.5
Multiple	Upgrade to Station Facilities (Building / Civil work)	2.4
152374	230kV Trench Replacement Program	2.0
151510	Station Primary Breaker and Transformer Protection Upgrade - Brampton MS21	1.9
150698	Station Switchgear Replacement - City Centre South MS61 LV1	1.8
152320	Station Primary Breaker and Transformer Protection Upgrade - Brampton MS19	1.7
150515	Sorbweb Oil Containment Systems - 4 Transformers -Multiyear Initiative- Central South	1.6
150611	Transformer Tank and Radiator Reconditioning- Multi-year initiative - East	1.5
Multiple	Reactive Replacement of P&C Equipment	1.5
151980	Proactive Battery Replacement in Alectra Field RTUs	1.1

* Please note that this project is different from “Reactive Capital” program in Appendix B05.

Appendix B05 - Reactive Capital

I Overview

Alectra Utilities' Reactive Capital investment portfolio addresses assets that have failed or are at a high risk of imminent failure, or which pose an immediate safety risk. Reactive capital work is required for a variety of unplanned circumstances such as:

- Equipment damage or failure during adverse weather conditions
- Equipment damage due to foreign interference events requiring replacement of assets
- Distribution equipment with defects identified through inspections (as detailed in *Chapter 5.3.3 Asset Lifecycle Optimization Policies and Practices*) or other channels posing risk of imminent failure, safety and environmental concerns (such as severe oil leaks leading to environmental risk and costly environmental remediation)

Reactive Capital investments are, by nature, unplanned and unpredictable. However, they are necessary to address the inevitable impacts of unpredictable events and circumstances while maintaining a reliable distribution system. While Alectra Utilities cannot plan for specific Reactive Capital projects, the expenditures in this portfolio are forecasted based on: historical Reactive Capital spending, observed trends in causal factors (e.g. historical weather impacts and frequency of foreign interference incidents, and trends in asset condition), and consideration of future factors (e.g. weather study results and modelling of the impacts of planned asset replacement investments).

Alectra Utilities has forecasted an overall decreasing trend in Reactive Capital expenditures over the 2027-2031 period. This is largely due to the expected decrease in incidents of defective equipment over the DSP period because of increases in System Renewal investments over the same period. In general, the replacement of assets on a planned basis is more cost effective than replacing assets reactively for a variety of reasons, such as (but not limited to) the ability to utilize regular rather than overtime labour and contracted resources, as well as the opportunity to consolidate work into larger packages, thereby reducing mobilization and administrative costs. Historically, the reactive replacement of defective equipment has been the primary investment

driver for the Reactive Capital portfolio, accounting for an average of 85% of yearly Reactive Capital expenditures (based on historical spending from 2020-2024). As the planned replacement of assets increases over the DSP period, replacement of deteriorated assets in Very Poor and Poor condition (as described in *Chapter 5.3.2 Overview of Assets Managed*) will lead to improvements in overall asset health and a corresponding reduction in failure risk as detailed in *Chapter 5.3.1 Asset Management Process Overview*. This reduced risk is expected to result in a decrease in the reactive replacement of defective equipment.

At the same time, Alectra Utilities expects this overall reduction in Reactive Capital spending to be partially offset by an increasing frequency and intensity of weather events and incidents of foreign interference. Climate risk and vulnerability studies have indicated increasing frequency and severity of weather events which are forecasted to increase the storm segment of the Reactive Capital portfolio over the DSP period (refer to *Appendix G - Climate Risk & Vulnerability Assessment)*. Additionally, Alectra Utilities has experienced increasing trends of foreign interference, primarily from motor vehicle incidents and vandalism, which will also put upward pressure on the need for Reactive Capital investment. Table B05 - 1 highlights the investment expenditures, drivers and outcomes below.

Table B05 - 1 Reactive Capital Investment Expenditures, Drivers and Outcomes

	Historical Spending					Bridge		Forecast Spending				
Year	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
CAPEX ($MM)	22.5	26.8	34.3	34.2	38.9	32.0	30.5	30.7	28.5	25.2	25.2	25.2
Primary Driver	Failure Risk											
Secondary Driver	Reliability, Safety											
Outcomes	Efficiency, Reliability, Customer Value, Safety, Co-ordination / interoperability, Environment											

II Investment Description

The Reactive Capital investment portfolio consists of unplanned work that must be done on an urgent or emergency basis to replace or repair equipment under the following circumstances:

- Equipment that has failed (such as due to deteriorated condition, loading conditions, adverse weather conditions including storms, adverse environmental conditions, human elements, and foreign interference)
- Equipment that is expected to fail imminently
- Where safety risks exist that require an urgent attention

The work conducted in the Reactive Capital investment portfolio is non-discretionary and is typically required to:

- Restore power to customers or critical infrastructure
- Mitigate or eliminate a threat of damage to or loss of customer, public or utility property
- Mitigate or eliminate a threat of injury or risk to customers, the public, or employees
- Respond to a compliance issue such as a public safety concern or deficient condition raised by a regulatory entity (for example, the Electrical Safety Authority), property owner, or other authorities having jurisdiction

Figure B05 - 1 to Figure B05 - 3 provide examples of assets that have failed due to external events such as poles damaged by fire or vehicle accidents.

Figure B05 - 1 Pole Damaged by Pole Fire

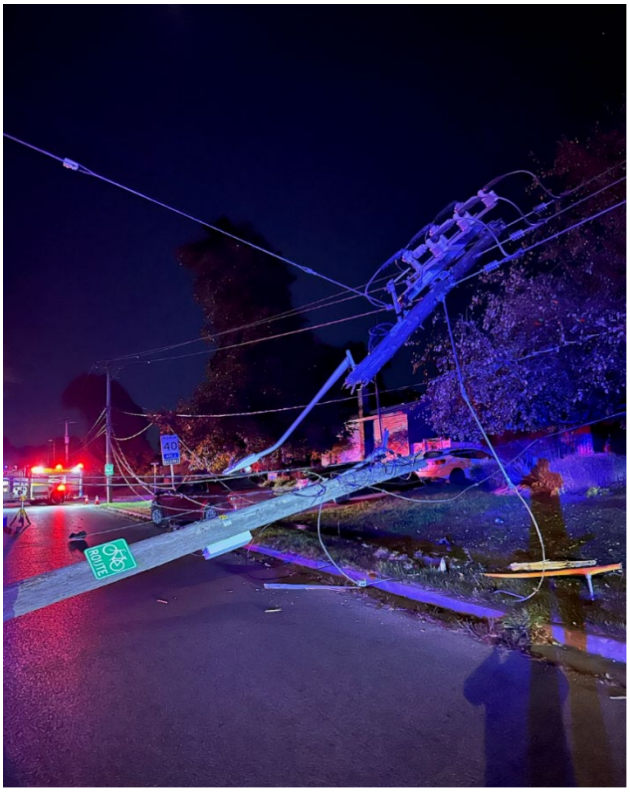


Figure B05 - 2 Pole Hit by Vehicle

Figure B05 - 3 Solid Dielectric Switchgear Damaged by Failure Puncturing Insulating Medium

In some cases, assets are replaced under the Reactive Capital portfolio prior to catastrophic failure. There are several channels that may lead to assets being replaced due to an imminent risk of failure or an existing safety concern. The channels Alectra Utilities uses to identify deficiencies are detailed below in Figure B05 - 4.

Alectra Utilities prioritizes its Reactive Capital portfolio investments to address the highest risk assets first. In some cases, assets deteriorate to the extent that a reactive replacement is required. The decision to replace an asset reactively rather than planned can be influenced by a variety of factors such as safety risks, environmental risks, reliability risks (e.g. downstream customer count and criticality of the asset to operation of the distribution system), compliance risks and customer or third party (such as ESA) complaints (refer to Figure B05 - 4 for relevant decision criteria).

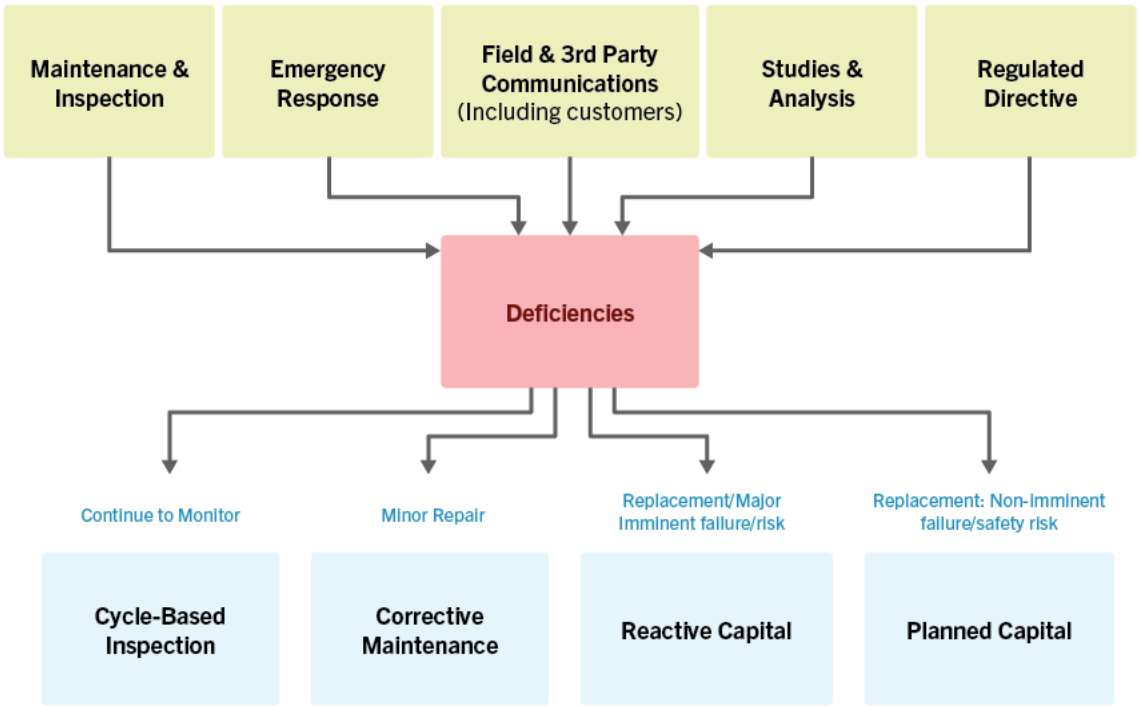


Figure B05 - 4 Deficiencies Flow Process

Immediate intervention may be required due to a range of factors. Equipment that has not failed will primarily be identified for replacement under the Reactive Capital program due to accelerated deterioration or because it poses a safety risk to the public or crews. To this end, the Reactive

Capital program includes the expenditures for failed assets and certain high-risk assets that Alectra Utilities cannot delay until a planned capital project is completed.

Some examples of Reactive Capital replacement decisions for equipment near failure, or posing a safety concern but not yet experiencing catastrophic failure include:

- Assets with serious safety concerns identified during maintenance and inspection activities, such as a pad-mounted piece of equipment with a serious oil leak
- Assets with compromised structural integrity identified during emergency response, such as poles that are severely damaged by vehicles, but found to be erect and supplying power when crews arrive on site
- Assets with imminent failure risk identified when responding to customer identified concerns, such as a switchgear unit making “loud humming noises” found to be electrically tracking
- Equipment identified in a regulated directive such as ESA Distributor Bulletins that may be at high risk of failure and may need to be replaced reactively with a suitable alternative before failure occurs

Due to the urgent and unplanned nature of this investment portfolio, when equipment is replaced reactively, it is typically replaced with a like-for-like substitute with no major reconfiguration. However, assets may be replaced with like-for-better options where Alectra Utilities standards have changed to account for factors such as electrification and storm hardening. Where standards have changed and the equipment is not replaced like-for-like, the replacement of equipment with like-for-better can introduce ancillary benefits to the distribution system and customers. Some examples of this include:

- Improving reliability by replacing an overhead transformer with fully exposed primary bushings with a new transformer with animal protection
- Improving safety and operational efficiency by replacing a pad-mounted transformer that did not have fault-indicating equipment or internal isolating switches with a unit equipped with these features
- Improving safety and reliability by replacing a live-front air-insulated switchgear unit with a dead-front solid-dielectrically insulated equivalent

2.1 Summary of Investment Outcomes and Benefits

Table B05 - 2 summarizes the benefits and objectives of the Reactive Capital investment portfolio and the outcomes these investments address.

Table B05 - 2 Summary of Investment Outcomes and Benefits

Outcome	Investment Benefits and Objectives
Customer Value	• This investment initiative allows Alectra Utilities to address assets at end-of-life or facing imminent failure prior to a catastrophic failure. In many cases, this can allow for service interruptions to be avoided or minimized through job planning. This can also reduce the cost to replace the asset where equipment can be replaced during regular business hours, utilizing standard crews and equipment. • In addition, replacing assets which have failed restores the intended operability of the distribution system. If the equipment has failed, but is not promptly replaced, the distribution system is left in an abnormal configuration which can place restrictions on equipment and available supply to customers.
Reliability	• Equipment failures often result in service interruptions to customers. Quickly replacing failed equipment or addressing imminent failures can minimize service interruptions to customers. In addition, replacing deteriorated equipment (posing imminent risks) or equipment that does not meet current Alectra Utilities standards and specifications reduces the risk of failure and introduces additional reliability benefits inherent in more contemporary equipment (for example, animal guard). • Prompt replacement of failed equipment can avoid impacting customer requested work, which may otherwise need to be delayed until the equipment is replaced, and the system is returned to a normal configuration. Abnormal system configurations can also increase the risk and duration of service interruptions due to unavailable equipment or alternative supply routes.
Safety	• These investments primarily address failed assets and safety issues. Adverse risk and impact to public and worker safety can be mitigated or eliminated by promptly addressing immediate safety issues. • In addition, promptly addressing public safety concerns raised by regulatory bodies such as the ESA or addressing defects found during

Outcome	Investment Benefits and Objectives
	asset inspections are mandatory to adhere to industry regulations, such as section 4 of O.Reg 22/04 and section 4.4 of the Distribution System Code (DSC).
Co-ordination / interoperability	• Failed equipment and equipment with immediate safety concerns can present a hazard for third parties and other utilities that may have equipment installed on the assets, such as with joint-use poles. A failure of these assets can result in outages to joint-use equipment and inadvertent contact with or reduction of clearances to energized equipment. Promptly addressing failed equipment and equipment at risk of failure will reduce safety risks for employees and contractors of third parties.
Environment	• Addressing assets at risk of imminent failure can avoid negative impacts to the environment. For example, contamination of soil or waterways and public exposure to toxins can be minimized or avoided by promptly addressing transformers found to be leaking oil.

III Investment Drivers & Need

3.1 Purpose

Alectra Utilities maintains a discrete investment budget for Reactive Capital expenditures. This budget recognizes that unplanned failures and issues requiring urgent attention arise during the operation of a distribution system and the utility must respond to these issues without requiring continuous reprioritization of other important, planned capital projects.

Distribution equipment fails for many reasons, such as deteriorated conditions, loading conditions, adverse weather conditions including storms, adverse environmental conditions, human elements, or foreign interference. Figure B05 - 5 provides the contribution to customer hours of interruption from 2020-2024 by cause code. Defective equipment, adverse weather, lightning, and foreign interference account for more than half of the customer hours of interruption experienced from 2020-2024. In this program, Alectra Utilities allocates Reactive Capital funding to address the failure and reliability risks associated with these outage causes.

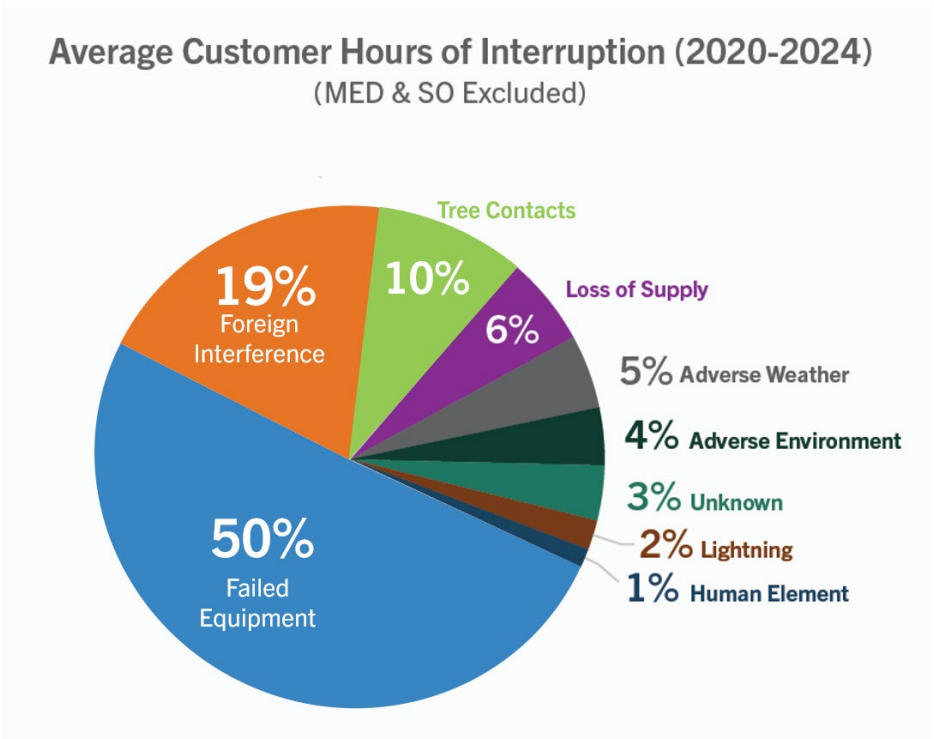


Figure B05 - 5 Alectra Utilities Five Year Contribution to Customer Hours of Interruption by Cause Code (Excluding Major Event Days and Scheduled Outages)

Figure B05 - 6 provides the portion of Reactive Capital investment across 2020-2024 attributed to each major asset type. Underground transformers (padmounted, vault and submersible) account for the largest portion of reactive spend, followed by poles, primary cable and switchgear. While Alectra Utilities has directed planned capital expenditures towards asset renewal in these categories, assets are currently deteriorating faster than they can be replaced. These historical Reactive Capital expenditures have been required to maintain reliability due to failing equipment.

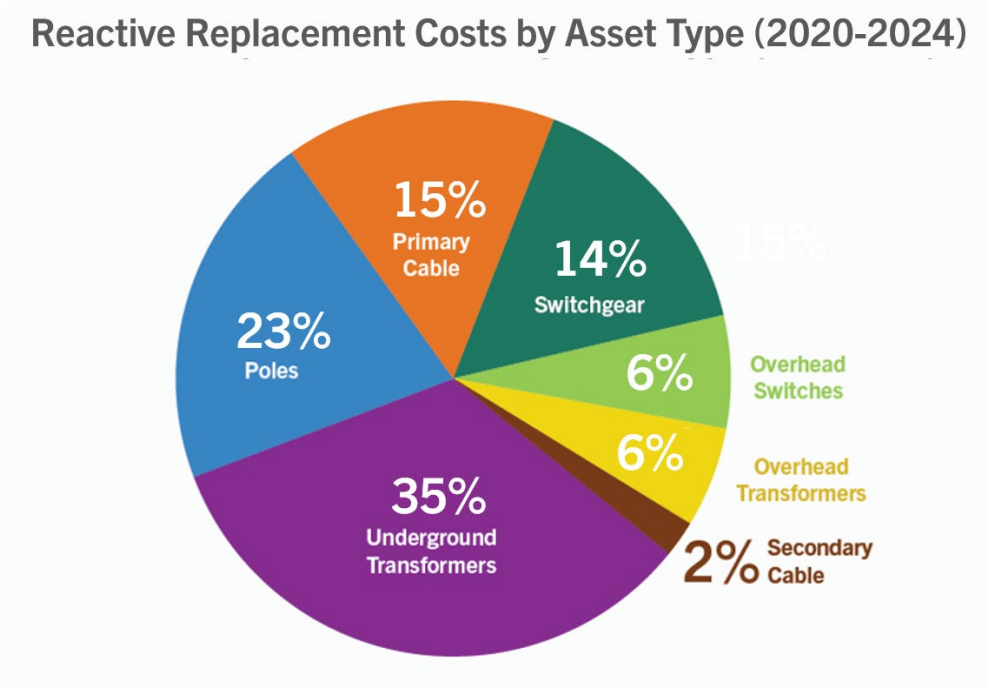


Figure B05 - 6 2020-2024 Reactive Replacement Costs by Asset Type

3.1.1 Reactive Replacement – Equipment Failure, Imminent Failure, Safety or Environmental Risk

Assets may be replaced on a reactive basis due to equipment failure or, in some cases, prior to catastrophic failure. Failed distribution assets (for example, transformers that no longer produce power, switches that cannot be operated or sections of cable that have faulted and require replacement) are replaced reactively as part of this portfolio. In addition, distribution assets may be replaced reactively if there is an imminent risk of failure or if the asset is posing a safety or environmental risk.

Some examples of Reactive Capital replacement decisions for equipment near failure or posing a safety concern but not yet experiencing catastrophic failure include:

- Assets with severe oil leaks that pose environmental risk or lead to costly environmental remediation efforts
- Padmounted equipment with broken doors or severe corrosion (for example, holes) that pose an entry risk for the public
- Poles that are tagged “rotten - do not climb” by pole inspection but must be worked on immediately for maintenance or other reasons outside of a planned capital project
- SF6 insulated switchgear that have low gas and cannot be topped up must be replaced to ensure adequate insulation for safe operation

Over the period of 2020-2024, Alectra Utilities reduced the customer impact of outages due to defective equipment as detailed in Figure B05 - 7. Reactive Capital investments contribute to managing the impact of outages by responding quickly to equipment failures. Reactive Capital investments also allow Alectra Utilities to respond promptly to assets at imminent risk of failure, and safety or environmental impact before a failure occurs, which reduces the customer hours of interruptions.

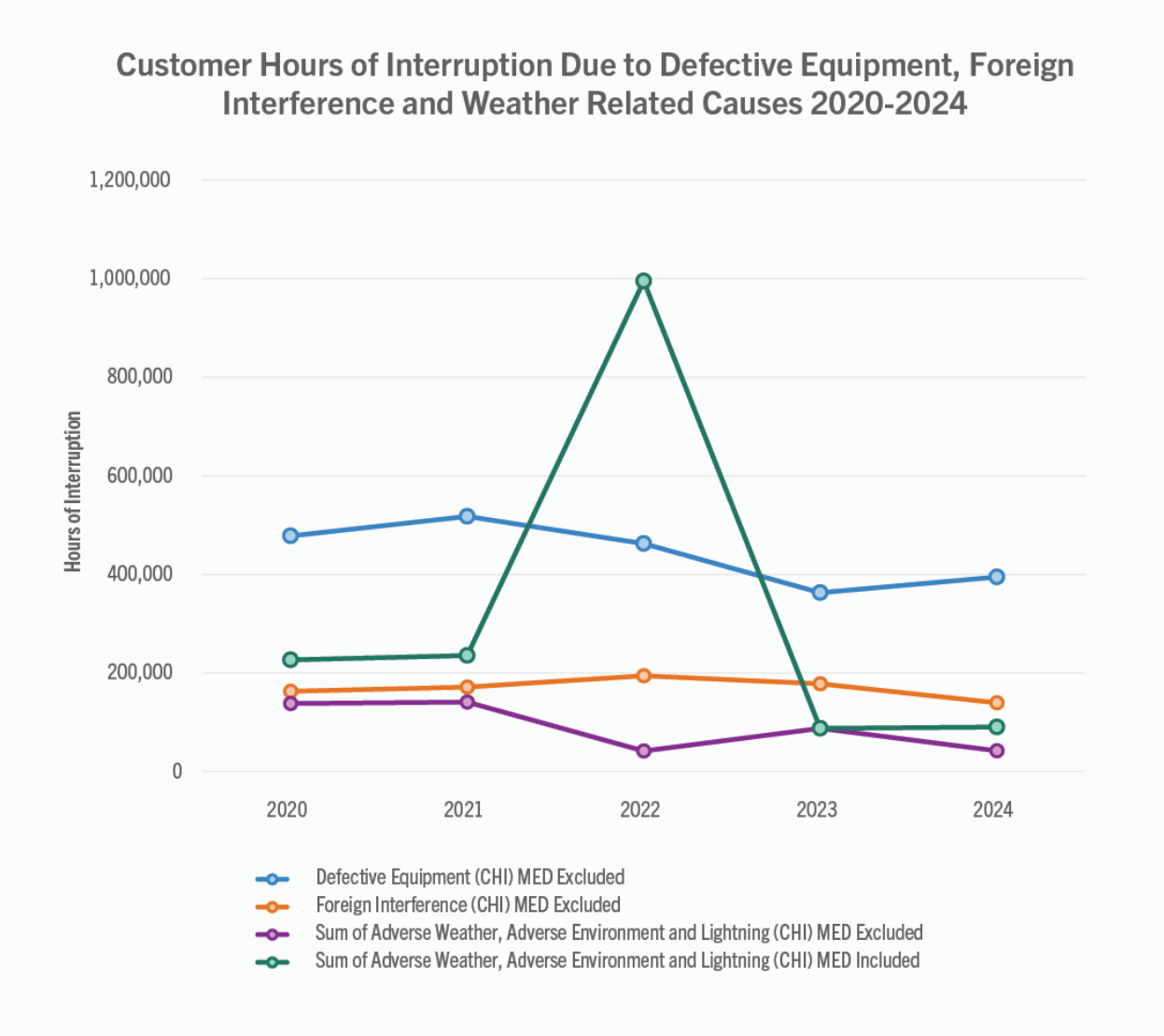


Figure B05 - 7 Customer Hours of Interruption Due to Defective Equipment, Foreign Interference and Weather Related Causes 2020-2024 (Excluding Major Event Days)

Reactive Capital investments are also required to respond to equipment failures occurring due to adverse weather (including storms), lightning events, adverse environment and foreign interference, which are each discussed in the following sections.

3.1.2 Foreign Interference Related Damage

During the period from 2020-2024, Alectra Utilities has experienced an increasing trend in foreign interference driven asset damage (e.g. motor vehicle accidents, vandalism, etc.) as indicated in Figure B05 - 8.

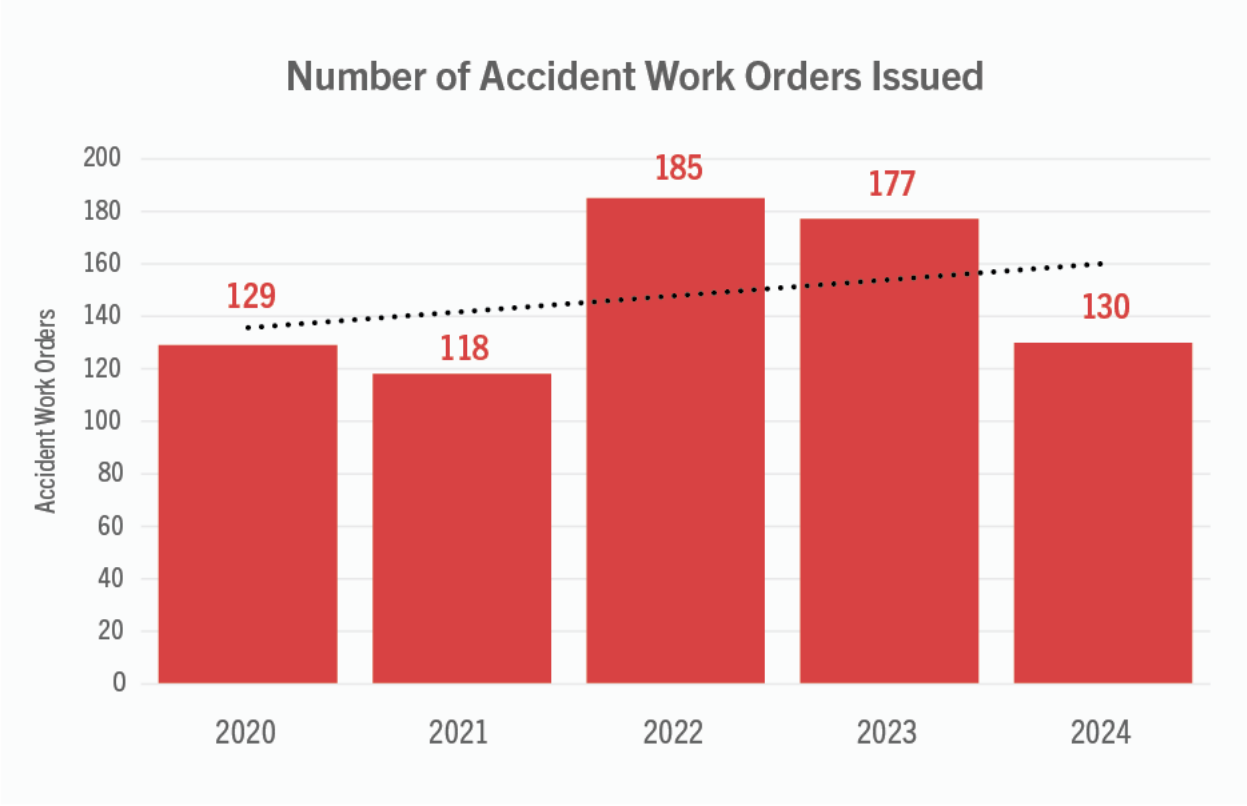


Figure B05 - 8 Number of Foreign Interference Work Orders Issued 2020-2024

Examples of such damage can be seen in Figure B05 - 9 through Figure B05 - 12.

Figure B05 - 9 Pole damaged in St. Catharines by a Motor Vehicle Accident

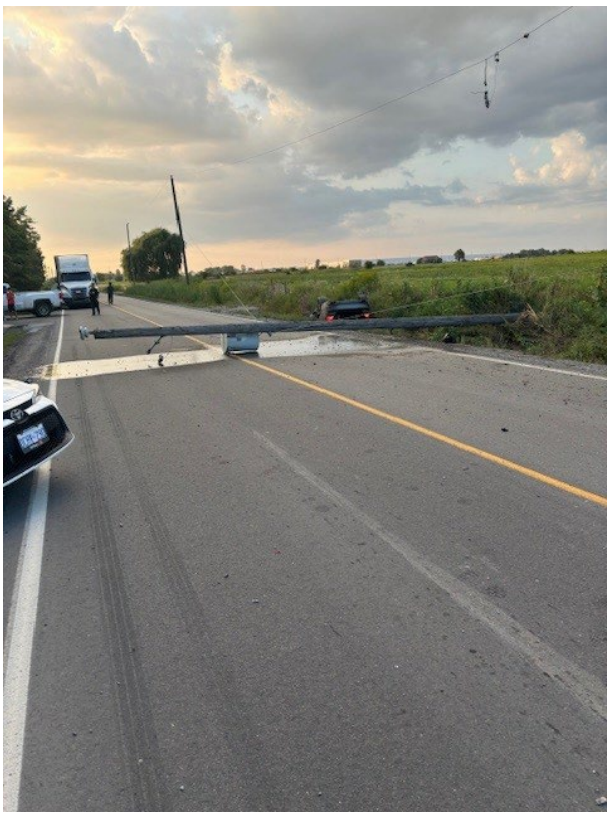


Figure B05 - 10 Pole Damaged in Central Region by a Motor Vehicle Accident, Causing Damage to Transformer and Oil Spill

Most Reactive Capital costs for foreign interference driven asset damage relate to motor vehicle accidents, such as where poles are struck by a vehicle and need replacement. Typically, when poles are broken due to these events, associated equipment like switches, cables, and most hardware must also be replaced due to damage (refer to Figure B05 - 3 for an example where the attached switch was damaged due to an event and needed to be replaced, and Figure B05 - 9 for examples where an attached transformer was damaged due to an event and required replacement). Other types of foreign interference events requiring Reactive Capital investments include damage caused by third party construction activities (for example excavations that sever underground cables, and contact with equipment where replacements are required), theft of cables and conductors requiring replacement, and vandalism causing irreparable damage to equipment.

Figure B05 - 11 Pole Damaged in Hamilton by a Motor Vehicle Accident, Causing Damaged Transformer and Oil Spill

Figure B05 - 12 Padmounted Transformer Damaged by Hit During Third Party Construction Resulting in Leak and Requiring Replacement

Alectra Utilities has forecast the funding requirement for foreign interference related damage using historical expenditures and accident frequency. Based on these historical trends, the current frequency is expected to continue over the DSP period.

3.1.3 Adverse Weather and Storm Damage

Adverse weather events have continued to have a large impact on Alectra Utilities' distribution system and reliability of its service. Reactive Capital funding is required where equipment is damaged by storms and requires replacement or major repairs. Storm damage can occur due to high winds (including from derechos and tornadoes), flooding, and ice storms.

The frequency and severity of adverse weather events across Alectra Utilities' service territory is expected to continue increasing in the future as detailed in *Appendix G - Climate Risk & Vulnerability Assessment*. Alectra Utilities has experienced several major storm events from 2020-2024, many of which resulted in Major Event Days (MEDs). A MED, as defined by the Ontario Energy Board (OEB), is a day where the system experiences a significant number of customer interruptions due to events beyond the distributor's control and is assessed using IEEE Standard 1366 (2012). Over the period of 2020-2024, Alectra Utilities has experienced seven Major Event Days as a result of severe weather, as detailed in Table B05 - 3. Reactive Capital investments to address severe weather events must increase from 2027-2031 due to the expectation of a continued trend in the increased frequency and severity of weather events.

Alectra Utilities utilized the forecasted risk profiles from *Appendix G - Climate Risk & Vulnerability Assessment* to assess the likely changes in frequency and severity of storm events that tend to cause damage requiring repair in each of its service regions. The increase in risk was used with historical expenditure information to forecast a higher funding need for reactive storm damage-related capital investments over the DSP period. The report details risks up until 2075, which far exceeds the 2027-2031 period, so only the relevant portion of the expected change in risk level was applied. The forecasted increased rate was determined by calculating the cumulative annual growth rate in risk level in each region which would result in the 2075 predicted risk level and applying this growth rate to the annual costs in this segment through the DSP period.

Table B05 - 3 Major Events Attributable to Weather 2020-2024

	2020	2021	2022	2023	2024
Major Events Attributable to Weather	1	1	3	0	2
Customer Hours of Interruption	165,934	153,943	1,778,057	0	86,169
Reactive Storm Damage Capital Expenditures ($MM)	0.4	0.6	4.9	0.5	0.2

Examples of storm damage requiring reactive capital investment are shown in Figure B05 - 13 through Figure B05 - 15.

Figure B05 - 13 Pole Damaged by Tornado in Barrie (July 2021)

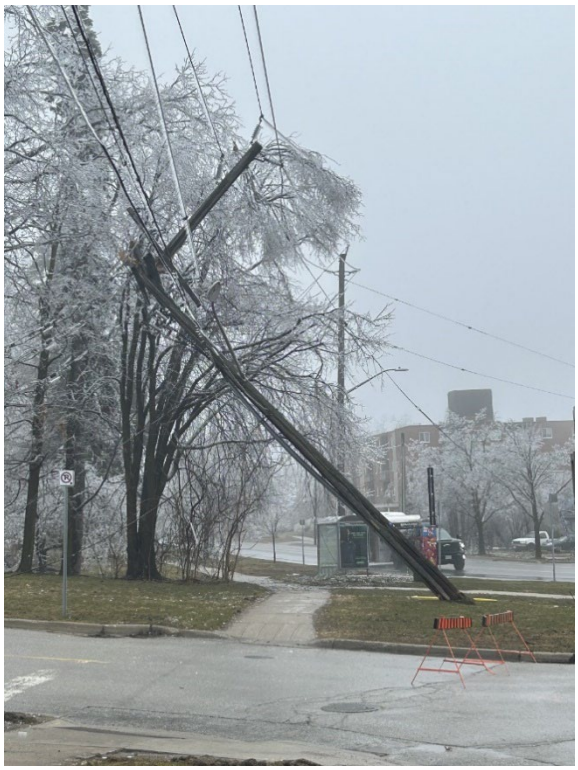


Figure B05 - 14 Pole Broken During Ice Storm in Barrie (April 2025)

Figure B05 - 15 Heavy Flooding in Mississauga (August 2024)

The work performed in the Reactive Capital investment portfolio is required to restore power when an asset fails, or to replace an asset that presents an immediate or imminent safety or reliability risk and is a critical component to maintaining a safe and reliable distribution system.

The primary and secondary drivers for this investment are described in Table B05 - 4.

Table B05 - 4 Investment Drivers, Reasoning and Benefits

Investment Driver	Reasoning & Investment Benefits
Primary Driver: **Failure**	• Reactive Capital investments are primarily driven by asset failure, in that the expenditure under this portfolio either relates to assets that have failed or are at imminent risk of failure.
Mandated Service Obligations	• *Ontario Regulation 22/04* requires that all distribution equipment must be maintained and repaired to reduce the probability of exposure to electrical safety hazards and must be maintained in proper operating condition. • In addition, the DSC requires that distributors maintain their distribution system in accordance with good utility practice and performance standards to ensure reliability and quality of electricity service and shall address any defects discovered during inspection activities within a reasonable period after discovery of the defect.
Secondary Driver: **Safety**	• Reactive Capital investments address failed assets or those at imminent risk of failing or causing a safety risk. Failing and failed assets may pose significant risks to public and crew safety. Assets that have been identified as posing an imminent safety risk must be addressed by the investments in this program.
Secondary Driver: **Reliability**	• Reactive Capital investments are necessary to restore power to customers when assets fail. Additionally, addressing defects posing imminent asset failure risk through Reactive Capital investments can reduce the need for outages, thereby improving service reliability.

IV Investment Timing & Pacing

This section discusses the overall timing and pacing of the Reactive Capital investments. Table B05 - 5 contains the investment summary including five-year historical expenditures from 2020-2024, two-year bridge period expenditures from 2025-2026 and five-year forecasted expenditures from 2027-2031.

Table B05 - 5 Historical & Proposed Investment Spending

	Historical Spending					Bridge		Forecast Spending				
Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Equipment Failure, Imminent Failure or Safety Risk	18.1	24.5	26.2	30.1	34.8	25.7	24.3	24.3	21.9	18.5	18.2	18.0
Foreign Interference Related Damage	4.0	1.7	3.2	3.6	3.9	3.6	3.4	3.5	3.5	3.5	3.6	3.6
Storm Damage	0.4	0.6	4.9	0.5	0.2	2.7	2.8	2.9	3.1	3.2	3.4	3.6
CAPEX ($MM)	22.5	26.8	34.3	34.2	38.9	32.0	30.5	30.7	28.5	25.2	25.2	25.2

4.1 Historical Expenditures (2020-2024)

Alectra Utilities experienced yearly increases in Reactive Capital expenditures over the historical 2020-2024 period primarily driven by rising equipment failures and imminent failures.

Throughout the period, equipment failure costs trended upward, with padmounted switchgear failures as a significant driver. In 2021, equipment failure costs increased by $6.4MM, largely due to a spike in switchgear failures in Brampton and Mississauga, as well as cable failures in Hamilton and St. Catharines. Although targeted dry-ice cleaning efforts helped to reduce switchgear failures in 2022, failures persisted in the East region, alongside increased overhead switch failures and a higher volume of leaking transformers identified during inspections post-pandemic. Reactive transformer replacements remained elevated through 2023 and 2024, as ongoing inspections continued to identify leaking units, compounded by high transformer material

costs driven by global supply chain disruptions. In 2024, equipment failure costs continued to increase with solid dielectric and SF6 switchgear failures contributing to higher replacement costs.

4.2 Bridge Year (2025-2026) and Future Expenditures (2027-2031)

Over the Bridge and Forecast periods, Alectra Utilities expects overall Reactive Capital expenditures to decline because of targeted increases in planned capital investment, while reactive expenditures related to foreign interference and storm damages are expected to moderately increase.

4.2.1 Bridge Years (2025-2026)

During the Bridge Period, Alectra Utilities expects Reactive Capital expenditures to decline from recent historical levels primarily due to increased planned capital investments on overhead and underground distribution equipment.

Between 2022 and 2024, Alectra Utilities completed a significant number of reactive transformer replacements. These replacements addressed an increased volume of leaking transformers identified during accelerated post-pandemic inspections, as well as replacements postponed in 2023 due to transformers delayed by supply chain issues. With much of this increased volume of replacements addressed, transformer-related reactive replacements caused by equipment failure are expected to decrease beginning in 2026. In addition, Alectra Utilities is increasing planned spending on poles, overhead switches, overhead transformers and underground transformers. The early impacts of this planned investment are expected to begin offsetting some reactive failures by 2027, particularly for asset classes such as poles, overhead switches, overhead transformers, and underground transformers, which together represent approximately 70% of historical equipment failure spending.

4.2.2 Forecast Expenditures (2027- 2031)

Over the forecast period, Alectra Utilities anticipates a flat trend in Reactive Capital expenditures. This trend is largely the result of a sustained and accelerating increase in planned capital investment.

The growing planned investments improve overall asset health and mitigate the need for reactive replacements. However, planned investment does not fully displace reactive needs year-to-year.

Alectra Utilities has assumed that changes in planned spending within an asset class will take approximately four years to fully materialize in decreases in reactive spending for the same asset class. As a result, the benefits of the increased planned program will progressively build throughout the forecast period.

While reactive expenditures due to equipment failures, imminent failures or safety risks decrease due to growing planned investments, the annual expected decreases are offset by the expected increases in storm damage from 2029-2031, resulting in an overall flat trend for Reactive Capital investments for the latter years of the forecast period.

V Options Analysis

Alectra Utilities has considered the following two options with respect to reactive capital:

- Do nothing - do not replace asset following failure or in anticipation of imminent failure
- Replacement of the asset - either reactively following failure, or, as inspection-based intervention to prevent imminent risk

Do Nothing

This option would involve taking no action once an asset has failed, allowing any related outage to persist. This is not a viable option due to the resulting safety risks and unacceptable outcomes and customer service. Furthermore, leaving customers without power would contravene Section 4.4 of the DSC.

In addition, not replacing assets at imminent risk of failure, or which present a safety risk but have not yet failed, would not be a viable option due to the resulting safety and environmental risks posed by these assets. For example, not responding to severely corroded transformers may result in an uncontrolled oil leak and environmental contamination.

Replacement of the Asset

Under this option, Alectra Utilities would continue with the status quo and replace assets reactively as required. Alectra Utilities has elected this option because it results in the best outcomes for risk mitigation, reliability and overall investment level. As previously mentioned, the non-discretionary nature of the expenditures in this program makes replacement the only viable option. Per Figure B05 - 4, Alectra Utilities uses Corrective Maintenance and Planned Capital where feasible as alternatives to a reactive replacement.

VI Investment Projects

The material investments in 2027-2031 that form the Reactive Capital investments portfolio are included in Table B05 - 6.

Table B05 - 6 Material Projects and Initiatives

Project Code	Project Name	CAPEX (MM)
Multiple	Equipment Failure, Imminent Failure or Safety Risk	100.9
Multiple	Foreign Interference Related Damage	17.7
Multiple	Storm Damage	16.2

Appendix B06 – Network Metering

I Overview

The Network Metering program (the "Program") funds investments in Alectra Utilities' meter technology to ensure the accurate and reliable measurement of electricity delivered to the utility through the provincial grid and distributed by the utility to customers.

Table B06 - 1 below provides an overview of the spending, as well as investment drivers and associated outcomes.

Table B06 - 1 Network Metering Investment Expenditures, Drivers and Outcomes

	Historical Spending					Bridge		Forecast Spending				
Year	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Traditional Metering Programs	17.0	14.3	14.0	14.1	11.7	15.2	15.9	15.9	12.3	11.2	10.0	8.4
AMI Renewal	0.0	0.0	0.0	2.5	11.3	10.6	10.4	38.2	57.6	57.4	49.8	44.6
Total CAPEX ($MM)	**17.0**	**14.3**	**14.0**	**16.6**	**23.0**	**25.8**	**26.3**	**54.1**	**69.9**	**68.6**	**59.8**	**53.0**
Primary Driver	Mandated Service Obligations											
Secondary Driver	Customer Service Requests, Failure Risk											
Outcomes	Customer Value, Reliability, Safety, Cyber Security and Privacy, Coordination and Interoperability, Environment, Compliance with Mandated Requirements											

The Program addresses regulatory compliance, asset health, and the technological obsolescence of Alectra Utilities' over one million meters, as well as growth from new and upgraded connections. The Program consists of the following five segments:

- **Wholesale Meter Compliance:** Installation, planned maintenance, and upgrades of meters and related equipment at Alectra Utilities' wholesale metering points in accordance with Measurement Canada regulations and the Independent Electricity System Operator's (IESO) *Market Rules*.

- **Revenue Meter Compliance:** Reverification of meters to ensure their accuracy and extend their operational life for set seal periods to meet Measurement Canada requirements.
- **New Connections and Customer Upgrades:** Investment in new meter infrastructure and related equipment to accommodate customer growth and service upgrade requests.
- **Addressing Failures**: Reactive replacement of meters and related equipment as failures occur.
- **Advanced Metering Infrastructure (AMI) Renewal:** Replacement of Alectra Utilities' end of life first generation AMI (AMI 1.0) meters and networks.

Apart from the AMI Renewal segment, the Network Metering Program is comprised primarily of non-discretionary activities including customer demand for new connections and upgrades, as well as regulatory compliance requirements. Regulatory compliance requires adherence to:

- The IESO Market *Rules*[24], Chapter 6, Wholesale Metering that sets out the requirements for wholesale metering installations.
- The *Electricity Gas and Inspection Act (Canada)*[25] and related regulations that provide the requirements regarding meter re-sealing to ensure meter accuracy. Once a seal expires, the meter can no longer be used for billing purposes. This *Act* is administered and enforced by Measurement Canada and sets out the obligations for ensuring good repair of equipment.
- The *Weights and Measures Act (Canada)*[26] and related regulations which sets out the requirements for the approval, certification, and proper operating condition of meters. The Act is administered and enforced by Measurement Canada.
- The Ontario Energy Board's *Distribution System* Code sets out service standards that require distributors to issue accurate bills to customers at least 98% of the time, and to issue no more than two estimated bills in a 12-month period.

[24] Market Rules for the Ontario Electricity Market, May 1, 2025
[25] Electricity and Gas Inspection Act R.S.C., 1985, c. E-4
[26] Weights and Measures Act R.S.C., 1985, c. W-6

- The Ontario Energy Board's *Standard Supply Service Code*[27] establishes customer billing requirements.

The AMI Renewal segment represents the largest portion of the Program's expenditures. More than 70% of Alectra Utilities' current fleet of retail meters were installed between 2006 and 2010. These meters, referred to as "AMI 1.0", are at end of life, technologically obsolete, and experiencing failure rates that are higher than historical averages and industry expectations. Meter failures pose risks to Alectra Utilities' operations and customers, including reduced billing reliability and decreased customer satisfaction from estimated, corrected, and delayed bills. The AMI 1.0 communication equipment is also at end-of-life. As the meters and communication equipment operate as an interdependent network, all AMI 1.0 meters must be replaced to ensure compatibility with the communications network and that meter data continues to be available daily for customer billing.

Compared to the cost of a planned mass replacement, reactive meter and network equipment replacements using the AMI 1.0 technology as the devices fail, could increase project costs by as much as $139.1MM by 2031.

Alectra Utilities' AMI Renewal strategy is expected to extend beyond the plan period by one year to 2032. This project timeframe is intended to address operational risk by replacing meters within AMI 1.0 networks with the highest failure rates first and, where possible, managing expenditures by maximizing the life of the original AMI 1.0 meters.

During the plan period, Alectra Utilities is proposing to replace approximately 900,000 AMI 1.0 meters with the second generation of AMI technology, commonly known as AMI 2.0. As compared to the continued use of AMI 1.0 meters, transitioning to AMI 2.0 meters is less expensive and enables advanced functionality for customers and utility operations. The renewed retail meter fleet is also expected to result in cost containment in Network Metering's OM&A expenditures through a reduction in trouble shooting and maintenance requirements, and a reduction in telephone lines needed to support the communications backbone.

Beyond Network Metering, AMI 2.0 functionality provides broader benefits to Alectra Utilities' operations and its customers. This includes proactive power quality information to support

[27] Standard Supply Service Code, Revised March 27, 2025

customers, remote meter disconnect and reconnect technology to enable faster restoration of service for customers, and "last gasp" outage technology to identify the location of customer power outages faster, and in a consistent manner, across all Alectra Utilities customers.

Unlike AMI 1.0, the AMI 2.0 meter technology selected by Alectra Utilities can support the Wireless Smart Utility Network (Wi-SUN) FAN 1.0 protocol and anticipated FAN 1.1 Technical Specification. Wi-SUN is an open wireless communication standard that is expected to provide a measure of future-proofing as devices require replacement. The open standard supports interoperability with other meters, network equipment, and grid devices as failures occur or as the meter network evolves.

AMI 2.0 meter functionality can be further extended through applications that can be downloaded over the air and installed on the meter to provide Distributed Intelligence (DI) and grid edge technology (such as management of Distributed Energy Resources (DER) and customer load disaggregation). The AMI 2.0 applications can enable a more intelligent grid, unlock opportunities for non-wires alternatives, and support customer education and engagement.

II Outcomes and Measures

Table B06 – 2: Outcomes and Measures Summary

Outcome	Summary

Customer Value	The Program contributes to Alectra Utilities' Customer Value objectives by:
	• Reducing the risk of having to issue bills based on estimated consumption[28] and maintaining billing accuracy of at least 98%[29] as required by the Ontario Energy Board by:
	  ○ ensuring the metering networks are in good working condition by upgrading and replacing meters and metering infrastructure
	  ○ limiting the percentage of meters past their useful life
	  ○ undertaking programs and initiatives that enhance the quality and accuracy of meter data
	• Enabling remote disconnections and reconnection functionality which:
	  ○ reduces visits to customer premises
	  ○ provides faster restoration of service to customers
	• Implementing infrastructure that can support customer operational and cost savings measures such as DERs and embedded generation
	• Implementing processes that proactively address power quality issues identified through AMI 2.0 meter functionality

Reliability	The Program contributes to Alectra Utilities' Reliability objectives by:
	• Implementing meters with last gasp functionality which allows for notifications to be sent to the Outage Management System to:
	  ○ facilitate the identification and location of outages
	  ○ identify nested outages
	• Confirm the restoration of outages, and aid in the efficient dispatch of crews
	• Installing next generation AMI 2.0 meters which have higher meter sampling rates, offering improved data for analysis to aid in monitoring the overall grid.

Safety	The Program contributes to Alectra Utilities' safety objectives by: • Decreasing the number of in-person interactions between employees and the public through the implementation of remote disconnect and reconnect functionality • Implementing granular bi-directional meter data to improve grid reliability through the development of refined analytic tools

[28] Ontario Energy Board: Distribution System Code 2.10, Estimated Billing
[29] Ontario Energy Board: Distribution System Code 7.11, Billing Accuracy

Outcome	Summary
	• Implementing enhanced processes that proactively identify potential safety and power quality issues.
Cybersecurity and Privacy	The Program contributes to Alectra Utilities' Cybersecurity and Privacy objectives by: • Providing enhanced cybersecurity via the new AMI 2.0 technology including enhanced data encryption protocols, improved hardware security that support physical isolation and additional authentication requirements, and hardened tamper-resistant "key safe" functionality that enables the secure storage and processing of all keys and certificates used by the back-office AMI system.
Coordination and Interoperability	The Program contributes to Alectra Utilities' Coordination and Interoperability objectives by: • Implementing new technology that can support Wi-SUN open standards, which increases interoperability of meters and other devices.
Environment	The Program contributes to Alectra Utilities' Environment objectives by: • Upgrading meters that will reduce failure rates and reducing the number of required field visits ("truck rolls") • Enabling the evaluation and resolution of issues from the office, thereby reducing the need to dispatch a crew through the new AMI 2.0 technology

Compliance with Mandated Requirements	The Program contributes to Alectra Utilities' Compliance with Mandated Requirement objectives by:
	• Ensuring Alectra Utilities' adherence to Measurement Canada requirements (in accordance with the *Weights and Measures Act*, the *Electricity and Gas Inspection Act*, and related regulations) by:
	  ○ using certified electrical meters and metering installations for charging customers based on electrical consumption; and,
	  ○ employing Alectra Utilities' Measurement Canada certified Meter Test Facility for meter verification and refurbishment.
	• Ensuring Alectra Utilities' compliance with IESO requirements by installing, renewing, and maintaining metering equipment at wholesale metering points in accordance with the *IESO Market Rules*.

1

III Investment Drivers and Need

Table B06 - 3 Investment Drivers

Investment Driver	Reasoning & Investment Benefits
Primary Driver: **Mandated Service Obligations**	• Install and maintain a meter installation for settlement and billing purposes for each customer connected to the distribution system (DSC 5.1.1) • Ensure that customers receive accurate and timely bills, with limited estimation of meter data (DSC 2.10, 7.11) • Ensure accurate billing of meter data by maintaining compliance with Measurement Canada requirements to measure and charge a customer for electrical consumptions (*Weights and Measures Act, Electricity and Gas Inspections Act*) • Install and maintain IESO compliant metering at Alectra Utilities' wholesale metering points *(IESO Market Rules*) • Upgrade wholesale meter installations that are non-compliant with the *IESO Market Rules* • Respond to customer requests to install new meter installations or upgrade existing meter installations within the Ontario Energy Board's service quality requirements[30]
Secondary Drivers: **Failure Risk, Asset Renewal**	• Replace failed meters and related meter installation components • Replace end of life and obsolete meters and equipment with AMI 2.0's enhanced functionality

3.1 Mandated Service Obligations

The condition, performance, and accuracy of metering assets is mandated by federal statutes (the *Weights and Measures Act and the Electricity and Gas Inspection Act)*, by OEB code requirements, and under the IESO's *Market Rules*. Together, these requirements establish the technical standards and regulatory framework for Wholesale Meter Compliance and Revenue Metering Compliance.

The *Weights and Measures Act and Electricity and Gas Inspection Act* are federal statutes that, along with the regulations established thereunder, are administered and enforced by Measurement Canada.

[30] Ontario Energy Board: Distribution System Code, 7.2

Meters and the broader metering network must also be sufficiently maintained to comply with OEB regulatory requirements including those under the *Standard Supply Service Code and Distribution System Code*. These codes stipulate standards for the quality of meter data including billing accuracy, and the limited use of meter data estimation.

In addition, Alectra Utilities as a Market Participant must adhere to the IESO *Market Rules* that govern the IESO-controlled grid inclusive of its wholesale metering points.

To meet its mandated service requirements, the Network Metering Program is organized into five segments: Wholesale Meter Compliance, Revenue Meter Compliance, New Connections and Upgrades, Meter Failures, and AMI Renewal.

3.1.1 Wholesale Revenue Meter Compliance

Table B06 - 4 Wholesale Meter Compliance Program

	Historical Spending					Bridge		Forecast Spending				
Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Wholesale Metering ($MM)	2.5	1.1	1.1	2.0	1.4	1.3	1.1	2.6	2.6	2.6	2.8	2.9

Wholesale revenue meter installations are required to accurately measure the flow of energy to Alectra Utilities' distribution system from the point of supply, which is usually a Hydro One transmission station.

Wholesale meter installations can vary in complexity and size. Each installation typically includes a lockable metering cabinet, two wholesale meters (a primary meter and its backup alternate), instrument transformers, test blocks, communication modems, and wiring. Instrument transformation includes current transformers and potential transformers that step down the current and voltage to the levels required of the meter and control equipment.

Alectra Utilities maintains 249 wholesale revenue meter installations inclusive of 508 instrument transformers, and 498 meters. These wholesale revenue meter installations enable the financial settlement of more than $3B in energy costs annually.

Figure B06 - 1 and Figure B06 - 2 provide examples of wholesale revenue meter installation equipment, including a Primary Metering Unit and some of the associated meters, wiring and cabling. The auxiliary wiring and meters are maintained in a locked cabinet.

Figure B06 - 1 Primary Metering Unit installed at an Alectra Utilities Transformer Station

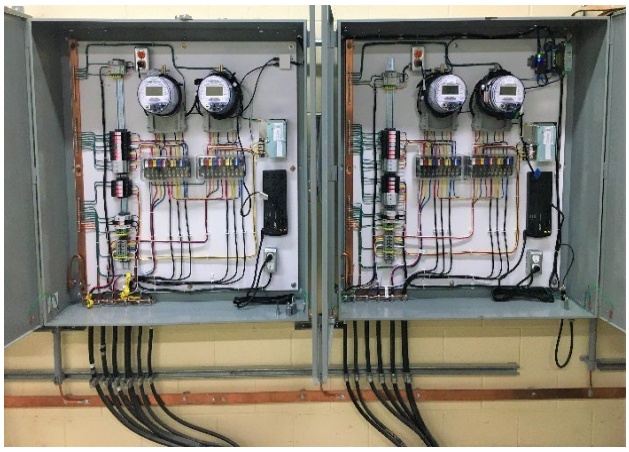


Figure B06 - 2 The auxiliary wiring to the Primary Metering Unit, located inside the Transformer Station building

Alectra Utilities' wholesale installations must comply with both provincial and federal regulation for metrology and market rules. As per the *Electricity Gas and Inspection Act*, any electricity meter used for settlement must be approved by Measurement Canada and installed and verified according to federal standards. The *Weights and Measures Act* reinforces these requirements by ensuring all measurements are accurate, expressed in authorized units (i.e. kWh or MW), and that assets are properly maintained. The IESO *Market Rules* govern wholesale electricity market participation, requiring all meters to be registered through a qualified Metering Service Provider, adhere to technical standards, and follow its registration process.

A Age of the Wholesale Installation Assets, Replacement Strategy

Instrument transformers are critical components of wholesale revenue metering installations. It is Alectra Utilities' experience that these assets are generally reliable. Alectra Utilities plans its replacement strategy based on operational risk, which includes the age and functionality of the assets as compared to current standards and operational requirements.

Alectra Utilities' instrument transformers have been provided by 15 manufacturers as identified in Table B06 - 5.

Table B06 - 5 Alectra Utilities' Wholesale Instrument Transformers by Manufacturer

Instrument Transformers by Manufacturer	Total
ABB	43
Arteche	4
Canadian General Electric	8
CGE	7
Federal Pioneer	6
Ferranti-Packard	10
ITE	4
GE	4
Kuhlman	24
Piedmont	10
Polycast	2
Ritz	24
Sadtem	312
Trench	40
Westinghouse	10
TOTAL	**508**

Alectra Utilities' instrument transformer vendors generally advise that the design life of the assets is approximately 40 years.

Table B06 - 6 details the age of in-service wholesale installations instrumentation.

Table B06 - 6 Age of Alectra Utilities' Wholesale Metering Instrument Transformers

Age Group	Total	%
0-10	112	22%
11-20	318	63%
21-30	58	11%
31-40	20	4%
Total	**508**	**100%**

Alectra Utilities has 52 wholesale metering equipment installations that are approaching end of life, have limited functionality, or do not meet the current standards for 3.0 element metering as

prescribed under the *IESO Market Rules.* Alectra Utilities plans to address these metering installations through a proactive and planned approach that will mitigate its operational, compliance, and financial risks and avoid having to perform time-sensitive reactive work.

Within this plan period, Alectra Utilities proposes to upgrade 31 of its 52 highest risk wholesale metering installations, beginning with:

- 18 metering installations that were installed prior to 2001 and are approaching end-of-life. Within this plan period, these installations will exceed the 40-year design life of the instrument transformers and are at an increased risk of failure. Additionally, these installations have "shared instrument transformers" that are not fully compliant with current *IESO Market Rules*. The IESO is currently allowing this type of installation under the *Alternative Metering Installation Standards* (AMIS) framework. However, if multiple components fail at one of these wholesale revenue installations, a complete upgrade would be immediately required to meet the *Declaration of Compliance* (DOC) standards. To mitigate the risk of performing costly and time-sensitive reactive work, Alectra Utilities proposes to proactively schedule nine upgrades for the 18 meters between 2027 and 2031.
- 13 metering installations that are 2.0 element configuration: 2.0 element metering technology does not comply with the current *IESO Market Rules* and is less precise than the current standard of 3.0 element metering, which measures all three-phase currents and voltages independently. The 3.0 element metering configuration ensures that settlements are accurate and that the likelihood of billing errors is minimized. This is growing in importance as grid complexity and diversity in load profiles increases. The 3.0 element meters provide enhanced power quality features including the identification of a lost phase, that provide accurate energy measurements when there are large phasing discrepancies or when DERs create system imbalances. Although the *Market Rules* allow 2.0 element meters to continue to be used during a transition period, upgrading to 3.0 element metering is critical to achieving accurate measurements, long-term regulatory compliance, and compatibility with the dynamic requirements of the distribution system grid.

The upgrades described above will allow Alectra Utilities to mitigate its most urgent operational, compliance, and financial risks related to wholesale metering installations. Alectra Utilities plans

to continuously assess its risks to prioritize this work program. The remaining wholesale meter installations assessed to be approaching end-of-life will be upgraded in the 2032 to 2037 timeframe.

B Age of the Wholesale Metering Assets, Replacement Strategy

Alectra Utilities' wholesale revenue metering fleet is comprised of Schneider Electric ION meters as provided in Table B06 - 7.

Table B06 - 7 Wholesale Revenue Meters by Meter Form

Model	Quantity Of Meters
ION8300	18
ION8400	4
ION8500	13
ION8600A	26
ION8600B	5
ION8600C	74
ION8650A	225
ION8650C	133
Total	**498**

Modern electronic wholesale revenue meters and related equipment have been found to be generally reliable. The assessment of their condition and replacement strategy is generally age-based and evaluated against the manufacturer's recommended service life and the practicality of meeting Measurement Canada seal requirements.

Alectra Utilities considers the practical end-of-life to be approximately 20 years for its wholesale revenue meters, after which the cost and practicality of Measurement Canada sealing requirements become prohibitive.

Figure B06 - 3 shows the age range of Alectra Utilities' wholesale revenue meters as of December 31, 2024.

Figure B06 - 3 Age of Alectra Utilities' Wholesale Revenue Meters

As of December 2024, Alectra Utilities had 51 meters between 15 and 17 years of age, and 59 that are between 18 and 20 years of age. Alectra Utilities plans to address this operational risk by replacing approximately 100 of its oldest wholesale revenue meters within this DSP plan.

Alectra Utilities will continue its non-discretionary wholesale metering compliance activities, which include reactive replacement of failed wholesale revenue meters and related equipment as well as replace wholesale installations as required by Hydro One as it expands or refurbishes transformer stations.

3.1.2 Revenue Meter Compliance

Table B06 - 8 Retail Meter Compliance Program

	Historical Spending					Bridge		Forecast Spending				
Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Meter Sampling and Reverification ($MM)	1.1	2.7	2.2	3.0	3.7	4.4	5.5	3.3	0.5	0.5	0.5	0.5

As of December 31, 2024, Alectra Utilities has 1,082,436 meters in service to measure electricity usage for its residential, commercial, and industrial customers as detailed in Table B06 - 9 below.

Table B06 - 9 Classification and Count of Alectra Utilities' Meters

Type Of Meter	Quantity Of Meters
Single Phase	954,648
Poly Phase	86,607
Suite	41,181
Total	**1,082,436**

The federal *Electricity and Gas Inspection Act* requires all meters to be verified to ensure that electricity usage is metered accurately for customer billing. Meters can only be used to charge customers for electrical consumption while under a certified seal. Seals are set for prescribed periods of time. Meters with expired seals cannot be used for billing purposes and must be either scrapped or undergo complete recertification. Measurement Canada issues Notices of Violation and can impose financial penalties for utilization of a non-certified meter.[31]

Procured meters are grouped homogeneously and sealed during an original meter certification process. These meter batches are tracked throughout their lifecycle. According to Measurement Canada requirements, before the seal expires, a utility may test all meters within the group or test a statistical sample as a proxy for the entire group's condition. If the sample passes, the balance of the group can remain installed in the field, and the meter records are updated with the new seal date. If the sample group fails, the utility must remove and scrap the entire group or test each meter individually. Each re-certification cycle has a decreasing seal extension timeframe.

In practical terms, the process of sampling an AMI 1.0 batch of meters requires: selecting the randomized meter set to test; removing the meters from the field; performing the meter verification activities in an accredited meter lab; advising Measurement Canada of the testing outcomes; updating the meter seal records; and, returning the meters into inventory for re-installation in the field.

[31] Measurement Canada: Weights and Measures Act, R.S., 1985, c. W-6 s. 22

Table B06 - 10 details the decreasing sealing schedules for an AMI 1.0 meter procured in 2006. As the meter ages and time between compliance sealing decreases, the expense related to meter testing becomes cost prohibitive as compared to the procurement of a new meter.

Table B06 - 10 Seal Period Example for an AMI 1.0 Meter Procured in 2006

Action	Seal Period	Year of Seal Expiry
Original Seal	10 years	2016
Verification #1	8 years	2024
Verification #2	6 years	2030
Verification #3	4 years	2034

Alectra Utilities' records indicate that approximately 700,000 meter seals from its current meter inventory will expire between 2027 and 2031 as detailed in Figure B06 - 4.

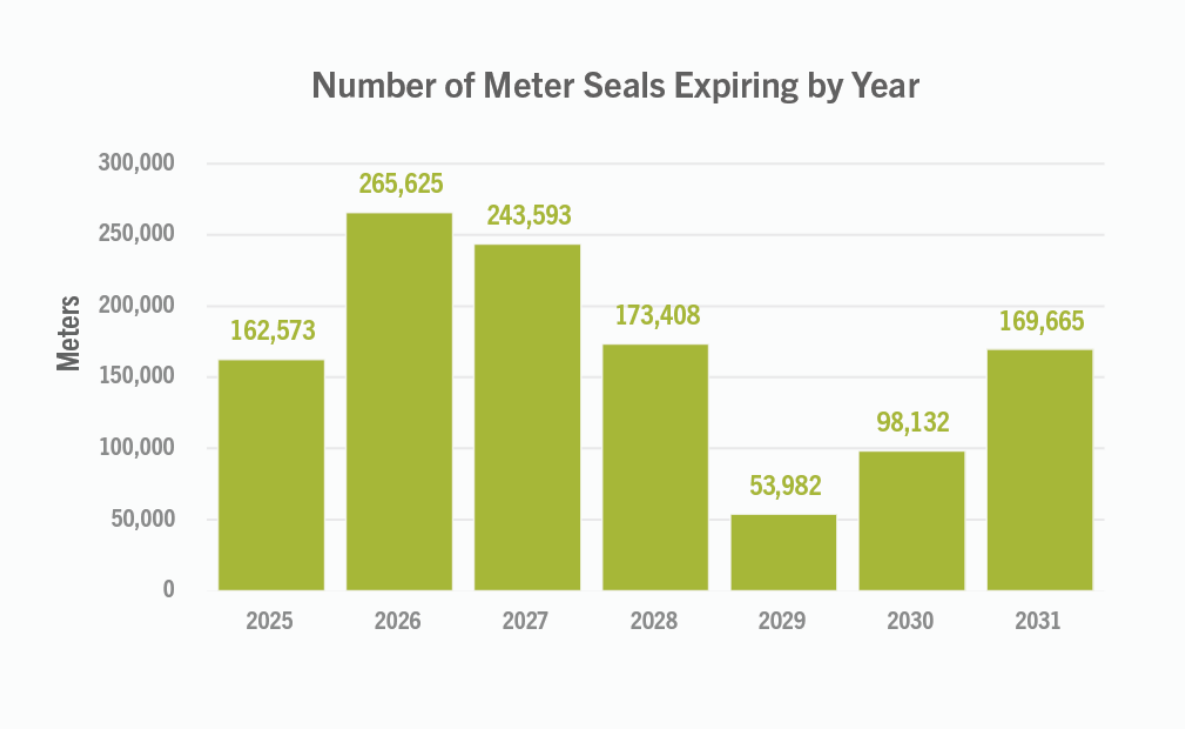


Figure B06 - 4 Number of Meter Seals Expiring by Year

Alectra Utilities uses its own Measurement Canada-certified Meter Testing Facility for re-verifying and re-sealing single phase, polyphase, and wholesale meters. The Meter Testing Facility is regularly audited, both internally and externally, to ensure it continues to meet ISO 9001:2015 quality management and compliance standards[32].

Figure B06 - 5 Alectra Utilities' Meter Testing Facility located in Hamilton

Given the large volumes of residential meters procured and installed in any given year, Alectra Utilities usually elects to test statistical samples of each meter type. For smaller populations of commercial, industrial, and wholesale meters, Alectra Utilities typically re-verifies each meter individually.

Figure B06 - 6 details the quantity of meters that Alectra Utilities expects to test in each year to ensure its compliance with Measurement Canada requirements.

[32] ISO 9001:2025 is available at www.iso.org

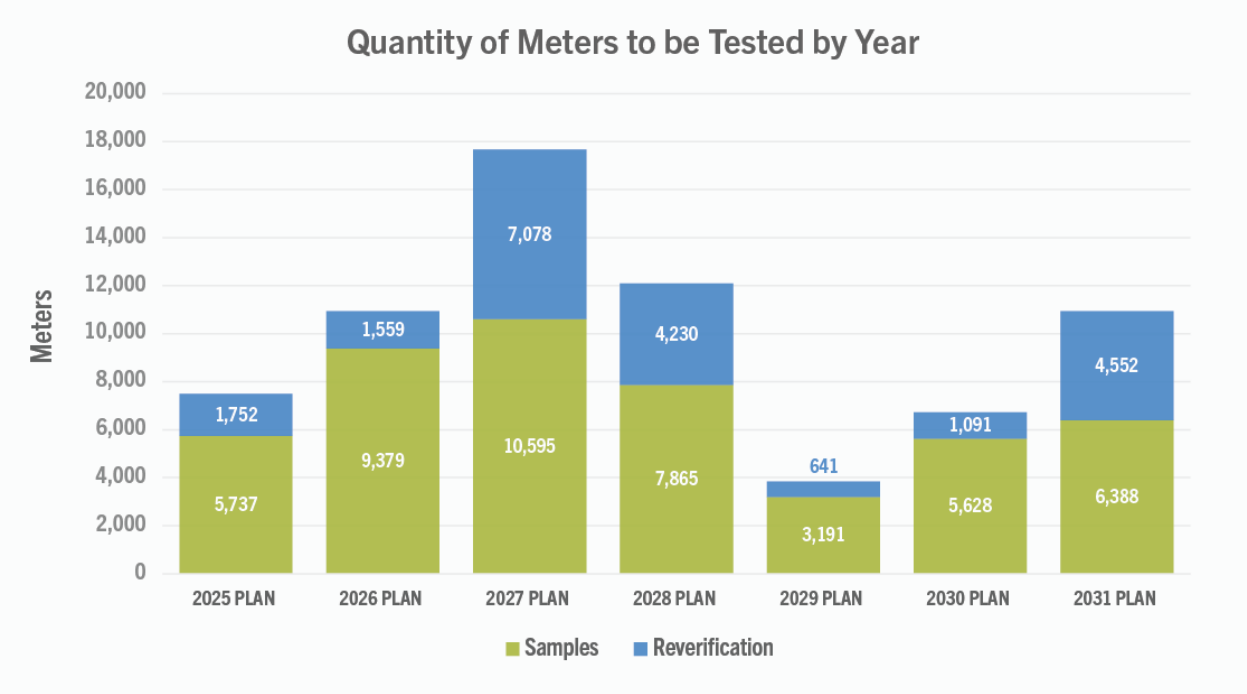


Figure B06 - 6 Quantity of Meters to be Tested

Alectra Utilities' AMI Renewal program as described in *Section 3.1.5*, if approved, will enable the replacement of AMI 1.0 meters that would otherwise require re-sealing during the plan period.

Measurement Canada has established processes for utilities to request temporary exemptions ("dispensation") from testing and re-sealing meters that are scheduled to be replaced in the near-term. Alectra Utilities plans to work closely with Measurement Canada to seek approvals for dispensation including submitting details regarding its meter replacement plan, meter removal timelines, and evidence of on-going meter data accuracy as per Measurement Canada's established process. Alectra Utilities submitted its first dispensation request for assessment by Measurement Canada in July 2025. If approved, this initial request would provide testing exceptions for 85,517 single-phase and 8,080 polyphase AMI 1.0 meters in the Brampton service territory.

The Revenue Meter Compliance capital budget is predicated on Measurement Canada approving dispensation for AMI 1.0 meters throughout the mass meter deployment period of 2028 to 2031 for an estimated average annual savings of $4.4MM in meter testing and re-sealing related costs.

Alectra Utilities has previously obtained dispensation from Measurement Canada and views the risk of having its current request denied as low.

3.1.3 New Connections (Growth) and Customer Requests for Upgrades

Table B06 - 11 New Connections and Upgrades Program

	Historical Spending					Bridge		Forecast Spending				
Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
New Connections and Upgrades ($MM)	7.0	6.1	6.1	4.9	3.8	4.5	3.9	3.7	3.8	3.8	3.9	4.0

Alectra Utilities is required to connect new customers within its service territory. As set out in section 7.2 of the *Distribution System Code*, new connections must be completed within five business days of all conditional activities being completed by the customer.

Metering requirements for new and upgraded meter installations vary depending on the premise's service size, voltage, and anticipated usage. Equipment and installation configurations range from self-contained single-phase meters to complex bi-directional polyphase installations that may include instrument transformers, test blocks, communication modems, and meters capable of power quality analysis and advanced real-time data outputs to customer devices. All new installations adhere to Alectra Utilities' Conditions of Service, which details the application, connection, and metering requirements and standards.

The Network Metering team installs approximately 5,500 single-phase meters and 800 polyphase meters annually in response to new connection requests and meter upgrade requests. Network Metering only performs a subset of Alectra Utilities' new connections and upgrades. Additional new connections are completed by the Network Operations teams.

3.1.4 Meter Failures

Table B06 - 12 Meter Failures Program

	Historical Spending					Bridge		Forecast Spending				
Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Meter Failures ($MM)	5.8	3.7	4.1	3.8	2.3	4.6	5.0	5.5	4.8	3.7	2.5	0.8

Examples of meters that have failed and are therefore unable to display or provide meter usage data are provided in Figure B06 - 6. Failed meters must be replaced immediately to maintain reliable and accurate customer billing in compliance with the Distribution System Code[33]. Timely replacement ensures the ability to deliver accurate meter data for customer billing and related services and mandated requirements such as the Green Button Initiative's[34] Connect My Data and Download My Data services.

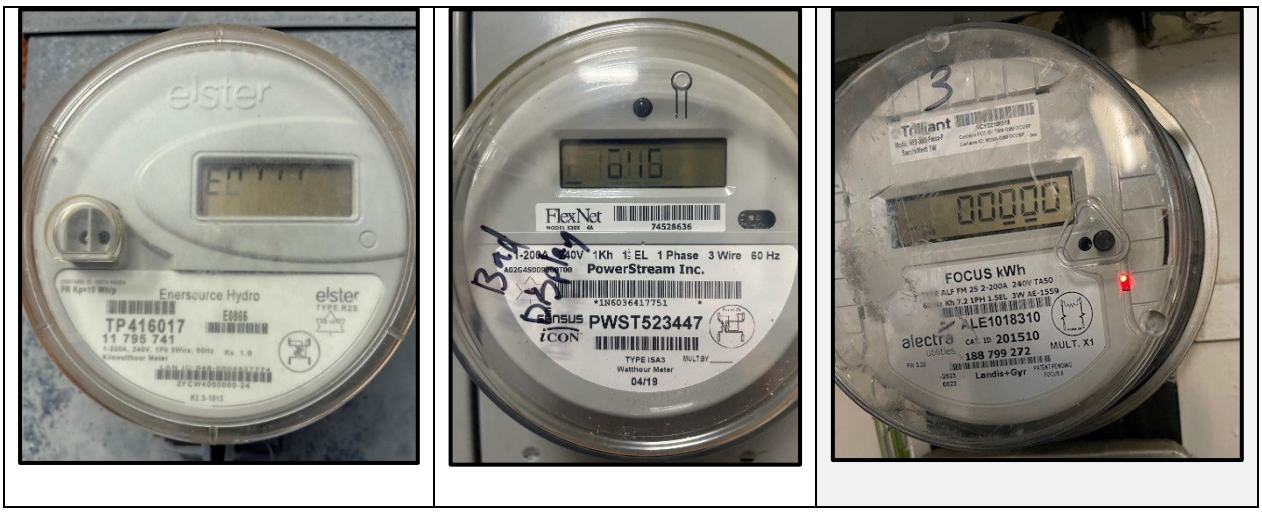


Figure B06 - 7 Failed Meters that are Unable to Display or Provide Meter Usage Data Must Be Replaced

[33] Ontario Energy Board: Distribution System Code 2.10, Estimated Billing, 7.11 Billing Accuracy
[34] O. Reg. 633/21: Energy Data

To ensure that customer billing processes are not negatively impacted, and to comply with the aforementioned regulatory requirements, Network Metering strives to replace failed meters within five business days, 90% of the time.

A Meter Failure Experience

Alectra Utilities was among the first utilities in Ontario to install AMI 1.0 meters as mandated by the 2004 Smart Metering Initiative[35]. Figure B06 - 8 depicts the AMI 1.0 meters that were installed annually between 2006 and 2024 and highlights the approximately 750,000 AMI 1.0 meters that were installed at residential and small commercial premises between 2006 and 2010.

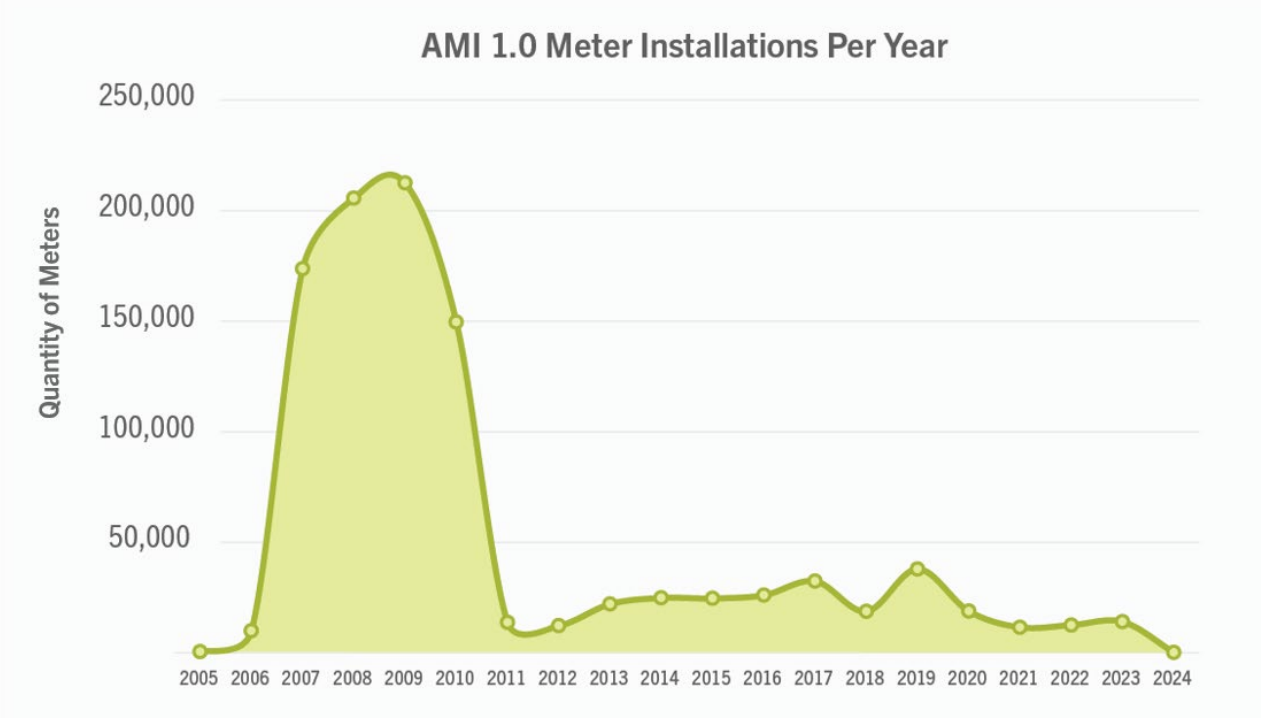


Figure B06 - 8 AMI 1.0 Meter Installations by Year

[35] Smart Metering Initiative (SMI) | Ontario Energy Board

At the end of 2024, Alectra Utilities had 1,021,571 AMI 1.0 meters installed in the field. Industry reports[36], vendor recommendations for replacement cycles, and the experience of peer Ontario utilities[37], indicate that the first generation of AMI 1.0 meters can be expected to have a lifespan of approximately 15 years.

In 2025, 75% of Alectra Utilities' AMI 1.0 meters will be at least 15 years of age. Table B06 - 13 provides the percentage of Alectra Utilities' AMI 1.0 meters that will be at or beyond 15 years throughout the plan period based on the existing population in the absence of an AMI Renewal plan.

Table B06 - 13 Age of AMI 1.0 Meters

Age of AMI 1.0 Meters by year	2024	2025	2026	2027	2028	2029	2030	2031
Total Meters < 15 years	269,867	256,120	243,817	221,768	196,948	172,317	146,267	113,882
15 years	149,589	13,747	12,303	22,049	24,820	24,631	26,050	32,385
16 years	212,467	149,589	13,747	12,303	22,049	24,820	24,631	26,050
17 years	205,640	212,467	149,589	13,747	12,303	22,049	24,820	24,631
18 years	173,652	205,640	212,467	149,589	13,747	12,303	22,049	24,820
19 years	9,904	173,652	205,640	212,467	149,589	13,747	12,303	22,049
20+ years	452	10,356	184,008	389,648	602,115	751,704	765,451	777,754
Total Meters >15 years	**751,704**	**765,451**	**777,754**	**799,803**	**824,623**	**849,254**	**875,304**	**907,689**
% of Meters at or beyond useful life	74%	75%	76%	78%	81%	83%	86%	89%

**Simple aging. Static AMI 1.0 population as of December 31, 2024*

[36] 3.11: Smart Metering Initiative Auditor General Report of 2014, page 391
Asset Depreciation Study for the Ontario Energy Board, Kinectrics In. Report No K-418033-RA0001-R000, July 8,2010.

[37] Hydro One Networks Inc. and Toronto Hydro-Electric System Limited have programs to replace their end-of-life AMI 1.0 assets as described in EB-2021-0110 and EB-2023-0195 respectively.

AMI 1.0 meters account for approximately 94% of Alectra Utilities' meter population. As the AMI 1.0 meters age, Alectra Utilities is experiencing a corresponding increase in the number of meter failures year-over-year as provided in Figure B06 - 9.

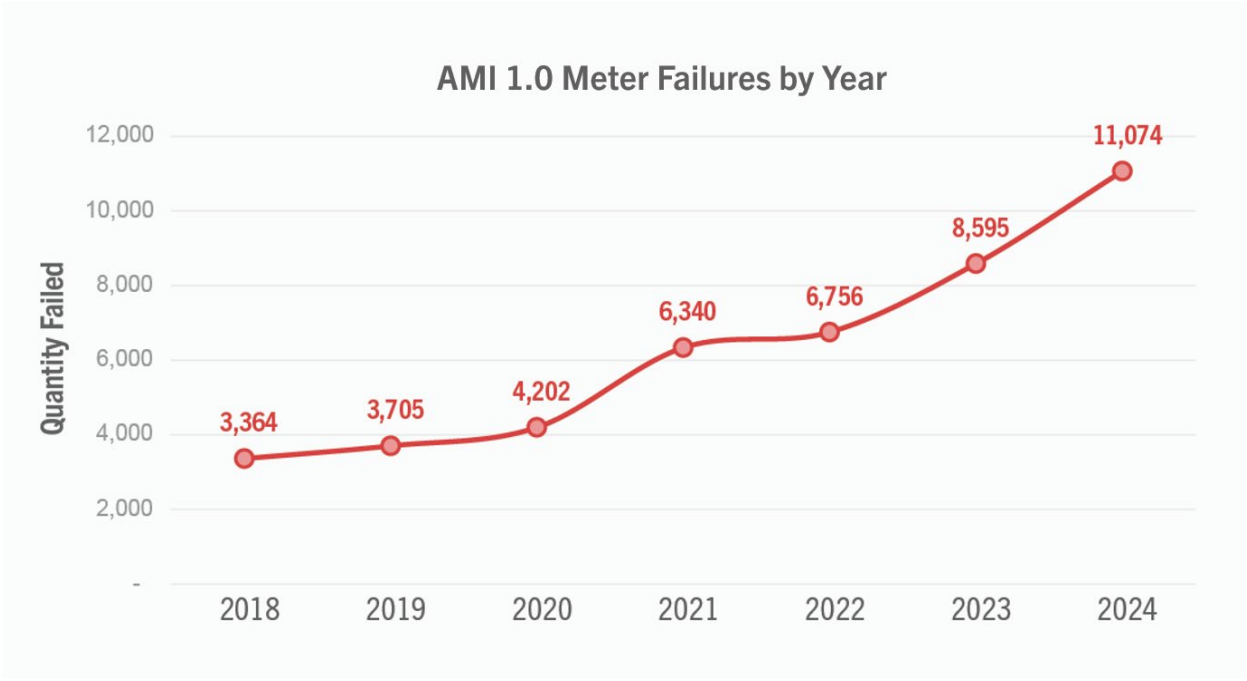


Figure B06 - 9 AMI 1.0 Meter Replacements due to Failure, 2018 to 2024

The increase in AMI 1.0-meter failures is expected based on their installation dates, age and service life.

Generally, meter vendor documentation provides that failure rates for a fleet of meters should be less than 0.5% annually. Due to age, Alectra Utilities' fleet of AMI 1.0 meters failed at a rate of 1.1% in 2024, more than double the industry expectation. While this is averaged over the population, some models are failing at even greater rates.

Figure B06 - 10 provides the annual failure rates for Alectra Utilities' AMI 1.0 meters. In the period prior to 2018, Alectra Utilities' legacy utilities were experiencing overall meter failures rates of approximately 0.25% annually.

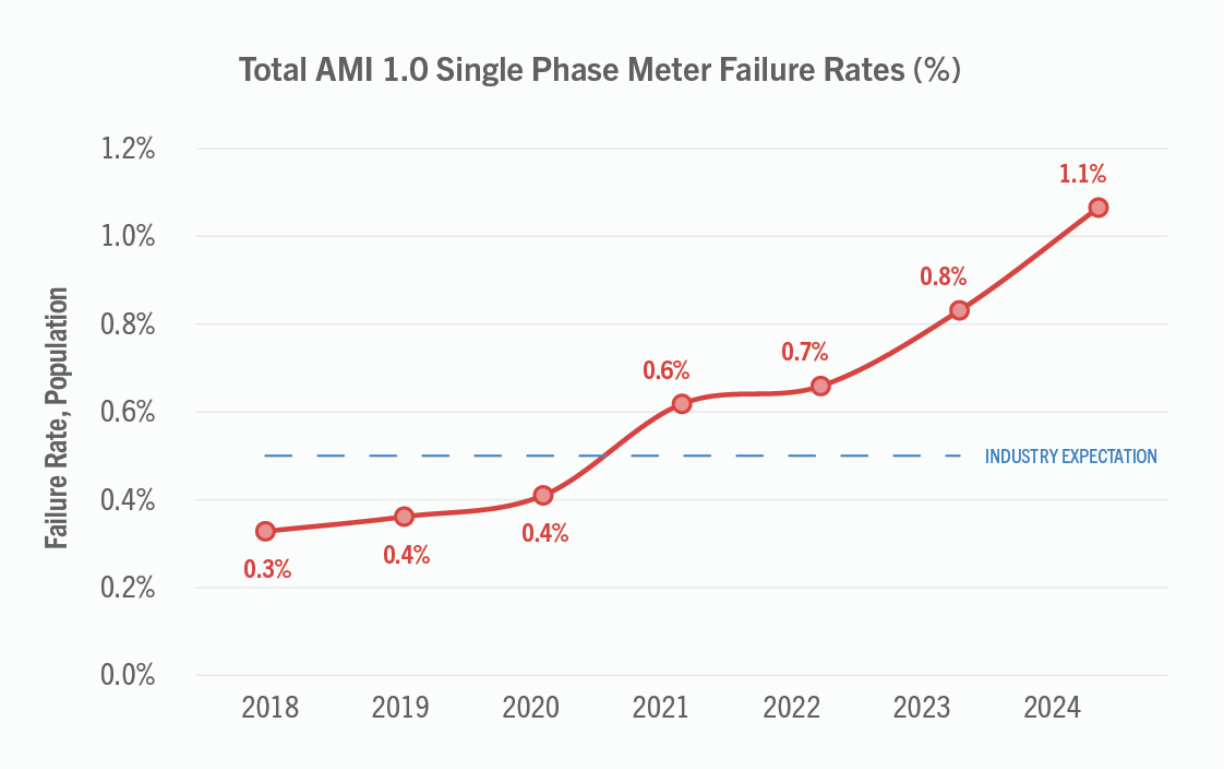


Figure B06 - 10 AMI 1.0 Failures

Unlike conventional meters with mechanical parts, AMI meters rarely provide indicators of pending failure. For example, AMI 1.0 meters do not present with intermittent data outputs or other obvious anomalies prior to complete failure.

AMI 1.0 meters are complex electronic devices that are subject to internal component failures over time. Visual inspection of internal components during a meter's useful life is not possible as the meters are sealed. Examination of failed meters and error codes provide some insights about causation. For example, Figure B06 - 11 shows the meter board of an AMI 1.0 that failed due to open circuitry within its transformer.

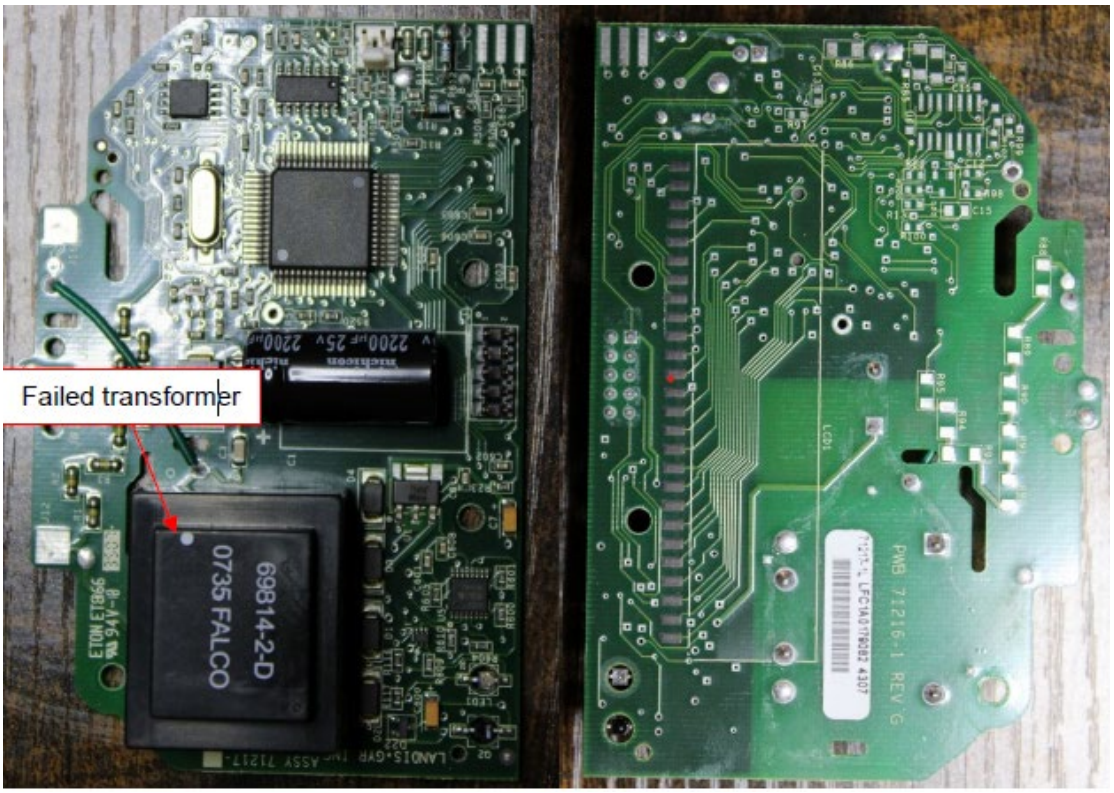


Figure B06 - 11 Meter Board of An AMI 1.0 Meter with Failed Transformer

For assets that do not provide advanced indicators of pending failure, such as meters, the "Bathtub Curve" is considered an appropriate reliability index. The Bathtub Curve[38] is used in reliability engineering and deterioration modelling to predict asset failure rates over time. By plotting the occurrences of failures over time, a bathtub curve maps out three periods that an asset set experiences within its lifetime: the Infant Mortality period which may be a temporary high rate of failure related primarily to manufacturing defects; the Normal Life period where the number of failures plateaus into a low and constant volume; and the Wear-Out period which is characterized by an increasing failure rate trend. In the Bathtub Curve model as shown in Figure B06 - 12, the end curve slopes sharply upward. Eventually, this leads to the total failure of an asset.

[38] Bathtub Curve - an overview | ScienceDirect Topics

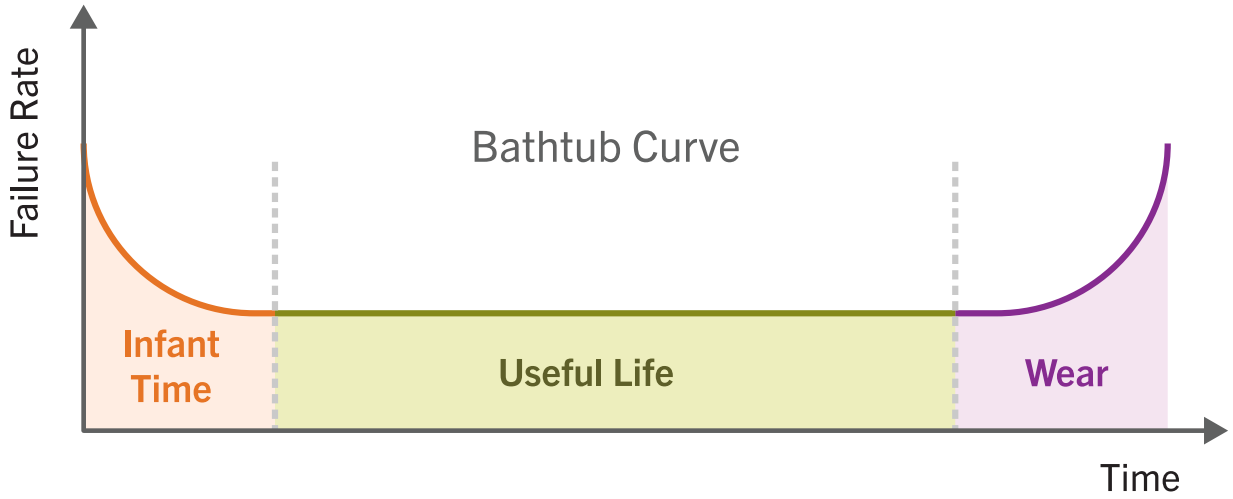


Figure B06 - 12 Bathtub Curve - an overview | ScienceDirect Topics

Alectra Utilities undertook a review of the age of the 11,074 meters that failed in 2024. Figure B06 - 13 summarizes the age of the meters at the time of their failure, which presents in a similar fashion to the Bathtub Curve model.

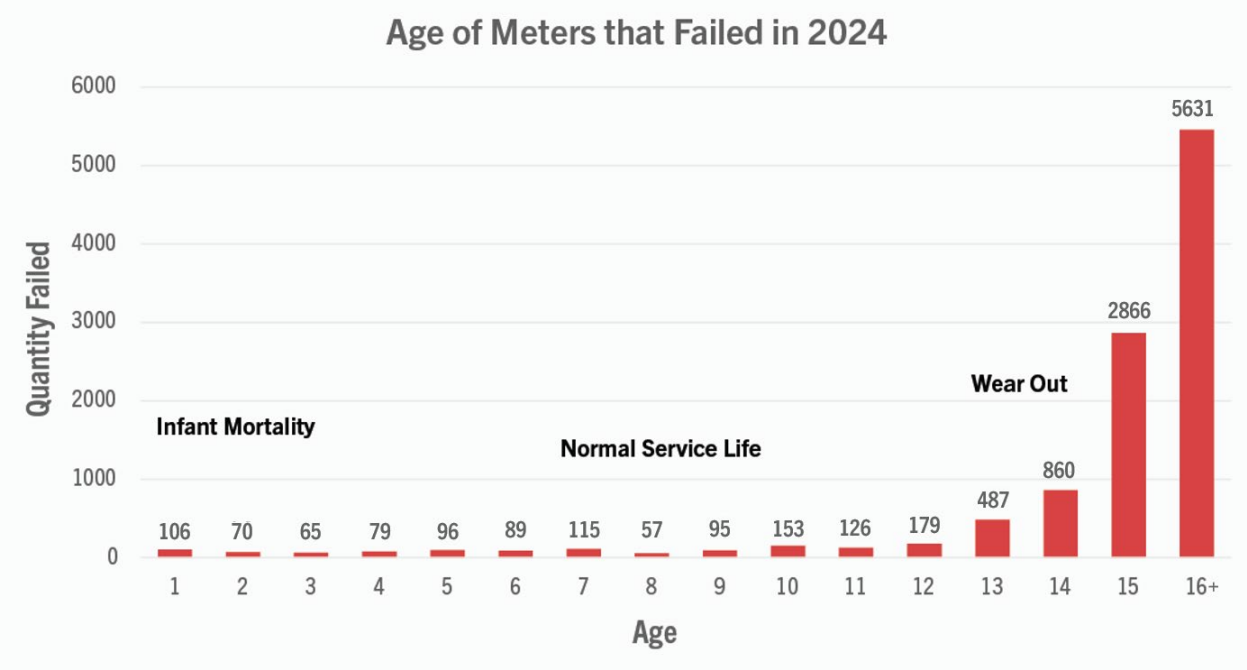


Figure B06 - 13 Age of Meters That Failed in 2024

Alectra Utilities' analysis of the age of the meters that failed in 2024 shows product stability through to the meter's 12th year of usage. The data shows that aged meters are failing at greater rates than newer meters. In fact, 77% of the meters that failed in 2024 were 15 years of age or greater. The growing failure rate beginning when the meters reach 13 years old is likely representing the beginning of the Wear-Out Period under the Bathtub Curve Principle.

Within its AMI 1.0 population, Alectra Utilities has some meter types that are experiencing higher rates of failures. In particular, Focus and ALF Focus meters manufactured by Trilliant, and REX2 meters by Honeywell experienced failure rates of 4.8% and 1.2%, respectively, in 2024 (refer to Figure B06 - 14 and Figure B06 - 15).

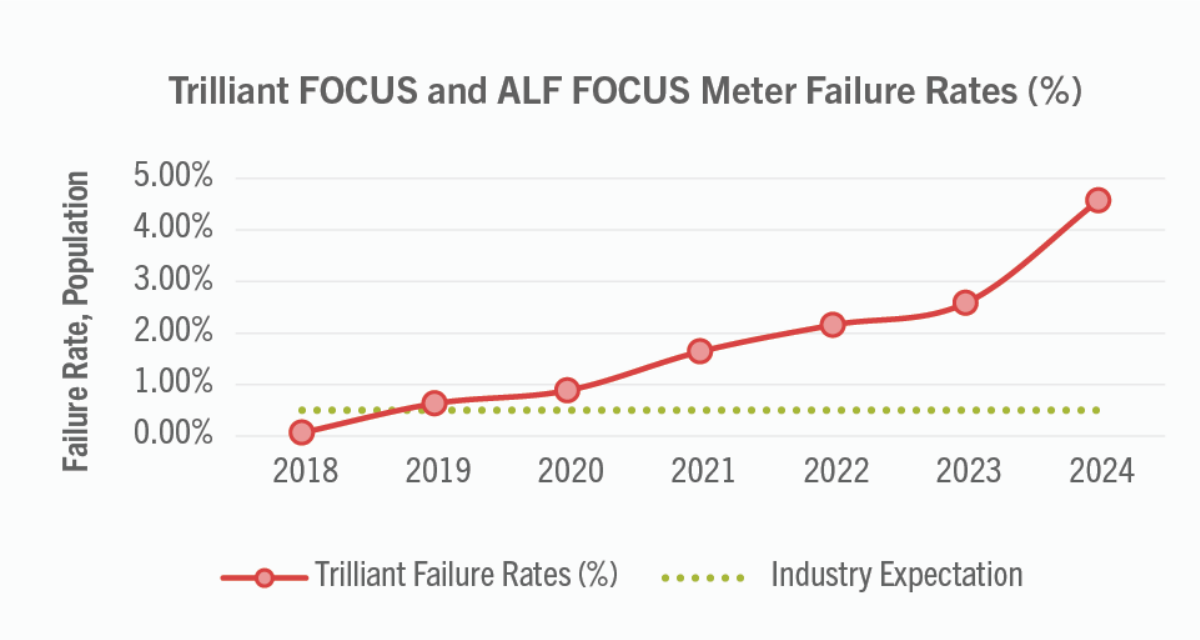


Figure B06 - 14 Trilliant FOCUS and ALF FOCUS Failure Rates

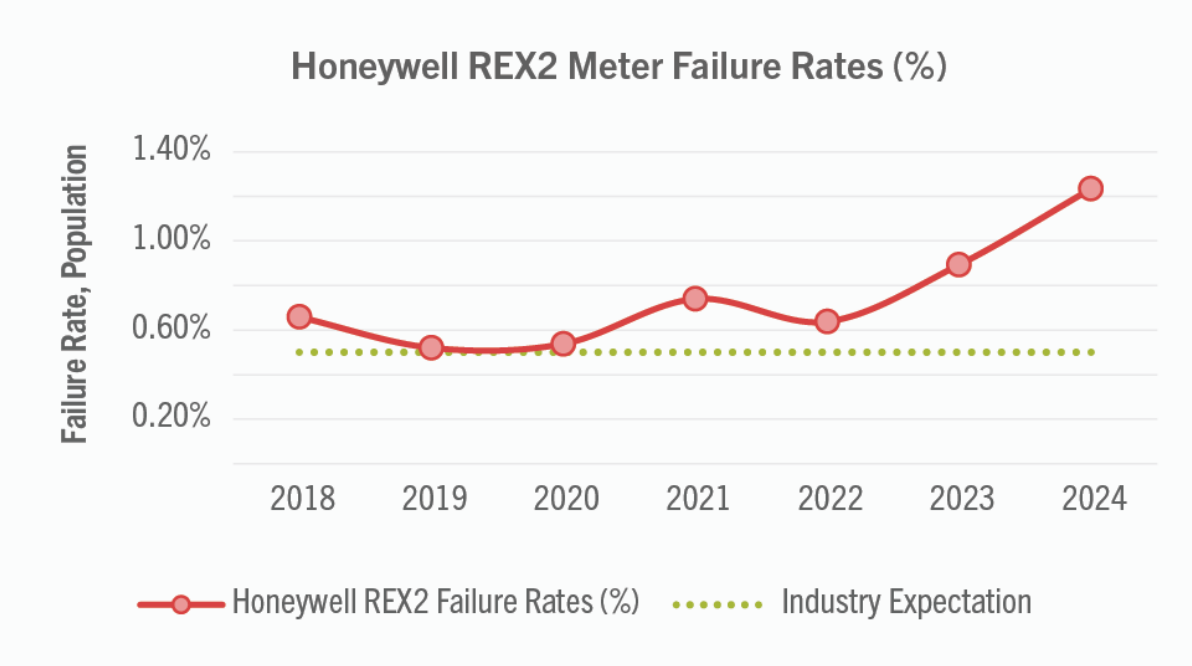


Figure B06 - 15 Honeywell REX2 Meter Failure Rates

To manage failure rates, Alectra Utilities began replacing its AMI 1.0 meters with the highest risk of failure, replacing approximately 25,000 Trilliant meters in 2023 and 2024. As of December 31, 2024, Alectra Utilities continues to have more than 310,000 Focus, ALF Focus, and REX2 meters installed at residential and small commercial premises.

Approximately 7% of Alectra Utilities' retail meters are not attached to its AMI 1.0 networks. This includes larger commercial and industrial meters and suite meters. Failure rates are within expected tolerances and are replaced reactively as required.

B Meter Failure Mitigation Plan

The Meter Failure segment is the reactive replacement of meters, primarily AMI 1.0 meters, as they fail. Due to their obsolescence, Alectra Utilities is unable to procure like-for-like AMI 1.0 meters and typically replaces failed AMI 1.0 meters with AMI 1.0 meters harvested and re-inventoried from its AMI 2.0 Renewal Program. As the legacy AMI 1.0 meter-type and the AMI 2.0 meters use separate and non-compatible networks, the meters cannot be installed inter-changeably.

It is not practical to manage meters in a "run-to-fail" model in the context of a meter fleet that is approaching the end of its useful life and exhibiting failure rates that are increasing annually beyond industry norms. Reactive single meter replacements, as the meters fail, result in higher costs due to exception management of the assets as well as field labour. This approach also increases risks to customer billing processes including risks of estimated, corrected, and delayed customer bills, and regulatory compliance requirements.

The Network Metering team has insufficient resources to reactively manage the growing volume of meter failures that has increased by 164% over the last four years. Delays in replacing failed meters will result in disruption to meter-to-bill processes and an inability to provide accurate and timely bills to customers. Meters that communicate reliably are also required to maintain the overall health of the AMI mesh communication networks. Higher volumes of meter failures may cause partial or full collapse of the AMI 1.0 networks, creating cascading issues to interdependent meters.

To return the failure rate in line with expectations, Alectra Utilities commenced an AMI Renewal program in 2023 as described in *Section 3.1.5*. Approximately 38,000 AMI 2.0 meters were installed by December 31, 2024, concentrated in areas of highest operational risk.

As the end-of-life AMI 1.0 meters are replaced in sufficient quantities, particularly the models with the highest failure rates, it is anticipated that the overall meter failure rate will decrease. Upon completion of the AMI Renewal Program, Alectra Utilities expects its meter failure rates will return to the industry norms of less than 0.5% annually.

The Smart Metering Initiative mandate to bill customers on Time-of-Use rates by 2009 necessitated that Alectra Utilities' legacy utilities install more than 750,000 AMI 1.0 meters within a five-year period between 2006 and 2010. By completing its AMI Renewal program over a ten-year period (2023 to 2032), Alectra Utilities expects to re-balance its lifecycle renewal requirements and mitigate risks of high-volume meter failures in the future.

C Meter Failures Program Costs

The capital expenditures related to Meter Failures do not intuitively align with the number of failures experienced in that year. This is due to several factors, including: the inability to procure certain meter types due to supply chain constraints from 2021 to 2023; the procurement of less expensive AMI 2.0 meters beginning in 2023; and the harvesting and re-deployment of AMI 1.0 meters from areas where AMI 2.0 pockets were established beginning in 2023.

3.1.5 AMI Renewal

Table B06 - 14 AMI Renewal Expenditures

	Historical Spending					Bridge		Forecast Spending				
Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
AMI Renewal ($MM)	0.0	0.0	0.0	2.5	11.3	10.6	10.4	38.2	57.6	57.4	49.8	44.6

AMI Renewal is required to replace Alectra Utilities' AMI 1.0 meters, related communications network components, and AMI 1.0 Head-End back-office systems, all of which are at end of life.

Meters are a critical component of Alectra Utilities' operations and customer services, including customer billing. Managing a large meter network using a "run-to-fail" approach is neither practical nor reliable. Each failed meter compromises the mesh network it supports, reducing overall system resilience. A high volume of meter failures can destabilize the network entirely, leading to cascading communication breakdowns and preventing meter data from reaching the AMI head-end system.

Figure B06 - 16 depicts a mesh network of meters, where the failure of one meter impacts the ability of neighbouring meters to communicate. The meters attempt to re-mesh but are increasingly unable to do so when multiple failures occur.

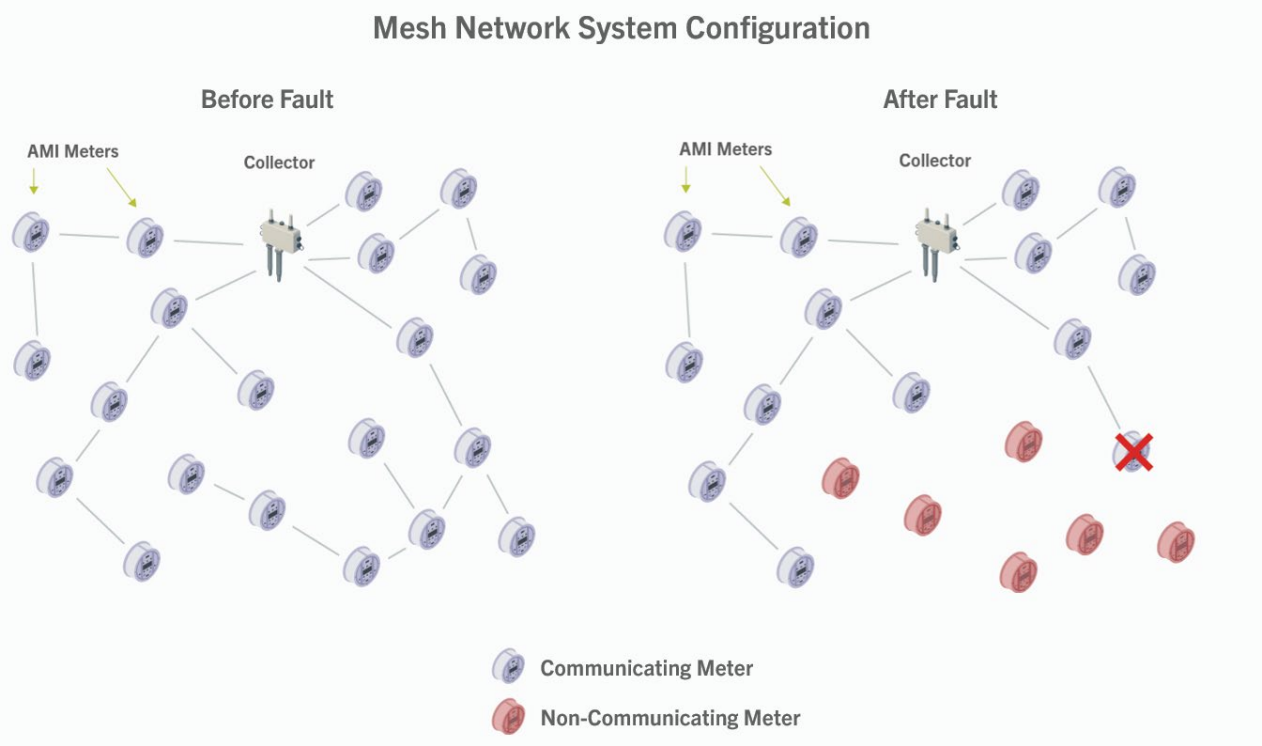


Figure B06 - 16 Sample Mesh Network System Configuration

Alectra Utilities' growing AMI 1.0 failure rates are described in *Section 3.1.4*.

Alectra Utilities (through its predecessors) procured AMI 1.0 meters from four different vendors: Honeywell (formerly Elster), Itron (formerly SilverSprings), Sensus, and Trilliant. AMI 1.0 vendors generally support 15 to 20 year meter replacement cycles and have discontinued[39] their original AMI 1.0 meters in favour of next generation meter technologies. Due to on-going technological obsolescence and procurement limitations, it is not prudent to continue AMI 1.0 investments.

It is also not practical to continue to maintain four AMI vendor networks through this lifecycle renewal. In general, the new meters are not backwards compatible, nor do they offer interoperability with each other. Maintaining the four existing vendor networks would necessitate the upgrading of the equipment of four separate communication networks and the need to maintain four sets of inventory and vendor-specific testing protocols. The continuation of four AMI

[39] Alectra Utilities' AMI 1.0 meters have been discontinued include Honeywell A3, Honeywell REXU, Trilliant FOCUS ALF, and Sensus ICON A. These meter types represent more than 90% of Alectra Utilities' 1.0 meter forms.

networks would also limit Alectra Utilities' ability to provide consistent customer experience due to the inconsistent functionality provided across each vendor model.

Additionally, the lack of interoperability, combined with the inability to leverage volume pricing, makes it more expensive to procure the next generation AMI technology from multiple vendors. As compared to AMI 1.0 technology, the AMI 2.0 meters selected by Alectra Utilities are less expensive on average and have greater functionality. As such, Alectra Utilities began transitioning to AMI 2.0 technology in 2023. As mentioned, Alectra Utilities plans to complete the replacement of its AMI 1.0 meters by 2032.

AMI 1.0 Technological Obsolescence and Procurement Limitations

93 per cent of Alectra Utilities' meter fleet uses AMI network technology to transmit meter data through a communication network or backbone[40]. As of 2024, Network Metering manages five separate AMI networks through four AMI Head End systems. Four of the meter networks are legacy AMI 1.0 networks established between 2006 and 2009 by Alectra Utilities' predecessors. The fifth is an AMI 2.0 meter network that was initiated in 2023.

AMI 1.0 technology was designed primarily to replace manual meter reading of independent conventional meters with automated AMI networks of smart meters that could provide hourly data intervals. The availability of hourly meter read data enabled new rate structures including Time-of-Use billing for customers.

Beyond the provision of hourly data, Alectra Utilities' four AMI 1.0 networks have varying functionality, negating the ability to provide integrated and consistent meter-based services for its customers. This includes variations of anomaly flagging for high voltage or high amperage, the ability to "ping" a meter to obtain real-time meter read data, "last gasp" outage messages as the meter experienced an interruption of power, or the ability to perform remote disconnect and reconnect actions.

AMI 1.0 networks operate as closed systems with proprietary technologies that do not allow interoperability between each other. Each AMI 1.0 system includes Head End software, a communications backbone of equipment including collectors and repeaters, and meters of various

[40] O. Reg 425/06: Criteria and requirements for meters and metering equipment, systems and technology
Functional specification for an advanced metering infrastructure | ontario.ca

types. AMI systems communicate through a wireless Radio Frequency (RF) mesh established between the collectors, repeaters and meters, or point-to-point via tower-based communications.

Alectra Utilities' AMI 1.0 networks include a complex array of 25 towers and more than 2,100 communication devices. The original AMI 1.0 network equipment was installed between 2006 and 2009 and is now beginning to show signs of failure. In 2023 and 2024, Alectra Utilities replaced, hardened, or moved 56 AMI 1.0 data collectors to mitigate network communications failure risk.

Table B06 - 15 Comparison of AMI 1.0 and AMI 2.0 Network Components

Infrastructure Requirements	AMI 1.0	AMI 2.0 (Forecasted)
Towers	25	0
Data Collectors (Access Points)	815	325
Repeaters (Relays)	780	600
Antennas	820	300
Communication Lines	4,815	300

AMI 2.0 technology offers simplified communications through fewer devices, as well as opportunities for redundancy not available with AMI 1.0. While AMI 1.0 communications rely on cellular telecommunications, AMI 2.0 can utilize secondary networks including Alectra Utilities' internal WiMAX network.

The need for renewal of AMI 1.0 assets is driven primarily by their incrementing failure rates, the cost to maintain the end-of-life network equipment, and the expense of shorter meter seal compliance requirements as the meters age. In addition, AMI 1.0 vendor limitations, obsolescence and supply chain constraints necessitated the need to transition and procure AMI 2.0 beginning in 2023.

As mitigation to the AMI 1.0 inventory shortages, Alectra Utilities began installing AMI 2.0 meters in geographic "pockets" to mitigate customer and operational risks where supply chain constraints of AMI 1.0 meters outpaced requirements. The AMI 1.0 meters harvested from the pockets are re-inventoried for future use including replacement of AMI 1.0-meter failures, meeting customer

demand for new connections and upgrades, and as operational inventory to manage sampling and re-verification program requirements.

AMI 2.0 Technology Benefits

Compared to the AMI 1.0 meters, the AMI 2.0 technology provides incremental benefits to the utility and its customers. AMI 2.0 meters are, on average, both less expensive than AMI 1.0 meters and more technically advanced,[41] offering additional "in the box" functionality including last gasp outage technology, remote disconnect and reconnect features, enhanced alerts, as well as new and improved power quality analytics. Combined with grid edge and DI add-ons, AMI 2.0 is expected to form the foundation of a more intelligent grid.

Table B06 - 16 summarizes the functionality available with Alectra Utilities' first generation of AMI meters as compared to the functionality of its Itron AMI 2.0 meters.

Table B06 - 16 AMI 2.0 Technology Benefits

AMI Feature / Functionality	Available with Alectra Utilities' AMI 1.0 meters / networks	Available with Alectra Utilities' AMI 2.0 meters / network
Outage management	Partial - 2 out of 4 AMI systems	Included in base functionality
Remote reconnect / disconnects	Partial - 1 out of 4 AMI systems	Included in base functionality
Analytics (amperage, voltage)	Partial	Included in base functionality
Enhanced analytics and alerts including power quality	No	Included in base functionality
Enhanced network connectivity options (900 MHz, cellular / Wi-max)	Partial - 2 out of 4 AMI systems	Included in base functionality
Supports bi-directional data flows	Yes, via an upgraded meter form	Included in base functionality
Bellwether network sensors	Basic	Included in base functionality
Interoperable with other networks	No	Yes, via Wi-SUN standard
Cybersecurity	Basic	Included in base functionality, robust

[41] Itron Gen5 Riva single phase meter specifications

AMI Feature / Functionality	Available with Alectra Utilities' AMI 1.0 meters / networks	Available with Alectra Utilities' AMI 2.0 meters / network
Quality of the communication backbone	Basic	Robust - Every meter connects to two network paths
Distributed Intelligence	No	Hardware included in base functionality, DI applications are future enablement
Distribution automation	No	Hardware included in base functionality, DI applications are future enablement

AMI 2.0 Enhanced Functionality

The AMI 2.0 technology selected by Alectra Utilities is the Gen5 Riva meter by Itron[42]. This meter provides enhanced "in the box" meter functionality including:

- Five or 15-minute interval data for single phase customers (compared to hourly intervals) to better inform system planning activities and provide enhanced usage data to customers.
- Five-minute interval data for polyphase customers (compared to 15-minute intervals) to better inform system planning activities and provide enhanced usage data to customers.
- Capability of each meter to perform bi-directional data flows and net metering, eliminating the need to install a second, more expensive AMI 1.0 meter when customer requirements change.
- Extended "Last Gasp" outage advisement in every single phase meter, with message bundling and forwarding. The first generation of "Last Gasp" technology did not filter the messaging in any way resulting in message "blasts" that made it challenging for Outage Management Systems to utilize the information.
- 48 configurable channels of meter data provided through three profiles and 12 registers including energy, demand, load, instrumentation and voltage, compared to an average of 14 channels and much more limited instrumentation for typical AMI 1.0-meter technologies.

[42] Itron Gen5 Riva single phase meter specifications

- Enhanced computing power and memory which increases the speed and reliability of firmware and communication upgrades.
- Reduced RF[43] emissions as compared to the original AMI 1.0 communications technology.
- Remote disconnection and reconnection capabilities in all single-phase meters to increase worker safety, decrease operational costs through a reduction of on-premises field activities, and increase customer satisfaction through faster power restoration.
- Enhanced power quality, operational alarms and safety alerts to detect issues within the meter installation such as arcing, reverse power flows, tamper detection, and higher than normal temperatures.
- Enhanced cybersecurity and encryption technology to reduce the risk of cyber-attacks inherent in digital and software centric grid systems.
- Enhanced operational dashboards and tools to increase visibility to the network and manage exceptions.
- Ability to use a secondary backhaul communication network for redundancy purposes.
- Interoperability enabling the ability to read other manufacturers' meters through the communications network and add other devices to the network such as distribution assets including line sensors or automated feeder devices.
- Ability to support 50% more meters per network access point, which simplifies the network design, as well as installation and maintenance costs. Network Metering expects to reduce its OM&A expenditures related to meter data retrieval due to the simplified network design and the ability to utilize alternative networks including Alectra Utilities' future Wi-MAX networks.
- Enhanced ability for the field network or "mesh" to "self-heal" as all devices are designed to have more than one communication path to the Head End. In the event of a meter or network device failure, manual human intervention is not immediately required, as meter traffic will be automatically rerouted through

[43] Radio Frequency Emissions. Analysis of Radio Frequency Exposure Associated with Itron's Advanced Metering Devices

alternate communication paths. Field activities to reactively repair or replace the failed network device can be deferred, and repairs can be scheduled in an efficient planned manner.

AMI 2.0 Customer, Operational and Future Benefits

Alectra Utilities expects the benefits of the AMI 2.0 program to include cost containment, faster outage identification and response, enhanced customer services, and future benefits including enhanced grid transparency.

A Cost Containment

Network Metering expects that it will have capital cost reduction opportunities of up to $139.1MM based on the deployment of its AMI 2.0 Renewal program compared to installing AMI 1.0 meters[44] as failures occur. This includes:

- $42.3MM by installing AMI 2.0 meters instead of the more expensive AMI 1.0 meters. Alectra Utilities negotiated volume-based pricing for its fleet of AMI 2.0 meters which resulted in a 26% reduction in meter expenditures.
- $37.5MM by avoiding the forecasted escalating failure rates of the aging meter population.
- $27.5MM from avoiding an incremental visit to the same premise to replace failed AMI 1.0 meters and then install an AMI 2.0 meter in the future (when the AMI 2.0 network is established).
- $17.7MM based on receiving dispensation from Measurement Canada that provides a temporary exemption from verifying meters that are planned for replacement.

[44] Assumes that AMI 1.0 meters are available for procurement from Alectra Utilities' four AMI 1.0 service providers. As of June 2025, two of Alectra Utilities' AMI 1.0 providers do not have Measurement Canada approved meters that are compatible with Alectra Utilities' AMI 1.0 networks. A third provider cannot provide AMI 1.0 meters in sufficient quantities to meet Alectra Utilities requirements. These three AMI 1.0 providers serve approximately 93% of the AMI 1.0 networks within Alectra Utilities' service territory.

- $9.2MM that would otherwise be required to replace AMI 1.0 communication equipment to maintain legacy meshes for an extended timeframe.
- $3.6MM in estimated incremental customer services support costs related to meter failures that cause estimated customer bills and billing delays.
- $1.3MM in efficiencies from having a single AMI meter and equipment provider with multi-function meters. This enables the need for fewer meter types to service customers, thereby reducing inventory and warehousing requirements and simplifying meter procurement.

B Improved Outage Response

Itron's AMI 2.0 meters are equipped with "extended last gasp" functionality. A super capacitor within each meter provides temporary power, enabling the meters to communicate with each other, filter out momentary interruptions and automated restoration activities, and bundle confirmed outage information from affected meters. Meters nominated as the "peer leads" will then communicate to Alectra Utilities' Outage Management System, confirm receipt of their information, and re-send their information if required.

Figure B06 – 17 details the enhanced functionality made possible through the Itron Gen5 meter's super-capacitor.

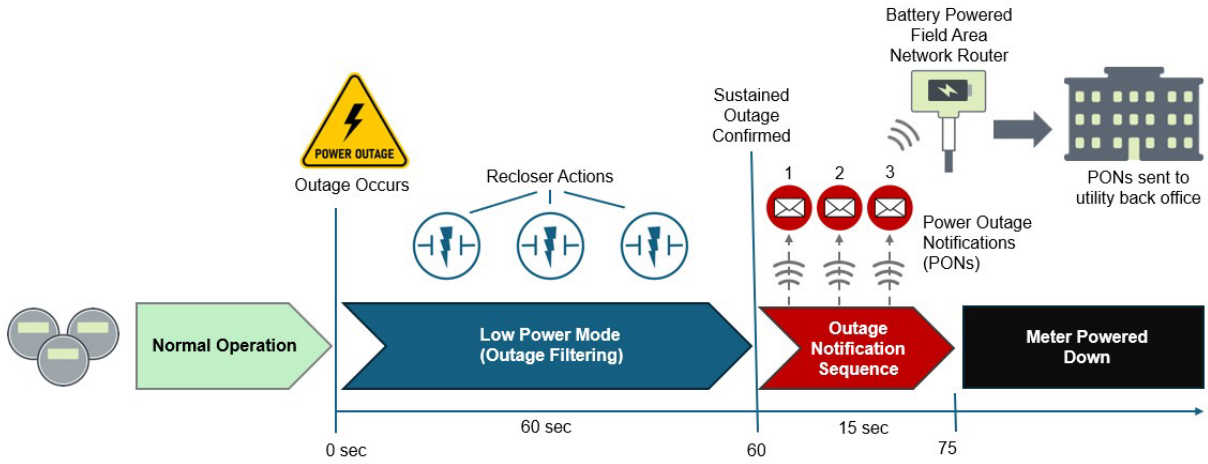


Figure B06 – 17 AMI 2.0 Outage Response within the AMI 2.0 Meter

Compared to the AMI 1.0 Technology, the AMI 2.0 meter functionality prevents false positives through its longer "filter window" and prevents the redundant messaging that results in network congestion. AMI 2.0 "last gasp" technology is also expected to provide more accurate information on the outage source area which will aid crews in trouble shooting more efficiently.

The AMI 2.0 meters have built-in functionality that minimizes the need to sectionalize feeders to avoid "cold load pick up" risks that extend the length of customer outages. "Cold load pick up" can occur when many services are restored at the same time and the momentary load spike trips the grid protection devices. AMI 2.0 meters have built-in restoration delay functionality that provides sufficient offsets that minimize these risks.

Alectra Utilities plans to begin assessing the AMI 2.0 outage functionality in 2026, with integration to the Outage Management System(s) scheduled in 2028. Fulsome integration of outage identification and restoration functionality may not be enabled until Alectra Utilities installs a sufficient volume of AMI 2.0 meters.

C Customer Benefits

The AMI 2.0 technology is expected to deliver numerous customer benefits, including:

- Increased meter data granularity, which assists customers in understanding their usage patterns, selecting optimal rate plan(s), making informed energy decisions and managing their electricity costs.
- Flexibility to update load profiles enables the development and utilization of new rate structures that support customer affordability and encourage adoption of new programs.
- Proactive response to safety and power quality alerts that may impact customer premises including high temperature alarms, arcing alarms, and non-typical instrumentation notifications.
- A reduction in estimated or delayed customer bills due to an upgraded and more reliable AMI network.
- Faster identification of outages and shorter duration of outages due to "last gasp" functionality and outage management enhancements.

- Customer communications to notify of power outages can be enabled through the "last gasp" communications to the Outage Management System, including more accurate estimations of power restoration times.
- A reduction in the need to access customer premises for meter changes due to multi-functional meter types that support bi-directional meter flows, net metering, and changes in customer loading.
- Faster reconnection times for customers where the service has been disconnected.
- The ability to transition some commercial and industrial customers from the MV-90 network to the AMI 2.0 network may reduce the impact on the customer of maintaining a telephone line.
- The ability to explore alternatives to service disconnection, including load limiting without incurring additional hardware costs.

Alectra Utilities plans to begin assessing its customer-facing functionality opportunities in 2026, with process development and integrations on a priority basis beginning in 2027.

Future Opportunities: Grid Edge Technology and Distributed Analytics

The "grid edge" refers to the interface between the distribution system and end-users, including the technologies and infrastructure at or near the point of electricity consumption. The Itron technology selected by Alectra Utilities supports DI [45] and grid edge use cases through applications that can be loaded onto the AMI 2.0 meters, much like applications on cell phones. The AMI 2.0 meters support applications to enhance reliability and planning, foster and manage flexible energy solutions including DERs, support customer energy transitions, provide customer analytics to guide behaviors that can improve affordability, and enable market participation.

The DI applications can be uploaded to the AMI 2.0 meters "over the air" using the AMI network. Certain DI applications utilize peer-to-peer capabilities where the meters use powerline carrier technology to exchange information and make decisions at the grid edge. This minimizes the amount of data to be communicated to the back-office and enables a real-time response to

[45] Itron: Distributed Intelligence overview

evolving conditions at the grid edge. The DI applications provide instantaneous data, rather than traditional hourly interval data.

Grid edge applications are rapidly being created and enhanced as new use cases are identified. Itron uses an open-source technology that allows other vendors, including utilities, to build applications for use within the AMI 2.0 meters.

Some of the applications available in the market Table B06 - 17.

Table B06 - 17 Distributed Intelligence Applications

DI "App"	Description	Potential Customer and Operational Benefits
Location Awareness	Provides the electrical location of every meter on the distribution grid, including transformer, phase, and feeder.	• Identifies discrepancies with traditional Geographic Information System records • Provides ability to continuously maintain an accurate system model • Improves scoping and scaling of outage information and restoration
Active Transformer Monitoring	Near real-time monitoring of system loading at the distribution transformer level that can be an input to utility control systems (SCADA/ ADMS) in resolutions of one to five minutes.	• Provides near real-time load monitoring at the distribution transformer level • Enables the ability to assess forecasted loads versus actual at the grid edge • Improves state analysis and decision making
High Impedance Detection	Detects and locates high impedance caused by poor electrical connections (“hot spots”) in low voltage secondary networks between the meter and the distribution transformer. Detection includes poor insulators, faulty meter installations, and poor wiring conditions.	• Provides early detection of causes of flickering lights, customer power issues and interruptions, and fire risk, enabling resolution before it impacts the customer • Identifies over-loaded conductor or distribution transformers
Electric Vehicle (“EV”) Awareness	Detects Level 1 and Level 2 EV charging at residential premises including near real-time disaggregation data to create a	• Advises EV owners of rates and programs to reduce their energy costs, and realize future curtailment opportunities

DI "App"	Description	Potential Customer and Operational Benefits
	start / stop charging series usage profile.	• Supports improved system planning and EV impact analysis
Load Disaggregation	Provides disaggregation of a customer's total load into segments including heating and cooling and large electrical appliances.	• Increases customer engagement • Enhances customer load profiling to identify causes of high costs, and help select preferred rate programs

In this DSP period, Alectra Utilities is focused on the replacement of its end-of-life AMI infrastructure and implementation of AMI 2.0 functionality. Small scale exploratory DI and grid edge technology pilots will be undertaken, and if successful, larger scale deployments can be explored in future DSP periods.

D AMI Renewal Program

Alectra Utilities' AMI Renewal program began in 2019 and has four phases: planning; small scale AMI 2.0 pocket deployments; AMI 2.0 Head End System installation and integration; and mass meter deployment.

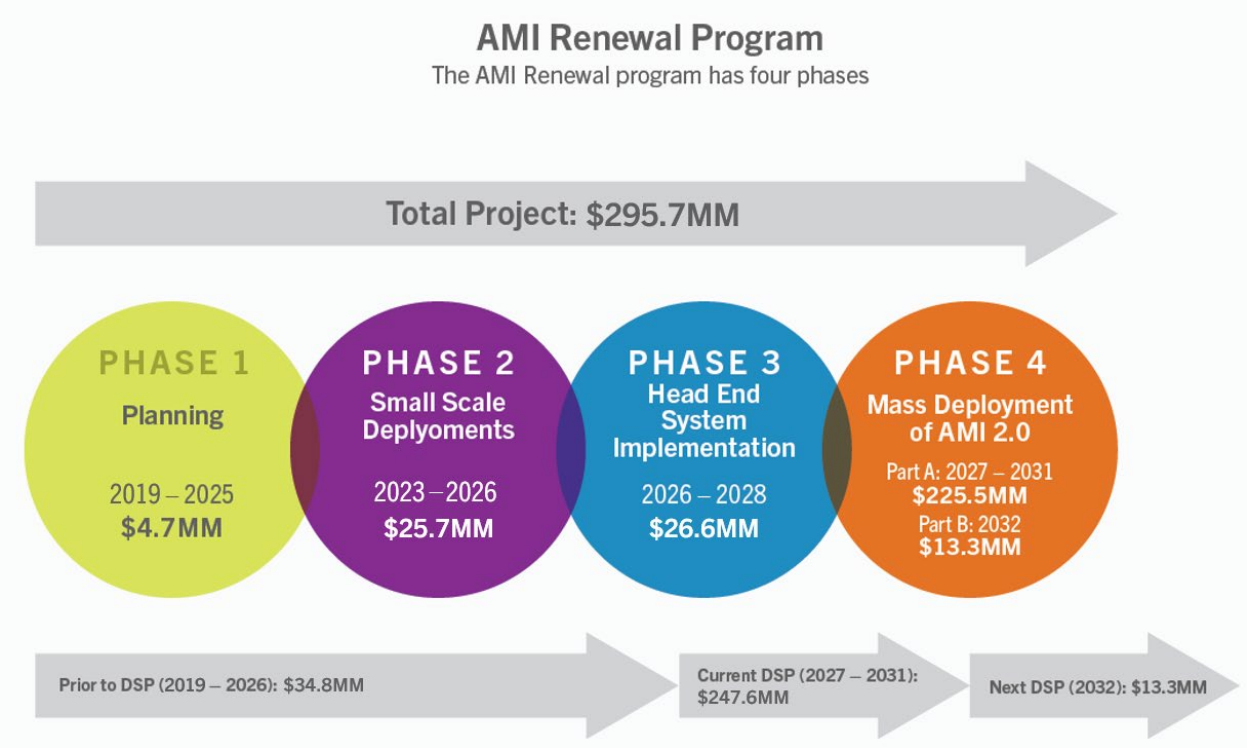


Figure B06 – 18 AMI Renewal Program Phases

Phase One: Planning (2019 – 2025) $4.7MM

Alectra Utilities began pre-project exploratory activities in 2018 and 2019 regarding its aging AMI 1.0 networks. In 2019, Alectra Utilities and Hydro One Networks Inc. (Hydro One) determined that collaboration on certain AMI Renewal activities, including procurement, could result in overall savings through minimizing duplication of efforts, enhanced identification of best practices, joint identification and mitigation of risks, and enhanced negotiating power.

In 2020, Alectra Utilities' AMI Renewal Project officially began with a joint procurement effort with Hydro One.

The assessment of AMI 2.0 technologies had more than 1,400 evaluation criteria, which Hydro One and Alectra Utilities evaluated separately. Both Alectra Utilities and Hydro One selected Itron as the preferred AMI 2.0 technology services provider, enabling joint contract negotiations. One of the key benefits of this collaboration was the negotiation of favorable pricing terms, including volume-based pricing for the combined total of Alectra Utilities and Hydro One's 2.4 million meters, and mitigation of risks related to uncertain future inflationary increases through a

negotiated inflation-sharing mechanism. Purchased in typical annual quantities, Alectra Utilities' AMI 2.0 meters are on average 26% less expensive than the continued procurement of AMI 1.0 meters. Alectra Utilities and Hydro One further negotiated that the favourable pricing for meters and related equipment can be extended to other Canadian utilities.

The planning phase also included the selection of a services vendor to manage the deployment of the AMI 2.0 meters. The services vendor will be responsible for AMI 2.0 inventory management and warehousing, meter installations, integration of field work activities with Alectra Utilities' Customer Information system, reporting and controls, customer support, and recycling and disposal of the removed AMI 1.0 meters. Alectra Utilities' Request for Proposals process resulted in the selection of a preferred services vendor in early 2025. Contract negotiations are expected to be completed in 2025, after which integration activities will commence.

Phase Two: Small Scale Deployments (2023 – 2026) $25.7MM

The small-scale deployment phase began in 2023 and is expected to extend through to 2026.

It involves testing the AMI 2.0 meters and related network equipment, network design, development of engineering and product standards, and development of new processes and protocols to support AMI 2.0 meter-to-bill processes.

Alectra Utilities began installing AMI 2.0 meters in 2023 in two small pocket locations. The AMI 2.0 meters are interrogated from Alectra Utilities' Itron AMI 1.0 Head End system as "like for like" technology. This approach enables the procurement of the less-expensive AMI 2.0 meters, mitigation of AMI 1.0 inventory risks, and the ability to test and refine processes including those that minimize customer impacts in small, controlled meter deployments.

Each deployment is planned to offer additional insights and process refinement opportunities. Testing and manual use of some "out of the box" AMI 2.0 functionality is occurring during the small-scale deployments. This includes observance of the enhanced meter alerts related to safety and power quality for correlation and response by field teams. The first phase of meter management including remote disconnections and reconnections is planned to begin in 2025 to reduce field visits, improve worker and customer safety, and provide faster service for customers.

During this phase, Alectra Utilities will complete the installation of the network equipment including approximately 600 Access Points (formerly known as "gate keepers" or "data collectors") and relays. This equipment must be installed prior to the mass deployment of AMI 2.0 meters.

Phase Three: Head End System Implementation (2026 - 2028) $26.6MM

This phase involves the design, configuration, testing, and implementation of the "Head End System" and the first integrations to downstream systems. The Head End System is the back-office software system that manages meter data interrogations. The meter data is subsequently distributed to other systems including Alectra Utilities' Centralized Meter Data Engine, Customer Information System and Outage Management System, and the provincial Meter Data Management Repository.

The Head End System implementation is expected to be a 12 to 18-month project including planning workshops and integration activities aimed at enabling the additional meter data channels and AMI 2.0 technology enhancements. The scope, pace, and priority of the integrations will be prioritized based on outcomes from pilots and preliminary assessments and readiness of downstream systems. Secondary integration activities will continue throughout the plan period.

The Itron AMI 1.0 Head End System is limited in its capabilities and scalability. As such, the AMI 2.0 Head End System must be implemented prior to the mass deployment of AMI 2.0 meters.

Phase Four: Mass Deployment of AMI 2.0 Meters (2027 – 2031 (Part A)) $225.5MM:

The Mass Deployment phase is the final phase of the AMI Renewal Project. It includes the replacement of all remaining AMI 1.0 meters with AMI 2.0 technology.

The cost of the AMI 2.0 meters[46] and associated installation services are the most significant program expenditures at $210.7MM. To minimize impact to its on-going Network Metering Program operations, Alectra Utilities has required that its deployment services vendor provide fulsome services over the mass deployment period, including:

- Supervision, training and materials for its employees including tablets, vehicles, cell phones, personal protective equipment and safety equipment as appropriate

[46] Costing of the meters and the associated deployment costs are commercially sensitive and therefore provided in aggregate.

- Up to 220,000 AMI 1.0 to AMI 2.0 meter changes annually during the mass deployment period between 2027 and 2031
- Tactical meter inventory management and warehousing
- A field management workflow system to track work requirement, controls, and exceptions which is to be fully integrated with Alectra Utilities' Customer Information System
- Customer management related to the meter changes including appointment scheduling and first-level resolution of escalations
- Follow-up repairs to customer premises or meter bases damaged during the meter change
- Recycling and disposal of the AMI 1.0 meters
- Daily, weekly, and monthly reporting of program activities as compared to the project plan(s)

Alectra Utilities' activities during the project include:

- Project governance provided by an Executive Steering Committee consisting of three Executive Vice Presidents and seven Vice Presidents
- Overall Project Management including:
    - Project reporting, controls, and analytics
    - Monitoring of Service Level Indicators and leading corrective actions
    - Budgeting and forecasting
    - Procurement
    - Oversight and relationship management of project vendors and service providers
- Creation and delivery of the customer communication and education strategy
- Monitoring of the AMI 1.0 and AMI 2.0 networks to identify and resolve meter data exceptions in real-time
- Customer escalations
- A subset of the complex polyphase meter changes, as capacity allows.

IV Investment Plan

Alectra Utilities' historical and forecast spending in its Network Metering Program is shown in Table B06 - 18. The total investment requested between 2027 and 2031 is $305.4MM.

Table B06 - 18 Network Metering Capital Plan

	Historical Spending					Bridge		Forecast Spending				
Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Wholesale Meter Compliance	2.5	1.1	1.1	2.0	1.4	1.3	1.1	2.6	2.6	2.6	2.8	2.9
Meter Sampling and Reverification	1.1	2.7	2.2	3.0	3.7	4.4	5.5	3.3	0.5	0.5	0.5	0.5
New Connections and Upgrades	7.0	6.1	6.1	4.9	3.8	4.5	3.9	3.7	3.8	3.8	3.9	4.0
Meter Failures	5.8	3.7	4.1	3.8	2.3	4.6	5.0	5.5	4.8	3.7	2.5	0.8
Miscellaneous Expenditures	0.6	0.7	0.5	0.4	0.5	0.4	0.4	0.8	0.6	0.6	0.3	0.2
Total Before AMI Renewal	**17.0**	**14.3**	**14.0**	**14.1**	**11.7**	**15.2**	**15.9**	**15.9**	**12.3**	**11.2**	**10.0**	**8.4**
AMI Renewal	0.0	0.0	0.0	2.5	11.3	10.6	10.4	38.2	57.6	57.4	49.8	44.6
Total ($MM)	**17.0**	**14.3**	**14.0**	**16.6**	**23.0**	**25.8**	**26.3**	**54.1**	**69.9**	**68.6**	**59.8**	**53.0**

4.1 Historical Expenditures

With the exception of AMI Renewal, the Metering program activities were generally consistent year over year. Some shifting of expenditure has occurred as field work orders have been harmonized between Network Metering teams.

Over the 2020 – 2024 period, Metering invested $84.9MM into the Metering fleet of assets. During this period, $27.9MM was related to the installation of approximately 4,000 new and upgraded customer services per year. An additional $19.7MM was required for the replacement of failing meters and network equipment. The wholesale and revenue meter compliance activities continued through this period at $20.8MM.

The additional $22MM over the previous DSP was largely related to AMI Renewal. Alectra Utilities installed approximately 38,000 AMI 2.0 meters and related network equipment in four deployment pockets. Ongoing risk assessments including meter failure rates and inventory requirements determine the location and size of the deployment pockets.

4.2 Bridge Year Expenditures

The bridge years of 2025 and 2026 will have total expenditure of $52.1MM. Metering program expenses during this time will be $31.1MM, focused on the replacement of failing meters and network equipment, new customer connections and upgrades, and wholesale and revenue meter compliance. Alectra Utilities expects to have higher costs related to failing end-of-life AMI 1.0 meters, and Measurement Canada re-sealing requirements.

The remaining $21.0MM will be focused on AMI Renewal with the installation of additional network equipment and approximately 50,000 AMI 2.0 meters. Integration activities related to standing up the new AMI 2.0 head end system will begin.

4.3 Forecast Plan Expenditures

With the exception of the AMI Renewal project and its implications to failing meters and re-sealing requirements, the Network Metering program activities are generally consistent year-over-year. This includes activities related to wholesale and retail meter compliance, meeting the demand for meter installations for customer connections and upgrades, and addressing meter failures.

Capital costs for the aforementioned ongoing program activities are expected to decrease from $15.9MM in 2026 and 2027 to $8.4MM in 2031. This is primarily due to a decrease in the average cost of an AMI 2.0 meter compared to an AMI 1.0 meter, a reduction in meter failures as the AMI Renewal project proceeds, and temporary exemptions from Measurement Canada for meter sampling and reverification requirements where AMI 1.0 meters will be replaced with AMI 2.0 meters.

The Network Metering expenditures between 2027 and 2031 are detailed below by program.

4.3.1 Wholesale Meter Compliance ($13.5MM)

As described in *Section 3.1.1*, the majority of Alectra Utilities' Wholesale Metering program is comprised of non-discretionary activities related to replacing failed and end-of-life meters and components including instrumentation transformers ($3.4MM) and installing new wholesale metering equipment as Alectra Utilities or Hydro One expands or refurbishes transformer stations.

Additionally, Alectra Utilities plans to incur expenditures of $10.1MM to partially mitigate operational, compliance, and financial risks related to 31 aged or obsolete meters that do not meet the current standards established under the IESO's *Market Rules*.

Alectra Utilities has not considered alternatives to its Wholesale Metering Compliance Program, as this work is non-discretionary.

4.3.2 Meter sampling and re-verification program ($5.3MM)

Alectra Utilities' meter sampling and reverification programs are described in *Section 3.1.2* Revenue Meter Compliance. In consideration of its planned AMI 2.0 Renewal program, Alectra Utilities will annually request dispensation from Measurement Canada. If approved, dispensation temporarily waives sampling and testing requirements for meters that are scheduled for replacement in the near-term.

Preliminary discussions with Measurement Canada have been positive as they consider the customer benefits to meter sampling for a short seal period against the program costs. Given the trajectory of these discussions, sampling and reverification expenses for AMI 1.0 meters with seals that expire prior to 2031 have not been included in Network Metering's capital program.

If dispensation is not approved for its fleet of AMI 1.0 meters, Alectra Utilities will incur up to $17.7MM in incremental sampling and re-verification expenditures not included in its capital program.

Alectra Utilities has not considered alternatives to its Meter Sampling and Re-verification Program, as this work is non-discretionary.

4.3.3 New Connections and Customer Upgrades ($19.2MM)

The Network Metering activities related to new customer connections and upgrades is described in *Section 3.1.3* above. Alectra Utilities expects to incur expenditures of $3.8MM annually, on average, to meet customer demand for metering at new connections and to support customer-requested service upgrades. Volumes of new connections and customer upgrades completed by the Network Metering team are expected to remain consistent with recent (non-pandemic) trends. However, annual costs are expected to be less than they were historically due to the utilization of less expensive AMI 2.0 meters, or harvested AMI 1.0 meters.

Alectra Utilities has not considered alternatives to its New Connections and Customer Upgrades Program, as this work is non-discretionary.

4.3.4 Meter Failures ($17.3MM)

The Meter Failures segment involves the reactive replacement of meters as they fail.

As described in *Section 3.1.4*, Alectra Utilities' end-of-life AMI 1.0 meters and related metering equipment have started to fail at a growing rate. Failure rates are expected to peak in 2027 and 2028 at volumes of 29,000 and 26,600, respectively. Failure rates are expected to decline as AMI 2.0 meters are installed in the areas of highest risk and in greater volumes.

Failure rates are expected to return to the industry expectation of less than 0.5% annually in 2032 at the conclusion of the AMI Renewal program.

4.3.5 AMI Renewal Project ($247.6MM)

The AMI Renewal Project is the lifecycle replacement of all AMI 1.0 meters, which have been used as Alectra Utilities' standard meter type since 2006, along with the associated AMI 1.0 network facilities.

The project includes the procurement and deployment of approximately 900,000 AMI 2.0 meters during this DSP period, including meters required to support new growth over the plan period, removal and disposal of roughly an equivalent number of obsolete AMI 1.0 meters and associated facilities, the procurement and installation of network equipment, implementation of the AMI 2.0 Head End System, integration of the AMI 2.0 Head End System to Alectra Utilities' software systems including the Customer Information System and Outage Management System, and project resources including Professional Services.

The AMI 2.0 Head End System needs to be implemented before mass deployment of AMI 2.0 meters can commence. The AMI 1.0 Head End that is managing and interrogating the existing AMI 2.0 meters cannot be sufficiently scaled to support mass deployment meter volumes.

The AMI Renewal projects cost over the DSP period is forecast to be $247.6MM. Project expenditures over the plan period are shown in Table B06 - 19.

Table B06 - 19 Planned AMI Renewal Expenditures

	2027	2028	2029	2030	2031	5 Year DSP
Meter Cost (Material & Labour)	15.8	50.0	49.9	42.6	39.2	197.4
Network Equipment Cost (Material & Labour)	4.2	-	-	-	-	4.2
Head End Integration	16.2	5.9	5.8	4.8	3.5	36.2
Professional Services	2.0	1.7	1.7	2.4	1.9	9.7
Total Project Cost ($MM)	**38.2**	**57.6**	**57.4**	**49.8**	**44.6**	**247.6**

The most significant costs in the AMI Renewal project during this DSP period are related to the procurement and installation of the AMI 2.0 meters at $197.4MM. The project's OM&A expenditures are described in *Exhibit 4, Tab 2, Schedule 13 Network Metering*. OM&A expenditures are related primarily to training, customer communications, and licensing and service fees related to the AMI 2.0 Head End System.

75% of the in-field AMI 1.0 meters will be fully depreciated as of the end of 2025. As the meters are part of a network, and the network equipment itself is also at end-of-life, all meters attached to that network, regardless of age, must be replaced.

Alectra Utilities has partially mitigated its stranded debt expense by discontinuing AMI 1.0 meter purchases as of 2023. The conservative scaling of the AMI 2.0 deployments between 2023 and 2027 also partially mitigates the financial burden of stranded debt expense as functioning non-depreciated AMI 1.0 meters are harvested and redeployed to support inventory requirements in areas where the AMI 2.0 network has not yet been deployed. The AMI 2.0 depreciation expense is detailed in *Exhibit 2B, Tab 3, Schedule 1 Depreciation and Amortization*.

V Options Analysis

As described in Table B06 - 2, Network Metering's investment is related primarily to compliance with mandated service requirements. This includes expenditures related to maintaining the wholesale and retail fleets of meters to ensure regulatory compliance, responding to new requests for customer connections and upgrades, and replacing failed meters. Alternatives have not been considered.

Alectra Utilities does have discretion regarding the pace of its AMI Renewal segment. As all Ontario distribution utilities were subject to regulation that required the installation of Smart Meters and the introduction of Time-of-Use rates by June 2011 for their residential and small business customers, it is expected that most utilities are developing or have recently started to implement renewal and replacement strategies for their AMI 1.0 networks. Alectra Utilities' AMI Renewal strategy and alternatives have been assessed on the ability to mitigate operational risks related to meter failures, extend the life of the AMI 1.0 networks as far as reasonably practical, and provide a cost-effective solution within this DSP period, for the overall project, and future renewal cycles.

The base alternative for AMI Renewal is to maintain the status quo. That is, to replace the four end-of-life AMI networks and associated AMI 1.0 meters as they fail, with similar and compatible equipment. This alternative is not expected to be feasible and has not been considered due to:

- **Procurement Limitations:** Three of Alectra Utilities' four AMI 1.0 providers have declared their AMI 1.0 meter lines as obsolete. At this time, these vendors are unable to provide Measurement Canada-approved next generation meters for all the meter forms required by Alectra Utilities.
- **Increasing Meter Failures:** AMI 1.0 failure rates are increasing rapidly due to their age. The failure rate in 2024 was 3.3 times greater than in 2018. It is not expected that Alectra Utilities can meet its mandated service obligations, including those related to providing timely and accurate customer billing, if failures continue to increase in the absence of a meter replacement program.
- **Increased Costs:** It is estimated that the continuation of AMI 1.0 meters would increase Alectra Utilities capital costs by $139.1MM as described in S*ection 3.1.5 A.* This is due primarily to Alectra Utilities' ability to obtain volume-based pricing

for its approximately one million AMI 2.0 meters, at a cost reduction of 26% compared to continuing to procure from its four AMI 1.0 vendors.

Likewise, Alectra Utilities has not considered strategies that align AMI 1.0 replacement to its Measurement Canada sealing requirements or replacing AMI 1.0 meters with AMI 2.0 meters as they reach a certain age. Alectra Utilities does not consider these strategies to be viable because they would result in degradation and overlap of the four AMI 1.0 systems and the AMI 2.0 system, which do not have interoperable qualities. The network properties of both AMI 1.0 and AMI 2.0 meters require fulsome meter saturation to create the strong mesh that is necessary for robust meter data interrogation. The creation of strong meshes mitigates the potential for non-communicating AMI 2.0 meters, while at the same time avoiding inadvertent damage or collapse of neighboring AMI 1.0 mesh networks. Either scenario can cause cascading risks to the ability to obtain reliable meter data for customer billing activities.

With four AMI Head End systems, five physical AMI networks, and numerous meter models, Alectra Utilities evaluated its plan alternatives based on mitigating operational, customer, project and financial risks and overall cost-effectiveness.

All plans begin in 2027 with the implementation of the new AMI 2.0 head end system, with three alternatives for the pace of mass meter deployment:

- Three-year mass deployment plan from 2027 to 2029 which provides an accelerated response to mitigate increasing meter failure risks
- Five-year mass deployment plan from 2027 to 2031 which is expected to provide “Just in time” risk mitigation activities to balance pace and plan expenditures
- Seven-year mass deployment plan from 2027 to 2033 with a slower pace to addressing risk with the benefit of reducing capital expenditures within this plan period

Table B06 - 20 details the expected meter installation volumes by year for each deployment alternative.

Table B06 - 20 Meter Volumes by Plan Alternative

	Integration of AMI2.0 Head End and First Year Mass Deployment	Mass Deployment					
	CURRENT DSP PERIOD					FUTURE DSP	
	2027	2028	2029	2030	2031	2032	2033
Three Year Mass Deployment	70,000	440,000	440,000	-	-	-	-
Five Year Mass Deployment	70,000	220,000	220,000	220,000	220,000	-	-
Seven Year Mass Deployment	70,000	150,000	150,000	140,000	140,000	150,000	150,000

Alternative Assessment: Mitigation of Operational Risks

Table B06 - 21 details key project risks including operational, project, financial and customer risks and their relative likelihood of materializing based on the three deployment alternatives.

Table B06 - 21 Risk Matrix, Pace of AMI Deployment

Risk	Three-year Deployment	Five-year Deployment	Seven-year Deployment
Meter Failures: Inability to "stay ahead" of failure rates, causing an insupportable volume of reactive work and cascading impacts to meter-to-bill processes and customer billing activities			
Operational: Inability to procure homogeneous meter models to streamline over the air updates, testing requirements, troubleshooting, etc.			
Project Execution / Customer: Inability to manage and resolve customer inquiries, issues and escalations in real-time			
Project Execution: "Network De-stabilization" due to an inability to gracefully collapse AMI 1.0 networks			

Risk	Three-year Deployment	Five-year Deployment	Seven-year Deployment
Project Execution: AMI & enterprise Information Systems integration risk due to competing priorities			
Project Execution: Challenges related to managing a project long term, continued management of AMI 1.0 networks for extended periods, team fatigue			
Financial: Higher total project costs - Capital, OM&A, incremental meter depreciation			
Financial: Inability to manage project costs related to inflation, USD exchange rates, warranties, incentives			
Financial: Inability to manage / extend future replacement cycles to stabilize capital requirements			
Financial: Inability to obtain Measurement Canada dispensation related to AMI 1.0 meter verification and sealing requirements, that will increase Network Metering work requirements and program costs			
Customer: Inability to provide consistent customer experience including improved customer restorations (remote reconnections) and outage management (last gasp technology)			
Customer: Inability to leverage system benefits related to safety and power quality in a reasonable period of time			

Likelihood of Risk Materializing

Low
Medium
High

All alternatives are expected to be viable with appropriate risk oversight and mitigations; however, the five-year deployment strategy has been assessed as the optimal alternative as it pertains to key risks, including customer experience over the complex multi-year project schedule.

The three-year alternative requires Alectra Utilities to replace more than 440,000 AMI 1.0 meters annually. Although Alectra Utilities is aware of utilities that have successfully installed 500,000 to more than 1,000,000 meters annually as part of their deployment plans, the three-year plan is expected to be unnecessarily disruptive to Alectra Utilities' customers.

In addition to the meter exchanges, Alectra Utilities would be required to manage high volumes of:

- Customer communications and education materials
- Requests to schedule appointments
- Customer follow-up activities during and after the meter change including concerns of property damage and meter base issues
- Meter-to bill exceptions following the meter change with the potential to create billing delays
- Any other customer inquiries and concerns in real-time, triggered by the meter change and attendance at customer properties

The five-year alternative offers fewer risks related to project execution. More than half of the AMI 1.0 meters will be replaced by the end of 2029, targeting the meters that are failing at the highest rates. This approach also balances financial risks as 80% of the meters are expected to be fully depreciated at the time of their removal, while forecasted expenditures for reactive work due to meter failures are contained. The five-year mass deployment with the full replacement cycle extending over the nine-year period of 2023 to 2031, combined with AMI network interoperability through the Wi-SUN standard, is expected to reduce operational and financial risks related to future replacement cycles.

Alectra Utilities has also considered a longer mass deployment period of seven years for its AMI Renewal program. Only 70% of the AMI 2.0 Renewal program would be completed within this DSP period, with the remainder completed in 2032 and 2033. It is expected that an additional 43,000 AMI 1.0 meters would fail between 2027 - 2031 under the seven-year replacement schedule compared to the five-year alternative. This is expected to create cascading risks to meter-to-bill processes, overall project execution related to maintaining stability in the AMI 1.0 networks, and customers.

It is likely that the meter vendor will introduce new meter form variations on a regular basis. The longer deployment time frame will necessitate procurement of the updated meter forms, creating additional testing cycles, and incremental complexity as the fleet of meters is maintained, and upgraded.

This alternative has a reduced ability to provide benefit to customers within this DSP period, as only 70% of the customers will have an AMI 2.0 meter by 2031. This may limit the feasibility of integrating some AMI 2.0 functionality including “last gasp” outage enhancements and delay the ability for some customers to have access to new options, programs, and a consistent experience.

In consideration of the aged AMI 1.0-meter infrastructure and forecasted meter failure rates, Alectra Utilities is not recommending the longer AMI Renewal deployment schedule.

5.1 Alternative Assessment: Financial Considerations

The pace for mass deployment has financial implications beyond project expenditures such as annual inflationary increases. The timeline for mass deployment will also impact the number of AMI 1.0 failures that can be expected to be replaced as reactive work and Alectra Utilities’ ability to obtain dispensation from Measurement Canada for its AMI 1.0 meter re-verification and resealing obligations. For example, where a meter requires re-sealing in 2026, Measurement Canada has advised that dispensation may be an appropriate outcome where the meter is scheduled for replacement in the next two or three years. It is assumed that Measurement Canada is unlikely to consider an exemption to its compliance requirements if the meter is not scheduled to be replaced until 2033 under the seven-year deployment alternative.

The capital costs for the three alternatives over the life of the AMI Renewal project are forecasted as shown below in Table B06 - 22.

Table B06 - 22 Comparison of Capital Expenditures by Alternative

Capital expenditures ($MM)	DSP: 2027 to 2031	DSP: 2032 to 2036	Total Project and Project-dependent Costs
AMI Renewal	257.4	N/A	257.4
AMI 1.0 Reactive Meter Failures	14.7	N/A	14.7
AMI 1.0 Meter reverifications and re-sealing, beyond dispensation exemptions	5.5	N/A	5.5
Total Three-year Deployment	**277.6**	**N/A**	**277.6**
AMI Renewal	261.9	N/A	261.9
AMI 1.0 Reactive Meter Failures	23.6	N/A	23.6
AMI 1.0 Meter reverifications and re-sealing, beyond dispensation exemptions	5.5	N/A	5.5
Total Five-year Deployment	**291.0**	**N/A**	**291.0**
AMI Renewal	193.2	69.5	262.7
AMI 1.0 Reactive Meter Failures	35.5	6.2	41.7
AMI 1.0 Meter reverifications and re-sealing, beyond dispensation exemptions	19.2	2.9	22.1
Total Seven-year Deployment	**247.9**	**78.6**	**326.5**

Inclusive of all capital costs related to expenditures impacted by the length of deployment, the three-year and five-year deployment alternatives are $277.6MM and $291.0MM, respectively. The project's timeline-dependent expenditures including the reactive replacement of meter failures and dispensation have been included with the largest impact from an expectation of higher failures due to prolonged use of aged equipment.

The seven-year plan is the least expensive option during the DSP period, at $247.9MM, inclusive of higher costs for reactive replacement of meter failures and higher meter reverification and resealing expenditures. This alternative completes approximately 70% of the meter replacements in this DSP period, with the final 30% of AMI 1.0 meters being replaced in the next DSP period

from 2032 to 2036. The total project and project-dependent costs over two DSP periods increase to $326.5MM due to less dispensation and more significant failure costs over the two DSP periods.

Across the two five-year DSP periods, the seven-year deployment strategy is expected to increase capital expenditures by $35.5MM. Meter failure expense is forecasted to increase from $23.6MM to $35.5MM with the seven-year plan over this single plan period. Over the two plan periods, reactive meter failure expenses are forecasted at $41.7MM under the seven-year mass deployment strategy.

Summary of alternative assessments:

The five-year deployment plan most appropriately balances risks and has similar overall project and timeline dependent expenditures, while extending the life of the AMI 1.0 network for up to 25 years, from 2006 to 2031. It is Alectra Utilities' assessment that the five-year deployment plan alternative is the optimal approach.

5.2 Customer Engagement Insights

Alectra Utilities' recent customer engagement activities included an overview of the Network Metering's program and forecasted rate impacts with the three, five, and seven-year deployment alternatives for AMI Renewal. The surveys targeted residential, small business, general service (>50kW), and Large Use customer segments. All customer groups were generally supportive of the recommended five-year alternative, while expressing concerns about affordability. Specifically, residential customers were seeking a four percent reduction from the proposed Network Metering program costs.

The surveys revealed that while a high overall satisfaction rate (approximately 83% among residential customers) persists, there is clear support for proactive investments that enhance billing accuracy, reliability, and customer experience.

Across all customer segments, respondents emphasized the importance of:

- **Enhanced Accuracy and Reliability:** Customers indicated that transitioning from legacy AMI 1.0 meters to the more economical and advanced AMI 2.0 technology would directly translate into fewer billing errors and more timely outage notifications. Large use customers noted that improved remote

disconnect and reconnect capabilities, and "last gasp" outage functionalities are critical for minimizing costly reactive interventions.

- **Cost Acceptance Aligned with Value Delivery:** The proposed spending for Alectra Utilities' plan was generally accepted by all customer classes with 81% of residential customers indicating their support. Specific to the Network Metering plan, customer groups indicated that a reduction in spending between 4.0% and 7.9% would be appropriate. A review of customer comments included concerns that Alectra Utilities ensure that its meters are not replaced before it is absolutely necessary and that any increased investment must be balanced against the need for affordability.
- **Future-Ready Grid Enhancements:** In addition to immediate metering upgrades, respondents expressed interest in Alectra Utilities' exploration of grid edge technologies. Feedback suggests strong support for initiatives that deploy DI applications, which will enable customers to tap into real-time energy usage analytics, support distributed energy resources, and participate in emerging transactive energy markets.

Recommended Alternative, inclusive of Customer feedback

Alectra Utilities appreciates the customer insights received, noting the two key themes of affordability and maximizing the life of assets, where possible. In response, the Network Metering program's total capital expenditures, inclusive of the recommended five-year AMI Renewal strategy, have been decreased by four percent.

In consideration that the Network Metering program is comprised primarily of mandatory requirements, the 4% reduction has been applied to the AMI Renewal project only. As such, the final approximately 50,000 AMI 1.0 meters will be replaced in 2032 as part of the 2032 to 2036 DSP, creating a five-and-one-half year deployment plan. It is expected that this reduction will reduce near-term rate impacts for customers, while extending the life of the AMI 1.0 assets up to 26 years (2006 to 2032).

Alectra Utilities originally assessed the five-year AMI Renewal deployment plan as its optimal approach based on the ability to manage project risks and as the project alternative with the lowest total costs.

After the additional consideration of customer preferences to further address affordability, a five-and-a-half-year deployment plan is the resulting recommended alternative. This approach defers 4% of capital costs, originally planned for the 2027 to 2031 DSP period, into 2032 thereby reducing near-term rate impacts for customers.

The resulting mass deployment schedule over a five-and-a-half-year period is detailed in Table B06 - 23.

Table B06 - 23 Meter Volumes by Year in the Recommended 5.5 Year Alternative

	Integration of AMI2.0 Head End and First Year Mass Deployment	Mass Deployment					
	CURRENT DSP PERIOD					FUTURE DSP	
	2027	2028	2029	2030	2031	2032	2033
5.5 Year Mass Deployment	70,000	220,000	210,000	200,000	200,000	50,000	-

This minor extension to the deployment schedule, which shifts costs related to the installation of 50,000 meters from the latter three years of the DSP period, is not expected to increase overall project costs. Project activities related to the final meter replacements are expected to continue for an additional three to six months, after which the project will be completed. The incremental risk related to meter failures is likewise anticipated to be manageable over this time frame, as Network Metering will continue to prioritize the replacement of its AMI 1.0 meters based on its operational risks.

5.3 Plan Execution Risks and Mitigation

Alectra Utilities has strived to mitigate project risks through its extensive planning and preparation period which began in 2019 and extends through 2025.

This planning period includes, or has included:

- An RFP to evaluate AMI 2.0 meter technology vendors in 2020
- Contract execution with the selected AMI 2.0 meter technology provider in 2022
- Development of AMI 2.0 standards and procurement requirements
- Testing of AMI 2.0 meter models, and end-to-end meter-to-bill testing
- Leveraging the existing AMI 1.0 Head End system (SilverSprings - Itron) for interrogation of AMI 2.0 meters prior to 2027 to minimize integration requirements, decrease testing requirements, decrease costs, and decrease overall project risk
- The first pilot of AMI 2.0 installations in 2023
- Deployment of approximately 35,000 AMI 2.0 meters in 2024, further testing functionality
- A RFP to evaluate meter mass deployment services in 2024
- Planned deployment of 35,000 AMI 2.0 meters in 2025 in a compressed time frame to further test processes
- Planned contracting with meter mass deployment vendor
- Planned integration with mass deployment vendor's workforce management tools

Alectra Utilities' Network Metering field services team capably responds to its normal volumes of new connections and meter movement activities in the range of 20,000 to 25,000-meter activities annually. At its peak, AMI Renewal meter change volumes will likely exceed 20,000-meter changes per month.

Considering the high volume of meter changes required over a short time frame, Alectra Utilities plans to use third-party services provider(s) for many of its mass deployment activities. Services to be provided by the mass deployment services vendor include:

- AMI 1.0 to AMI 2.0 meter exchanges, including validation measurements for transformer-rated meter installations

- Automated uploading of meter exchange information to Alectra Utilities' systems, including integration of third-party's system to Alectra Utilities' CIS
- Warehousing of AMI 2.0 meters to be deployed
- Warehousing, recycling and disposal of AMI 1.0 meters, as required, throughout the deployment time frame
- Customer support to mitigate and resolve concerns related to the mass deployment including scheduling appointments, access issues, and damages to customer equipment during the meter exchange including organizing of meter base repairs
- Comprehensive reporting encompassing project progress, accuracy and customer service metrics

Alectra Utilities' teams are accountable for the overall success of the project. The project team includes a Project Manager with a combination of dedicated resources and team members leveraged from the Network Metering teams.

The project is governed by a Steering Committee consisting of three Executive Vice Presidents and nine Vice Presidents, enabling representation and stakeholder representation across the organization. The internal team will also be responsible for:

- Overall project governance and project management
- Procurement activities
- Implementation of the AMI 2.0 Head End and required integrations
- A portion of the complex polyphase meter installations
- Resolution of escalated customer concerns
- Hyper care of the AMI 1.0 and AMI 2.0 meter data as the AMI networks collapse and mesh, and
- Robust oversight of the AMI 2.0 service providers including the meter technology vendor and mass meter deployment services provider, ensuring adherence of service level agreements, project milestones and costs

VI Investment Projects

The material investments from 2027 to 2031 that form the Network Metering investments are included in Table B06 - 24.

Table B06 - 24 Material Projects and Initiatives

Project Code	Project Name	CAPEX ($MM)
Multiple	AMI Renewal	247.6
Multiple	New Connections and Upgrades	19.2
Multiple	Meter Failures	17.3
152897	AMIS Upgrades to DOC	9.0
Multiple	Meter Sampling and Reverification	5.3
Multiple	Wholesale Metering	3.5
152900	Upgrade Two Element to Three Element Metering	1.0

Appendix B07 - Facilities Management

I Overview

Alectra Utilities occupies nine facilities (three Office Buildings and six Service Centres) to service all communities across Alectra Utilities' service area.

Figure B07 - 1 Alectra Utilities Service Territory and Facilities Map

Table B07 - 1 Alectra Utilities Facilities Details

Facility Name	City	Type	Square Feet	Year Built
Cityview	161 Cityview Blvd, Vaughan, ON	Office Building	92,000	2008
Addiscott	80 Addiscott Crt, Markham, ON	Service Centre	107,000	2009
Derry	2185 Derry Rd W, Mississauga, ON	Office Building	80,000	1994
John	55 John St N, Hamilton, ON	Office Building	160,000	1930 / 1950
Kennedy	200 Kennedy Rd S, Brampton, ON	Service Centre	250,000	2023
Nebo	450 Nebo Rd, Hamilton, ON	Service Centre	94,000	1982
Patterson	55 Patterson Rd, Barrie, ON	Service Centre	85,000	1990
Southgate	395 Southgate Dr, Guelph, ON	Service Centre	106,000	1995
Vansickle Rd	340 Vansickle Rd, St. Catharines, ON	Service Centre	63,000	1978

The Facilities Management program includes the investments necessary to maintain Alectra Utilities' facilities, ensuring they support the efficient operation of the distribution system and ongoing business activities. The Facilities Management program is comprised of the following seven categories of work aligned with respective building systems:

- Security/Life Safety
- Building Electrical Systems for Vehicle Electrification
- Building Envelope
- Building Outdoor Walkways/Driveways
- Building Heating Ventilation and Air Conditioning (HVAC)
- Roofing Structure and Roofing
- Reactive Capital (Asset Failure & Emergency Replacements)

Table B07 - 2 presents a summary of the capital expenditures, primary and secondary drivers and outcomes associated with the Facilities Management investment plan.

Table B07 - 2 Facilities Management Investment Expenditures, Drivers and Outcomes

	Historical Spending					Bridge		Forecast Spending				
Year	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
CAPEX ($MM)	10.1	10.8	27.9	48.1	3.1	1.1	1.4	2.6	5.6	7.2	6.5	7.4
Primary Driver	System Maintenance and Capital Investment Support											
Secondary Driver	Reliability, Safety, Failure Risk											
Outcomes	Reliability, Safety, Efficiency, Customer Value, Environment											

II Investment Description

The proposed Facilities Management investments are required to enable Alectra Utilities to plan, execute, and support critical utility functions, on a 24/7 basis. These investments ensure that the facilities housing critical IT systems, control rooms, operations centres and work offices are equipped to serve customers and respond to operational demands, especially during emergencies. They also facilitate compliance with applicable legislative and regulatory standards, ensuring that safety requirements protecting Alectra Utilities' employees and the public are met.

Alectra Utilities classifies its facilities investments under two categories:

- **Planned Investments:** scheduled replacement or repairs of assets before failure. Planned capital projects are based on asset condition, age, and lifecycle assessments. These investments focus on the proactive renewal, modernization, and optimization of facility assets. Planned capital work maintains safety and reliability and ensures that facilities are capable of supporting the utility's business and operational needs.
- **Reactive Investments:** occurs when assets fail and emergency replacements are required (same as planned yet under emergency situations). Reactive capital projects within facilities management address asset failures and critical deficiencies that must be resolved immediately to maintain operations. These include urgent repairs to restore critical systems such as HVAC, security, or life safety equipment, or to correct deficiencies identified through audits or assessments. Over this DSP period, the planned Facilities investments include:
  - (i) Security/Life Safety - Upgrade cameras and implement an integrated security platform for better physical security
    - Building Electrical Systems for Vehicle Electrification – to support Alectra Utilities' Fleet Investments
    - Building Envelope – Windows and External Walls
  - (ii) Building Outdoor Walkways/Driveways - Paving and Parking
    - Building Heating Ventilation and Air Conditioning (HVAC)
  - (iii) Roofing Structure and Roofing

The following sections summarize Alectra Utilities' capital expenditures on Facilities Management during the DSP period. The drivers of each category are set out in *Section III*.

2.1 Planned Capital Investments

In March 2024, Alectra Utilities engaged Pinchin to complete eight Baseline Property Condition Assessments for Alectra Utilities' buildings to identify any critical issues requiring immediate attention (refer to *Appendix N - Baseline Property Condition Assessment*).

2.1.1 Security/Life Safety

Security/Life Safety enhancements are necessary to protect Alectra Utilities' employees and assets as well as the general public using updated security systems and measures.

In 2019, Alectra Utilities began the implementation of a [redacted] will improve efficiency and enhance overall security by streamlining processes, workflows, and reporting. [redacted] improving situational awareness, response times, and overall coordination. Four of Alectra Utilities building properties [redacted] The remaining five building properties [redacted]

In addition to [redacted] Frequent repairs to the current system have also led to rising operational costs.

The update of security/life safety work in facilities is expected to yield the following benefits:

[redacted]

- Improve employee safety in and around Alectra Utilities' facilities
- Protect physical assets such as inventory and IT equipment

- Improve response time and proactive monitoring activities by streamlining processes through the consolidation of five legacy security systems
- Avoid increases in operating expenses associated with the maintenance of aging security systems
- Assist in evidence gathering where incidents require investigation
- Prevent unauthorized access to restricted areas

2.1.2 Building Electrical Systems for Vehicle Electrification

Alectra Utilities has a strategy to replace its Fleet vehicles with EVs in circumstances where it makes financial and operational sense to do so. Therefore, with the growth of Fleet EVs, it was essential for Alectra Utilities to complete a third-party study to investigate if its current buildings' electrical service can support such growth. The third-party assessment was completed by S&S Electric (refer to *Appendix O - Electrical Services & Generator Capacities and Current Demand*) and based on a set of planning assumptions regarding the potential scale and timing of fleet electrification. These assumptions were based primarily on a phased fleet conversion and charging infrastructure scaled to the anticipated adoption of the technology (for further information refer to *Appendix B08 - Fleet Renewal*. The purpose of this electrical work is to increase electrical services, generator capacities and current demand to support EV growth. The findings from this study provide an estimate of the infrastructure upgrades required to support Alectra Utilities' EV investments. Estimated costs are found in Table B07 - 3 .

2.1.3 Building Envelope

Alectra Utilities plans to address issues affecting the building envelope (i.e. building exterior facia) as they fail or become safety hazards. In particular, Alectra Utilities plans to address brick masonry walls and windows at specific locations as they fail. The age of many of these assets has resulted in an increase in repairs and operating expenditures to maintain a reliable and safe work environment for employees and the public. Alectra Utilities plans to implement building envelope repairs/replacements through its Replacement and Reactive Capital budgets throughout 2027-2031 once they are identified as safety risks. For the estimated costs for Building Envelope replacements/repairs for Alectra Utilities' buildings, refer to Pinchin's eight Baseline Property Condition Assessments that were completed in March 2024 in *Appendix N - Baseline*

Property Condition Assessment. The age and deterioration of many of these assets has resulted in an increase in repairs and operating expenditures to maintain a reliable and safe work environment for employees and the public.

2.1.4 Building Outdoor Walkways/Driveways

Alectra Utilities plans to address issues affecting outdoor walkways and driveways as they occur. Interlocking walkways, sidewalks and paving of parking lots at various facilities will likely require renewal investment to mitigate the risk of accidents and permit proper water drainage from the rain and snow. Repairing sections that are damaged will result in a safer work environment for Alectra Utilities employees. Alectra Utilities plans to implement building outdoor walkways/driveway repairs/replacements through its Replacement and Reactive Capital budgets throughout 2027-2031.

2.1.5 Building HVAC

Certain HVAC systems within Alectra Utilities' buildings have not undergone modernization or major renewal since their original installation. Several HVAC units are anticipated to approach or exceed the end of their useful life over the 2027-2031 period. As such, Alectra Utilities plans to renew the HVAC systems through a run-to-failure approach, replacing or repairing systems only when they fail or can no longer be cost-effectively maintained. Estimated costs for these replacements are based on the eight Pinchin Baseline Property Condition Assessments that were completed in March 2024 (refer to *Appendix N - Baseline Property Condition Assessment*).

2.1.6 Roof Structure and Roofing

Currently, there exists a risk of failure of key building components roofs and roof structures. Alectra Utilities needs to address deteriorated assets to minimize safety risks to employees and to the facility assets and critical operation systems secured within. For example, water damage as shown in the Figure B07 - 2 may introduce mold as well as permanent damage to foundation and building structures.

This approach ensures that capital is allocated where and when it is most needed, while maintaining safe, functional, and compliant facilities.

Table B07 - 3 Facilities Planned Capital by Type

Investment Type	2027	2028	2029	2030	2031	Total
Security/Life Safety	0.0	1.7	0.4	0.4	0.3	2.8
Building Electrical Systems for Vehicle Electrification	1.3	1.0	0.9	0.2	0.2	3.6
Building Envelope	0.0	0.5	0.6	0.6	1.4	3.1
Building Outdoor Walkways/Driveways	0.0	0.6	0.3	0.2	0.8	1.9
Building Heating Ventilation and Air Conditioning (HVAC)	0.0	0.2	0.4	1.2	1.0	2.8
Roofing Structure and Roofing	0.0	0.0	2.8	1.9	1.5	6.2
Total ($MM)	**1.3**	**4.0**	**5.4**	**4.5**	**5.2**	**20.4**

2.2 Reactive Capital Investments

The level of expenditure for these activities is largely informed by historical spending patterns. Typical investments within the Reactive Capital budget over the 2027–2031 period are expected to include emergency HVAC repairs, failure of elements relating to the building envelope such as brick masonry, windows, and roofs that fail or pose safety hazards, and outdoor infrastructure such as walkways, driveways, and parking areas that require renewal to address damage, safety risks, or drainage issues. The reactive investments are the same as planned except Alectra Utilities addresses the replacement of the failed assets on an emergency basis.

2.3 Summary of Investment Benefits

Table B07 - 4 summarizes the outcomes and benefits associated with the Facilities Management investments.

Table B07 - 4 Facilities Management Investment Outcomes and Benefits

Investment Benefits	Reasoning and Investment Benefits
Reliability	• Sustainment of backup facility assets ensures business continuity to mitigate risks to system operations and ensure system reliability during emergency event response.
Customer Value	• Alectra Utilities is required to address security and facility issues to ensure that employees are adequately equipped to provide timely and effective customer service if entering our facilities.
Safety	• Security enhancements will deter potential authorized intrusions and theft from Alectra Utilities premises and improve employee and public safety.
Environment	• Removal of any hazardous substances (e.g. asbestos, vermiculite, lead) that may be identified. • Utilization of energy efficient assets such as lighting, HVAC, and other appliances that will contribute to lower energy use and operating costs.
Efficiency	• Improve worker productivity and efficiencies across the organization through the application of facility standards and updated workspaces to optimize and streamline work practices and address identified ergonomic issues. • Renewal of end-of-life facility assets such as HVAC, lighting, building envelopes to present day building codes will reduce operating costs. • Addressing obsolete systems which are not functional and/or reliable such as security systems and HVAC/boiler equipment.

III Investment Drivers and Need

The main drivers of Alectra Utilities' Facilities Management investments during the 2027-2031 period are the renewal of specific facility assets that are at end-of-life, the reduction of potential safety risks to employees and the public, the need to mitigate operating risks and potential damage to other assets and decreasing maintenance costs.

Alectra Utilities maintains nine buildings totaling approximately one million square feet of space within its service territory. To ensure that its facilities are appropriately maintained, Alectra Utilities utilizes independent experts to evaluate its buildings and identify required capital investments. In 2024, Alectra Utilities retained Pinchin Ltd. to complete a Baseline Property Condition Assessment (refer to *Appendix N - Baseline Property Condition Assessment*) to assess the current condition of each of the eight buildings (excluding the Brampton Service Centre, as it was a new building).

As part of the assessment, teams of specialists inspected each system or asset in Alectra Utilities' buildings to understand their condition. This review was extensive, encompassing all mechanical, electrical, plumbing and architectural elements in a building. Pinchin assessed the facilities' condition based on any deficiencies and the remaining useful life of the system, and provided an overall facility/asset condition, recommended budget, and replacement schedule. This information was a key input in preparing the repair and renewal investments set out in this portfolio.

The planned Facilities Management investments are required to support Alectra Utilities' day-to-day activities which include workflow collaboration, customer service, communications, employee productivity and engagement.

The Facilities Management investments also include necessary building infrastructure and component renewals, including replacement of end-of-life assets such as windows, roofs, elevators, and HVAC systems.

The planned Facilities Management Investments are needed to address the range of risks and operational requirements, as summarized below:

- [redacted] **Security/Life Safety:** Risks of physical security intrusions due to limitations in existing security systems, including [redacted]

[redacted]

- **Building HVAC:** Outdated HVAC systems at end of life pose significant risks and constraints to the working environments and conditions of Alectra Utilities' employees. The persistent failure of these systems increases maintenance and repair costs. In some cases, replacement materials are no longer available, or difficult to procure.
- **Building Deficiencies (Including Roof Structure and Building Envelope Investments):** The risk of failure of key building components (e.g., roofs, windows, ceilings, etc.) requires Alectra Utilities to address deteriorated assets to minimize safety risks to employees and critical operation systems secured within. For example, water damage as shown in the Figure B07 - 2 may introduce mold as well as permanent damage to foundation and building structures.

The following photographs show examples of:

- Ceiling tiles with water damage caused by water leaks
- Roof damage which creates water leaks
- Foundational cracks which cause water damage

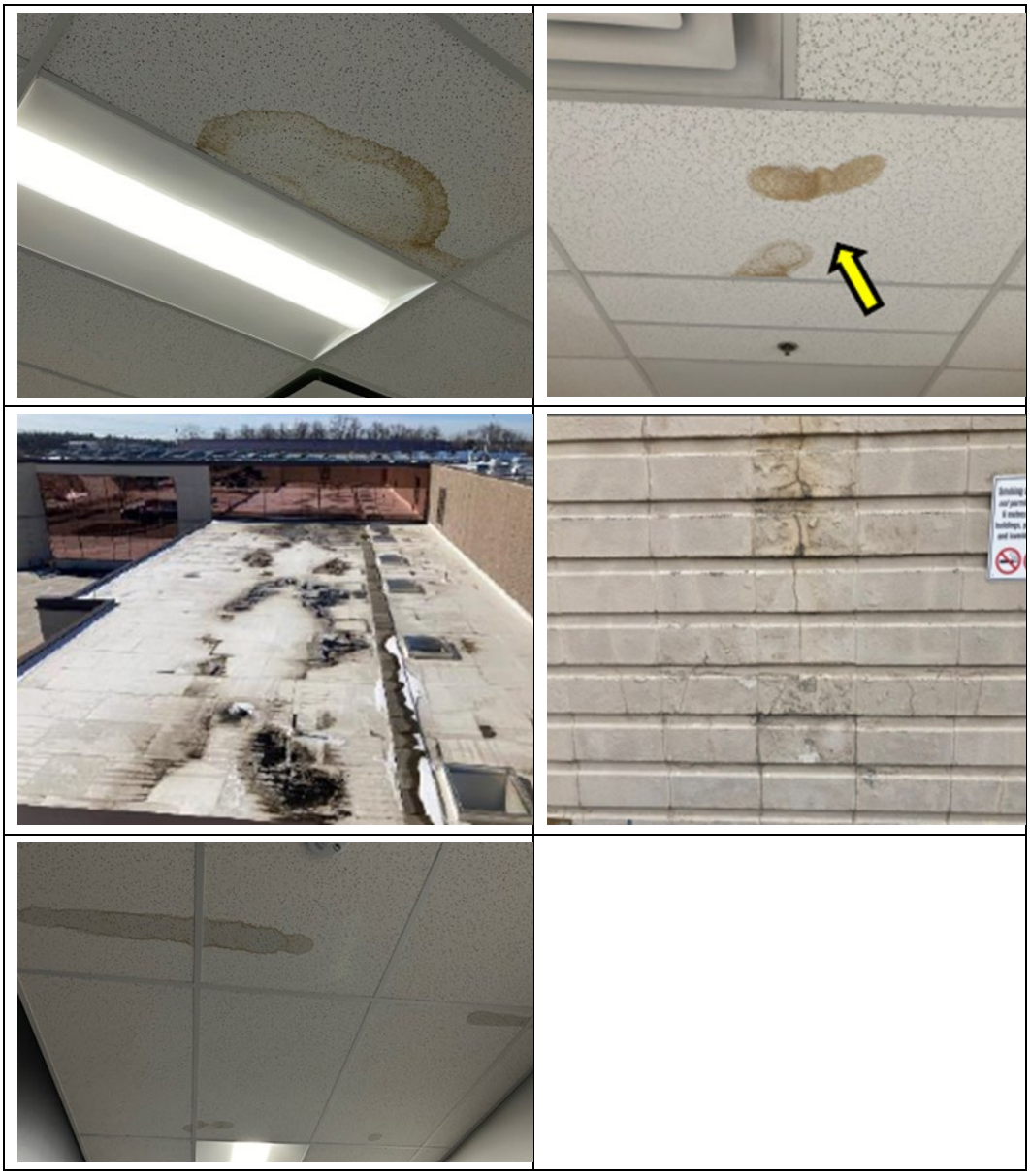


Figure B07 - 2 Examples of Building Deficiencies

- **Building Outdoor Walkways/Driveways:** These investments will address current accident and flooding risks due to deterioration and operational issues affecting various walkways, driveways and drainage systems.

Figure B07 - 3 Examples of Outdoor Walkways/Driveways Deficiencies

Table B07 - 5 Investment Drivers

Investment Driver	Reasoning and Investment Benefits
Primary Driver: **System Maintenance and Capital Investment Support**	• Alectra Utilities' facilities house functions that are essential to the effective and efficient operations of all elements of the utility's business, including the planning and execution of maintenance and capital work. • Specific building assets have reached the end of their typical useful lives and are no longer supported by the vendor. • Failure of deteriorated or end-of-life building assets can hinder the execution and productivity of Alectra Utilities' business functions and may directly impact Alectra Utilities' ability to respond effectively to power interruptions or emergencies.
Secondary Driver: **Failure Risk**	• Alectra Utilities' facilities have components that have reached the end of their typical useful lives and are obsolete. Maintenance costs for deteriorated and obsolete assets are expected to continue to increase over time.
Secondary Driver: **Reliability**	• HVAC systems and back-up generators are reaching the condition and age where major repairs or replacements are required. These assets are required to maintain temperature and power to critical infrastructure.
Secondary Driver: **Safety & Security**	• Alectra Utilities' facilities continue to require investments in security infrastructure enhancements and upgrades to help eliminate potential dangers and threats to the public and Alectra Utilities' personnel and property. [redacted]

IV Investment Timing & Pacing

4.1 Summary of Expenditures

Table B07 - 6 provides the year-over-year breakdown of Facilities Management investments, including the historical period from 2020-2024, the 2025-2026 bridge years, and the DSP period from 2027-2031.

Table B07 - 6 Historical and Proposed Investment Spending

	Historical Spending					Bridge		Forecast Spending				
Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Facilities-Planned	6.4	1.7	2.7	2.9	1.9	0.0	0.2	1.3	4.0	5.4	4.5	5.2
Facilities-Reactive	1.0	0.9	1.2	1.0	1.5	1.1	1.2	1.3	1.6	1.8	2.0	2.2
Kennedy Road Consolidation	2.7	8.2	24.0	44.2	-0.3*	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CAPEX ($MM)	**10.1**	**10.8**	**27.9**	**48.1**	**3.1**	**1.1**	**1.4**	**2.6**	**5.6**	**7.2**	**6.5**	**7.4**

* Note: The negative value represents some reallocation of expenses and reversal of over accruals

4.2 Historical Expenditures (2020-2024)

The program's capital expenditures between 2020 and 2024 focused on the assets that had surpassed end of life and were negatively affecting other assets and overall building operations, the removal of hazard materials, new and/or revised regulation requirements, safety risks and bringing all locations up to a common Alectra Utilities standard since the merger of the predecessor utilities. This included repairs to building envelopes and security system replacements and/or upgrades, electrical LED retrofits, retrofitting facilities to comply with the *Accessibility for Ontario with Disabilities Act* (AODA), and landscaping and concrete work to exterior sections of Alectra Utilities' properties. Also, as shown in Table B07 - 6 above, the Kennedy Road consolidation cost totalled $78.8MM between 2020 and 2024. Further details of the Kennedy Road consolidation are found in *Section VII*. Planned Capital expenditures were on items described in *Section 2.1* above. Historical reactive expenditures were on items described in *Section 2.2*.

4.3 Future Expenditures (2027-2031)

As outlined in *Section 4.1*, Facilities Management reactive capital projects focus on restoring equipment/assets to maintain normal operations after a breakdown to ensure business continuity. To accomplish this, the replacement of faulty parts and/or components/assets will be required. The Facilities Management capital expenditures include planned capital investments in security systems, building electrical systems for vehicle electrification, and generator replacements as described in *Section 2.1*. In addition, Alectra Utilities has proposed an average reactive capital budget of $1.8MM per year based on historical actual expenditures and including annual escalations for inflation. Further details on reactive investments were provided in *Section 2.2.*

4.4 Execution Approach

The planned Facilities Management investments between 2027-2031 have been determined based on known conditions, regulatory requirements, potential safety risks, operational requirements and third-party assessments. Alectra Utilities' approach to such investments are based on the following guidelines and factors:

- Approved capital expenditures
- Required external and internal resources availability
- Additional findings not originally identified and/or known during the project
- Asset conditions
- Operational requirements
- Safety risks
- Regulatory compliance
- Engineering, design, and permits activities

Qualified contractors and service providers will perform all work once the scope, schedules, resource availability and final cost have been established. All projects will be sourced and purchased based on Alectra Utilities' Procurement Policy and Processes. Alectra Utilities must plan and secure the required capital budget years in advance to maintain its building assets in proper operational order.

V Options Analysis

Alectra Utilities considered the following options concerning Facilities Management investments:

- Planned Replacement
- Reactive (Asset Failure Emergency Replacements)

5.1 Planned Replacement

Under the Planned Replacement option, facilities assets would continue to deteriorate impacting operations, damaging other assets, increasing operating expenditures, increasing safety or security risks and/or not being in compliance with regulations and standards. As set out in the sections above, the facilities investments planned during the DSP period are driven by risks and issues, as assessed by the third-party consultants. Alectra Utilities cannot accept the reactive approach, as it would allow these risks and issues to continue and likely worsen. Without proper planning and/or the reactive approach cost control is nonexistent and can ballon during repairs.

5.2 Reactive (Asset Failure Emergency Replacements)

Under this option, Alectra Utilities has deemed certain assets to have less impact on the business if they fail. Investments throughout the DSP period are based on expenditures and failure rate levels that Alectra Utilities has experienced historically.

VI Investment Projects

The material Facilities Management investments from 2027 to 2031 are included in Table B07 - 7.

Table B07 - 7 Material Projects and Initiatives

Project Code	Project Name	CAPEX ($MM)
Multiple	GP - Facilities Misc	25.6
153018	Facilities_Building Electrical Service for Electrification	2.6
152567	Facilities_EV_Charging_Stations_CRFP	1.1

VII Central Region Facilities Review Summary

In 2018, Alectra Utilities conducted a high-level review of each facility, assessing available workspaces, building conditions, planned renewal projects, and existing capital budgets to establish an investment baseline. Facilities also reviewed operational space requirements, including line operations, metering, substations, warehouse and yard space, vehicle parking, and fleet shops at each facility.

During the review it was determined that the Mavis site in Mississauga and the Sandalwood site in Brampton, would not be able to accommodate Alectra Utilities' long term operational requirements in its current configuration. For the Mavis site, there was too much office space, the warehouse and garage areas were too small, there was not enough parking to accommodate fleet and employee needs, and there was not enough outside storage. There were also several Region of Peel easements for pedestrian and vehicle access registered for the adjacent property, and for CP Rail railway within a portion of the property, which limited the use of lands to support Alectra Utilities' operations. The City of Mississauga also had access rights to the traffic signals and sensors to exit and enter the property, impacting operations use of the property.

To satisfy its requirement for outside storage, Alectra Utilities (previously Enersource) had to lease another site north of the existing Mavis site at 3456 Mavis Road. The annual costs to Alectra Utilities for leasing this facility was approximately $254,500 per year.

The Mavis building was constructed in three phases starting circa 1965. The South and North towers were added to the building circa 1970s and 1980s, respectively. Given the age of the building, major structural items needed significant repair. The building was originally constructed for Mississauga Hydro/Enersource.

Overall, the Sandalwood facility had some space concerns and some building and supporting assets that were in poor condition. The main building was originally constructed to include the head office functions of legacy Hydro One Brampton, however, Alectra Utilities determined there would be redundant office space which could not be leased out mainly due to the design of the building. Significant capital investments would be required to retrofit the building for multi-tenant use.

Site Information Background

The review identified two service centres that presented significant risks in their existing condition at the time: 3240 Mavis Road (Mississauga) and 175 Sandalwood Parkway West (Brampton). Deficiencies at each location included:

7.1 3240 Mavis Road (Mississauga)

- The warehouse and parking garage were too small to accommodate the required inventory and vehicles.
- The warehouse space, interior parking garage, and fleet repair shop shared the same space separated only by fence walls and plastic tarps which created health and safety concerns for employees due to vehicle fumes and space restrictions.
- The building consisted of the main building with two separate additions (different grading and levels) that were constructed in different years making it difficult to use the space properly and created air quality concerns and a poor work environment.
- There were no elevators in the building, creating AODA compliance issues.
- The site had insufficient parking to satisfy both fleet and employee vehicle requirements.
- The building and supporting assets were in poor condition and beyond their expected life, which would require additional capital investments.
- A rail line (permanent easement) intersecting the property diminished the efficiency and effectiveness of the outside storage and any future growth requirements.
- A few Region of Peel permanent access easements diminished the efficiency and effectiveness of the lands and any future growth requirements.
- Due to its location, traffic congestion made it difficult to enter and exit the facilities, impacting customer response times and creating accident concerns.

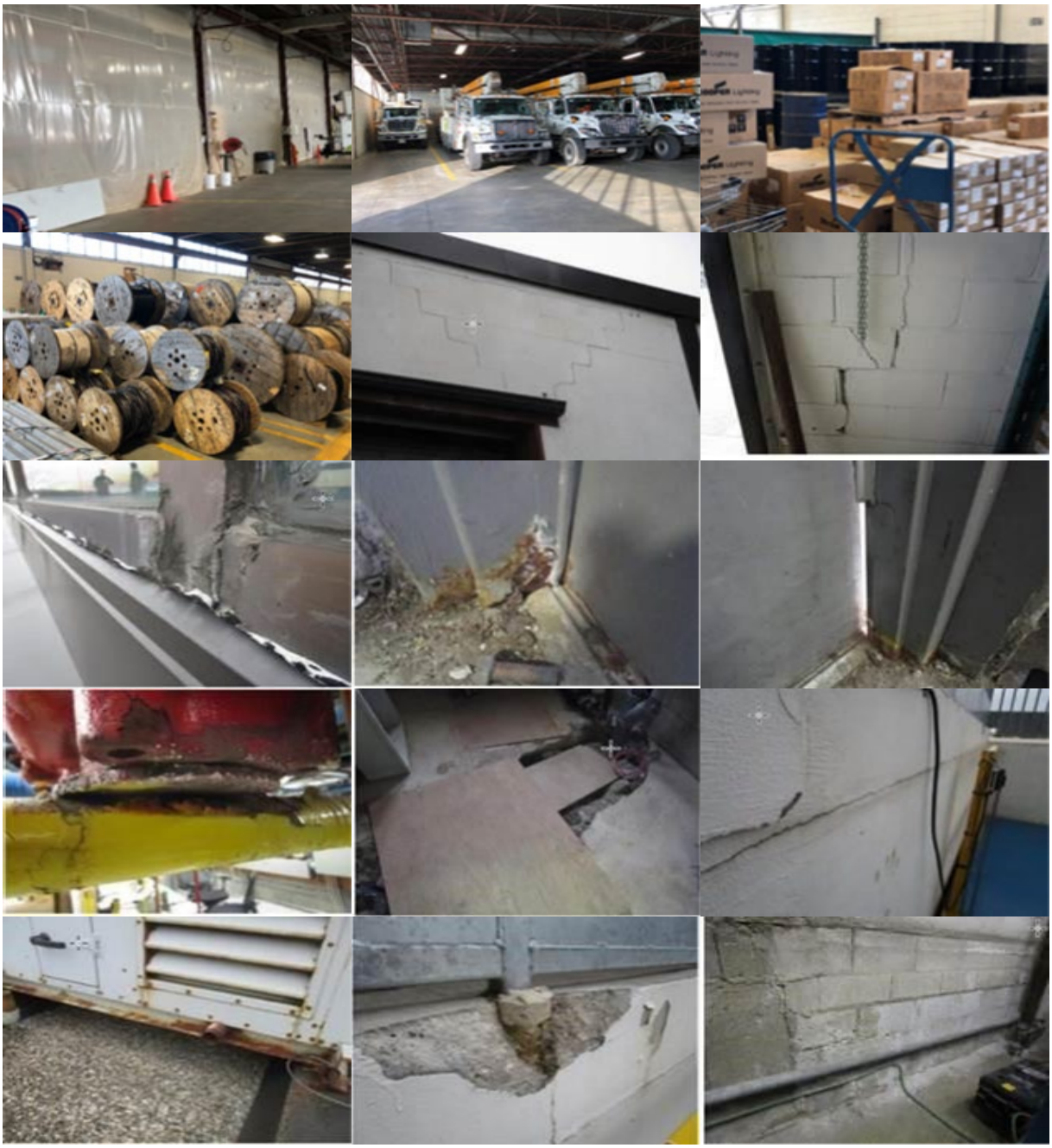


Figure B07 - 4 3240 Mavis Road Photo Gallery

7.2 175 Sandalwood Parkway West (Brampton)

- The site had more office space than needed, and significant investment would be required to convert it into alternative uses or joint tenancy.
- The warehouse, stores yard and interior parking garage were not large enough to accommodate the necessary Alectra Utilities inventory and vehicles requirements.
- Space to support operations in the back office was not sufficient. Significant capital investment would have been required to update the space. Operations would have to be relocated to temporary leased space during the renovations, which would have had an impact on employees, customers, and overall operations.
- The building's configuration did not provide sufficient fleet parking. Substantial capital investment would have been necessary to modify the site to meet fleet requirements.
- The building and supporting assets were in poor condition and beyond their expected life which would require significant capital investments.
- Permanent communication easements supporting the City of Brampton communication systems diminished the efficiency and effectiveness of the land and any future growth requirements. The possibility of the city extending Railside Drive to Sandalwood Parkway in the future would reduce available space and have a negative impact on the function of the site.

Figure B07 - 5 175 Sandalwood Parkway West Photo Gallery

Based on the review and findings above, Alectra Utilities engaged Cresa Toronto (Cresa) in 2019 to conduct a third-party assessment of these two facilities.

7.3 Analysis Background

A Building Condition Survey completed by EXP Services Inc. for each of the two existing Operations Centres was conducted to understand capital repair and replacement requirements for the existing facilities. Alectra Utilities also had an additional building condition assessment conducted by Pinchin Ltd. for each of the two existing Operations Centres to understand capital repair and replacement requirements for the existing facilities.

A preliminary site plan for the proposed redevelopment of 3240 Mavis Road was completed by Paradigm Architecture and Design on behalf of Cresa. Market surveys were completed by Cresa to understand the cost and availability of temporary lands/buildings to meet Alectra Utilities' requirements in the event of a redevelopment of 3240 Mavis Road.

A detailed transportation study was completed by BA Group Inc. to understand the impact of a relocation to 174 Kennedy Road South to both employees and customers.

Phase II Environmental Site Assessments for both 3240 Mavis Road and 175 Sandalwood Parkway West were completed by BluMetric Environmental Inc. to understand any potential environmental concerns with these existing facilities that would have been needed in the event of a sale or redevelopment.

As part of its evaluation, given the age of the existing buildings at 3240 Mavis Road and 175 Sandalwood Parkway West, Cresa was asked to estimate the capital repairs and/or replacements required to maintain the existing facilities. It is important to note that these initial reports were based upon visual inspection of the major components of the buildings only and did not consider any renovations or upgrades that Alectra Utilities might have considered or had to be remediated due to the presence of any hazardous substances, PCBs or concealed mold. Specifically, given the age of 3240 Mavis Road, the costs to maintain this facility could easily have exceeded the original estimates. These reports did not consider current operational requirements and future growth.

7.4 Review and Assessment

The review and assessment included looking at the following options:

- Option 1 - Remain at both Mavis and Sandalwood on an 'as is' basis and continue to lease 3456 Mavis Road and use Alectra Utilities' substation yard at 7345 Bramalea Road to satisfy south-central outside storage requirements.
- Option 2 - Redevelop the Mavis site and remain at Sandalwood on an 'as is' basis.
- Option 3 - Dispose of both Mavis and Sandalwood and relocate to a new "purpose built" Consolidated Central Operations Centre. (Selected Option)

Cresa's assessment concluded that option 1 and option 2 were not appropriate solutions for meeting Alectra Utilities' operational requirements and mitigating potential safety and environmental risks. Both options would also require significant investments in both facilities that, even after upgrades, would not meet current and long-term needs. Accordingly, Cresa recommended proceeding with Option 3.

7.4.1 Option 1 – Deferred Central Operations Centre

This option would only delay the need for a new Central Operations Centre and would expose Alectra Utilities to future financial risks from rising land values and construction costs. Given the limited availability of land with the necessary zoning, size, and location, securing a suitable site in the future could be challenging. The details of each site are listed below.

3240 Mavis Road Inspection and Capital Required – "AS IS"

- The North Tower, Central Building and Warehouse portions were constructed using Conventional Built-Up Roofing. The roofing system installed in these areas had been replaced within the past several years (i.e. North Tower circa 2012 and remaining areas circa 2009). Based upon EXP's observations, the roofing system in these areas was in good to fair condition at the time of evaluation. The roofing system in the South Tower and above the entrance canopy was Modified Bituminous Sheet Membrane Roof Assembly. Sloped metal roofs were also present at the South Tower and appeared to be in fair condition with some faded finishes at the time of inspection. The South Tower was replaced circa 2008 with an estimated age of 11 years. Based upon visual observations, the roofing system

of the South Tower was in fair condition however some areas of deterioration were visible.

- Significant repairs of the exterior wall systems were required, including repairs to the building's exterior stucco finish and perimeter block walls (some block masonry units were noted to be displaced/out of place and not properly supporting loads) and all deteriorated sealants required removal and replacement.
- The exterior windows were generally comprised of metal framed fixed window units comprised of sealed insulating glass units (IGUs). Curtain wall systems were also present throughout the building, particularly at the North Tower and South Tower. The curtain wall system consisted of vision glass portions and spandrel glass portions with metal frames. The glazing of the vision glass consisted of IGUs. The normal effective life of IGUs is in the range of 15 to 20 years. According to the date stamps on the aluminum spacers of the IGUs, the majority of the IGUs present in the North Tower appeared to be from 1979 while IGUs present in the South Tower appeared to be from 1990. The IGUs in the Central Building and Warehouse appeared to be from 1998 or 1999. Therefore, the IGUs ranged from 20 to 40 years old, and would have had to be replaced.
- The structural framing of the building complex appeared to be in generally fair condition, subject to specific observations including a large unsupported opening at the western portion of the warehouse, surface corrosion on sections of the exposed structural deck, peeling paint on portions of coated structural deck, surface corrosion on a few of the structural columns, impact damage on a few of the structural columns, exterior waterproofing required replacement, cracking was noted on interior block walls, chipping and spalling was observed on the ends of a concrete slab at a trench drain, cracking in the concrete slab and cracking along sections of foundation wall.
- The main switchgear was manufactured in 2006 and appeared to be in serviceable condition. Although the electrical equipment associated with the distribution systems generally appeared to be in operable condition, some of the equipment required maintenance including panels that were missing knockout plates, a splitter in North Tower basement noted to be corroding, some wiring on the roof

which did not appear to be terminated properly, transformers in the main electrical room and Facility Shop that were emitting loud humming noises and the rooftop conduit powering the backlit sign on the North Tower which was noted to be loose and had its supports turned over. The lighting systems and receptacles all appeared to be in functional condition. EXP recommended replacing older T12 tubes with more efficient fixtures and there were a few receptacles in the kitchenettes that did not appear to be GFI rated and were recommended for replacement.

- The emergency generators were in operable condition and were serviced regularly.
- Heating and cooling for the office portions was accomplished by approximately 30 heat pumps, rooftop HVAC units and electrical cooling units. Allowances had been included for the ongoing replacement of the heat pumps. The cooling tower was manufactured in 2007 and appeared to be in good condition. The boiler was recently replaced and was in good condition at the time of inspection.
- HVAC for the Central warehouse was accomplished by roof mounted natural gas HVAC units. The majority of the units were manufactured between 2007 and 2016. One of the units needed to be replaced at the time of inspection. Overall, ventilation equipment appeared to be in good, serviceable condition.
- The condition of the water, storm, sanitary piping as well as internal drains and underground piping were unknown and may have required replacement as the piping continued to age. A detailed review of the building piping by a qualified contractor to determine the condition of piping, including internal remote video inspection would have been required.
- The building was fully sprinkled via a wet and dry sprinkler system. The system did not appear to have a backflow preventer at the time of inspection which would have been required. There was some corrosion noted on the piping which may have required replacement.
- The exterior site features primarily consisted of asphalt paved parking areas bounded by concrete curbs. Limited soft landscape and sodded areas were noted along the perimeter of the site. Overall, the asphalt pavement was in fair condition

with several areas in poor condition including several areas where the pavement had cracked and vegetation had grown in, cracking and spalling of the concrete enclosures and retaining walls, uneven/settled unit pavers, cracking and deterioration on the exterior concrete steps/ramps and cracking and corrosion at the base of several fence posts.

- Approximately $2.8MM of additional capital (excluding inflation, impacts from COVID-19 Pandemic, etc.) would have been required to fix the above identified items and Alectra Utilities would still have the same concerns as listed under *Section 7.1*.

175 Sandalwood Parkway Inspection and Capital Required – "AS IS"

- The roofing system of the building complex consisted of a combination of "Modified Bituminous Sheet Membrane Roof Assemblies", sloped metal roofs, skylights and balcony spaces with patio stone surfacing. The roofing systems for the complex were replaced circa 2004 with an estimated age of 15 years. Based upon visual inspections the roofing systems appeared to be in good to fair condition at the time of inspection.
- Exterior Walls - The exterior wall systems were a combination of insulated metal siding, curtain wall glazing, precast concrete panels with some areas of corrugated metal siding. No major capital expenditure was expected to be required for the metal panels, precast concrete panels, and metal siding, however some work would have been required on the exterior caulking and at the base of the exterior walls.
- Exterior Windows and Doors - The exterior windows were generally comprised of metal framed fixed window units comprised of sealed insulating glass units. The IGUs in the complex were mainly from 1992 with an estimated age of 27 years at the time of inspection. Several units had previously failed and EXP Services recommended Alectra Utilities budget for the ongoing replacement of window glazing units.
- Exterior Doors - It was noted that some capital expenditure will be required for the ongoing refurbishment of the exterior doorways as the building continued to age.

- The structural framing of the building appeared to be generally in good to fair condition. Several deficiencies were noted in EXP's report including step cracking of block walls, cracking of the floor slab in the lobby, which should be further investigated, cracking of the concrete slab typically near trench drain locations and cracking on some of the exposed foundations.
- Electrical Systems - The main switch gear was manufactured in 2001 and had a life expectancy of 45 to 50 years. The switchgear was expected to remain serviceable for several more years.
- The electrical distribution systems appeared to be in good condition subject to some deficiencies as outlined in the EXP report including some of the transformers emitting a loud humming sound.
- The lighting systems appeared to be in good condition, however due to the overall age, the system may have required future replacement.
- While the generator appeared to be in serviceable condition, given its age, EXP recommended budgeting for replacement. The oil tank installed within the generator room was not double walled nor was it placed within a concrete spill containment.
- Elevators - The elevators appeared to be original to the building and were approaching the end of their life. A review of the elevators was not part of EXP's report. EXP recommended a review by an expert as these would have likely needed to be upgraded. Preliminary forecasts were provided in the estimate based upon the previous report completed by Pinchin.
- Security Gates - Some of the electrical equipment servicing the gates were noted to be in poor condition and would have needed to be replaced.
- Mechanical Systems - Primary heating and cooling for the office portions of the building was accomplished by several heat pumps, heat recovery units, multiple fan coil units and a few electrical heaters. A replacement program would have been required.
- The cooling tower was expected to require replacement.
- Plumbing and Drainage Systems – Overall, the plumbing and drainage systems were in good working condition.

- Fire Suppression Systems - The sprinkler system did not appear to have a backflow preventer which should have been provided. The building appeared to utilize over 1,000 sprinkler heads for fire suppression, which would have required a sprinkler head box that contains 24 sprinkler heads as per Ontario Fire Code. The existing sprinkler headbox only contained 9 sprinkler heads and EXP recommended further review of the sprinkler system.
- Fire and Life Safety Systems - There were a few penetrations between the office and warehouse that would have needed to be properly sealed to maintain integrity of fire suppression. EXP noted step cracking on some of the masonry block walls and cast in place and the concrete walls needed to be properly sealed.
- The fire alarm panel near the server room appeared to be original and may have needed to be replaced.
- Pavements and Exterior Site Features - There were several deficiencies that were noted in EXP's report including refurbishment of asphalt pavement, repair of concrete curbs, cracking on retaining wall and cracking on concrete piers.
- The elevated interlock walkway at the main entrance was noted to be in poor condition and a complete refurbishment was recommended.
- Approximately $1.7MM of additional Capital (excluding inflation, impacts from COVID-19 Pandemic, etc.) would have been required to fix the above identified items and Alectra Utilities would still have the same concerns as listed under *Section 7.2*.

7.4.2 Option 2 – Redevelopment of Mavis Road

Redeveloping Mavis Road would have required leasing a comparable facility within Mississauga, with the appropriate zoning, structure, lands for inventory, company and employee parking, security measures, etc. for three to five years. This would have significantly impacted employees, customers, operations, and the operating budget. Moreover, the redeveloped Mavis site would have still fallen short of meeting present and future operational requirements.

Both the Mavis and Sandalwood sites were aging, space-constrained, and required substantial capital investment to meet operational needs. Mavis presented safety and functionality issues, including shared access with adjacent properties (permanent easements), uneven yard surfaces,

inadequate vehicle storage, and limited space for safe warehouse and fleet operations. While temporary mitigation measures were in place, they did not address the underlying risks or inefficiencies.

Continuing to operate from these sites would require additional capital expenditure without achieving the capacity or functionality needed to support Alectra Utilities' long-term operations as described above in *Section 7.4.1*.

Mavis Redevelopment

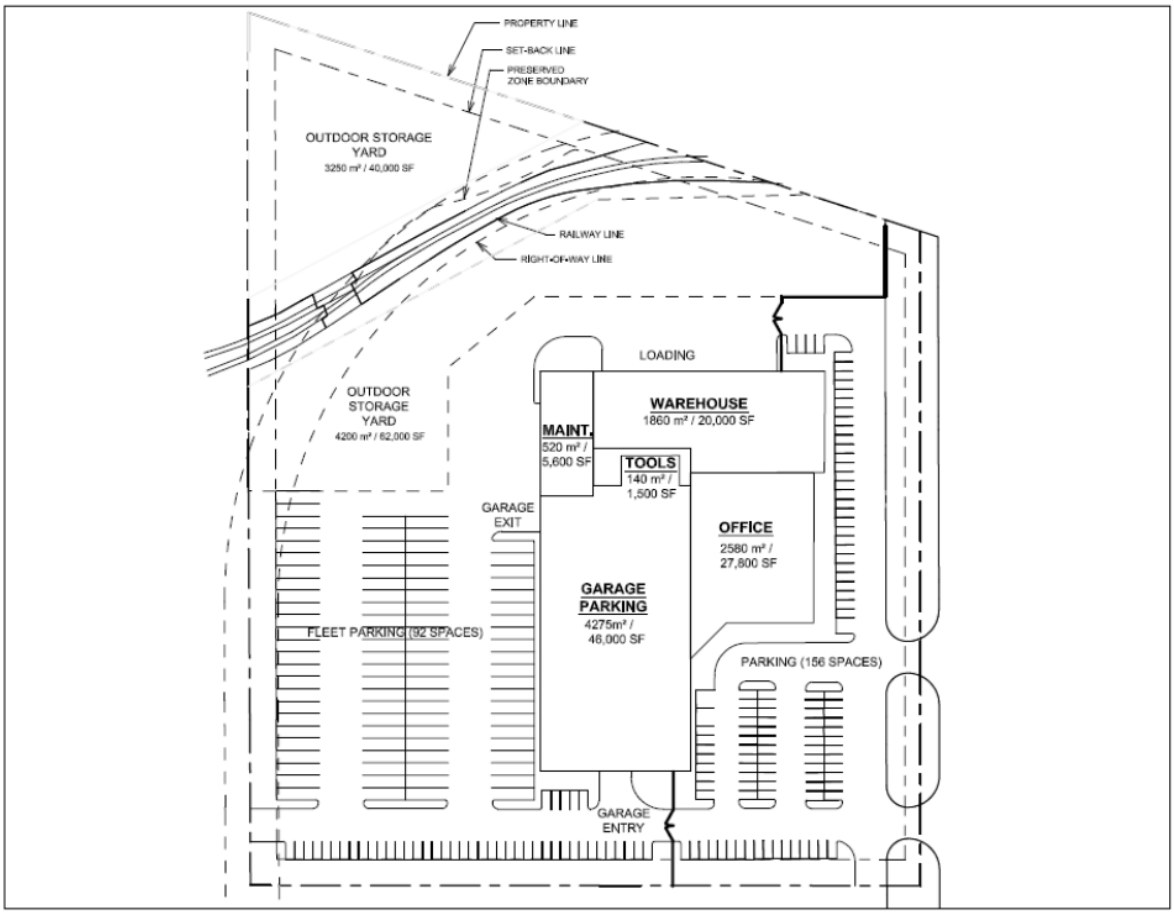


Figure B07 - 6 Mavis Development

The site plan in Figure B07 - 6 was developed to show the possible redevelopment of the Mavis Road site to create a more efficient and effective building. The two existing entrances to the site off Mavis Road would have been maintained as Cresa did not believe that Alectra Utilities would have received approval to relocate these entrances.

While the site plan showed approximately 100,000 square feet of outside storage, initial zoning investigations indicated that current zoning only permits 10% of the total site area dedicated to outside zoning. Therefore, Alectra Utilities' intended use of the site may not have complied with the City of Mississauga bylaws. Further investigation would have been required to determine if any site-specific zoning was needed, however, this was not completed during this review due to the issues described in *Section 7.4.1*.

Cresa investigated the possibility of removing the rail line located in the northwest portion of the site and did not believe that it would be possible. Cresa noted that there was another right of way easement indicated on the site plan for an additional rail line. While the building and parking requirements would have been met, given the unique shape of the outside storage and the existence of the rail line, Alectra Utilities would not have been able to meet all its outside storage requirements.

In the event Alectra Utilities was able to move forward with a redevelopment, it would have needed to secure temporary land to accommodate outside storage functions and fleet parking. This assumed that all office functions could be moved temporarily to other Alectra Utilities facilities. Alectra Utilities would have likely required approximately 3.5 to 4 acres to temporarily accommodate its outside storage and fleet parking requirements, and the land would have needed to be zoned to allow for outside storage. If the office staff could not be moved to other Alectra Utilities facilities, additional office space would have had to be leased during the redevelopment.

There was also limited land with outside storage available for lease. This land is usually in high demand from logistics companies looking for temporary trailer storage.

The current industrial vacancy rate for Mississauga and Brampton at the time was estimated to be only 1.1%.

Cresa provided a preliminary redevelopment estimate, which would have been subject to change. Additional testing, design and engineering would have been needed for a more refined budget. Cresa's initial budget forecast was approximately $25MM (excluding inflation, impact of COVID-19 pandemic, etc.). The capital budget also did not consider the cost to lease space while the site was being redeveloped. Cresa also did not forecast an allowance for any environmental remediation that may have been required.

The redevelopment of 3240 Mavis Road might have accommodated the majority of Alectra Utilities' requirements on the existing site, however, additional outside storage would still have been required, and Alectra Utilities would still have many of the issues as outlined in *Section 7.1* (e.g. rail easements).

Sandalwood "as is" was described in *Section 7.4.2*.

Due to the costs and remaining concerns with both locations, Option 2 was not pursued.

7.4.3 Option 3 - Dispose of both Mavis and Sandalwood and Relocate (Selected Option)

Option 3 would see Alectra Utilities dispose of both 3240 Mavis Road and 175 Sandalwood Parkway West and relocate to a new purpose-built consolidated Operations Centre. Some of the initial pros and cons that Alectra Utilities identified are listed in Table B07 - 8.

Table B07 - 8 Pros and Cons to Relocate

Pros	Cons
Operational gains by operating out of single facility	Higher upfront costs than just redeveloping Mavis
Lower operating costs due to less square footage	Possible disruption of moving employees to a new location
New facility with new building systems all under warranty	Market Risk and timing considerations related to the sale of existing facilities at 3240 Mavis Road and 175 Sandalwood Parkway West include aligning the move out date with the move in date and securing appropriate value.
Ability to design a facility to meet all of Alectra Utilities' long-term requirements	

Initial Search Parameters

The initial parameters that Alectra Utilities identified were as follows:

- Area of 15 to 25 acres of land in North Mississauga or South Brampton, relatively equidistant from the two existing facilities.
- Good access to major arterial and highway systems to optimize travel time and provide service visibility to the public.

- Permissive zoning to provide for industrial use with outside storage capability.
- Minimal planning approvals required.
- Ability to lay out an efficient building to accommodate a 150,000 to 200,000 square feet facility including required parking and outside storage.
- No significant environmental, land use or zoning conflicts.
- No significant local use conflicts with sensitive land uses adjacent to the site.
- Available, on or off market.

The Search Process

Over two years, Cresa actively searched for available sites that met the criteria. The overall strategy included:

- Active searches on MLS listings.
- Active searches on the Co Star and Loop Net listings.
- Active searches on Realnet and Realtrac system.
- Ongoing calls, in-person meetings and follow-up with the Economic Development staff in both Brampton and Mississauga.
- Ongoing calls, in person meetings and follow up with major institutional landowners.
- Outreach to key real estate brokers active in the industrial market in Mississauga and Brampton.
- Ongoing monitoring of social media, industry blogs and investor news to identify organizations that may be disposing of assets.

The "Potential" Sites

Cresa was able to identify several vacant properties that would have met Alectra Utilities' central operational requirements, but many of the sites were not available for sale.

After an extensive search, Cresa became aware of a site in South Brampton (174 Kennedy Road) that had an existing building on the property that was in the process of being demolished. This property would support Alectra Utilities' operational requirements for the central region and align with the recommendation to pursue Option 3.

Cresa's efforts identified a series of options and possibilities which are outlined below:

- A site was identified at 7869 Tenth Line, Halton Hills. The site was not zoned and was in the "Hold" Area identified for the new 400 series highway in north Halton. While the site was located in the municipal boundary of Halton Hills, it would have been able to service the Brampton and Mississauga communities. Through a lengthy process and negotiations with the landowner, the approval risk was elevated due to the building and site only being available for lease and the development horizon was judged to be too long to provide certainty for Alectra Utilities.
- Several sites were identified as being available from one developer, including a number of sites on the Highway 410 corridor. Many of the available sites were too small at less than 15 acres. The one site on Highway 10 at Derry Road was very appealing to Alectra Utilities at 25 acres but there were planning issues that were significant and a lack of political support for this site to be brought forward. Informal pricing for this site was set at about $2.5MM per acre.
- Another site on Mississauga Road, north of highway 401 and adjacent to the Streetsville Glen Golf Course was identified. The site was small at 13 acres and Alectra Utilities and Cresa examined several alternatives to accommodate the required area but could not come up with a workable solution given the site topography and the watercourse issues.
- One site was identified by Cresa through the City of Mississauga Economic Development Department. Cresa did an initial review of the site and rejected the opportunity as there was a TRCA restriction on the site and it was in a regulated TRCA area that would have Alectra Utilities lose over 40% of the available 22 acre land area.
- Cresa worked with First Gulf to identify two off-market opportunities that they were aware of, including one at 134 Kennedy Road, Brampton. Cresa met with the ownership group, and they had an initial asking price of $2.5MM to $2.6MM per acre for their 16 acre site. The site had an existing building on it that would have had to be demolished. Due to land size, shape and access points, this site was

judged to be inferior to the site to the south and not suited to meet Alectra Utilities' operational requirements.

- The 174 Kennedy Road South site was identified by First Gulf but was under different ownership than 134 Kennedy Road South. The owner was in the process of trying to get municipal approval for a major distribution centre which was not compliant with the current zoning. The site previously had a building on the site that was demolished (Benson and Hedges) and the site was decommissioned with crushed concrete. Through an extensive negotiation process and an evaluation of the overall site, Alectra Utilities considered this site to be the most viable option and a draft Agreement of Purchase and Sale was negotiated.

In July 2019, Management recommended the Audit, Finance and Risk Management (AFRM) Committee approve and recommend to the Board of Directors to proceed with option 3 to purchase 174 Kennedy Road and construct a new Central Operations Centre. Management also recommended that the AFRM approve and recommend to the Board of Directors that Management be authorized to sell Alectra Utilities' Mavis and Sandalwood facilities, to offset the upfront cash flow requirements of the acquisition of 174 Kennedy Road and construction costs of the new Central Operations Centre and to ensure the move in date to Kennedy was aligned to the move out date from the Mavis and Sandalwood locations.

7.5 Timeline

- 174 Kennedy Road South property was purchased in July of 2019.
- 175 Sandalwood Parkway West was sold to BVD Petroleum in 2020 and leased back until December 2023.
- To determine the property market value, in 2019, Cresa obtained two independent property market appraisals. Wagner, Andrews & Kovacs Real Estate Valuation (WAK) appraised the property at $29.8MM and Altus Group at $31.5MM
- Two purchasing offers were presented by Cresa, and the property was sold in 2020 to BVD Petroleum for $32.5MM.
- 3240 Mavis Road facility was sold to the City of Mississauga in 2021 and leased back until December 2023.

- To determine the property market value, in 2021, Cresa obtained two independent property market appraisals. WAK appraised the property at $27.4MM and Altus Group at $30.6MM.
- The City of Mississauga engaged Antec Appraisal Group to complete a review of the Appraisal Report prepared by WAK as well as the Appraisal Report prepared by Atlus Group. Antec Appraisal Group concluded that both reports were within a reasonable range of each other and that WAK was more supportable in terms of representing the current market value as of the effective date, based on the analysis provided within their report.
- The City of Mississauga then initially presented an offer lower than the average of the three appraisals. Cresa negotiated a sale price of $28.4MM, which was the average of the three appraisals, which was subsequently approved by Alectra Utilities' Board of Directors.
    - It is important to note that due to the Region of Peel's pedestrian and vehicles access easements, and CP Rail railway tracks and access easements, it was Cresa's opinion that the property would be a difficult sale to any third party.
- 174 Kennedy Road construction started in 2020 and was completed in December 2023. The move from both Mavis and Sandalwood coincided with the occupancy date of the new building.
- 174 Kennedy Road occupancy was mid-December 2023, with a new address of 200 Kennedy Road South.

7.6 Costs and Savings:

Project Cost – The project was completed within schedule, even with significant challenges caused by the COVID-19 Pandemic. Alectra Utilities wanted to occupy the building by December 2023 to prevent additional Mavis and Sandalwood lease term renewals and reduce Alectra Utilities' operating expenses. However, additional capital budget was required to complete the project from the original forecast. Most of the overall project increases were due to:

- Material and labour costs increased during the COVID-19 Pandemic
- Trades strike delayed the project and increased costs

- Weather conditions increased the cost relating to soil, gravel and grading (drainage, water, snow, etc.)
- Unforeseen regulatory & municipal requirements (Toronto Regional Conservation Authority, City of Brampton Parkland Dedication)
- Changes in building regulations and requirements during project design and construction
- Increase project scope and budget to include installation of a 500kW Solar Plant to power the property, Dedicated Outdoor Air System (DOAS), EV Charging Stations, etc. to support Alectra Utilities' sustainable efforts and reduce operating costs

OM&A Savings (Efficiencies) - In December 2023, Alectra Utilities consolidated its two Central Region sites in Brampton and Mississauga into a single operating centre at 200 Kennedy Road South to better meet business needs and reduce costs. This initiative reduced operational costs by an average of $2.9MM annually and results in cumulative savings of $8.6MM from 2024 to 2026 from multiple business units. A key contributor to these savings is reduced facility operating costs. These savings are based on a comparison between the "do-nothing" baseline for maintaining operations at both sites and the costs of running the new consolidated facility. For more OM&A information please reference *Exhibit 4, Tab 2, Schedule 18 Facilities*.

By streamlining operations, Alectra Utilities also reduced its fleet by 21 vehicles and eliminated one mechanic position effective 2025, resulting in average annual operational savings of $1.2MM and cumulative savings of $3.6MM from 2024 to 2026). These savings represent the estimated running costs that would have been incurred if the 21 vehicles remained in service, along with the associated costs of retaining the mechanic. This consolidation also streamlined team structures, reducing duplication in supervision, communications, and safety initiatives (for more information on regarding this, refer to *Exhibit 1, Tab 6, Schedule 5 Productivity)*.

Other Revenue and Lease Costs – With the sale of the Mavis and Sandalwood properties, Alectra Utilities negotiated lease agreements to align with Kennedy property occupancy timelines. 3240 Mavis, Mississauga and 175 Sandalwood Parkway West, Brampton were sold and leased back until Alectra Utilities moved into 200 Kennedy Rd South in December 2023. The sale of Sandalwood in 2020 resulted in a gain of $4.8MM (pre-tax) and an initial lease liability of $4.3MM

for a 30-month term (November 2020 to May 2023). A lease extension was subsequently exercised, resulting in an additional lease liability of $1.2MM. The sale of Mavis Road in 2021 resulted in a gain of $13.9MM (pre-tax) and a lease liability of $3MM with a lease term of 27.5 months (December 2021 to March 2024). For more on gains from property sales refer to *Exhibit 6, Tab 3, Schedule 1 Other Revenue*.

Appendix B08 - Fleet Investments

I Overview

Alectra Utilities requires trucks, vehicles and equipment to perform work, and to transport materials as well as employees to and from job sites. The Fleet Renewal investments during the 2027-2031 period maintain the vehicles, trailers, and other equipment necessary to support system capital and maintenance work across Alectra Utilities' distribution system.

The Fleet Renewal program's primary objectives are to optimize the utility's vehicle and equipment asset lifecycle cost, and to ensure that fleet assets perform reliably and maintain employee and public safety. Capital investments within fleet are grouped into two categories: Vehicles and Equipment.

1. **Vehicles**: Includes heavy and medium duty vehicles (used primarily to perform distribution work and transport operators and equipment) and light duty vehicles (which are fully equipped for employees to inform, manage, and monitor distribution work).
2. **Equipment**: Includes equipment for employees and vehicles such as forklifts, trailers, boom lifts, and protective gear.

Over the 2027-2031 period, Alectra Utilities must replace approximately half of the vehicles in its current fleet that have surpassed their typical useful life or are identified as being in "poor" condition (i.e. Over the 2027-2031 period, Alectra Utilities must replace approximately half of the vehicles in its current fleet that have surpassed their typical useful life or are identified as being in "poor" condition (i.e. due to high mileage, wear and tear, excessive operating costs, etc.) and increase its fleet size by 72 vehicles (two additional vehicles are required in 2026 to support growth). These investments are required to ensure vehicle availability to support operations and reduce potential safety risks to employees and public.

As outlined in *Section II*, Alectra Utilities conducts regular evaluations of its fleet assets to ensure that capital plans align with Alectra Utilities' current requirements. Considerations are also given to emissions and fuel efficiency when comparing new vehicles to those being replaced. Planned investments in Fleet Renewal are intended to support Alectra Utilities in delivering timely customer

service, maintaining system reliability, and addressing safety and environmental concerns effectively.

Alectra Utilities' approach to fleet electrification involves evaluating the suitability of electric vehicles at the time of scheduled replacement. Each vehicle purchase is assessed to determine whether an Electric vehicles (EVs) is operationally appropriate and cost-effective for its intended use. Where these conditions are met, Alectra Utilities proceeds with the conversion to an electric vehicle as part of the normal replacement cycle. This phased approach ensures that fleet electrification is advanced in a prudent and financially responsible manner, while also aligning with broader asset management practices.

Alectra Utilities capital investments in its vehicle fleet yield the following benefits:

- Optimization of vehicle operating costs
- Minimization of fleet downtime due to repairs and a corresponding increase in fleet reliability
- Increase in vehicle efficiency through replacing older and poor condition vehicles that are more labor-intensive for maintenance purposes with new vehicles
- Reduction in environmental impacts such as reductions in greenhouse gas emissions and the amount of maintenance fluids used
- Increased employee, field crew, and public safety, as newer vehicles are equipped with new safety technology (e.g. back up cameras, lane departure warning, emergency braking warning, driver safety alerts, etc.)

Table B08 - 1 Fleet Investment Expenditures, Drivers and Outcomes

	Historical Spending					Bridge		Forecast Spending				
Year	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
CAPEX ($MM)	8.1	6.6	4.0	7.5	6.9	12.1	12.3	24.2	23.3	18.6	17.3	14.5
Primary Driver	System capital and maintenance work support											
Secondary Driver	Business operational efficiency											
Outcomes	Customer Value, Safety, Reliability, Environment and Efficiency											

Alectra Utilities Fleet Management Strategy

Alectra Utilities optimizes the level and pace of capital investments to minimize its maintenance and repair costs while maintaining safety and vehicle availability. Alectra Utilities takes a two-step approach when managing its fleet.

In the first step, it uses a Life Cycle Analysis (LCA) approach to identify groups of assets whose characteristics (e.g. vehicle type, age, mileage, anticipated corrosion) enable the utility to estimate potential increases in their operating costs. As vehicles age, ownership costs such as purchase costs decrease and operating costs such as fuel, maintenance, and downtime increase. Alectra Utilities uses its LCA to anticipate vehicle needs and fleet turnover for short term (0-2 years) and long term (2-7 years) expenditure planning purposes.

In the second step, the strategy then assesses the actual condition of assets under consideration using a condition assessment to decide whether to replace or dispose of a given vehicle. This is an 85-point vehicle condition inspection to annually evaluate all asset components and determine whether parts and systems are working effectively. Because a replacement cycle varies depending on the vehicle make, model year, equipment design, and operating environment, some vehicles that are in poor condition may require replacement before the LCA criteria is met and some vehicles that meet the LCA criteria may be in good condition and not warrant replacement. Replacement cycles are additionally impacted by organizational objectives, such as the decarbonization and electrification of fleet assets.

EVs offer several advantages over internal combustion engine (ICE) vehicles, including reduced greenhouse gas emissions, lower operating costs, and decreased maintenance requirements due to fewer moving parts. As EV technology continues to improve, Alectra Utilities anticipates increasing the total number of EVs within its fleet assets. However, the decision to transition from ICE to EV is not the same for all vehicle types or operational needs. When Alectra Utilities determines that an existing ICE vehicle needs to be replaced, or a new vehicle needs to be added, an additional evaluation takes place to determine whether an EV currently available in the marketplace can meet the utility's operational needs, is cost-effective, and can be supplied on a timely basis.

When replacing vehicles with potential EVs, Alectra Utilities considers some of the following items:

- Charging infrastructure requirements
- Vehicle usage profile
- Vehicle type and functionality
- Total cost of ownership
- Environmental impact
- Downtime and maintenance requirements
- Supplier capacity and delivery timelines
- Previous experience, if any

This approach enables Alectra Utilities to replace vehicles at the lowest lifecycle cost, which occurs at the point in time immediately before operating costs exceed ownership costs. It also promotes utility performance through the maintenance of a reliable fleet for completing distribution work in a timely and safe manner and enables Alectra Utilities to prudently plan and pace its fleet investments. Finally, fleet management enables Alectra Utilities to meet its organizational objectives, such as the decarbonization of the utility's fleet assets. When the marketplace has available EVs that meet operational requirements, and are comparable in cost, Alectra Utilities will replace internal combustion engine vehicles with an EV.

Alectra Utilities engaged a third-party to do a condition assessment to validate its fleet budgets. The third-party consultant replacement recommendations were in line with Alectra Utilities' fleet capital investments plan over the 2027-2031 period.

II Investment Description

Alectra Utilities' planned fleet investments are focused on: (i) increasing the fleet size to meet growth needs and enable the required capital and maintenance work required over the DSP period and (ii) renewing vehicles that are either in poor condition or have high mileage.

Figure B08 - 1 Fleet Statistics

Alectra Utilities maintains a fleet of over 500 vehicles and approximately 200 other assets and pieces of equipment to ensure safe and reliable vehicles for employees to perform their daily activities. Alectra Utilities has service centres in Markham, Barrie, Brampton, St. Catharines, Guelph and Hamilton. All service centers operate with extended hours of operation to provide Alectra Utilities with more flexibility in managing its fleet inventory, maintenance and repairs.

Alectra Utilities' fleet consists of:

- Heavy-duty vehicles
- Medium-duty vehicles
- Light-duty vehicles
- Trailers
- Fleet equipment (e.g. forklifts, generators, and compressors)

Heavy-duty and medium-duty vehicles are the primary means of transporting equipment and materials to and from job sites. Light duty vehicles facilitate the engineering, management and planning functions of Alectra Utilities. Trailers mainly provide storage for equipment at work sites. Fleet equipment is used to perform lifting and towing, mainly by the Operations and Stores departments at Alectra Utilities.

As discussed below, a significant number of vehicles in Alectra Utilities' fleet have deteriorated to unacceptable levels. These vehicles pose safety risks for employees and the public and must be replaced. To the extent that they are unable to fulfil their operational functions, either partially or entirely, these deteriorated vehicles negatively impact Alectra Utilities' ability to serve its customers. Replacing these vehicles is the focus of Alectra Utilities' fleet investments during the 2027-2031 period.

Table B08 - 2 identifies the quantity and the types of vehicles and other assets that Alectra Utilities plans to replace through Fleet Renewal & Growth investments during the DSP period.

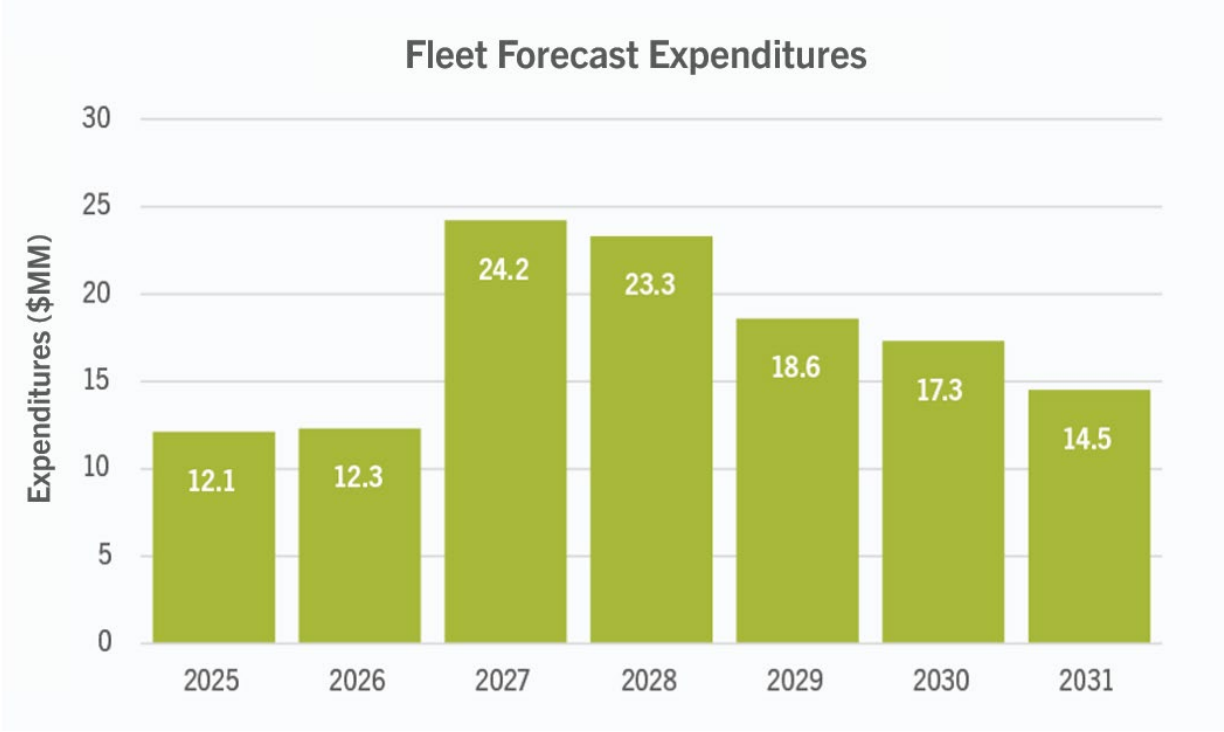


Figure B08 - 2 Fleet Forecast Expenditures

2.1 Fleet Growth

Alectra Utilities requires funding to support its fleet growth from 2027 to 2031. This investment is critical for the organization to expand and modernize its fleet, ensuring it meets growth, stays efficient, and adopts new technologies for the future. Over this DSP period, Alectra Utilities will allocate funds to purchase new vehicles and invest in necessary infrastructure improvements. The chart below provides a breakdown of the specific financial allocation for fleet growth, illustrating how Alectra Utilities plans to distribute its resources across different years. This strategy is designed to ensure that Alectra Utilities can sustain its operations and improve service delivery, ultimately benefiting both the organization and its customers. Alectra Utilities relies heavily on its fleet of vehicles and equipment to carry out day-to-day operations, which include delivering reliable service to customers, responding to emergencies, and maintaining infrastructure needed for electricity distribution. Fleet growth is directly tied to the growth of Alectra Utilities' Operations team. As the utility expands to meet increasing customer and system demands, additional field crews are required to perform critical work such as new service connections and infrastructure replacements, capital expansion, and emergency response.

These additional crews cannot function effectively without the proper level of fleet vehicles and equipment. Simply put, without the same investment in fleet growth, the Operations team will not have the necessary resources to complete their work safely, efficiently, and reliably.

Between 2027 and 2031, Alectra Utilities anticipates continued growth in its operations workforce to address needs driven by population growth, aging infrastructure and electrification initiatives. Each new crew requires access to appropriately equipped vehicles, ranging from light duty trucks and vans to specialized heavy duty equipment such as bucket trucks and trailers. Expanding the fleet ensures that every crew is equipped to respond to customer requests, execute planned projects, and support emergency restoration efforts when severe weather events occur. Aligning fleet growth with Operations team expansion can improve efficiency and productivity. When crews have dedicated access to the proper vehicles, downtime is reduced and waiting periods for equipment are minimized. Figure B08 - 3 provides the investments needed to support Fleet Growth. Table B08 - 2 details Fleet Growth Investments by vehicle type.

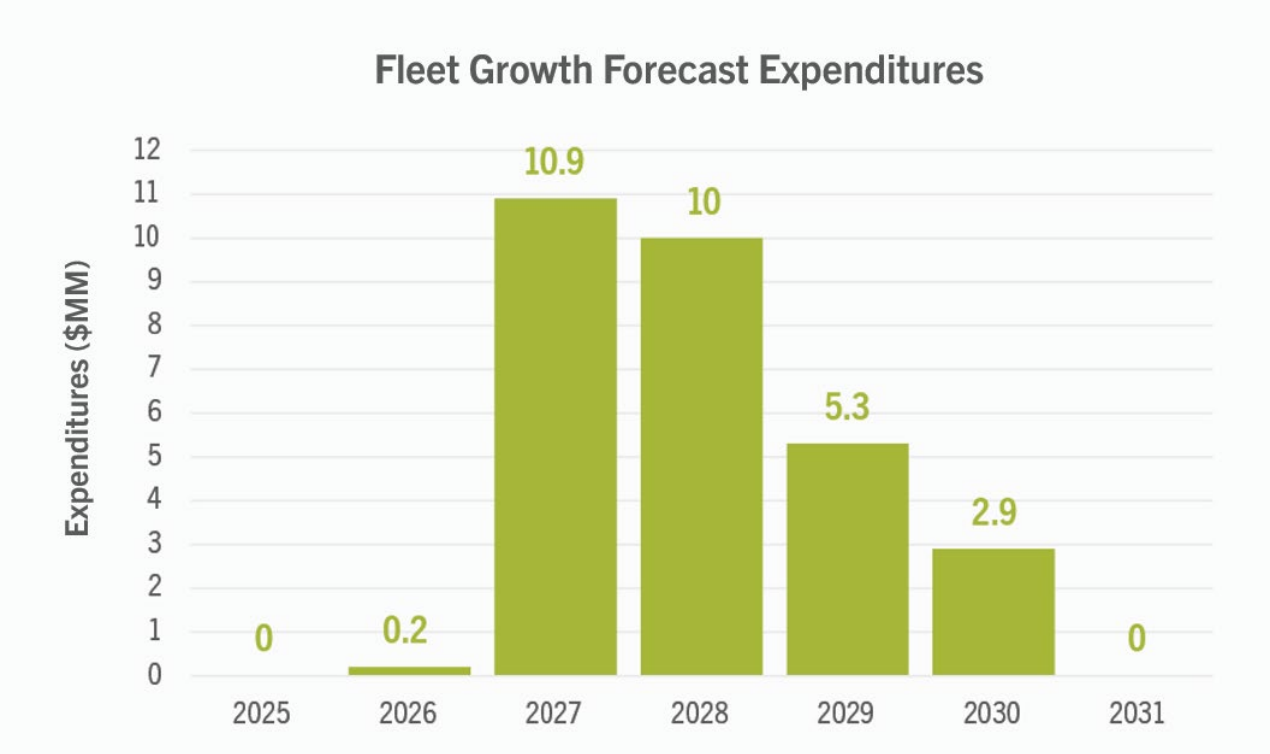


Figure B08 - 3 Fleet Growth Forecast Expenditures

Table B08 - 2 Alectra Fleet Growth - All Regions

Asset Type	2025	2026	2027	2028	2029	2030	2031	Overall Total
Double Bucket	0	0	5	6	2	1	0	14
Single Bucket	0	0	5	6	2	1	0	14
Radial Boom Derrick (RBD)	0	0	4	1	2	1	0	8
Medium & Heavy Duty Van	0	0	2	1	2	1	0	6
Light Duty Van	0	2	3	3	0	0	0	8
Pickup	0	0	6	7	6	5	0	24
Yearly Total	**0**	**2**	**25**	**24**	**14**	**9**	**0**	**74**

2.2 Planned Fleet Renewal Investment by Vehicle Type.

The planned investments reflect a set of objectives and drivers, ranging from the condition of existing vehicles to external regulatory and safety requirements. Table B08 - 3 outlines the objectives and drivers of Alectra Utilities' planned fleet renewal investments. Table B08 - 4 provides planned renewal investments by vehicle type.

Table B08 - 3 Fleet Renewal and Sustainment Objectives and Drivers

Objectives	Drivers of Replacement Investments
Alectra Utilities' fleet replacement and sustainment objectives are to: • Identify vehicle replacements required to ensure adequate support for capital work, maintenance and corporate travel requirements on an annual basis • Ensure that Alectra Utilities' vehicle replacement criteria are aligned with utility best practices, vehicle manufacturer requirements and applicable industry standards • Ensure vehicle specification standards appropriate for each vehicle class are established to reduce inventory requirements, streamline vehicle maintenance and expedite delivery timelines	Alectra Utilities identifies specific investments based on the following factors, as applicable to the different classes of vehicles, trailers, and other equipment that are the subject of the plan: • Manufacturing Standards • Industry Standards • Construction and Operating Standards • Vehicle Operational Conditions • Vehicle Age • Vehicle Total Mileage • Highway Traffic Act • Canadian Motor Vehicle Safety Standards • All related Canadian Safety Association standards, specifically those that relate

Objectives	Drivers of Replacement Investments
• Ensure that Alectra Utilities' fleet operates in compliance with all appropriate federal, provincial, and municipal legislation, and specific licences • Establish and maintain a fleet that can meet existing and future geographic challenges and operating environments • Continue to assess, investigate and evaluate efficiencies and benefits of fleet inventory with vehicles powered by alternative sources of energy • Ensure alignment to support Alectra Utilities' Environmental and Sustainability Development initiatives	to aerial devices and hydraulic equipment • Motor Vehicle Inspection Station requirements • Infrastructure Health and Safety Association of Ontario, where applicable • Corporate Health and Safety and Environmental Policies

Table B08 - 4 Alectra Fleet Replacement - All Regions

Asset Type	2025	2026	2027	2028	2029	2030	2031	Overall Total
Double Bucket	2	0	2	1	3	5	2	15
Single Bucket	5	3	5	3	6	9	8	39
Radial Boom Derrick (RBD)	2	5	4	6	4	2	1	24
Dump-Flatbed Truck	2	3	2	0	1	1	2	11
Medium & Heavy Duty Van	5	2	6	6	2	0	1	22
Light Duty Van	17	8	10	21	6	1	11	74
Pickup	26	31	31	33	17	22	26	186
SUV	2	23	19	0	4	5	13	66
Trailer	1	14	2	8	2	5	23	55
Yearly Total	**62**	**89**	**81**	**78**	**45**	**50**	**87**	**492**

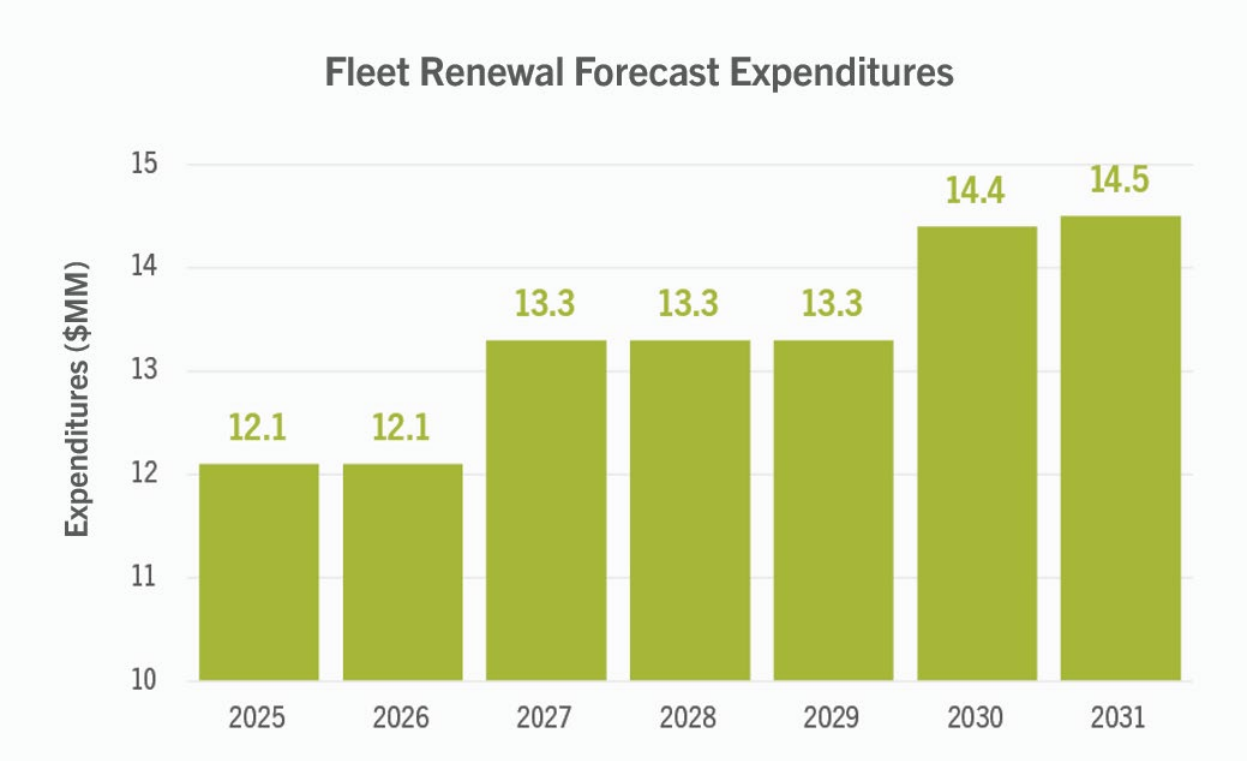


Figure B08 - 4 Fleet Renewal Forecast Expenditures

Alectra Utilities assesses its trucks and vehicles based on the replacement assessment criteria that focus on vehicle condition, age, mileage, engine hours, and operational requirements.

Table B08 - 5 below provides a breakdown of the assessment criteria used by Alectra Utilities to decide on vehicle renewal across various vehicle types.

Table B08 - 5 Vehicle Renewal Assessment Criteria

Fleet Class	Renewal Assessment Criteria
Light Duty Vehicles	• Vehicles have an estimated useful life of seven years or 250,000KM, whichever occurs first. Once a vehicle reaches this threshold, it is assessed for replacement. If replacement is deferred, the vehicle undergoes reassessment annually to ensure it remains safe, reliable, and cost-effective to operate.
Medium Duty Vehicles	• Vehicles are assessed for replacement at 10 years of service or once mileage exceeds 250,000KM. If replacement is not undertaken at that point, the vehicle is re-evaluated annually to confirm it remains suitable for continued use. The estimated useful life of these vehicles is 12 years or 250,000KM, whichever occurs first.
Heavy Duty Vehicles	• Vehicles are assessed for replacement after 12 years of service, once mileage exceeds 500,000KM, or when engine hours surpass 12,000. If replacement is not completed at that time, the vehicle is re-evaluated annually to ensure continued safety and reliability. The estimated useful life for these vehicles is 15 years, or 500,000KM, or 12,000 engine hours, whichever comes first.
Trailers	• Trailers are assessed after 15 years of service to determine their ongoing suitability. Where feasible, trailers may be refurbished to extend their useful life. However, if a trailer cannot be refurbished due to its condition or a change in application requirements, it is flagged for replacement. The estimated useful life of trailers is 15 years.

2.3 Summary of Investment Outcomes and Benefits

Table B08 - 6 summarizes the outcomes and benefits associated with the Fleet Renewal investment.

Table B08 - 6 Investment Outcomes and Benefits

Investment Benefits	Reasoning
Customer Value	Working and operational vehicles ensure that Alectra Utilities can manage its commitment to customers by getting to work locations on time and effectively addressing issues on-site.
Reliability	Contributes to Alectra Utilities' system reliability by ensuring work crews have the necessary vehicles and equipment to perform distribution work when required on a 24/7 basis.
Safety	Contributes to the safety of Alectra Utilities' operations by minimizing safety risks to crews and to the public.
Environment	Contributes to Alectra Utilities' environmental performance by reducing GHG emissions associated with fleet fuel consumption by: • Utilizing hybrid and electric vehicles • Implementation of anti-idling technology and GPS reporting
Efficiency	Through the replacement of fleet assets, Alectra Utilities can realize efficiency savings in several ways: • Via reduction in total life-cycle costs, including a reduction in maintenance costs associated with new vehicles • Via reduction in fuel costs, due to the improved fuel economy of new vehicles, along with the use of hybrid and electric vehicles and idle-reduction technologies New Alectra Utilities vehicles will align with the utility's current-state processes and practices, and new vehicle specifications allowing the organization to avoid the cost associated with maintaining vehicles with different capabilities and maintenance requirements.

III Investment Drivers and Need

3.1 Purpose for Planned Fleet Renewal & Growth

The planned Fleet Renewal investments are driven by the condition of the utility's existing fleet, and by the operational needs of the distribution system. Both drivers are discussed in the following subsections.

The planned Fleet Growth investments are driven by the expansion of Alectra Utilities operations teams. As operational demands increase to support system growth and electrification initiatives, additional vehicles and fleet equipment are required to enable operations teams to perform their work effectively. More information on how Fleet Growth is tied to staff increases in the Operations department can be found in *Chapter 5.3.1 (Section 5.3.1.3)*.

3.1.1 Condition of Existing Fleet

Alectra Utilities' fleet consists of different types of trucks and vehicles that are each designed for specific work purposes. At the job site, truck and vehicle uses include:

- Lifting and positioning material
- Storing material
- Preparing material for installation
- Planning and coordinating work

Fleet vehicles must be available to support these functions in a safe, reliable, and operationally efficient manner.

In 2024, Alectra Utilities commissioned a third-party assessment by ARI to evaluate the health and condition of its entire fleet of vehicles. ARI, a well-established fleet management service provider, conducted a comprehensive review to assess the age, performance, maintenance needs and overall condition of each vehicle. This assessment was conducted to validate Alectra Utilities fleet replacement strategy and identify any additional vehicles that may be nearing the end of their useful life or require costly repairs. By conducting this assessment, Alectra Utilities wanted to ensure its fleet maintenance, replacement, and expansion plans align with its long-term goals for service excellence and operational sustainability. ARI's assessment aligned with Alectra Utilities' long-term replacement strategy.

3.1.2 Fleet Maintenance and Capital Investment Support

Alectra Utilities' top priority across the organization is safety. Therefore, in terms of its Fleet department, safe and reliable vehicles that support the utility's capital work during the 2027-2031 period and beyond are of highest importance. Alectra Utilities requires access to vehicles and equipment to transport employees and materials to and from job sites and perform distribution work onsite. Fleet vehicles must be available to support these work functions in a safe, reliable, and operationally efficient manner to service our customers in a timely manner.

Alectra Utilities fleet capital expenditures between 2027 and 2031 will focus on replacement of vehicles that have reached or surpassed their end of life. As vehicles deteriorate with use, age and exposure to weather conditions, Alectra Utilities has experienced an increased risk of potential safety issues because of structural failures, component failures, as well as vehicle electrical faults. Vehicle failures and faults are typically triggered by a number of factors, including corrosion. Alectra Utilities' fleet vehicles are continuously used throughout the year and endlessly exposed to environmental conditions including severe weather and rugged job site elements.

Figure B08 - 5 shows photos that highlight instances of vehicle corrosion within Alectra Utilities' fleet. These images provide a visual representation of the wear and tear on vehicles, showcasing areas where corrosion has occurred. This deterioration impacts the performance, safety, and longevity of the fleet, further emphasizing the need for fleet growth and modernization.

Figure B08 - 5 Examples of Alectra Utilities' Fleet Vehicle Degradation

Vehicle age, use, and salt on city streets are the main reasons for increasing corrosion conditions as it damages and weakens the frame of the truck or vehicle over time. The frame is the main structure of a vehicle in which all running gears are secured and supports the entire weight of the vehicle. It is fastened to the wheels, suspension, and steering components. Severe rust to the frame can lead to breaks while under load (e.g. during a lift operation, pulling cable, or material loading). Frame weakness can also decrease the ability of the vehicle to withstand vehicle crash incidents, thus jeopardizing the safety of the operators and the public.

Corrosion may also occur on components that are critical to the operation of the vehicle, such as transmission and brake lines, that are often not observable without substantial teardown. Rust on these components results in weak spots that have the potential to rupture, leak and cause failures while in use. For example, a transmission line rupture could result in a seized transmission. A transmission failure of heavy-duty trucks and vehicles introduces significant risk to operator safety and public safety. Similarly, brake line failures introduce safety risks due to loss of control and ability of the operator to appropriately stop the truck or vehicle.

Regular use of the fleet assets over time can lead to the failure of critical components that are not readily serviceable or observable by maintenance staff. Components such as the hydraulic hoses running through an aerial bucket truck, for instance, cannot be directly inspected at service intervals. As these hoses age, they become less flexible and more brittle. Hose failure results in hydraulic fluid leaking into the environment and could potentially result in stranding an employee operating a bucket at significant heights. Rescuing an employee from an aerial bucket truck presents a potential risk to the employee in the bucket as well as other field employees and the public in the vicinity.

As vehicles age and deteriorate with regular use, components designed to protect the vehicles' electrical circuitry can become compromised, leading to potential electrical failures. The risk of electrical circuitry failure increases with the use and age of the truck or vehicle. Vehicle electrical failures introduce the risk of failing auxiliary safety lighting systems and onboard equipment that are mandatory to protect the public and permit staff to perform the work safely.

Timely vehicle replacement is necessary to avoid undue vehicle downtime and associated negative impacts on customer response time and employee productivity. Trucks and vehicles are "the workplace" for over 60% of Alectra Utilities' workforce. Providing and maintaining a safe and

reliable fleet is key to building a safer workplace for Alectra Utilities' employees and providing them with the tools required to provide service to Alectra Utilities' customers. As vehicles approach their end of life, Alectra Utilities must consider the impacts of corrosion, hydraulics performance, vehicle reliability, and business operations efficiency.

3.1.2.1 Corrosion

Managing corrosion and replacing corroded vehicles is important to maintain fleet reliability and safety. Alectra Utilities' vehicles are continuously used throughout the year and spend most of the time outdoors in direct exposure to the weather and extreme elements. Humid weather and road salt can lead to corrosion that damages and weakens a unit's frame over time. As shown in the above photo corrosion can also make vehicle body parts weak and fragile. Fragile panels are commonly known to break, leaving sharp edges or presenting potential hazards if rusting occurs on a step, handle, or vehicle floor.

Corrosion on a vehicle's frame can lead to the frame breaking during a lift operation, cable pull, or material loading. Frame weakness can also decrease a vehicle's ability to withstand crashes and jeopardize the safety of the operators and the public. Corroded vehicle components can also impact safety and are difficult and costly to repair.

3.1.2.2 Hydraulics

Similar to the impact of corrosion, hydraulic issues that are not addressed can contribute to vehicle replacement, as repairs are costly, take the vehicle out of service, and indicate that the vehicle's overall condition has deteriorated. Components such as hydraulic hoses running through an aerial boom cannot be directly inspected at service intervals. As the hoses age, they become less flexible and more brittle. Hose failure results in hydraulic fluid leaks to the environment and could also render aerial buckets on bucket trucks inoperable or cause a failure while an employee is operating the bucket.

3.1.2.3 Reliability

Alectra Utilities' fleet investments ensure the reliability of the utility's distribution operations and the execution of its capital and maintenance programs. As vehicles age, they become increasingly unreliable and require more maintenance. In addition, even with regular

maintenance, vehicles are more likely to fail while in use or will need to be held out of service for repairs following an inspection. Furthermore, parts availability for aging vehicle models decreases over time, especially as certain makes and models of vehicles become obsolete. As a result, there is an increased probability that an older vehicle will remain out of service for longer periods of time while Alectra Utilities procures the required parts. Unreliable or unavailable vehicles adversely impact the utility's ability to provide acceptable levels of reliable service to customers and result in lost productivity and business disruption.

3.1.2.4 Business Operations Efficiency

Alectra Utilities uses the ARI fleet management system to measure and provide details on how often a vehicle is used on any given day. This information informs the investment management process and allows Alectra Utilities to ensure a sufficient number of vehicles are available to enable operations, without retaining more vehicles than necessary. Optimal fleet utilization also allows for the regular maintenance of vehicles without interrupting distribution operations. Alectra Utilities also tracks and measures the usage of particular vehicles against other vehicles of the same class within the fleet, to continuously assess whether vehicles can be reallocated to different departments and areas of distribution work to increase productivity.

3.1.3 Operational Needs

As operational needs and work requirements evolve with standards and technologies, specific vehicle and equipment configurations are required to be updated such as higher and heavier poles requiring bigger trucks with longer and higher capacity booms. Alectra Utilities is also installing underground infrastructure within its service territory which requires differently designed vehicles to handle longer and heavier underground cabling. Larger capacity transformers also require vehicles with higher lifting capacity and, finally, smaller vehicles that can accommodate work within higher population density areas are required. As part of the planned vehicle replacements, Alectra Utilities will work closely with internal Operations departments and external vehicle manufactures to procure vehicles that are in a better position to support operational needs and work requirements in the years to come.

The primary driver of the fleet renewal investment is to provide trucks and vehicles necessary to support Alectra Utilities' capital and maintenance work and 24/7 trouble response. The secondary

driver of the investments is business operations efficiency, as the renewal investment will ensure that Alectra Utilities continues to deliver reliable and timely services to customers in an efficient manner.

IV Investment Timing & Pacing

4.1 Summary of Expenditures

Table B08 - 7 summarizes investments including the historical period from 2020-2024, the 2025-2026 bridge years, and the DSP period from 2027-2031.

Table B08 - 7 Summary of Expenditures

	Historical Spending					Bridge		Forecast Spending				
Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Fleet Renewal	8.1	6.6	4.0	7.5	6.9	12.1	12.1	13.3	13.3	13.3	14.4	14.5
Fleet Growth	0.0	0.0	0.0	0.0	0.0	0.0	0.2	10.9	10.0	5.3	2.9	0.0
Total CAPEX ($MM)	**8.1**	**6.6**	**4.0**	**7.5**	**6.9**	**12.1**	**12.3**	**24.2**	**23.3**	**18.6**	**17.3**	**14.5**

4.2 Historical Expenditures (2020-2024)

Historical fleet expenditures between 2020 and 2024 total $33.1MM. During the historical period fleet investments varied due mainly to global supply chain issues and limited supply.

4.3 Bridge Year (2025-2026) and Forecast Expenditures (2027-2031)

Over the two-year Bridge Period, planned expenditures total $24.4MM. Forecast expenditures in 2027-2031 total $97.9MM. There are several interconnected factors that account for the increase in the average annual spend compared to the historical period.

- In recent years, the cost of vehicles has risen due primarily to inflation, lingering supply chain impacts from the COVID-19 pandemic, and more recently, the implementation of tariffs. These external economic factors have directly impacted the price Alectra Utilities pays for both new vehicles and replacement assets.
- As the Fleet ages, maintenance becomes more frequent and expensive. Older vehicles require more repairs, driving up overall maintenance costs. Rather than continuing to invest in maintaining aging assets, Alectra Utilities plans to replace more vehicles in the forecast period, a strategy that, while increasing upfront expenditures, is intended to reduce ongoing maintenance costs and improve

operational reliability (refer to *Exhibit 4, Tab 2, Schedule 19 Fleet* for the analysis of historical and forecasted repairs and maintenance expenses).

- Ensuring the safety of employees and the public is a top priority of Alectra Utilities. Older vehicles may present increased safety risks both in terms of reliability and compliance with safety standards. By investing in new Fleet assets, Alectra Utilities intends to mitigate these risks and maintain efficient operations.
- While the planned number of vehicle replacements is higher in the forecast period, Alectra Utilities expects that the related OM&A costs will grow more slowly than inflation, as newer vehicles generally require less repairs and maintenance, which helps temper ongoing operational costs even as upfront capital costs increase.
- Most of Alectra Utilities' Fleet assets are purchased to service its customers or to build and maintain distribution assets. Alectra Utilities uses a Vehicle Burden to reallocate a significant portion of its annual Fleet operating and depreciation costs to other assets (refer to *Exhibit 4, Tab 2, Schedule 21 Allocations and Recoveries*). The methodology is described in *Exhibit 2B, Tab 7, Schedule 2 Overhead Costs*.

4.4 Investment Pacing & Prioritization

When planning and executing Fleet Renewal investments, Alectra Utilities considers several factors as part of an ongoing screening process for fleet assets. To execute and sufficiently pace and prioritize the Fleet Renewal investment, Alectra Utilities implemented a first pass screening process which includes an assessment of the vehicle type, usage, age, and overall condition. This assessment provides Alectra Utilities with a baseline to initiate the capital replacement assessment process. During this time, vehicle utilization is also examined, and internal discussions take place with various business units on the vehicle requirement.

When planning and executing Fleet Growth investments, Alectra Utilities applies a structured approach to ensure that new fleet resources are introduced in alignment with operational needs and system demands. The pacing of Fleet Growth is coordinated with projected increases in operations crews and service territory requirements to prioritize growth investments. Alectra Utilities evaluates the type of fleet vehicles required for new or expanding crews and the operational roles that must be filled to maintain efficiency and reliability. Internal collaboration

with the Operations and Capital Planning teams ensures that Fleet Growth investments are organized in a timely manner and directly tied to delivering essential utility services.

4.5 Execution Approach

Once vehicle replacements have been confirmed and approved, vehicles are sourced and purchased in accordance with Alectra Utilities' procurement policies and processes. Historically, Alectra Utilities issued a Request for Proposal (RFP) every three years, awarding purchases based on the defined scope and selection criteria. Moving forward, Alectra Utilities will conduct the RFP process every five years, working directly with vehicle manufacturers to maximize its purchasing volume and obtain more favorable pricing and terms.

V Options Analysis

5.1 Fleet Renewal

Alectra Utilities considered the following options for Fleet Renewal investments:

- Run to Failure
- Replacing Portions of Heavy-Duty Vehicles instead of full replacement
- Replacing Medium-Duty and Heavy-Duty Vehicles with Demonstration Vehicles Instead of New
- Replacing Fleet Vehicles Based on Alectra Utilities Renewal Criteria

5.1.1 Run to Failure

Under the Run to Failure option, Alectra Utilities would continue to use existing and deteriorating fleet vehicles, which will continue to expose Alectra Utilities employees as well as the public to potential safety hazards should these vehicles fail. Furthermore, system reliability will be impacted as Alectra Utilities crews risk prolonged transport to outage sites should trucks and vehicles fail to function.

5.1.2 Replacing Components in Heavy-Duty Vehicles Instead of Full Replacement

Replacing components of a heavy-duty vehicle is a viable option and one that Alectra Utilities and its predecessor utilities have exercised in the past with some success, and Alectra Utilities will continue to consider this as an option. The challenge with this option is the overall vehicle condition that may not make financial or operating sense (extended downtime, costly repairs, scarcity of replacement parts, etc.), to get the vehicles back in service. Vehicle replacements need to be planned due to manufacturing scheduling, long delivery timeframes, and to obtain better pricing.

5.1.3 Replacing Medium- and Heavy-Duty Vehicles with Demonstration Vehicles Instead of New

Replacing medium- and heavy-duty vehicles with demonstration models instead of new vehicles would theoretically help mitigate the cost of needed Fleet Renewal investments. However, it is difficult to locate demonstration vehicles that meet the operational criteria.

Alectra Utilities cannot rely on this approach, since the availability and quality of demonstration vehicles cannot be planned or depended upon. Further, in the event that Alectra Utilities can locate a satisfactory demonstration vehicle that is available for purchase, it does not believe that a sufficient volume will be available to address its needs. Alectra Utilities rejected this approach because it would not be able to rely on a reliable supply of available demonstration vehicles.

5.1.4 Replacing Fleet Vehicles Based on Alectra Utilities Renewal Criteria

Alectra Utilities has developed its planned Fleet Renewal investments by referencing its internal vehicle replacement criteria, which consider a combination of factors, including vehicle age, mileage thresholds, and physical condition. However, as outlined in *Section 4.3*, the proposed investment level during the DSP period is below what would be required to replace all the vehicles that meet these criteria. Instead, Alectra Utilities has opted for a reduced investment approach that prioritizes only the most critical renewals, based on risk and operational necessity. This more conservative investment level reflects Alectra Utilities' preferred approach as it is considered the minimum required to manage operational risk and maintain fleet reliability. This approach balances the need for responsible capital planning with prudent risk mitigation.

5.2 Fleet Growth

Alectra Utilities considered the following options regarding Fleet Growth investments:

- Leasing Additional Fleet Instead of Purchasing
- Delaying Fleet Growth Investments

5.2.1 Leasing Additional Fleet Instead of Purchasing

Leasing vehicles provides the option of spreading costs out over time. However, just like personal vehicles, leasing can be more expensive than owning a vehicle. In this instance, Alectra Utilities customized vehicles would certainly increase the costs of leasing. As well, leasing could create issues around vehicle availability at the end of lease terms which could create issues if replacements are not secured in time. Alectra Utilities will consider leasing in limited cases where it is cost-effective, however, does not view it as a primary option for Fleet Growth.

5.2.2 Delaying Fleet Growth Investments

Another option is to defer or limit fleet growth investments, essentially slowing the pace of expansion. Although this would reduce short term costs, it would significantly restrict Alectra Utilities Operations team as it grows. Without Fleet Growth, new operations crews would not have the vehicle amounts required to perform their jobs such as service connections, infrastructure upgrades, and emergency responses during storms or power outages. This would reduce efficiency, and potentially negatively impact service reliability and safety. Due to these concerns, delaying fleet growth is not a viable long-term option for Alectra Utilities.

The current fleet and equipment are insufficient to handle the projected growth in capital requirements.

Below is the fleet growth budget summary:

Table B08 - 8 Fleet Growth Budget Summary

	Fleet Growth Budget Summary (Includes Network Ops., Substations, P&C)					
Year	**2027**	**2028**	**2029**	**2030**	**2031**	**Total**
CAPEX ($MM)	10.9	10.0	5.3	2.9	0.0	29.1

Table B08 - 9 Total Fleet Inventory from 2025-2031

	Current Inventory	Planned Growth						
Asset Type	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**Total**
Double Bucket	39	0	5	6	2	1	0	53
Single Bucket	70	0	5	6	2	1	0	84
Radial Boom Derrick (RBD)	42	0	4	1	2	1	0	50
Medium + Heavy Duty Vans	49	0	2	1	2	1	0	55
Light Duty Vans	83	2	3	3	0	0	0	91
Pickup Trucks	179	0	6	7	6	5	0	203
SUV	71	0	0	0	0	0	0	71
Trailers	132	0	0	0	0	0	0	132
Equipment	58	0	0	0	0	0	0	58
Total Per Year	**723**	**2**	**24**	**25**	**14**	**9**	**0**	**797**

VI Material Investment Projects

The material investments from 2027 to 2031 from the Fleet Renewal investments are included in Table B08 - 10.

Table B08 - 10 Material Projects and Initiatives

Project Code	Project Name	CAPEX ($MM)
Multiple	Fleet Renewal	68.8
Multiple	Fleet Growth	29.1

Appendix B09 - Information Technology Systems

I Overview

Alectra Utilities relies on supported, reliable, and stable Information Technology (IT) systems to operate its distribution network, manage internal corporate services, and effectively serve its customers and communities. Over the course of the Distribution System Plan (DSP) period (2027-2031), Alectra Utilities has planned investments to upgrade end-of-life systems, replace outdated equipment, enhance platforms to support evolving business operations, and implement new technologies to expand and mature its business capabilities. Investments in IT systems are vital to the continued operational stability of Alectra Utilities' distribution network, to ensure continued adherence to regulatory mandates, safeguard the utility from increasingly sophisticated cyber threats, and ultimately sustain long-term operational reliability.

The planned IT Systems investments are divided into four segments:

Figure B09 - 1 IT Investment Categories

1. **IT Software** - Alectra Utilities relies on several integrated software systems to deliver customer-facing services, effectively manage the electrical grid, and support business operations. During the DSP period, Alectra Utilities plans to invest in several critical software systems, such as:
    - **Meter-to-Cash:** Systems used for billing and payment collection from customers.
    - **Operational Technologies:** Systems and tools designed to improve grid visibility, control, process efficiency, and analytics, ensuring safe and reliable power delivery.
    - **Enterprise Resource Planning (ERP):** System used to ensure effective utility-wide financial, operational, and supply chain management and regulatory reporting.
    - **Business Optimization:** System used for capital investment planning, computer operating systems, and applications that are essential to run business operations.
2. **IT Hardware** - Data centre infrastructure, such as physical servers, network and communications equipment; end user technology, including desktops, laptops, field tablets, and multi-function printers; and hardware to sustain Alectra Utilities' Enterprise Backup and Recovery solution.
3. **IT Security** - Cybersecurity systems, services, and infrastructure essential for the ongoing protection of Alectra Utilities' technology systems, customer and employee information, and to ensure compliance with the Ontario Cyber Security Framework (OCSF)[47].
4. **Distributed Energy Resources (DER) Supporting Technologies** - Tools for DER performance analysis, system modelling, and supporting IT infrastructure required for integration, implementation planning, and customer engagement; supporting the evaluation and deployment of non-wires solutions (NWS) leveraging DERs.

[47] On March 15, 2018, the Ontario Energy Board amended the Transmission System Code and Distribution System Code requiring licensed electricity transmitters and distributors in Ontario to report on their cybersecurity preparedness relative to the newly established Ontario Cyber Security Framework. The code amendments define "cyber security" as "a body of technologies, processes, and practices designed to protect networks, computers, programs, data and personal information from attack, damage or unauthorized access", and reference both electronic and physical security.

Table B09 - 1 Information Technology Systems Investment Plan, Drivers, and Outcomes

	Historical Spending					Bridge		Forecast Spending				
Year	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
CAPEX ($MM)	14.1	13.3	21.0	14.8	15.1	13.4	13.0	21.5	31.4	28.4	7.6	9.1
Primary Driver	Functional Obsolescence, Operational Efficiency, Cybersecurity and Resilience, Regulatory Compliance and Readiness											
Outcomes	Customer Focus, Operational Effectiveness, Public Policy Responsiveness, Financial Performance											

II Investment Description

This section summarizes planned investments in Alectra Utilities' IT Systems over the 2027 to 2031 DSP period.

Table B09 - 2 IT Investment by Sub-category

IT Investment Sub-categories	2027	2028	2029	2030	2031	Total 2027 to 2031
IT Software	12.4	23.8	21.0	4.1	5.6	66.9
IT Hardware	5.4	4.6	6.7	2.9	3.0	22.6
IT Security	3.5	2.7	0.4	0.3	0.4	7.3
DER Supporting Technologies	0.2	0.3	0.3	0.3	0.1	1.2
Total ($MM)	21.5	31.4	28.4	7.6	9.1	98.0

2.1 IT Software

Alectra Utilities has a planned investment portfolio totaling $66.9MM in IT software projects over the DSP period. These investments focus on maintaining operational stability, system security, and overall reliability of its enterprise applications that can scale with organizational growth and adapt to evolving business and regulatory requirements.

Alectra Utilities' planned software investments during the DSP period include:

Table B09 - 3 IT Software Investments

IT Software Investments	Total 2027 to 2031 ($MM)
2.1.1 Meter-to-Cash System	25.8
2.1.2 Operational Technologies	15.3
2.1.3 Enterprise Resource Planning	12.0
2.1.4 Business Optimization	13.8
Total	**66.9**

2.1.1 Meter-to-Cash System

Over the DSP period, Alectra Utilities plans to invest approximately $25.8MM in the Meter-to-Cash System, as detailed below in Table B09 - 4. Alectra Utilities' Meter-to-Cash System is a

suite of several integrated sub-systems that provide efficient and accurate meter readings and billing services[48]. This system is essential to Alectra Utilities' customer interactions as it supports customer service[49], billing and related services[50], retail transactions and settlements, as well as wholesale settlements with the Independent Electricity System Operator (IESO).

Table B09 - 4 Meter-to-Cash System Investments

Project Code(s)	Meter-to-Cash System Investments	Total 2027 to 2031 ($MM)
152539-Meter -to-Cash - CIS - CC&B CCS/C2M upgrade	2.1.1.1 CC&B C2M Upgrade	14.4
150325-Meter-to-Cash CIS CC&B Enhancements	2.1.1.2 CC&B Enhancements	3.4
150453-Meter-to-Cash - CIS CC&B Modifications (Regulatory Enhancements)	2.1.1.3 CC&B Regulatory Modifications	2.9
150465-Meter-to-Cash LPSS (Load profile and settlements system) Upgrade	2.1.1.4 Load Profile & Settlements (LPSS)	1.3
150468-Meter-to- Cash Annual Licenses Growth on Meter-to-Cash platforms	2.1.1.5 Meter-to-Cash Annual License Growth	1.2
152343-Connexo Upgrade 152350-Primeread Upgrade 152351-Sensus Upgrade 152352-Trilliant Upgrade 152377-Meterlab Software (EMTS) 152396-SSN, Silver Springs AMI Upgrade, Legacy Guelph 152395-MV90 Upgrade	2.1.1.6 Network Metering upgrades	1.6
	Other (non-material projects)	1.0
	Total	**25.8**

[48] The Meter-to-Cash System includes the following sub-systems: Meter Readings, Advanced Metering Infrastructure (AMI), Meter Data Management, Wholesale and Retail Settlement, Electronic Business Transactions, Meter Data Management and Repository (MDM/R), Billing, Payments, Credit & Collections, Business Intelligence, and Reporting (and related field activity). All these systems and processes are supported by a host of interfaces and underlying technology, including complex monitoring tools, databases, and enterprise integration tools.

[49] Customer account management, service location management, and customer contact functions are all integrated with the Meter-to-Cash System.

[50] Including credit and collection, metering, and billing (including complex billing for embedded and wholesale market participants).

The Oracle Customer Care & Billing (CC&B) platform is Alectra Utilities' main enterprise system for billing and customer care. This system maintains customer account details and transactional data such as billing records, meter reads, metering installation data, and all other transactional data related to customers. CC&B enables Alectra Utilities to issue accurate bills, respond to customer inquiries, manage customer contact data, facilitate customer requests such as move-in/move-out, and track field service activities related to metering and other equipment.

Planned investments in the Meter-to-Cash System focus on updating software to remain compliant with vendor supported versions, addressing known security vulnerabilities, and improving application functionality in support of evolving business processes. Enhancements to the CC&B application support billing accuracy and efficiency, while enabling customer self-service options, such as chatbots, that depend on this system. Without these updates, this core meter-to-cash system would face increasing and unacceptable levels of reliability and cybersecurity risk, potentially compromising the security and privacy of Alectra Utilities' customer data, the integrity of the meter-to-cash system, and would increase the likelihood of negative operational impacts to internal processes and customer facing services.

[redacted] illustrates the various systems that comprise the Meter-to-Cash solutions and the interactions between each system.

[redacted]

2.1.1.1 CC&B C2M Upgrade

During the DSP period, Alectra Utilities plans to invest $14.4MM to upgrade the current version of CC&B to the latest version to maintain support from Oracle and other integrated system vendors. [redacted] Therefore, upgrading to Oracle's latest version of CC&B, known as Customer to Meter (C2M), by 2029, is necessary for continued vendor support,

sustained operations of the Meter-to-Cash system environment, and [redacted]

2.1.1.2 CC&B Enhancements

The CC&B system functions as the central system to Alectra Utilities' Meter-to-Cash operations, supporting business functions such as Customer Care, Billing, Payments & Collections, and Metering. Over the course of the DSP period, Alectra Utilities plans to invest $3.4MM to enhance its CC&B platform to meet evolving business needs, improve process efficiencies, and elevate the customer experience through its integration with customer-facing applications.

While the upgrade project outlined in *Section 2.1.1.1* addresses system currency, the CC&B Enhancements project focuses on building capabilities within the platform to support operational improvements and business process development. Improvements are subject to detailed value assessments and time studies[51] to ensure measurable benefits are tracked to baseline. The corresponding productivity benefit estimated to be realized between 2023 and 2026 is $1.7MM in cumulative savings, yielding an estimated $0.4MM in average annual operational savings tied to an average of 60 system change requests per year[52].

The CC&B Enhancement program focuses on:

- **Mitigating Risks and Improving Efficiency:** Software enhancements address known system issues that could disrupt operations or cause tedious manual workarounds. In some instances, these may lead to correcting errors manually, slowing processes, and increasing the risk of human error. Enhancements that seek to introduce efficiencies, reduce manual intervention, streamline processes, and support smoother day-to-day operations.
- **Supporting Growing Business Needs:** As the utility industry continues to evolve and adapt to changing customer demands, industry transformations, and technological changes, investments in software enhancements enable Alectra Utilities to adapt in kind. Examples are reflected in new billing models, increased

[51] Change Request (CR) owners are asked to perform a time study to compare time spent on a specific process prior to the CR implementation and expected time post CR implementation.
[52] Performance Measurement – *Exhibit 1, Tab 6, Schedule 5 Productivity*

demand for digital services and communication channels, and the need for scalable data integrations to and from the CC&B platform.

2.1.1.3 CC&B Regulatory Modifications

CC&B Regulatory Modifications are mandated by regulatory bodies such as the Ontario Energy Board (OEB), IESO, and Measurement Canada. Unlike CC&B enhancements driven by business need, this investment is required to fund changes to the CC&B software to accommodate mandatory regulatory requirements, particularly as it relates to customer billing. These changes can vary in magnitude, complexity, and impact. For example, notable historical changes include the Time-of-Use rollout, Price Optionality, Ultra Low Overnight rate, the COVID Energy Assistance Program, and the Green Button initiative. From 2020 to 2024, Alectra Utilities spent an average of $0.7MM annually to modify CC&B in response to regulatory requirements. Using this historical average as a guide, Alectra Utilities intends to spend approximately $2.9MM over the DSP period on CC&B regulatory modifications.

2.1.1.4 Load Profile & Settlements

Over the DSP period, Alectra Utilities plans to invest $1.3MM to transition from its current Load Profile and Settlements System (LPSS) to Oracle Market Settlement Management (MSM). LPSS is critical for wholesale settlements with the IESO, Hydro One, and embedded generators, as well as for billing interval customers, including large users and commercial customers with a demand of over 50kW.

Alectra Utilities' current LPSS is no longer supported by Oracle. In 2022, Alectra Utilities secured a temporary license support extension with Oracle through 2024 and secured a third-party maintenance contract to address regulatory changes, such as those introduced by the IESO's Market Renewal Program. However, this support does not include product upgrades or security enhancements.

Transitioning to MSM will ensure full support for the entire application lifecycle, including feature updates, security patches, and system fixes. As a core application, MSM is vital to Alectra Utilities' billing and settlement operations for both interval and Net System Load Shape accounts. This investment will keep the settlement system aligned with vendor support cycles, enabling ongoing operational stability.

2.1.1.5 Meter-to-Cash Annual License Growth

To remain in compliance with Oracle's licensing model, Alectra Utilities must invest $1.2MM in its Customer Information System licensing over the DSP period. As part of its broader effort to transition customers to its cloud offerings, Oracle now requires organizations upgrading to the C2M platform to adopt a new license model. While Alectra Utilities does not currently plan to move to Oracle's cloud, this model provides the right to deploy C2M either on-premises or via Oracle's Customer Cloud Service. By proceeding with the on-premises upgrade under this new model, Alectra Utilities preserves future flexibility to transition to the cloud if it becomes advantageous or necessary.

2.1.1.6 Network Metering Upgrades

During the DSP period, Alectra Utilities plans to invest approximately $1.6MM in Network Metering related upgrades to ensure operational sustainability, service reliability and operational efficiency of these systems. Timely and accurate meter read data is required to maintain compliance with the Distribution System Code which mandates that distributors issue accurate bills to customers at least 98% of the time, and to issue no more than two estimated bills in a 12-month period.

Alectra Utilities typically follows an N-1[53] upgrade strategy to ensure that it continues to receive system vendor support, while not incurring unnecessary risks related to new software releases.

Alectra Utilities currently maintains eight software systems to read its residential, commercial, industrial, wholesale and suite-metered customers. By the end of this DSP period, Alectra Utilities plans to transition to four meter reading systems including two AMI Head End systems, an MV90 system, and a single suite metering software system. Consolidation of these systems will reduce the duplication of effort related to testing, training, integrations, and compliance obligations.

2.1.2 Operational Technologies

Alectra Utilities plans to invest $15.3MM in operational technologies over the DSP period, with approximately 75% allocated to the implementation of Alectra Utilities' Mobile Workforce

[53] N-1 Upgrade Strategy is an IT approach to software and systems, where "N" represents the current, most recent version available, and "N-1" signifies the previous version, one step behind the latest. By deliberately installing the N-1 version, organizations aim to reduce the risks associated with brand new releases, such as unforeseen bugs or compatibility issues, while still maintaining a relatively recent and well-supported software state.

Management (WFM) solution. In addition to WFM, Alectra Utilities will upgrade and enhance its Supervisory Control and Data Acquisition (SCADA) system, Geographical Information System (GIS), and Outage Management System (OMS) to meet evolving operational requirements and address any known security vulnerabilities. These investments will enhance Alectra Utilities' ability to plan, manage, and respond to system operations effectively, contributing to a more modern and resilient grid.

Table B09 - 5 Operational Technologies Investments

Project Code(s)	Operational Technologies Investments	Total 2027 to 2031 ($MM)
102263-Work Force Management / Mobile Dispatch	2.1.2.1 – Workforce Management	11.5
150563- SCADA - SCADA/OMS Software Upgrade Cycle	2.1.2.2 – SCADA/OMS Software Upgrade Cycle	1.6
	Other (non-material projects)	2.2
	Total	**15.3**

2.1.2.1 Workforce Management / Mobile Dispatch

Over the course of the DSP period, Alectra Utilities has a planned $11.5MM investment to implement a Mobile WFM solution. This project will introduce a sophisticated and digitized fieldwork management tool equipped with critical functionalities that will improve the efficiency of fieldwork, streamline operations, and enhance the customer experience through its planned integration with Alectra Utilities' customer portal for service request scheduling and customer communications.

The WFM project is a multi-year, multi-phase initiative. The phases that are planned and budgeted are as follows:

- Phase 1: Service Connections and Metering Work
- Phase 2: Distribution Capital Work
- Phase 3: Inspections and Maintenance Work
- Phase 4: Reactive and Emergency Work

Implementing a WFM solution is important for Alectra Utilities as the company faces an increasing volume of maintenance and capital activities, which necessitate a computerized tool to optimize

resource allocation, job scheduling, dispatch, and routing. Alectra Utilities expects work volumes to rise as it reinforces, expands, and modernizes its grid to address customer growth, increasing extreme weather challenges, increased DER access, and electrification growth within its service territories. The implementation of the WFM system will drive productivity gains by optimizing and automating several manual functions related to field service work.

The WFM investment enables improvements in work execution, reporting, operations, and customer service as follows:

- **Work Execution and Reporting**: Alectra Utilities' existing workflow processes for field service are based primarily on manual paper-based methods. Consequently, data collected in the field must be entered by hand into back-office systems, leading to delays in data availability and making these processes susceptible to human error. Reporting on the status of work and performance metrics is done manually as well, which restricts visibility for potential improvements. The WFM system will deliver benefits by automating and digitizing workflow processes, creating a unified platform for scheduling, dispatching, and reporting for all types of fieldwork, including contractor activities. It will significantly reduce manual effort in managing documentation, work packages, and data updates. The system will streamline material ordering, allowing field crews to pre-order materials for scheduled pickup, optimizing material use and field operations. Real-time asset updates to GIS, EAM, and ERP systems will enhance data accuracy and accelerate workflows, while automated scheduling will increase efficiency, particularly for short-duration tasks. The system's geospatial capabilities will enhance crew routing and field activity allocation, further boosting productivity.
- **Operations**: The WFM system will support operational reliability by improving the execution and reporting of inspection and maintenance tasks, potentially reducing equipment failures, and ensuring a more resilient grid. The WFM system is expected to drive significant productivity gains, creating additional capacity for internal and external staff to manage increased workloads. By digitizing data capture, the WFM system will improve the accuracy of the GIS system, enabling more effective operation of the ADMS, a key component of grid operations.

- **Customer Experience**: The WFM system will enrich the customer experience through improved appointment scheduling, compliance, and communication, offering real-time updates on service requests, improved communication regarding scheduled appointments, and by providing online self-service options, ensuring a positive customer experience. Key customer preferences and shifts that underpin Alectra Utilities' investment plan include, growth in digital-first preferences, as usage of digital online service channels continue to grow year-over-year[54]. These comprehensive improvements to Alectra Utilities' field operations and customer engagement will deliver enhanced service quality, while supporting enterprise-wide growth and delivering tangible process efficiency.

The benefits that will be realized from the implementation of the WFM system are significant. Two of the most significant benefits are in the areas of personnel efficiencies and reliability gains, as summarized below:

- **Efficiency gains** amongst field, supervisory, and back-office (clerical) are primarily from:
  - Improvements in scheduling, resource allocation, and route optimization that will result in time savings in the planning and scheduling of work, and a reduction in crew travel times. This will result in efficiency gains amongst field staff, supervisory personnel, and staff involved in job scheduling.
  - Process digitization will result in the automation of current manual, paper-based processes. This will result in time savings amongst field, supervisory, and clerical staff.
- **Reliability gains** over the useful life of the WFM system are realized primarily from:
  - Digitization of Distribution System Inspection processes that will result in an improved flow of data for asset analytics purposes, thereby allowing for more effective issuing, execution, and tracking of follow-up corrective actions. This will result in fewer unplanned equipment failures, leading to improved reliability.

[54] Engagement section: *Exhibit 1, Tab 5, Schedule 1 Ongoing Customer Engagement*

- Improved scheduling and tracking of maintenance work, primarily vegetation management activities, will result in a more effective vegetation management program and consequently will result in reliability improvements.

2.1.2.2 SCADA/OMS Software Upgrade Cycle

Over the DSP period, Alectra Utilities plans to spend $1.6MM to keep its SCADA/OMS software current and supported. The SCADA/OMS Software Upgrade Cycle project involves upgrading Alectra Utilities' SCADA system, which is also embedded with its OMS system for a portion of its service territory. There is no available option to purchase support to stay on the current version.

Alectra Utilities operates a single-vendor SCADA system that includes an integrated OMS for its Central North (Brampton) and Guelph service areas. As the SCADA and OMS platforms are integrated, any SCADA system upgrade also results in an upgrade to the OMS in these territories. Under this program, Alectra Utilities will upgrade its SCADA system, which in turn, will update the OMS in the Central North and Guelph territories to the latest version.

Enhancements made by the vendor to fix issues or system bugs will be provided as system patches. Failing to address issues on this critical application could lead to safety concerns and potential work refusals, if staff are not able to safely execute a task due to an unresolved system issue.

Upgrading SCADA/OMS software provides essential developments in monitoring, control, and security, ensuring safer and more efficient operations. Additionally, system patches typically address cybersecurity vulnerabilities and incorporate security features such as stronger encryption, enhanced authentication, and improved access controls, which further reduce the risk of system exploitation. The proposed upgrades will ensure continued vendor support, including critical security updates, and continued compliance with standards such as NIST and IEC 62443.

2.1.3 Enterprise Resource Planning (ERP)

Alectra Utilities has allocated a budget of $12.0MM for ERP investment over the DSP period. The Oracle JD Edwards (JDE) serves as Alectra Utilities' ERP system, acting as the primary enterprise system for financial and regulatory reporting. JDE handles various business processes, such as managing capital and operational expenditures, supply chain operations, financial and estimation

routines, work order management as well as asset registry and nameplate information. Furthermore, JDE provides extensive functionalities for supply chain management, including procurement, inventory control, and order processing.

The ERP investment is comprised of Continuous Improvement ($7.5MM) and System Upgrades ($4.5MM) projects.

Table B09 - 6 ERP Investments

Project Code(s)	ERP Investments	Total 2027 to 2031 ($MM)
150469-ERP Continuous Improvement	2.1.3.1 ERP Continuous Improvement	7.5
152996-ERP System Upgrades	2.1.3.2 ERP System Upgrades	4.5
	Total	**12.0**

2.1.3.1 ERP Continuous Improvement

Alectra Utilities plans to invest $7.5MM over the DSP period to implement fixes and process enhancements to its ERP platform. In alignment with Alectra Utilities' commitment to continuous improvement and operational efficiency, each proposed ERP enhancement undergoes a value assessment and time study to ensure it delivers meaningful operational benefits and is prioritized through a steering committee of internal stakeholders.

The planned investment focuses on improving process efficiency through targeted integrations and system refinements, serving as a proactive measure to mitigate risks, such as data integrity issues resulting from manual entry errors, operational inefficiencies leading to manual rework, and limitations imposed by outdated technologies. Through these enhancements, Alectra Utilities will address current challenges, including manual invoicing, inefficient payment and work order processes, and outdated approval and validation controls. The planned enhancements will automate key workflows, reduce manual tasks, and introduce strengthened validation mechanisms, resulting in increased productivity, improved data accuracy, and enhanced compliance readiness. These improvements will better position Alectra Utilities to meet regulatory, financial, and internal control requirements, which are essential for successfully completing annual financial audits and general computer control reviews.

The ERP Continuous Improvement Program will be delivered through a model that brings together the expertise of internal teams, vendors, and specialist advisors. This approach ensures the enhancements are efficiently implemented, achieve the intended value targets, and are aligned with evolving business processes and operational requirements.

2.1.3.2 ERP System Upgrades

Over the DSP period, Alectra Utilities plans to invest $4.5MM in periodic ERP upgrades. This investment will ensure Alectra Utilities' ERP system remains secure, supported, and capable of adapting to evolving business and regulatory requirements. As technological advancements continue, routine ERP upgrades are essential for sustaining operational stability, safeguarding data integrity, mitigating cybersecurity risks, and adhering to regulatory standards.

While Oracle issues annual releases accompanied by quarterly feature updates under its continuous improvement model, Alectra Utilities has opted for a biennial upgrade schedule. This approach maintains cost-effectiveness, operational efficiency, and up-to-date technology, preventing risk from outdated or unsupported software.

The requirement for cyclical ERP upgrades is driven by the following:

- **Vendor Support Requirements:** Oracle requires customers to maintain version currency based on their application lifecycle to receive technical support, security patches, and critical defect fixes. Without these upgrades, Alectra Utilities would risk losing vendor support, increasing exposure to unpatched vulnerabilities, and incurring higher costs for extended support arrangements.
- **Cybersecurity and Operational Risk**: Outdated and unsupported software is more susceptible to security exploits because of a lack of remediation in the form of regular security patches. Regular upgrades ensure the latest security patches and performance improvements are applied to the system, reducing the risk of data breaches, system outages, or integrity issues in financial and operational data.
- **Regulatory and Reporting Compliance:** ERP upgrades are essential to maintain alignment with changing regulatory and reporting standards (e.g. financial accounting updates, tax changes, regulatory reporting for utilities). Without regular upgrades, Alectra Utilities risks non-compliance with regulatory requirements.

- **Business Functionality Improvements:** Oracle's updates introduce features and functionality that improve automation, reporting, integration capabilities, and user efficiency. Upgrades may include enhanced workflow orchestration tools, improved analytics, and new integration connectors, enhancing interoperability with other systems.

2.1.4 Business Optimization

Alectra Utilities, through its Business Optimization investment portfolio, plans to invest $13.8MM towards upgrading and enhancing existing core applications not covered under previously identified IT software categories, including for capital investment planning, computer operating systems, and applications that are essential to run business operations. The Business Optimization investment is comprised of the C55 Alectra Utilities: Optimization of Business Practices ($7.7MM), AMI 2.0 – Grid Edge Analytics ($4.3MM), and other non-material projects ($1.8MM).

Table B09 - 7 Business Optimization Investments

Project Code(s)	Business Optimization Investments	Total 2027 to 2031 ($MM)
151136-C55 Alectra: Optimization of Business Practices	2.1.4.1 – C55 Alectra Utilities: Optimization of Business Practices	7.7
152576-AMI 2.0 - Grid Edge Analytics	2.1.4.2 – AMI 2.0 – Grid Edge Analytics	4.3
	Other (non-material projects)	1.8
	Total	**13.8**

2.1.4.1 C55 Alectra Utilities: Optimization of Business Practices

Since 2014, Alectra Utilities has adopted the Industrial and Financial Systems (IFS) Copperleaf platform (C55) from Copperleaf Technologies Inc., an Asset Investment Planning & Management platform. The C55 platform has played a pivotal role in developing and optimizing Alectra Utilities' capital budget. It leverages a calibrated Value Framework to evaluate individual investments and optimize the value of an investment portfolio (refer to *Chapter 5.3.1 Asset Management Process* for more detail regarding the optimization).

During the 2027-2031 period, Alectra Utilities plans to invest $7.7MM in capital to further develop and enhance the IFS C55 platform as part of the platform's continuous improvement. Improvements include, but are not limited to, integration of multiple enterprise systems responsible for planning, scheduling, execution, and tracking of both capital and operating projects. Such integrations will facilitate seamless data transfer between systems, ensuring data accuracy and consistency, minimizing manual data entries, and enhancing overall portfolio management. Alectra Utilities also plans to use the budget to meet and comply with future OEB requirements. For example, Alectra Utilities will incorporate the Benefit-Cost Analysis (BCA) Framework and the Vulnerability Assessment and System Hardening (VASH) into C55.

In addition, Alectra Utilities will continue to refine its capital planning tools, including the roll-out of a Self-Serve Analytics reporting tool that aims to simplify financial reporting, address OEB requirements, and improve employee productivity.

2.1.4.2 AMI 2.0 – Grid Edge Analytics

Alectra Utilities plans to invest $4.3MM in grid edge analytics over the DSP period, using the enhanced functionalities offered by the new Advanced Metering Infrastructure (AMI) 2.0 system. The deployment of AMI 2.0 analytics will generate more frequent and detailed data than current AMI systems. This data and associated analytics will allow Alectra Utilities to analyze its system and customer patterns, supporting the development of revised processes and services. For example, more detailed information about transformer loading can help to identify where to prioritize maintenance and/or replacement work and identify overheating equipment, which can result in injuries and damage to property. Reports from enabled meters can more accurately identify where meters are located in the field, helping to keep GIS up to date and reducing time spent making field visits to meters.

Alectra Utilities intends to implement grid-edge analytic technology on a limited basis after deploying the next-generation AMI system. This initiative will focus on roughly 5% of installed meters and is designed to enable Alectra Utilities employees to become familiar with new data and information from the AMI system. The process will allow business units to incorporate additional data streams into their processes. Improved data quality will benefit system operations, planning, and customer service. For example, system operations would have improved information about transformer loading, which would be an input into maintenance schedules that

would more efficiently allocate resources. Increased granularity of customer load profile data would provide system planning with insights that would be incorporated into future system forecasts that would more accurately forecast demand and more efficiently allocate capital. Customer service would also be able to use that data to support customer requests and to provide more rapid and accurate updates regarding outages, providing an improved customer experience. The grid-edge analytics deployment would begin in 2028 and continue through at least 2031. The data collected from this initial implementation will inform future decisions regarding broader adoption of this technology by Alectra Utilities.

This project corresponds with global technology trends to provide increased functionality through software. Software enables ongoing improvements, often mitigating the need for hardware replacement. This investment will enable Alectra Utilities to take a phased approach to technology implementation, ensuring thorough due diligence is completed before committing to a larger-scale investment. Alectra Utilities anticipates that this solution will allow the organization to respond to current and future needs, including increased loads, greater use of DERs, and meeting customer expectations for timely and relevant information (refer to *Exhibit 1, Tab 5, Schedule 1 Ongoing Customer Engagement*, page 8, lines 5-26). This approach enhances the operational resiliency of grid operations and assists in preparing for future requirements in a coordinated manner.

2.2 IT Hardware

Alectra Utilities has a planned investment portfolio of $22.6MM in IT Hardware projects over the DSP period. The primary driver of this investment portfolio is functional obsolescence, as replacing IT hardware on a cyclical basis is a necessity to ensure the reliable performance of systems that support customer services, core distribution operations, and other critical business functions. IT hardware includes backend infrastructure (servers, storage, networking, and communication systems) and endpoint devices (desktops, laptops, tablets, and printers), all of which are critical to field and business operations.

Hardware failures can disrupt outage response, limit access to critical systems, and compromise the safety and security of both employees and customers. To mitigate these risks, Alectra Utilities follows asset lifecycle management best practices, replacing out-of-warranty and end-of-life hardware to minimize potential system downtime, reduce maintenance costs, improve system

performance, and address security vulnerabilities. Throughout the DSP period, Alectra Utilities plans to replace approximately 20% of endpoint assets and 15% of backend infrastructure assets each year (based on asset amortization schedule and asset criticality) to maintain system performance, supportability, and operational stability.

Alectra Utilities' planned hardware investments during the DSP period are categorized in Table B09 - 8 for 2027 to 2031.

Table B09 - 8 IT Hardware Investments

Project Code(s)	IT Hardware Investments	Total 2027 to 2031 ($MM)
102098-IT End User - Client Computing 102099-IT End User - Printer & Copier Fleet Replacement 103030-SCADA - Technology Upgrades Improving the System Control Room Environment 152556-Metering Tablets 152339-OT Infrastructure - Control Room Hardware Upgrade Cycle 152646-Interactive Digital Communications System	2.2.1 End User Technology	10.4
102157-IT Infrastructure - Server Refresh 150391-IT Infrastructure - Wireless LAN Upgrade 150396-IT Infrastructure - Network Refresh 150558-OT Infrastructure - Network Hardware Upgrade Cycle 150583-SCADA - Server Hardware Upgrade Cycle 151525-Meter-to-Cash Hardware Expansion/Renewal for all Oracle based applications 152097-OT Infrastructure - Software Defined Networking 152390-OT Infrastructure - Core Network Switch Replacement 152516-IT Infrastructure - Control Room Phone System Refresh 152955-GIS Hardware Upgrade Cycle	2.2.2 Data Centre Infrastructure	9.9
153072-IT Infrastructure- Backup Refresh Current	2.2.3 Enterprise Backup & Recovery	2.3
	Total	**22.6**

2.2.1 End User Technology

Alectra Utilities plans to invest approximately $10.4MM over the DSP period in End User Technology, due primarily to functional obsolescence of client hardware. This includes desktops, laptops, tablets, printers, and mobile devices used by office staff, field crews, and control room operators. Alectra Utilities' asset lifecycle management practices align with industry standards such as Information Technology Infrastructure Library (ITIL) and vendor-recommended refresh cycles, which typically range from three to five years. By replacing devices older than five years, Alectra Utilities ensures continued vendor support, including warranty coverage, access to firmware and security updates, and compatibility with modern enterprise applications. This approach not only maintains device reliability and performance but also reduces the risk of downtime, cyber security vulnerabilities, and increased support costs associated with aging, unsupported hardware.

Regarding its multifunction printer fleet, Alectra Utilities will optimize the fleet through centralization and consolidation efforts where possible. Despite this overall reduction, these devices remain essential tools for employees who require printed materials to perform their job functions. Large multifunction printers typically possess a six-year lifespan for parts availability, security updates, and vendor support, making a regular upgrade cycle necessary. Neglecting to maintain an updated printer fleet can result in increased operational costs, including higher toner expenses and out-of-warranty repair fees. Additionally, printers are known to be common targets of cyber-attacks, such as network breaches and denial-of-service attacks. Regularly updating Alectra Utilities' printer fleet is essential for mitigating these risks and enhancing Alectra Utilities' overall cybersecurity posture.

2.2.2 Data Centre Infrastructure

During the DSP period, Alectra Utilities plans to invest $9.9MM in data centre infrastructure. Alectra Utilities must regularly replace back-end hardware devices to ensure operational reliability and stability of its core systems. This investment will be used to replace hardware that has reached its end-of-life as part of normal asset lifecycle management best practices, and in alignment with Alectra Utilities' asset useful life timeframes. Alectra Utilities follows asset lifecycle management best practices for infrastructure hardware, guided by ITIL and aligned with industry benchmarks recommending refresh cycles of three to seven years. By replacing servers, storage,

and network devices within their supported lifecycle, Alectra ensures continued vendor support, including warranty coverage, firmware and security updates, and access to technical expertise. This approach reduces the risk of system failures, cyber vulnerabilities, and costly downtime, while ensuring infrastructure remains reliable, efficient, and compliant with regulatory and security requirements. Planned investments include renewing:

- Physical servers and storage devices, that enable web-based services, individual applications, and databases
- Networking devices, including routers, switches, load balancers, and wireless access points
- Phone system equipment for control room operations

Alectra Utilities relies on infrastructure hardware to operate reliably and securely. Replacing network, storage, and server related hardware as part of normal asset lifecycle management is cost-effective and essential for maintaining core business operations.

2.2.3 Enterprise Backup & Recovery

Alectra Utilities plans to invest $2.3MM to renew its backup infrastructure to meet growing data demands. The current system faces capacity and reliability challenges due to increasing data production and system implementations. Without a timely refresh, Alectra Utilities faces increased risk of backup storage limitations, server failures, incomplete backups, and potential data loss. These risks jeopardize business continuity, disaster recovery, data integrity and resiliency, as well as risks adherence to data retention requirements. This investment will deploy supported infrastructure sized for current and future needs, ensuring the continued operations of Alectra Utilities' backup and recovery system.

2.3 IT Security

Alectra Utilities' investment in its IT Security portfolio is both a necessity and a strategic commitment to maintaining a robust security framework, supporting business continuity, and protecting the customers and communities we serve. Over the DSP period, Alectra Utilities' planned IT Security investment portfolio is $7.3MM. With the growth of artificial intelligence and the increasing capabilities of rapidly evolving technologies, Alectra Utilities requires ongoing investment to address increasingly more sophisticated cybersecurity threats. This is especially

important as Alectra Utilities' distribution system and several back-office systems become increasingly connected. To effectively identify, detect, respond to, and recover from these threats, Alectra Utilities is investing in IT security infrastructure and services to protect system operations, safeguard sensitive data, and ensure compliance with the Ontario Cyber Security Framework (OCSF). In contrast to other investments where cybersecurity is a secondary consideration, the initiatives described here concentrate mainly on reducing cyber risk.

During the DSP period, Alectra Utilities planned IT security investments are categorized in [redacted]

[redacted]

2.3.1 Cyber Security Device Upgrades

Over the course of the DSP period, Alectra Utilities has planned a $5.6MM investment to replace its aging security devices and infrastructure following vendor-scheduled end-of-life or end-of-support periods. These upgrades are vital to ensuring a secure and resilient technology environment, enabling resilient operations while safeguarding Alectra Utilities' critical assets and data that support internal business and field operations.

Most of this investment is directed at replacing Alectra Utilities' aging network firewalls that are critical for protecting both corporate and operational technology networks. As vendor support for these systems is ending, security patches and technical support will become unavailable, which would create an unacceptable level of risk to the organization due to the increased potential for cyber exploits from exposed vulnerabilities and the increased possibility for extended downtime of critical security infrastructure.

Similarly, upgrading Alectra Utilities' [redacted] systems is of critical importance to ensuring effective [redacted] of Alectra Utilities' corporate and OT networks, particularly given the growing use of mobile computing devices and reliance on third-party service providers connecting to Alectra Utilities' networks. [redacted]

The enhanced [redacted] will strengthen network security through tighter access controls. [redacted]

2.3.2 Foundational Governance & Security Services

During the DSP period, Alectra Utilities plans to invest $1.7MM on foundational governance and security services. With advancements in technologies such as artificial intelligence, cyber threats are becoming increasingly sophisticated and more difficult to detect. This investment will enable Alectra Utilities to adapt to, and address, new cyber threats with the speed and resources needed to proactively thwart impending attacks. This will involve enhancing current security technologies and implementing new security services to address the growing digital threat landscape. These measures will strengthen Alectra Utilities' defenses against cyber threats, promote compliance with the OCSF, and meet the specific requirements of Alectra Utilities' cyber insurance providers.

The goals of this investment are to:

- Improve Alectra Utilities' security posture
- Promote regulatory compliance
- Address identified risks through regular annual audits
- Develop and improve necessary cyber capabilities to address new and advanced cyber threats

Ultimately, Alectra Utilities' investment in IT Security will support its efforts to protect its systems and data in accordance with relevant laws, maintain ongoing enhancements in cybersecurity

practices to mitigate cyber risk, and continue to encourage and educate employees on cybersecurity best practices.

2.4 DER Supporting Technologies

Alectra Utilities is proactively addressing the growing adoption of DERs detailed in *Appendix J - Load Forecast & System Capacity Adequacy Assessment Report (Section 3)*, to support grid planning and operations, enhance customer value, and manage the impact of electrification on the grid. With electric vehicle transportation and heating electrification introducing significant and increasing electricity demands, DERs are an essential and innovative approach to balance these demands while maintaining grid reliability and minimizing infrastructure costs.

The following section outlines the investment Alectra Utilities is making in DER supporting technologies over the DSP period.

Table B09 - 10 DER Investments

Project Code(s)	DER Supporting Technologies Investments	Total 2027 to 2031 ($MM)
152995-Customer Non-Wires Solution Design & Development 152589-Alectra Drive for Fleets 152574-SEW Customer Engagement eMobility 152603-Grid Enablement: School Bus Fleets	2.4.1 Customer Non-Wires Solution Design & Development & other DER	1.2
	Total	**1.2**

2.4.1 Customer Non-Wires Solution Design & Development

As detailed in *Appendix J - Load Forecast & System Capacity Adequacy Assessment Report (Section 3)*, Alectra Utilities' distribution system continues to have a net increase in electrical demand on its grid. In some cases, load growth will necessitate investment for Alectra Utilities to serve its customers safely and effectively, as the increase in load exceeds the capacity of the existing infrastructure. If unaddressed, this could lead to infrastructure failures before the end of

the asset's expected lifespan, resulting in earlier replacement and renewal, and resulting in higher costs for customers.

Customer-sited DERs offer valuable flexibility and capacity for the distribution system. Efficient use of DERs enables load curtailment and shifting to off-peak periods, helping manage and defer load growth within current limits until upgrades are made. Where there is alignment between the system need and the availability of flexible load, DERs can serve as Non-Wires Solutions (NWS). Where there is an appropriate fit with system needs, the use of NWS is expected to be able to provide cost savings to ratepayers. NWS allow existing assets to be used for their anticipated lifespan rather than requiring early replacement due to stress and overuse, and system expansion can be deferred or avoided. This reasoning is documented in the OEB's *Non-Wires Solutions Guidelines for Electricity Distributors*, issued March 28, 2024 *(*NWS Guidelines). Utilities are to undertake their analysis in line with the OEB's *Benefit-Cost Analysis Framework for Addressing Electricity System Needs*, issued May 16,2024 (BCA Framework).

Alectra Utilities has a planned investment of $1.2MM over the DSP period to support the development of customer NWS by developing a set of DER program models that can be deployed to serve as NWS, and an analytical process by which these NWS can be evaluated against system needs to identify where they meet performance and cost/benefit requirements provided by the Non-Wires Solutions Guidelines. A comprehensive design approach informed by various Alectra Utilities business functions will allow the organization to use the potential of NWS effectively. For clarity, this project does not include the deployment of NWS to address system needs; it is to develop the analytical framework, perform modelling, and develop working program and technology models to be able to use DERs in the field to meet appropriate system needs.

Through this project, Alectra Utilities will first collect a list of DERs that could be used to provide grid services. DER technologies will be assessed based on a review of performance literature and validated through interviews with those familiar with the in-field performance of the technology. The resulting performance characteristics will create a consolidated database which can be used to inform the selection of optimal DER solutions.

Once the tools have been identified, customer research will be leveraged to develop customer-centric program designs which can produce NWS. Factors relevant for customer decision making will be documented and made available for use through the design process. These insights will

help shape program parameters to ensure alignment with customer needs and expectations as program prototypes are developed. Review of existing program evaluations will also be used to inform preliminary designs and document assumptions and scenarios.

Once draft program designs have been developed, they will be modelled against system needs to assess their ability to address system requirements, and how they perform in terms of cost-effectiveness depending upon different input assumptions. This will result in mapping of programs against system needs, essentially creating a list of tools that are available for use, and under what conditions.

In alignment with the program designs, one or more implementation plans will be developed to establish a structured framework for deploying NWS. This process will involve acquiring and integrating technology, defining vendor requirements, and educating customers to drive NWS awareness and adoption within target segments. These efforts will also align NWS resources with Alectra Utilities' operations to support grid needs.

2.5 Summary of Investment Outcomes and Benefits

Table B09 - 11 summarizes the overall outcomes and benefits associated with the Information Technology Systems portfolio.

Table B09 - 11 Investment Outcomes and Benefits

Outcome	Investment Benefits & Objectives
Customer Focus	Reliability and Service Continuity: • Ensures the consistent delivery of reliable services by upholding secure and well-functioning systems. • Supports outage restoration efforts and timely access to data during disruptions. • Reduces system disruptions associated with unsupported or less efficient technology. • Implements advanced security protocols to protect company and customer data. Enhanced Customer Experience: • Improves appointment compliance, scheduling, and customer communication through timely updates for service requests. • Ensures scalability to handle growing customer demand.

Outcome	Investment Benefits & Objectives
	Safety and Security: • Enhances operational security measures to safeguard confidential customer interactions and data.
Operational Effectiveness	Enhanced System Reliability and Continuity: • Decreases the risk of software challenges through regular updates and enhancements, ensuring operational continuity and compatibility with updated systems. • Maintains operational efficiency and system stability by updating hardware and software that have reached their end-of-life. • Adopts modern technologies (e.g. Oracle MSM, C2M) for reliable lifecycle support and improved process efficiency. Process Automation and Workflow Efficiency: • Automates workflows and reduces manual intervention to increase productivity and reduce human error. • Streamlines operations, reporting, and resource usage across enterprise tools. • Improves interoperability between systems to ensure secure, scalable, and reusable integrations. Advanced Analytics and Decision-Making: • Uses advanced analytics and real-time monitoring to enhance situational awareness. • Optimizes crew routing and resource allocation using geospatial capabilities. Cybersecurity and Resilience: [redacted] • Reduces risks associated with outdated systems by refreshing critical security infrastructure. • Ensures resilience against potential threats by aligning to the regulatory requirements and security standards of the OCSF.
Public Policy Responsiveness	Regulatory Compliance and Alignment: • Maintains compliance with regulatory requirements through modifications and enhancements to its existing enterprise systems. • Aligns with OEB NWS guidelines to implement cost-effective alternatives to traditional infrastructure upgrades.

Outcome	Investment Benefits & Objectives
	• Aligns with the OCSF, industry best practices, and cyber insurance standards. Supporting Sustainability and Energy Transition: • Promotes alignment with broader energy sustainability and resilience objectives. • Encourages grid resilience and flexibility by advancing DER-based solutions.
Financial Performance	Cost Management and Efficiency Gains: • Reduces operational costs through automation, process efficiency, and resource consolidation. • Mitigates risks and costs of outdated hardware and unsupported systems by adhering to vendor updates and support cycles. Strategic Investments and Planning: • Invests in software and system upgrades with continuous value assessments to measure improvement efficacy and prioritize system changes. • Improves financial planning through robust value frameworks, enhanced reporting, and strategic project selection. Risk Mitigation and Compliance: • Avoids costs from potential data breaches, compliance violations, and operational downtime by addressing security vulnerabilities. • Prevents potential financial losses by maintaining regulatory compliance and adhering to cybersecurity standards. Productivity and Resource Optimization: • Extends asset life and reduces maintenance costs with advanced planning and lifecycle management. • Enhances cost-effectiveness through labour efficiencies and automated systems.

III Investment Drivers & Needs

The IT Systems portfolio plays a critical role in ensuring the safe, secure, and efficient operation of Alectra Utilities' distribution system. This portfolio encompasses the implementation of new system solutions, ongoing maintenance, targeted strategic enhancements, and the replacement of unsupported and end-of-life hardware and software.

This program is guided by six key investment drivers: functional obsolescence, addressing the need to update critical end-of-life systems; operational efficiency, which ensures streamlined processes and optimal resource utilization; cybersecurity and resilience, which focuses on mitigating emerging security threats to safeguard sensitive information and maintain operational integrity; and regulatory compliance and readiness, ensuring adherence to evolving mandates.

These drivers exemplify Alectra Utilities' dedication to the OEB's Renewed Regulatory Framework (RRF) outcomes: customer focus, operational effectiveness, public policy responsiveness, and financial performance.

Further details on these drivers are included in Table B09 - 12.

Table B09 - 12 Investment Drivers, Reasoning, and Investment Benefits

Investment Driver	Reasoning & Investment Benefits
Functional Obsolescence	Many of Alectra Utilities' IT systems are nearing end-of-life, increasing risks of failures, inefficiency, and higher maintenance costs. Upgrading ensures stability, reliability, modern compatibility, and vendor support while reducing downtime, security threats, and compliance issues. These improvements help maintain business continuity and long-term sustainability.
Operational Efficiency	The modernization and enhancement of systems such as ERP and Meter-to-Cash, alongside the deployment of new platforms like Workforce Management, are strategically designed to optimize operational workflows through automation, minimization of manual processes, and more efficient allocation of resources. These initiatives aim to lower operational costs and standardize procedures across key business functions. By improving overall efficiency, Alectra Utilities will be better positioned to manage increased workloads.
Cybersecurity and Resilience	As cyber threats increase and become more complex and utility systems become increasingly interconnected, robust cybersecurity measures are essential. [redacted]

Investment Driver	Reasoning & Investment Benefits
	[redacted] boosts data security, minimizes vulnerabilities, ensures OCSF compliance, and protects critical assets, reducing financial and operational risks from cyberattacks.
Regulatory Compliance and Readiness	Alectra Utilities invests in IT systems to help meet OEB, IESO, and regulatory requirements. Strategic IT upgrades and enhancements enable the organization to address compliance changes, such as new rate structures or modifications in reporting requirements. Maintaining adaptable and flexible systems and processes allows Alectra Utilities to respond to changes in the market, customer needs, and regulations.

IV Investment Timing & Pacing

4.1 Summary of Expenditures

Table B09 – 13 provides the year-over-year breakdown of Information Technology Systems investments, including the historical period from 2020 to 2024, the forecasted bridge years from 2025 and 2026, and the forecast period from 2027 to 2031.

Table B09 – 13 Historical & Proposed Investment Spending

	Historical Spending					Bridge		Forecast Spending				
Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
CAPEX ($MM)	14.1	13.3	21.0	14.8	15.1	13.4	13.0	21.5	31.4	28.4	7.6	9.1

4.2 Historical Expenditures (2020-2024)

Table B09 – 14 provides the historical budget allocated from the 2020 – 2024 DSP period, actual spend, and the subsequent variance to budget.

Table B09 – 14 Historical Investment Spending Compared To 2020-2024 DSP

Year	2020	2021	2022	2023	2024	Total
2020-2024 DSP Budget CAPEX ($MM)	14.9	18.6	20.7	13.2	9.4	76.8
Actual Spend CAPEX ($MM)	14.1	13.3	21.0	14.8	15.1	78.3
Variance CAPEX ($MM)	0.8	5.3	(0.3)	(1.6)	(5.7)	(1.5)

IT Systems' historical expenditures between 2020 and 2024 total $78.3MM, with a total variance to budget of approximately 2% or $1.5MM.

During the historical rate period, Alectra Utilities' expenditures under the IT Systems program were as follows.

Table B09 - 15 IT Systems Historical Expenditures from 2020 to 2024

IT Investment Sub-categories	2020	2021	2022	2023	2024	Total
IT Software:						
Meter-to-Cash	3.3	3.1	8.4	5.6	3.9	24.3
Operational Technologies	0.3	0.8	1.3	1.1	2.7	6.2
Enterprise Resource Planning	1.5	2.2	1.3	1.9	1.9	8.8
Business Optimization	1.7	2.8	3.1	2.8	1.5	11.9
Total IT Software	**6.8**	**8.9**	**14.1**	**11.4**	**10.0**	**51.2**
IT Hardware:						
End User Technology	2.4	1.6	1.6	1.5	1.1	8.2
Data Centre Infrastructure	3.3	1.9	3.5	1.4	1.3	11.4
Enterprise Backup & Recovery	0.0	0.0	0.0	0.0	1.6	1.6
Operational Technologies	0.0	0.0	0.2	0.0	0.0	0.2
Business Optimization	0.4	0.0	0.5	0.0	0.0	0.9
Total IT Hardware	**6.1**	**3.5**	**5.8**	**2.9**	**4.0**	**22.3**
IT Security:						
Cyber Security Upgrades	0.0	0.0	0.4	0.3	0.1	0.8
Foundational Governance & Security Services	0.8	0.6	0.4	0.4	0.4	2.6
Total IT Security	**0.8**	**0.6**	**0.8**	**0.7**	**0.5**	**3.4**
Total DER Supporting Technologies	**0.4**	**0.3**	**0.3**	**(0.2)**	**0.6**	**1.4**
Total ($MM)	**14.1**	**13.3**	**21.0**	**14.8**	**15.1**	**78.3**

4.2.1 IT Software

Alectra Utilities invested $51.2MM in IT Software, which accounts for 65% of the total planned IT Systems investment over the 2020-2024 historical period. Within this category, the Meter-to-Cash system received a $24.3MM investment, which includes an $8.5MM investment to upgrade Alectra Utilities' CC&B system. The project finished under budget by $4.8MM due to favourable contract terms, adjustments to the original project scope, and the use of lower-cost off-shore resources.

Alectra Utilities allocated $11.9MM to Business Optimization expenditures, primarily to address system licensing and enhancements to its capital planning and optimization platform (Copperleaf C55). These enhancements included developing and implementing Alectra Utilities' capital planning reporting environment, enabling additional security measures, and updating its business case value framework if needed. These improvements ensured that Alectra Utilities' investment planning system remained well-aligned with the detailed reporting and accountability requirements of its regulated environment.

During this period, Alectra Utilities' historical ERP investments totalled $8.8MM, primarily for ERP upgrades to maintain vendor compliance with supported versions, address cybersecurity vulnerabilities, and introduce ongoing improvements that better aligned system capabilities with business processes and evolving operational needs. During this time, Alectra Utilities introduced its productivity framework. As a result, enhancements planned for enterprise systems such as Alectra Utilities' ERP system undergo a rigorous value assessment to ensure proper prioritization of enhancements tied to value for investment.

Lasty, Alectra Utilities allocated $6.2MM to Operational Technology capital expenditures, focusing primarily on upgrades and enhancements to its OMS, GIS, and SCADA platforms. These investments ensured that at the relevant time, the platforms remained up-to-date and fully supported by vendors, addressed key security vulnerabilities, and provided targeted improvements to address business process inefficiencies in line with evolving operational requirements.

4.2.2 IT Hardware

IT Hardware investments accounted for approximately 28% or $22.3MM of the total IT Systems expenditures over the 2020-2024 historical period. Specifically, investments in data centre infrastructure totalling $11.4MM were used to replace obsolete and end-of-life infrastructure hardware. This was followed by $8.2MM in end-user technology costs, which saw a significant increase due to the COVID-19 pandemic, as the organization diligently worked to procure client computing hardware necessary to enable business continuity through remote work. Lastly, Alectra Utilities allocated $1.6MM towards an enterprise backup and recovery solution, enhancing its data resilience by implementing a modernized architecture that leverages both hybrid cloud and on-premises environments.

4.2.3 IT Security

IT security investments accounted for approximately 4%, or $3.4MM, of total IT System expenditures during this historical period. These investments were primarily focused on replacing end-of-life security infrastructure, including [redacted] Additional investments supported the development and implementation of an [redacted] enhancing Alectra Utilities' overall cybersecurity posture and access management capabilities.

4.2.4 DER Supporting Technologies

Over this historical period, Alectra Utilities' GRE&T Centre invested approximately $1.4MM in several Distributed Energy Resource (DER) enablement initiatives, aimed at enhancing grid flexibility and supporting customer electrification. These initiatives were supported and partially funded by various government agencies including NRCan, the OEB, and the IESO.

Key projects included the development of a transactive energy platform to facilitate customer participation in an energy marketplace ($0.8MM), the commencement of a digital eMobility customer engagement platform to support residential Electric Vehicle (EV) adoption and explore managed EV charging ($0.4MM), and a vehicle-to-grid project exploring bidirectional charging with electric school buses to provide grid services ($0.1MM). The 2023 credit of $0.2MM in Table B09 - 15 was attributable to the timing of government funding received on the transactive energy platform.

These DER initiatives support Alectra Utilities' strategic transition to a distributed, decarbonized, and customer-centric electricity system.

4.3 Bridge Expenditures (2025 to 2026)

Capital expenditures over the bridge period between 2025 and 2026 are forecasted to be $26.4MM.

Table B09 - 16 Bridge Expenditure 2025-2026

IT Investment Sub-categories	2025	2026	Total
IT Software:			
Meter-to-Cash	3.5	2.6	6.1
Operational Technologies	2.1	2.0	4.1
Enterprise Resource Planning	1.8	2.7	4.5
Business Optimization	1.9	1.0	2.9
Total IT Software	**9.3**	**8.3**	**17.6**
IT Hardware:			
End User Technology	1.0	1.4	2.4
Data Centre Infrastructure	1.2	1.3	2.5
Total IT Hardware	**2.2**	**2.7**	**4.9**
Total IT Security	**0.3**	**0.4**	**0.7**
Total DER Supporting Technologies	**1.6**	**1.6**	**3.2**
Total ($MM)	**13.4**	**13.0**	**26.4**

4.3.1 IT Software

Over the bridge period, Alectra Utilities plans to invest $17.6MM in its IT software, which represents approximately 67% of the total IT system budget.

This investment includes $6.1MM in Meter-to-Cash investments broken out by $1.4MM for enhancements to Customer Care and Billing (CC&B) and $1.2MM for regulatory modifications. $2.4MM is allocated for CC&B licensing as Alectra Utilities transitions to Oracle's new licensing model in preparation for its Customer to Meter (C2M) upgrade. The remaining $1.1MM will be distributed across several minor projects related to network metering upgrades on its core Advanced Metering Infrastructure (AMI) 1.0 platforms, including Trillliant, Connexo, and others (refer to *Section 2.1.*1 for more details).

Investments in ERP total $4.5MM or 26% of the total IT Software budget over the bridge years. Of this, $3.3MM is attributable to ERP Continuous Improvements and $1.2MM allocated to ERP System Upgrades (refer to *Section 2.1.3* for more details).

Additionally, Alectra Utilities plans to invest $2.9MM in Business Optimization, attributed to optimizing business practices via its Copperleaf C55 platform for capital investment planning and optimization (refer to *Section 2.1.4* for more details).

Lastly, Alectra Utilities intends to invest $4.1MM in Operational Technologies. The primary investment is attributable to the purchase and phase one implementation of Alectra Utilities' Workforce Management system ($2.7MM), with the remaining $1.4MM split between five upgrade and enhancement projects to Alectra Utilities' GIS, OMS, SCADA, and PI platforms respectively (refer to *Section 2.1.2* for more details).

4.3.2 IT Hardware

Over the bridge years, Alectra Utilities plans to invest $4.9MM in IT hardware to refresh its aging infrastructure and client devices. This investment includes $2.5MM for upgrading end-of-life data center infrastructure and $2.4MM for replacing outdated client computing hardware. These upgrades are in line with asset management lifecycle best practices and Alectra Utilities' useful life timelines (refer to *Section 2.2.1* and *Section 2.2.2* for more details*).*

4.3.3 IT Security

Over the bridge years, Alectra Utilities plans to invest $0.7MM in IT Security to advance our cybersecurity tools and controls to align with the Ontario Cyber Security Framework (OCSF).

4.3.4 DER Supporting Technologies

Over the bridge years, Alectra Utilities plans to invest $3.2MM in DER Supporting Technologies. Specifically, $2MM on Alectra Utilities Drive for Fleets, and $1.1MM on the continuation of the Customer Engagement eMobility project respectively.

The Alectra Utilities Drive for Fleets program will be designed to enable smart managed EV charging in a limited capacity, evaluating and supporting companies as they move from internal combustion engine fleets to EVs. Through the integration of advanced technologies and advisory offerings, the initiative aims to create mutually beneficial outcomes for both customers and Alectra Utilities. The initiative aims to support customers' efforts to decarbonize their transportation assets and enhance Alectra Utilities' grid resilience while ensuring cost efficiency for its ratepayers. This program is a key element of Alectra Utilities' broader strategy to support the energy transition and meet the increasing demand for sustainable energy solutions.

Regarding the $1.1MM investment in Customer Engagement eMobility, Alectra Utilities intends to continue its deployment of an eMobility module on its customer portal to enhance residential customer engagement and participation in DERs. The goal is to assess the value of the information and tools provided to customers on their electrification journey and to evaluate how customers perceive a program designed to support their transition into prosumers through managed EV charging.

4.4 Future Expenditures (2027 to 2031)

Expenditures between 2027 and 2031 are forecast to be $98.0MM. Significant IT Systems cost drivers during the DSP period include:

4.4.1 IT Software

Investments in IT Software over the DSP period total $66.9MM or approximately 68% of the total planned IT Systems investment. The primary drivers for this investment are functional obsolescence and operational efficiency, specifically within the Meter-to-Cash sub-category, totaling $25.8MM. Of this investment, $14.4MM is attributable to upgrading Alectra Utilities' CC&B system to the latest version of Oracle Customer to Meter (C2M) over 2028 and 2029, ensuring system currency and remaining compliant with Oracle's support requirements. Additionally, planned CC&B enhancements ($3.4MM), regulatory modifications ($2.9MM), Load Profile and Settlements system upgrade ($1.3MM), and Meter-to-Cash license growth ($1.2MM) make up the remaining material Meter-to-Cash investments. The remaining $2.6MM will be distributed across several minor projects related to network metering upgrades on its core Advanced Metering Infrastructure (AMI) 1.0 platforms, including Primeread, Sensus, Connexo, and others (refer to *Section 2.1.1* for more details on Alectra Utilities' planned Meter-to-Cash investments).

Over the DSP period, investments in Alectra Utilities' Operational Technologies total $15.3MM driven specifically by the need for improved operational efficiency related to Alectra Utilities' field services and mobile dispatching capabilities. Of the planned $15.3MM investment in operational technologies, $11.5MM is attributable to the phased implementation of a new Workforce Management and Mobile Dispatch system. This project is aimed at digitizing and modernizing Alectra Utilities' fieldwork, ensuring optimization of Alectra Utilities' field service processes regarding crew scheduling, automated routing, field data capture, customer communications, and other core field services capabilities. This investment ensures that Alectra Utilities' field services function has the necessary technology to efficiently manage field operations both from a back-office and front-line perspective. Phases for this project commence in 2025 and end in 2029 *(*refer to *Section 2.1.2* for more details on Alectra Utilities' planned Operational Technology investments*).*

Investments in Alectra Utilities' ERP software total $12.0MM over the DSP period, specifically attributed to ERP Continuous Improvements ($7.5MM) and ERP System Upgrades ($4.5MM). These investments will continue to improve system capabilities and align system requirements with business processes. As with all core enterprise systems, ERP improvements are subject to a rigorous value assessment, ensuring that Alectra Utilities is receiving value for its investment *(*refer to *Section 2.1.3* for more details on Alectra Utilities' planned ERP investments*).*

Lastly, Alectra Utilities has a planned investment of $13.8MM in Business Optimization. Of this investment, $7.7MM is attributable to the optimization of Alectra Utilities' Copperleaf C55 system, to continue enhancing the system to meet and comply with future OEB requirements (e.g. BCA framework for NWS). This program spans the entire DSP period, with an average annual spend of $1.5MM. Additionally, Alectra Utilities has planned a $4.3MM investment in AMI 2.0 – Grid Edge Analytics. This project aims to utilize the advanced analytical capabilities of the new AMI 2.0 meters, allowing Alectra Utilities to gain a deeper understanding of its system and customers, which will enable the development of more efficient processes and services *(*refer to *Section 2.1.4* for more details on Alectra Utilities' planned Business Optimization investments*).*

4.4.2 IT Hardware

Over the DSP period, Alectra Utilities plans to invest $22.6MM in IT hardware to refresh its aging infrastructure, client devices, and enterprise backup and recovery solution. This investment includes $9.9MM for upgrading end-of-life data centre infrastructure and $10.4MM for replacing outdated client computing hardware. These upgrades are in line with asset management lifecycle best practices and Alectra Utilities' useful life timelines, ensuring annual investments are tied to an asset replacement schedule. Additionally, Alectra Utilities intends to refresh its backup and recovery solution in 2029, ensuring the system has the necessary capacity and capabilities to address Alectra Utilities' growing digital and hybrid technology landscape *(*refer to *Section 2.2* for more details on Alectra Utilities' planned IT Hardware investments*).*

4.4.3 IT Security

Over the DSP period, Alectra Utilities has planned $7.3MM in IT Security investments. From this amount, $5.6MM is driven by functional obsolescence as Alectra Utilities plans to replace several components of its security infrastructure such as [redacted] in

alignment with asset management best practices and vendor-supported lifecycle timelines. The remaining $1.7MM investment is attributable to foundational governance and security services. This investment is planned annually, with an average annual spend of $0.3MM. This investment will position Alectra Utilities to effectively respond to emerging cyber threats throughout the DSP period. The initiative includes [redacted] These actions will reinforce Alectra Utilities' cybersecurity posture, facilitate compliance with the OCSF, and ensure alignment with the requirements of Alectra Utilities' cyber insurance providers (refer to *Section 2.3* for more details on Alectra Utilities' planned IT Security investments).

4.4.4 DER Supporting Technologies

Over the DSP period, Alectra Utilities plans to invest $1.2MM in DER Supporting Technologies. This investment is related primarily to the Customer Non-Wires Solution (NWS) Design and Development project. This project will develop a set of DER program models that can be deployed to serve as NWS. A comprehensive design approach, informed by various Alectra Utilities business units, will allow Alectra Utilities to effectively utilize the potential of NWS (refer to *Section 2.4* for more details on Alectra Utilities' planned DER Supporting Technologies investments).

1 **Table B09 - 17 Planned Investment Projects 2027-2031**

IT Investment Sub-categories	2027	2028	2029	2030	2031	Total
IT Software:						
Meter-to-Cash	2.9	10.5	9.5	1.3	1.6	25.8
Operational Technologies	4.5	4.8	4.7	0.5	0.8	15.3
Enterprise Resource Planning	3.0	2.4	3.4	1.0	2.2	12.0
Business Optimization	2.0	6.1	3.4	1.3	1.0	13.8
Total IT Software	**12.4**	**23.8**	**21.0**	**4.1**	**5.6**	**66.9**
IT Hardware:						
End User Technology	1.9	2.3	2.0	2.1	2.1	10.4
Data Centre Infrastructure	3.5	2.3	2.4	0.8	0.9	9.9
Enterprise Backup & Recovery	0.0	0.0	2.3	0.0	0.0	2.3
Total IT Hardware	**5.4**	**4.6**	**6.7**	**2.9**	**3.0**	**22.6**
IT Security:						
Cyber Security Device Upgrades	3.1	2.4	0.1	0.0	0.0	5.6
Foundational Governance & Security Services	0.4	0.3	0.3	0.3	0.4	1.7
Total IT Security	**3.5**	**2.7**	**0.4**	**0.3**	**0.4**	**7.3**
Total DER Supporting Technologies	**0.2**	**0.3**	**0.3**	**0.3**	**0.1**	**1.2**
Total ($MM)	**21.5**	**31.4**	**28.4**	**7.6**	**9.1**	**98.0**

2

V Options Analysis

Alectra Utilities develops several scope and pacing options for its capital investment plan which is designed to align with both internal priorities and external needs. This section summarizes the options analysis, aggregated at the category level, for the IT Systems portfolio. According to the Customer Engagement Report, residential, GS<50, and GS>50 customers are aligned with the proposed plan and associated rate increase derived from the investment options selected[55].

5.1 IT Software

Status Quo Option (No Investment):

The status quo option involves maintaining Alectra Utilities' current software systems in place, with no investment during the DSP period. Most investments in the IT software portfolio are related to enterprise system upgrades and enhancements, and touch on all investment drivers listed in *Section III*. Software upgrades and enhancements are necessary to avoid functional obsolescence, maintain operational efficiency and stability, reduce the risk of cyber threats by patching known vulnerabilities, and allow for the modifications of core enterprise systems to meet regulatory mandates. Therefore, maintaining the current state of Alectra Utilities' IT Software landscape, whether by deferring upgrades, foregoing enhancements, or relying on aging and outdated systems, was consistently viewed as an unsustainable option.

The status quo approach would expose Alectra Utilities to several risks, including:

- Loss of vendor support and system upgrades/patches
- Increased vulnerability to system failures and cyber threats
- Operational inefficiencies and declining user satisfaction
- Non-compliance with evolving regulatory requirements
- Escalating long-term costs due to reactive remediation

Foregoing or deferring investment in IT software will result in elevated operational risk and reduce the organization's ability to meet customer, regulatory, and operational needs effectively.

[55] Exhibit 1, Tab 5, Schedule 2 Application Specific Customer Engagement

Options Considered:

While each IT software project has detailed options considered on a per project basis, across the IT software portfolio, Alectra Utilities typically evaluated three approaches with respect to its investments in IT Software in addition to maintaining the status quo:

1. **Pacing Upgrades Based on Vendor Support:** Options included upgrading software platforms either annually, biennially, or on a deferred schedule. Alectra Utilities considered the appropriate frequency of introducing upgrades based on several factors such as maintaining alignment with vendor-supported versions, managing internal resource demands, and balancing capital and operational expenditures. More frequent upgrades (e.g. annual) offered functionality improvements but imposed higher resource overhead. Biennial or strategically timed upgrades were often preferred for balancing functional improvements and security with business impact and resource efficiency.
2. **Outsourcing or Third-Party Support:** Some alternatives involved outsourcing system enhancements to contractors or relying on third-party support vendors for systems nearing end-of-life. While these could offer temporary resource relief, they typically introduced complexity, integration risk, diminished control over critical business processes, and increased cost. As a result, these options were not recommended due to high costs and potential for operational misalignment.
3. **System Replacement or License Model Restructuring:** In cases where existing systems were approaching functional or contractual limitations, full system replacement or licensing model changes were considered. While more capital intensive upfront, these options were evaluated for their long-term cost-effectiveness, scalability, and alignment with enterprise architecture and digital strategy goals.

Recommended Option:

Alectra Utilities' recommended approach to its IT Software investment portfolio emphasizes proactive investment methods that prioritize:

- Maintaining vendor-supported upgrade cycles, ensuring platforms remain supported, secure, and stable

- Implementing targeted system enhancements which have undergone a rigorous evaluation process and prioritized by a steering committee of business stakeholders to drive measurable efficiency gains, support regulatory compliance, and improve customer and employee experience
- Transitioning to modern licensing or cloud-based models when financially beneficial and aligned with system roadmaps
- Coordinating software investments with broader system changes to maximize integration benefits, avoid duplication of effort, and reduce implementation risks

This approach enables Alectra Utilities to modernize its software ecosystem in a cost-effective, secure, and business-aligned manner, balancing improvements with operational continuity and stability.

5.2 IT Hardware

Status Quo Option (No Investment)

The status quo option involves maintaining Alectra Utilities' current hardware systems in place, with no investment during the DSP period. Across the IT Hardware portfolio, including end-user technology, data centre infrastructure, and enterprise backup systems, functional obsolescence is the primary investment driver. Maintaining the status quo, with no additional investment over the DSP period, will result in aging and unsupported hardware, which poses significant risks to Alectra Utilities' operations. These risks include:

- Increased downtime, degraded performance, and inconsistent user experiences
- Escalating cybersecurity threats due to a lack of firmware and patch support
- Higher maintenance and repair costs for aging or out-of-warranty equipment
- Operational inefficiencies and inability to scale or run modern applications
- Increased OPEX from extended third-party support for end-of-life systems

In all cases, the status quo option failed to provide a sustainable and secure approach to maintaining IT infrastructure, user productivity, and operational stability of Alectra Utilities' core technology platforms and client devices.

Options Considered:

Alectra Utilities generally evaluated three types of investment strategies across IT Hardware in addition to maintaining the status quo:

1. **Extended Hardware Lifecycles:** Extending device lifecycles (e.g. five to six years for end-user devices, seven to eight years for infrastructure hardware) helped smooth capital expenditures, but increased operational risk and costs. Higher failure rates, out-of-warranty repairs, and loss of vendor support creates the potential for long-term inefficiencies and security vulnerabilities. These approaches often shift costs from CAPEX to OPEX and are suboptimal for systems critical to maintain operational stability.
2. **Staggered Refresh Strategies:** For hardware such as client devices or network infrastructure, staggered refreshes were considered to align investments across the DSP period. Staggered refreshes focus on maintaining refresh timelines for most hardware, while deferring some less critical hardware for another year where the risk of failure or performance degradation would not have a significant impact. This approach was aimed at reducing budget volatility and to accommodate financial constraints, while still mitigating risk by prioritizing the most critical assets.

- **Cloud Alternatives:** In select scenarios (e.g. backup and recovery), a transition to a cloud-only solution was explored. While potentially eliminating hardware costs and simplifying scalability, a cloud-only approach was found to be more expensive overall and not well-suited to Alectra Utilities' hybrid environment due to the significant presence of on-premise systems and data. This option also introduces concerns around slower recovery times.

Recommended Option:

Alectra Utilities adopted the staggered option as a proactive and risk-balanced refresh strategy for its IT Hardware investments. This approach involved:

- Phased refresh cycles for end-user technology, maintaining most of the fleet on a four-year cycle, while selectively extending device lifecycles for a portion of the fleet to optimize capital allocation

- Five to six-year refresh cycles for data centre infrastructure, aligned with vendor support timelines to reduce security and performance risks while balancing its financial investment with other priorities
- Adopting a scalable, hyperscale architecture for enterprise backup and recovery with a five-year lifecycle, supporting hybrid environments and enabling seamless expansion and operational resilience

This proactive and balanced approach ensures Alectra Utilities maintains a secure, efficient, and reliable IT hardware foundation, minimizing lifecycle risk while balancing capital and operating costs. IT Hardware investments decisions were made in alignment with IT asset management best practices, ensuring operational stability while supporting essential business operations.

5.3 IT Security

Status Quo Option (Do Nothing):

The status quo option involves maintaining Alectra Utilities' current IT Security systems in place, with no investment during the DSP period. No investment in IT Security would expose the organization to growing cybersecurity vulnerabilities, operational disruptions, and regulatory non-compliance with Ontario's Cyber Security Framework (OCSF). As a result, the status quo is not a viable investment option.

Risks associated with outdated cybersecurity devices and governance tools include:

- Increased susceptibility to malware, ransomware, and unauthorized access
- Inability to meet evolving regulatory and cyber insurance requirements, including the OCSF
- [redacted]

Without proactive investments in IT Security devices and services, Alectra Utilities would lack the resilience and agility to defend against modern cyber risks, putting our employees, customers, and grid operations at risk.

Options Considered:

Alectra Utilities evaluated multiple investment options to modernize its cybersecurity infrastructure and governance framework against constantly evolving cyber threats:

1. **Fixed Replacement Cycles:** A standardized refresh schedule ensures consistent upgrades across the security stack, replacing firewalls, access controls, and other devices at regular intervals. While this reduces risk exposure and simplifies planning, it leads to higher capital costs by replacing hardware before end-of-life, reducing asset utilization efficiency.
2. **Cloud-Based or Subscription Security Services:** Subscription-based and cloud-native security tools offer real-time updates, scalability, and operational flexibility, particularly for threat detection and response. While these models may reduce upfront capital costs, they typically increase long-term operating costs and reliance on third-party providers. Additionally, full cloud adoption is limited for critical OT environments that still require on-premises controls.
3. **On-Premises-Only Models:** Alectra Utilities considered an investment approach that centered solely on utilizing on-premises security infrastructure and services. While this approach offered a higher degree of control, it was deemed to lack agility and scalability. This approach may be effective for foundational systems, especially in the OT environment, but it cannot respond as quickly to the dynamic threat landscape, limiting long-term resilience.
4. **Hybrid Investment Strategy:** Alectra Utilities considered a hybrid investment approach that combines targeted capital investment with scalable, cloud-based security solutions, balancing organizational risk with value, cost, and agility to respond to increasingly sophisticated cyber threats.

Recommended Option:

Alectra Utilities has adopted a hybrid cybersecurity investment strategy, that combines targeted capital investment with scalable, cloud-based security solutions, the optimal approach to balance organization risk, value, cost, and agility:

- Device replacements are scheduled based on asset lifecycle best practices and vendor supported versioning, rather than fixed cycles to balance cost with risk mitigation. In some cases, extended support agreements ensure continuous protection while avoiding premature replacements.

[redacted]

This blended approach ensures Alectra Utilities remains compliant with the OCSF while maintaining a strong cybersecurity posture that is adaptable, cost-effective, and responsive to constantly evolving cyber threats.

5.4 DER Supporting Technologies

Status Quo Option (No Investment):

Alectra Utilities explored the option of not investing in DER Supporting Technologies over the DSP period. However, a lack of investment in the exploration, design, and integration DER NWS would potentially expose Alectra Utilities to regulatory non-compliance and operational inefficiencies.

Specifically, these include:

- Challenges to meet OEB requirements mandating the evaluation of NWS for projects over $2MM
- Suboptimal grid planning and investment decisions, potentially resulting in higher long-term costs

- Diminished understanding of customer behaviour and market dynamics, leading to low program participation and limited DER adoption, and
- Missed opportunities to defer traditional infrastructure investments, improve grid reliability, and reduce peak demand through cost-effective, customer-centric alternatives

Given these risks, the status quo is not a viable approach for the DER Supporting Technologies investment category.

Options Considered:

Alectra Utilities evaluated two principal strategies for advancing its DER and NWS design capabilities:

1. **Adapting External Program Models Without Local Validation:** This approach refers to the adoption of established NWS program frameworks from other jurisdictions without conducting comprehensive local feasibility studies or customer engagement. It can reduce initial design costs and accelerate implementation timelines. However, this method may not account for Alectra Utilities' specific grid characteristics, customer demographics, and market conditions. The absence of localized analysis could impact procurement costs, program performance, and long-term outcomes.
2. **Primary Research and Custom Program Development:** Building all NWS program components from scratch through extensive local research and tailored design ensures optimal alignment with local needs but increases initial costs and timelines. This approach may also duplicate existing efforts by other utilities, causing inefficiencies.

Recommended Option:

Alectra Utilities recommends a data-driven and tailored design approach for DER NWS. This strategy leverages established best practices and resources from other utilities while incorporating local system, customer, and market data to ensure regulatory compliance and cost-effectiveness.

Key features of this approach include:

- Customizing NWS program design to reflect Alectra Utilities' grid characteristics and customer demographics
- Conducting targeted feasibility assessments to ensure effectiveness and operational integration
- Embedding regulatory requirements and procurement considerations early in the design phase
- Focusing on customer-centric design to drive adoption and program success

This balanced strategy avoids reinventing existing models while ensuring solutions are aligned to Alectra Utilities' operational context and regulatory obligations. It supports more informed decision-making, facilitates DER adoption, and positions Alectra Utilities to optimize its grid investments through innovative, NWS alternatives.

VI Investment Projects

The material investments from 2027 to 2031 that form the IT Systems investments are included in Table B09 - 18.

Table B09 - 18 Material Projects and Initiatives (2027-2031)

Project Code	Project Name	CAPEX ($MM)
152539	Meter -to-Cash - CIS - CC&B CCS/C2M upgrade	14.4
102263	Work Force Management / Mobile Dispatch	11.5
102098	IT End User - Client Computing	8.5
151136	C55 Alectra Utilities: Optimization of Business Practices	7.7
150469	ERP Continuous Improvement	7.5
151812	Cyber Security - Security Upgrades	5.4
152996	ERP System Upgrades	4.5
152576	AMI 2.0 - Grid Edge Analytics	4.3
150325	Meter-to-Cash CIS CC&B Enhancements	3.4
102157	IT Infrastructure - Server Refresh	3.4
150453	Meter-to-Cash - CIS CC&B Modifications(Regulatory Enhancements)	2.9
153072	IT Infrastructure- Backup Refresh Current	2.3
150396	IT Infrastructure - Network Refresh	1.9
150520	Cyber Security - Security Additions & Enhancements	1.7
150563	SCADA - SCADA/OMS Software Upgrade Cycle	1.6
152995	Customer Non-Wires Solution Design & Development	1.4
150465	Meter-to-Cash LPSS(Load profile and settlements system)Upgrade	1.3
150468	Meter-to- Cash Annual Licenses Growth on Meter-to-Cash platforms	1.2
152097	OT Infrastructure - Software Defined Networking	1.2

Appendix B10 - Customer Connections

I Overview

Customer Connections investments are required for connecting, modifying, or realigning Alectra Utilities' distribution system to provide customers with electricity access. These investments are mandatory and required by Alectra Utilities' license and the Distribution System Code (DSC).

Alectra Utilities’ service territory is forecasted to undergo continuous growth over the DSP period from 2027-2031. Since 2022, the urban centres that Alectra Utilities serves have been intensifying, including a rise in high-density condominium developments, commercial developments, transit initiatives, large residential developments/mixed use and data centers. This has driven the volume and size of customer-initiated expansion and relocation projects. Over the 2027-2031 period, Alectra Utilities forecasts that these trends will continue and, in some cases, materially increase.

The methods used to forecast necessary expenditures include a combination of historical analysis, trending, and known projects. Beyond volumes and specific project needs, general growth in expenditures is also forecasted because of increased costs for selected distribution system materials such as transformers, switchgear and primary cables, labour, and increases in the number of Very Large Projects (VLP).

To execute these projects, Alectra Utilities leverages both internal and external (contractor) resources and coordinates with design consultants and civil contractors. The utility aims to complete projects expeditiously and in line with its construction and material standards. Alectra Utilities engages, developers, city planners, joint use tenants, and civil consultants to provide efficient and cost-effective distribution system designs early in project planning. These investments are crucial for meeting customer connection demands and may include system expansions or enhancements where Alectra Utilities is required to make an Offer to Connect (OTC).

Table B10 - 1 describes the proposed investment expenditures, drivers and outcomes under the Customer Connections program.

Table B10 - 1 Customer Connections Investment Expenditures, Drivers and Outcomes

	Historical Spending - NET					Bridge - NET		Forecast Spending - NET				
Year	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
CAPEX ($MM)	33.8	39.4	27.5	40.3	60.0	47.2	52.7	75.1	91.3	82.4	66.0	72.0
Primary Driver	Customer Service Requests											
Secondary Driver	Mandated Service Requirements											
Outcomes	Customer Value, Reliability, Safety, Coordination and Interoperability, Environment, Efficiency.											

II Investment Description

Customer Connections - Overview

The Customer Connections Program is made up of non-discretionary investments intended to maintain compliance with various obligations including Section 6 of the DSC, and with Alectra Utilities' *Conditions of Service (Section 2.1.5 Relocation of Plant)*. Furthermore, the *Electricity Act* requires Alectra Utilities to connect a building to its distribution system if:

- The building lies along any of the lines of the distributor's distribution system
- The owner, occupant or other person in charge of the building requests the connection in writing[56]

To execute this work, Alectra Utilities communicates and coordinates with various city and planning groups such as the municipalities' Public Utilities Coordinating Committees. Alectra Utilities also engages in discussions with the municipalities as upcoming and proposed developments are identified. Developers ultimately contact Alectra Utilities following approval of their subdivision draft plan applications to confirm their electrical servicing requirements.

There are six types of investments within the Customer Connection category, which are listed below and summarized in the sections that follow.

- Residential and Small Commercial Layouts (Layouts)
- New Industrial Commercial and Institutional (ICI) Services
- New Subdivisions
- Renewable Generation (REGEN)
- Customer Initiated
- Transit Connections

[56] *Electricity Act, 1998, S.O. 1998, c. 15, Sched. A*, s. 28.

Table B10 - 2 Summary of Expenditures

	Historical Spending - NET					Bridge - NET		Forecast Spending - NET				
Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Layouts	6.2	5.8	8.5	9.5	12.6	8.2	8.2	8.4	9.5	10.7	12.1	12.2
ICI Services	4.4	2.7	3.1	3.1	1.9	3.3	3.3	0.8	0.8	0.8	0.9	0.9
New Subdivisions	15.5	18.9	13.2	12.7	20.9	16.5	23.0	23.6	24.3	25.1	26.3	27.5
REGEN	(0.2)	0.2	(0.1)	(0.1)	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Customer Initiated	7.9	11.8	2.6	14.9	24.8	19.2	18.2	42.3	56.7	45.8	26.7	31.4
Transit Connections	0.0	0.0	0.2	0.2	(0.3)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL ($MM)	**33.8**	**39.4**	**27.5**	**40.3**	**60.0**	**47.2**	**52.7**	**75.1**	**91.3**	**82.4**	**66.0**	**72.0**

Residential and Small Commercial Layouts

Investments in Residential and Small Commercial Layouts consist of work to make the system ready for new residential infill services and upgrading residential and small commercial services. Layouts document how individual services connect to the distribution system. These are driven by customer requests and vary based on the type, location, size and connection specifics. The customer's service could be underground or overhead and is the connection from the main plant on the boulevard to the building. A layout is typically comprised of a single page drawing with sufficient detail to provide crews or contractors the information required to construct the service. It also includes a cost estimate that is provided to the customer for design, materials and construction of the service. Costs are shared between the customer and Alectra Utilities in accordance with the DSC and Alectra Utilities' Conditions of Service (COS). This includes the provision of a basic connection allowance for each residential service in accordance with *Section 3.1.4* of the DSC. This basic connection credit equates to 30m of an overhead service or of an equivalent credit for underground service.

Layouts document how individual services connect to the distribution system. These are driven by customer requests and vary based on the type, location, size and connection specifics.

Forecasts for residential and small commercial layouts are based on historical volumes and pricing information as well as growth in residential EV charging. EV penetration is anticipated to continue over the DSP period as included in *Appendix J - Load Forecast & System Capacity*

Adequacy Assessment Report. The forecasted EV volumes were calculated by categorizing the loads based on the type of vehicles and charger levels, including level 1, level 2, and level 3 chargers. It is Alectra Utilities' experience that customers installing level 2 chargers are likely to initiate residential service upgrades, and this assumption has been applied to the residential services forecast. The total forecasted service connections are detailed in Table B10 - 6.

New ICI Services

Investments in New ICI Services are mandatory expenditures driven by customer requests. They include both the design and the connection of ICI projects.

New ICI Services consist of new or upgraded primary services to industrial, commercial and institutional customers (such as medical buildings, small plazas or factories). A New Service typically consists of a Work Order being issued with complete drawings and work instructions and an Offer to Connect (OTC). These services are normally underground from the existing distribution or sub-transmission system and up to and including the padmount transformer.

Forecasts for New ICI Services were developed the same way as Layouts, including an allowance for EV charging growth. Historically, a portion of ICI projects have been attributed to EV level 3 chargers, and this proportion was applied to the total forecasted ICI services to determine the number of EV commercial service upgrades. The total forecasted service connections are detailed in Table B10 - 6.

New Subdivisions

Investments in New Subdivisions are the capital expenditures Alectra Utilities incurs to serve development projects, including residential and condominium-tower subdivisions, new industrial, commercial and institutional (ICI) subdivisions, and relocation work directly attributable to those developments.

New Subdivisions expenditures consist of the primary and secondary underground cables and connections as well as transformers installed to the street line of each lot within a new residential "Greenfield" subdivision development. In accordance with *Appendix B* of the DSC, the Economic Evaluation Model (EEM) is conducted to determine the distributor and developer cost responsibilities based on forecasted load, capital costs, and revenue over a defined period. A

new subdivision consists of an OTC that prescribes the responsibilities and cost sharing of both parties.

These developments are based on Alectra Utilities-approved materials, standards and specifications. An approved drawing and work instruction package are issued for construction to initiate the project. New residential subdivisions are installed in a "looped supply" configuration, with fault indicators installed at each transformer, underground switch, and riser pole to ensure that restoration procedures can occur as efficiently as possible in the event of an asset failure. Designs also incorporate planning criteria to mitigate the overloading of installed circuits considering new and pending developments. Phasing of developments is strategically planned and scheduled to ensure developments are energized from one phase to the next with minimal interruption to existing customers. Designs that incorporate these items allow for safe and reliable delivery of electricity while ensuring additional customers can be accommodated as the systems expands to meet new development needs.

The quantity of new residential and condominium tower subdivisions is expected to increase based on *Bill 23* and the *More Homes Built Faster Act*. However, as described in *Section 4.3*, Alectra Utilities has taken a conservative approach to forecasting new subdivision connection costs, based on historical average residential connections and specific, known high-rise condominium developments.

Renewable Generation

Renewable Generation investments are distributed energy resource connections to the distribution system. These investments are required as per the DSC and include connections as part of programs such as the feed-in-tariff (FIT) and micro-FIT. Renewable Generation currently includes biogas facilities, wind generation, solar, co-generation, battery storage, combined heat and power, as well as other evolving technologies.

These costs are typically incurred by the connecting customer.

Customer Initiated

Customer Initiated Distribution System Projects are driven by customers, transit authorities or sponsors (Metrolinx, regional transit agencies, federally regulated railways such as CN Rail, CP Rail and municipal transit departments) and joint use partners (telecommunications companies,

local and regional municipalities and other LDCs). These projects result in either distribution system expansions or asset relocations. System expansion usually occurs when Alectra Utilities does not have existing or adequate supply for a proposed development. System relocations are usually initiated by developers that have a conflict with a component of the distribution system. Expansion costs are included in an OTC, and relocations are either 100% chargeable to a customer or cost shared with other government agencies depending on the circumstances. Customer Initiated expenditures consist of three sub-categories: (i) Customer Initiated Expansion and Relocation Projects, (ii) Transit Expansion Projects and (iii) Customer Initiated Joint Use Projects. Each sub-category is summarized below:

Customer Initiated Expansion and Relocation Projects

Customer Initiated Relocations support connections to the existing distribution system from the development community or customers in Alectra Utilities' service territory.

These projects are externally driven, and Alectra Utilities is obligated to provide a quotation for the connection in accordance with the DSC, and the cost allocation between the customer and Alectra Utilities is determined using prescribed economic evaluation parameters. Alectra Utilities must perform the work to permit customer connections in a timely manner.

The method used to forecast necessary expenditures is based on historical spending and any known customer relocation requests that will be required during the 2027-2031 period. Once a customer applies for the service with a site plan that has been approved by the city, the customer will provide a design deposit and the project is initiated. During these projects, Alectra Utilities reviews its system requirements and determines if distribution system modifications are required.

For relocation projects with road authorities, Alectra Utilities' distribution assets need to be relocated prior to any road work commencing. This is necessary to comply with Ministry of Labour regulations regarding single contractors on site, as well as space/time requirements.

Transit Expansion Projects

Transit initiated expansion projects are initiated by Transit sponsors when Alectra Utilities does not have existing or adequate supply to connect a proposed Transit project, requiring an expansion to the distribution system to support the development.

The method used to forecast the Customer Initiated Expansion projects in the Transit category is based on known projects. Once a Transit sponsor applies for service and they provide a design deposit, the project is then initiated.

Customer Initiated Joint Use Projects

Customer Initiated Joint Use expenditures are for design and consultant fees as well as hydro make ready expenditures associated with Alectra Utilities' permit review process for all third- party attachments to Alectra Utilities owned poles. These costs are typically almost fully recoverable from the customer.

Transit Connections

Investments in Transit Connections are for the expenditures to connect transit infrastructure to the distribution system.

These investments are typically made over multiple years. Individual projects with an estimated gross cost greater than $5MM have separate business cases and are referred to as “Very Large Projects” or VLPs. Table B10 - 3 contains a list of very large Transit Connections projects. The table also includes Customer Initiated Expansions, Relocation Projects and Transit Expansion Projects.

Table B10 - 3 Very Large Projects

Project Code	Project Name	NET 2027-2031 ($MM)	Gross 2027-2031 ($MM)
151584	Customer Initiated Distribution System Project (West) McMaster Innovation Park - Dedicated Feeder- Business Park	5.9	8.8
152335	HaLRT OMSF Expansion	5.7	11.6
152482	Customer Initiated Distribution System Expansion Project - Trillium Health Partners	7.6	9.4
152602	Customer Initiated Distribution System Expansion Project - GTAA Feeders	9.5	9.5
152676	Lakeview Expansion	6.6	9.2
153088	Customer Initiated Distribution System Expansion Project (East) DC5/DC6 Urbacon Data Centers	13.7	17.1
153090	YNSE - TPSS System Expansion	0.0	41.4
153092	HaLRT - TPSS 4 System Expansion	9.2	11.5
153134	HaLRT TPSS 8 Expansion	3.1	14.5
153229	Customer Initiated Distribution System Expansion Project - 2395 Speakman Drive	10.6	16.9
153230	Customer Initiated Distribution System Expansion - Toronto Gore (Block 47)	15.3	15.3
153231	Customer Initiated Distribution System Expansion (East South) - Angus Glen Developments	11.1	11.1
153233	Customer Initiated Distribution System Expansion (East South) - Block 27	5.9	5.9
153236	Customer Initiated Distribution System Expansion Project - Block 52 Mississauga Rd & Williams Pkwy	29.0	29.0

* The table above displays VLP with funding allocated for the 2027–2031 period. However, projects marked with an asterisk (*) have started earlier.

2.1 Summary of Investment Outcomes and Benefits

Table B10 - 4 summarizes the outcomes and benefits associated with the Customer Connections investments.

Table B10 - 4 Investment Outcomes and Benefits

Outcome	Investment Benefits and Objectives
Efficiency	• All subdivision projects are coordinated with system planning to ensure optimal coordination of capacity supply • Alectra Utilities coordinates with other utilities to ensure the most cost-effective installation is achieved. • New developments incorporate joint use trenches, which includes electric, gas and digital services (internet, telephone and TV).
Customer Value	• Ensures that Alectra Utilities continues to meet its customer service objectives (e.g. customers continue to be connected within five business days as mandated by the DSC.) • Ensures that customers receive an appropriate supply based upon their usage requirements.
Reliability	• Current standards and designs improve reliability and Alectra Utilities' response to an outage event.
Safety	• Current standards and procedures help mitigate safety risks.
Co-ordination / interoperability	• Alectra Utilities coordinates future supply requirements in conjunction with City road widening projects to ensure assets are in place ahead of development projects. When development is ahead of new road construction, Alectra Utilities will schedule capital projects to extend primary supply to new developments.
Environment	• Project designs adhere to Toronto & Region Conservation Authority and Ministry of Natural Resources & Forestry requirements when constructing in environmentally sensitive areas. • Proper approvals and permits are obtained before constructing along or crossing creeks or rivers. The Endangered Species Act will also dictate design and scheduling requirements to remove risk to species.

III Investment Drivers & Need

3.1 Purpose

The primary drivers of this investment are customer service requests that require expansion and/or connection to Alectra Utilities' distribution system and service upgrades for existing customers. The secondary driver is Alectra Utilities' regulatory obligations to connect new and existing customers to its distribution system.

Table B10 - 5 Investment Drivers

Investment Driver	Reasoning & Investment Benefits
Primary Driver: Customer Service Requests	These investments are required to connect customers to the distribution system.
Secondary Driver: Mandated Service Requirements	These investments are required to comply with the legislative and regulatory requirements including the DSC, Electricity Act, Alectra Utilities' Conditions of Service and a requirement of Alectra Utilities' distribution license.

Overall, Alectra Utilities expects connection and development to trend upward across the utility's service territory from 2027 to 2031 as provided in Table B10 - 6. There are several provincial initiatives that support this expectation that are listed in *Section VII*.

Table B10 - 6 Number of Connections 2020-2031

	Historical Connections					Bridge - Connections		Forecasted Connections				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Number of New Subdivisions (lots - EEM)	NA	5608	5424	4609	5350	5128	5231	5283	5336	5389	5443	5498
Number of Condo Buildings	NA	1	37	38	10	22	26	26	26	27	30	34
Number of ICIs	165	229	259	265	297	282	292	297	303	310	319	337
Number of Res and Small Commercial Layouts	3039	2768	3321	3468	3869	3498	3678	4139	4613	5214	5825	5732
Number of REGEN connections	62	88	154	248	392	388	393	398	402	408	413	419

IV Investment Timing & Pacing

4.1 Summary of Expenditures

Table B10 - 7 provides the year-over-year breakdown of Customer Connection investments, including the historical period from 2021-2024, the bridge years in 2025 and 2026, and the future period from 2027-2031. All costs are net of contributed capital.

Table B10 - 7 Customer Connection Investment Breakdown

	Historical Spending - NET					Bridge - NET		Forecast Spending - NET				
Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Layouts	6.2	5.8	8.5	9.5	12.6	8.2	8.2	8.4	9.5	10.7	12.1	12.2
ICI Services	4.4	2.7	3.1	3.1	1.9	3.3	3.3	0.8	0.8	0.8	0.9	0.9
New Subdivisions	15.5	18.9	13.2	12.7	20.9	16.5	23.0	23.6	24.3	25.1	26.3	27.5
REGEN	(0.2)	0.2	(0.1)	(0.1)	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Customer Initiated	7.9	11.8	2.6	14.9	24.8	19.2	18.2	42.3	56.7	45.8	26.7	31.4
Transit Connections	0.0	0.0	0.2	0.2	(0.3)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL ($MM)	**33.8**	**39.4**	**27.5**	**40.3**	**60.0**	**47.2**	**52.7**	**75.1**	**91.3**	**82.4**	**66.0**	**72.0**

*Negative values represent timing differences between expenditures and cost recoveries. In these instances, Alectra Utilities incurred costs in one fiscal year, while the corresponding reimbursement from the sponsor was recorded in a subsequent year. Where accruals were missed or later corrected, the adjustment appears to be a negative amount in the year shown.

4.2 Historical Expenditures

4.2.1 Historical Expenditures (2020-2024)

Between 2020 and 2024, there were fluctuations in total annual net customer connection expenditures. These fluctuations were due to several factors, including the harmonization of practices in Alectra Utilities' Condition of Service, and the impact of the COVID-19 pandemic on the cost of labour and materials. While spending gradually increased from 2020 onward, the most material increase occurred between 2023 and 2024, driven by extraordinary growth in large customer connections.

Alectra Utilities experienced a surge in demand from data centers during this time in the East and Central-North regions, which required substantial system expansions to meet capacity needs. There was also a notable increase in expansion requests from commercial developments and high-rise residential buildings.

4.2.2 Bridge Year Expenditures (2025-2026)

The bridge years of 2025 and 2026 will have total spending of $99.9MM, with each year having lower spending than in 2024 (a year in which spending was much higher than forecast).

4.3 Future Expenditures (2027-2031)

Alectra Utilities and the cities/regions it serves are expecting continuous growth over the DSP period of 2027-2031. Alongside historic escalation in materials costs, this trend results in a material increase in Customer Connections capital expenditures over the 2027-2031 forecast period.

As detailed below, the forecasted costs of Customer Connections capital work are based on a combination of historical actual costs for programmatic categories of connections, with forecasts based on specific large connection projects where known. For the latter category of connections, *Appendix B13 - Stations Capacity* outlines the expected growth over the DSP period. The figures from that appendix listed below indicate the growth areas that support the increased need for investments in Customer Connections.

- Figure B13 - 2: York Region Station - Markham and Richmond Hill, Ongoing Expansions and Growth Expected to 2035
- Figure B13 - 5: York Region Station - Vaughan, Ongoing Expansions and Growth Expected to 2035
- Figure B13 - 7: Population & Employment Initial Target vs. Current Trend for VMC
- Figure B13 - 8 Town of Alliston & Associated Commercial Developments
- Figure B13 - 9 Town of Bradford Proposed Developments
- Figure B13 - 12 Mississauga Station, Ongoing Expansions and Growth Expected to 2035
- Figure B13 - 13 City of Mississauga Downtown Core

- Figure B13 - 15 Lakeview Village Concept Plan
- Figure B13 - 16 Lakeview Village Phasing Plan
- Figure B13 - 17 Hurontario-Eglinton Concept Plan
- Figure B13 - 18 Brampton Secondary Plan Area
- Figure B13 - 19 Brampton 2040 Vision Plan
- Figure B13 - 20 Brampton Region Stations, Ongoing Expansions and Growth Expected to 2035
- Figure B13 - 23 Countryside Villages (SP48) Development
- Figure B13 - 24 Block 47 The Gore Road Development Plan
- Figure B13 - 25 Heritage Heights Development Plan
- Figure B13 - 26 Hamilton Secondary Plan
- Figure B13 - 29 Hamilton Region Stations, Ongoing Expansions and Growth Expected to 2035
- Figure B13 - 31 Guelph Downtown Secondary Plan
- Figure B13 - 32 Guelph Region Stations, Ongoing Expansions and Growth Expected to 2035

The lasting impact of the COVID-19 pandemic has affected Customer Connections expenditures. The price of materials increased significantly from 2022 to 2024. Refer to following tables below for increase in material costs:

- Table B01 - 4 Percentage Increase in Pole Costs from 2020 Baseline
- Table B02 - 5 Percentage Increase in Cable Material Costs from 2020 Baseline
- Table B02 - 10 Percentage Increase in Switchgear Costs from 2020 Baseline
- Table B03 - 5 Percentage Increase in Transformers Costs from 2020 Baseline

An explanation of the forecast methodology applied to each investment category is explained below:

4.3.1 Layouts

Average historical 2020-2023 service connection volumes and historical unit cost pricing were applied as the initial basis to determine forecasted connection volumes and gross expenditures in Layouts. Additional EV related connections were factored into the forecasts.

Consistent with historical averages, Layouts are forecasted to include 53% contributed capital after 2027.

4.3.2 ICI Services

Average historical 2020-2023 service connection volumes and historical unit cost pricing were applied as the initial basis to determine forecasted connection volumes and gross expenditures in ICI Services. Additional EV related connections were factored into the forecast.

Historically, some legacy utilities exercised their option under Section 3.1.5 of the DSC to offer service credits for connecting non-residential connections, beyond the OEB prescribed credits, while some other legacy utilities did not. Non-residential service credits were previously introduced for ICI Services to equalize cost sharing responsibilities and ensure alignment across Alectra Utilities' service territory. With the removal of the non-residential service credits and new harmonized rates, the customer experience will be the same throughout Alectra Utilities' service territory with respect to connecting and delivering power to its customers. As a result, in 2027 onwards, there will be a reduction in Alectra Utilities' annual forecasted net expenditures as illustrated in Table B10 - 7, including the removal of the non-residential service credits, amounting to approximately $2.5MM annually.

The historical averages for ICIs were 85% contributed capital and 15% NET. From 2027 onwards, with the removal of service credits, these are forecasted to change to 98% contributed capital and 2% NET. The forecasted 2% NET is a result of Alectra Utilities providing credits for the residual values of removed equipment or the need to fund portions of the work.

4.3.3 New Subdivisions

New Subdivision expenditures are comprised of 4 components:

- New residential subdivisions (~90% of the total)
- New ICI subdivisions (~7% of the total)
- Developer driven relocation work for subdivisions (~2% of the total)
- Damage and restoration (less than 1% of the total)

New Residential Subdivisions

The historical spending for all subdivisions including residential and condo developments is based on the costs from each Offer to Connect provided to the developers. These costs are derived from the Economic Evaluation Model (EEM) in accordance with the Distribution System Code. The actual spending incurred during the given year can differ from the number of connections for a year due to timing of energization of these units. Furthermore, the connections can occur anytime during the connection horizon agreed to in the Offer to Connect.

Historically, the number of new residential connections have grown modestly, and is expected to continue growing, whereas the costs have been increasing more rapidly after COVID.

For condo buildings, the upfront cost per connection is usually higher as most of the costs for the distribution system include concrete encased ducts, cables and switchgears.

Since 2022, there has been a shift towards intensification and increased activity in new high density condominium construction within Alectra Utilities' service area. This shift has changed the method for forecasting future new subdivision expenditures. The forecast is now comprised of:

- Residential Subdivisions (single family houses, townhouses, semi detached etc.), for which Alectra Utilities used the average historical volumes and current pricing to forecast future expenditures for residential subdivisions, with a 1% annual increase in volumes. For this category, the average gross unit cost expenditures from 2022 to 2024 were used as a baseline to forecast future expenditures. This represents 85% of the New Residential Subdivision expenditures.
- High Rise Condominium buildings are forecasted based on the proposed developments noted in *Appendix B13 - Stations Capacity*. Alectra Utilities believes that the total number of developments indicated may not be fully realized within

the DSP period, and as such, the volume has been slightly reduced from 2027 to 2031. For this category, the average gross unit cost expenditures from 2022 to 2024 were used as a baseline to forecast future expenditures. This represents 15% of the New Residential Subdivision expenditures.

The sum of the four categories results in the total gross forecast for new subdivisions. With respect to contributed capital, the historical average was used. For high rise condominiums, a recent regulatory policy changed the revenue horizon in the economic model (DSC EB-2024-0092) from 25 to 40 years. This results in more revenue derived by Alectra Utilities from the condominiums, which decreases the developer contributions and increases Alectra Utilities' net expenditures.

This forecasting approach is conservative, as it only accounts for the connections from identified developments. Alectra Utilities expects that government policies may drive higher connection volumes over the DSP period. However, Alectra Utilities cannot predict the impact of such policies and other external factors with sufficient certainty to account for them in the forecast.

4.3.4 Customer Initiated

The Customer Initiated expenditures are comprised of three components:

- Customer Initiated Expansion and Relocation Projects
- Transit Expansion Projects
- Customer Initiated Joint Use Projects

Customer Initiated Expansion and Relocation Projects

Since 2022, there has been a notable shift towards urban intensification, including a rise in high-density condominium developments, commercial developments, transit initiatives, large residential developments/mixed use and data centres in Alectra Utilities' service territory. This has led to an increase in the volume and size of customer-initiated expansion and relocation projects.

Alectra Utilities has recognized the impact of this shift and has adjusted the forecasting methodology accordingly.

Customer initiated expansion and relocation projects are forecasted in 2 parts:

- Annual volumes for unspecified projects that will arise, which are unknown at the time of this plan's creation and for known projects that are below the very large projects (VLP) threshold of $5MM net
- Estimates for known specific VLP projects (above $5MM net)

For the unspecified projects component and known projects below the VLP threshold, the average actual gross expenditures from 2022 to 2023 and 2024 forecasted gross expenditures were used as a baseline to forecast future expenditures. Estimates for known specific VLP projects were created based on high level estimates for projects of similar past scopes and magnitudes and have discrete individual project budgets prepared, and individual business cases created.

The customer contributions for system expansion projects are based on historical data and the outcomes of the Economic Evaluation Model for the projects included in the DSP period. This result in average of 24% for Contributed Capital and 76% for NET amount.

The customer contributions for relocation projects were based on the averages of historical economic evaluation model results. This results in 79% contributed capital and 21% net amounts.

All material projects are listed in Table B10 - 8.

4.3.5 Transit Expansion Projects

Transit Expansion Projects forecasts were based on estimates for known specific projects.

Estimates for known specific projects were created based on high level estimates from 2022-2024 projects of similar past scopes and magnitudes and have discrete individual project budgets prepared, and individual business cases created.

The customer contributions for Transit Expansion projects are a result of the Economic Evaluation Model outputs. This results in an average of 77% for contributed capital and 23% for net.

All material projects are listed in Table B10 - 9.

4.3.6 Customer Initiated Joint Use Projects

The forecast for future expenditures was derived using the average actual gross expenditures from 2022 to 2023 and 2024 forecasted gross expenditures as a baseline to forecast future expenditures.

For forecasting the DSP period of 2027 to 2031, adjustments were made for a modest increase in volume due to the deployment of fibre optic cables by telecom providers, increased costs for materials, labour, and third-party costs.

The joint use tenant's contributions are generally almost fully recoverable. The net expenditures were based on comparable project types. This results in 98% contributed capital and 2% net. The 2% cost reflects Alectra Utilities' responsibility for non-recoverable expenditures that are either driven by internal standards or due to operational factors outside of tenant responsibility.

4.3.7 Transit Connections

Transit Connections were forecasted based on known projects that are large and have a long duration.

The Transit Connections contributions were based on historical amounts. Transit Connections are forecasted at 0% net.

4.4 Investment Pacing and Prioritization

The pacing of Customer Connections work is largely determined by factors outside of Alectra Utilities' control. Alectra Utilities works with customers at all levels to optimize the workplan and minimize costs, while maintaining its legal and regulatory requirements.

Scheduling of projects is finalized once the Developer or Customer provide the necessary securities, signed agreements, approved drawings and has received the necessary approvals from the City Planning department.

Historical service connections are reviewed and are applied as the initial basis to determine forecasted connections. Alectra Utilities continually collaborates with the development community in discussing future plans within the various territories. City draft plan submissions are circulated to Alectra Utilities, allowing the opportunity to review and provide comments regarding future developments at the preliminary stage. Municipal growth forecasts and economic development plans are also referenced to better understand potential developments.

Subdivision developments are scheduled for construction once all the necessary requirements, as outlined in the Offer to Connect, are provided by the Developer or Customers to Alectra

Utilities. Once received, Alectra Utilities coordinates with the Developer for timing requirements outlined within both the OTC and the DSC.

It is expected that an increase in EVs over the 2027-2031 period will result in an increase in service upgrades to homes and businesses as well as an increase in EV Charger Connections within Alectra Utilities' Service Territory.

4.5 Execution Approach

Customer Connections are projects that are dependent on developers and customers providing pre-service requirements (e.g., Project design deposits, Letter of Credit deposits, approved engineering drawings and a signed Offer to Connect) for all types of work (layouts, subdivisions, customer-initiated projects, ICIs). Once Alectra Utilities receives the information that is related to the type of work, designs are completed and scheduled to accommodate Developers/Customers proposed dates to ensure that the site/facility can be energized prior to its occupancy date.

The start date for projects may be contingent on municipal draft plan approvals, site plan approvals, variances or other specific regional or municipal requirements. Developers/customers must provide the necessary project deposits. During project pre-construction meetings, Alectra Utilities discusses relevant requirements with developers and finalizes project timelines. Alectra Utilities allocates crews to accommodate energization dates for new service connections and DSC obligations are met.

Alectra Utilities tries to minimize on-site revisions to avoid incremental costs. Alectra Utilities has established a process by which firm pricing is received from approved design consulting companies and civil contractors to design and install the required infrastructure within ICI and greenfield subdivision developments to Alectra Utilities' standards and specifications. The approved consultants and contractors were selected through a rigorous tendering process resulting in competitive pricing providing best value. Firm pricing is used when preparing Alectra Utilities' OTC to the Developers.

Winter weather can be a major constraint to connections work in new subdivisions. Alectra Utilities applies "frost charges" to projects completed during winter months to recover the increased costs associated with this work. Winter construction is typically initiated by Developers, who are made aware of the cost impacts of seasonal work.

V Options Analysis

All work within the Customer Connections portfolio is mandated by regulatory requirements, and therefore, no options were considered for this program. However, Alectra Utilities continually seeks to optimize and enhance efficiency within this portfolio. The strategies that are employed to achieve these goals are presented in Figure B10 - 1 and described in detail below:

Figure B10 - 1 Customer Connections Options Analysis

- **Streamlined Processes**: Alectra Utilities has implemented streamlined processes for handling customer requests and project initiation. By leveraging digital tools and automation, the utility reduces the time from application to project completion, ensuring compliance with regulatory timelines while improving customer satisfaction.
- **Design Optimization**: Within the constraints of the DSC and Alectra Utilities' standards, the utility explores design optimizations that can reduce costs and improve system reliability. This includes the use of standardized designs for common connection types, which can be adapted to specific site conditions, thereby reducing design time and costs.

- **Resource Allocation**: Alectra Utilities employs a dynamic resource allocation model to ensure that crews and materials are efficiently deployed across projects. This approach minimizes idle time and maximizes the utilization of resources, leading to cost savings and faster project completion.
- **Collaborative Planning**: Early engagement with developers, city planners, and other stakeholders allows for better coordination and planning. This collaboration can lead to more efficient project execution, as potential issues are identified and addressed early in the planning stages.
- **Cost Sharing**: Alectra Utilities explores opportunities for cost-sharing arrangements with developers and customers, where feasible, to reduce the financial burden on the utility while maintaining compliance with regulatory requirements.
- **Continuous Improvement**: Alectra Utilities maintains a culture of continuous improvement, regularly reviewing its processes and outcomes to identify areas for enhancement. This includes analyzing historical data to refine forecasting models and improve the accuracy of future investment plans.

By implementing these strategies, Alectra Utilities aims to maximize efficiency and value within the mandated framework of the Customer Connections portfolio, ensuring that regulatory obligations are met while delivering the best possible service to customers.

VI Investment Projects

The material investments from 2027 to 2031 that form the Customer Connections investments are listed in Table B10 - 8.

Table B10 - 8 Material Projects and Initiatives

Project Code	Project Name	CAPEX NET ($MM)
101887	New Residential Subdivision and Condo Tower Development - Alectra East	60.1
153236	Customer Initiated Distribution System Expansion Project - Block 52 Mississauga Rd & Williams Pkwy	29.0
150630	New Residential Subdivision and Condo Tower Development - Alectra Central North	23.2
150588	New Residential Subdivision and Condo Tower Development - Alectra West	20.6
152359	Customer Initiated Distribution System Expansion Projects - East South	17.6
152453	Customer Initiated Distribution System Expansion Projects - Central North	16.7
153230	Customer Initiated Distribution System Expansion - Toronto Gore (Block 47)	15.3
151578	Services (New and Upgrades) - Layouts - East South	13.9
153088	Customer Initiated Distribution System Expansion Project (East) DC5/DC6 Urbacon Data Centers	13.7
150388	Services (New and Upgrades) - Layouts – Central South	12.2
150456	Services (New and Upgrades) - Layouts – Hamilton	12.0
152381	Customer Initiated Distribution System Expansion Projects - West	11.4
153231	Customer Initiated Distribution System Expansion (East South) - Angus Glen Developments	11.1
153229	Customer Initiated Distribution System Expansion Project - 2395 Speakman Drive	10.6
152602	Customer Initiated Distribution System Expansion Project - GTAA Feeders	9.5
152302	Customer Initiated Distribution System Expansion Projects - Central South	9.4
153092	HaLRT - TPSS 4 System Expansion	9.2
150652	New Residential Subdivision and Condo Tower Development - Alectra Central South	7.9
152482	Customer Initiated Distribution System Expansion Project - Trillium Health Partners	7.6
152676	Lakeview Expansion	6.6
153233	Customer Initiated Distribution System Expansion (East South) - Block 27	5.9

Project Code	Project Name	CAPEX NET ($MM)
151584	Customer Initiated Distribution System Project (West) McMaster Innovation Park - Dedicated Feeder- Business Park	5.9
152335	HaLRT OMSF Expansion	5.7
150389	Services (New and Upgrades) - Layouts – Central North	5.6
101896	New Institutional/Commercial/Industrial Subdivision Development - Alectra East	4.5
150457	Services (New and Upgrades) - Layouts – St Catharines	4.4
153232	Customer Initiated Distribution System Expansion Project - Block 48 Torbram Rd and Mayfield Rd	3.2
153134	HaLRT TPSS 8 Expansion	3.1
151696	New Residential Subdivision and Condo Tower Development - Alectra Guelph	2.8
151577	Services (New and Upgrades) - Layouts - East North	2.6
153234	Customer Initiated Distribution System Expansion (East South) - Hwy 48	2.5
152365	Equinox System Expansion	2.4
151550	Services (New and Upgrades) - Layouts - Guelph	2.3
151673	New Industrial/Commercial/Institutional Subdivision Development - Alectra Central North	1.7
152422	Customer Initiated Distribution System Expansion Projects - East North	1.7
151652	New Industrial/Commercial/Institutional Subdivision Development - Alectra West	1.5
151531	Subdivision Developer Capital Plant Relocation - Alectra East	1.4
101761	Customer Initiated Distribution System Relocation Projects - East South	1.3
150384	Services (new and upgrades) - Commercial, Industrial and Institutional (ICI) Projects - Central South	1.2
101791	Services (New and Upgrades) - Commercial, Industrial and Institutional (ICI) Projects - East South	1.0

Appendix B11 - Road Authority & Transit Projects

Alectra Utilities' investments in Road Authority and Transit Projects are comprised of two separate portfolios:

a) **Road Authority Projects** – Non-discretionary projects that are governed under the *Public Service Works on Highways Act* (PSWHA)[57] and are a result of projects by Road Authorities that require Alectra Utilities to perform work on the distribution system within the public right-of-way

b) **Transit Projects** – Non-discretionary modifications to Alectra Utilities' distribution system that are initiated by transit or rail agencies at any jurisdictional level — federal, provincial, regional, or municipal and governed by *Building Transit Faster Act* (BTFA), and the PSWHA, and applicable agreements. These projects can involve:

- Rail infrastructure (freight or passenger), including federally regulated freight lines (e.g. CN), commuter rail (GO Expansion), subways, and light-rail transit (LRT)
- Bus-based transit infrastructure, such as dedicated Bus Rapid Transit (BRT) corridors, terminals, and supporting roadworks. Where the primary sponsor is a transit entity and the works are carried out for transit operating purposes, the costs are recorded in the Transit Projects portfolio; otherwise, similar road-based projects remain in the Road Authority portfolio

Because the authority responsible determines the scope and schedule of Road Authority projects and Transit Projects, Alectra Utilities must relocate or modify its assets as directed and cannot defer or decline the work in compliance with BTFA, PSWHA and applicable agreements.

These two portfolios are presented separately in this investment summary due to the different nature of cost sharing arrangements.[58]

[57] R.S.O. 1990, c. P.49.
[58] Road Authority Projects involve distribution system modifications as a result of road authority requests governed by the PSWHA. Transit Projects are rail-related or BRT-related initiatives that require Alectra Utilities to modify the

Refer to Table B11 - 1 for net expenditures related to Road Authority and Transit Investment.

Table B11 - 1 Road Authority & Transit NET Investment Expenditures, Drivers and Outcomes

	Historical Spending - NET					Bridge - NET		Forecast Spending - NET				
Year	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Road Authority	12.0	14.2	5.8	8.5	16.5	14.0	14.8	19.3	15.1	13.2	13.3	13.7
Transit[59]	0.5	(0.7)	0.1	(0.3)	(0.1)	0.4	2.1	4.2	4.1	0.0	0.0	0.0
Total ($MM)	12.5	13.5	5.9	8.2	16.4	14.4	16.9	23.5	19.2	13.2	13.3	13.7
Primary Driver	Mandated Service Obligations											
Outcomes	Reliability, Safety, Efficiency, Coordination and Interoperability, Adherence to Public Policy											

distribution system and are expected to be funded by the Provincial transit agencies. Some Transit Projects may also be governed by PSWHA.

[59] In certain years, the timing of final cost-recovery invoices and accrual reversals create a situation where sponsor reimbursements booked during the fiscal year exceed the new relocation costs incurred in that same year. The resulting accounting entry appears as a negative NET-capital or reduced capital spending amount even though the underlying gross construction spending remained positive.

Part A: Road Authority

I Overview

Road Authority Projects consist of capital work that Alectra Utilities must perform to comply with the PSWHA.

Alectra Utilities' distribution infrastructure is largely installed along road allowances either above or below public roads (or designated as "highways" under provincial legislation). The municipal, regional and provincial bodies responsible for managing these roads are defined as Road Authorities under the PSWHA. When a Road Authority does work on a road, it may require a utility to relocate or reconstruct its equipment. Under the PSWHA, Alectra Utilities (and other utilities) must comply with Road Authority directives. Accordingly, the expenditures in this portfolio are non-discretionary.

Section 2(1) of the PSWHA provides that if, in constructing, altering, or improving a road or highway, it becomes necessary for a utility to take up, remove, or change the location of its infrastructure located on, under, or over the road, the Road Authority may give notice requiring the utility to complete the work by a specified date.

The impacts of the PSWHA on Alectra Utilities' approach to performing the work associated with Road Authority Projects include:

- Operational Flexibility: The PSWHA limits Alectra Utilities' ability to independently plan and schedule its capital expenditures because the timing and scope of Road Authority projects can change abruptly. Accommodating such changes necessitates a flexible operational approach.
- Cost Allocation: Under Section 2(2) of the PSWHA, the Road Authority and Alectra Utilities may agree on the apportionment of the cost of labour used for the taking up, removal, or change in location of the utility infrastructure, but where there is no such agreement, the cost of labour is apportioned equally between them. Moreover, Section 2(2) of the PSWHA requires that all other costs of the work (i.e. non-labour costs) shall be borne by Alectra Utilities (subject to additional project costs associated with additive scope imposed by the Road Authority as discussed

below). In most cases, Alectra Utilities follows the 50/50 labour cost-sharing arrangement prescribed by the legislation.

- Coordination and Planning. Alectra Utilities engages in extensive coordination with Road Authorities, city planners, and civil consultants during the preliminary stages of project planning. This ensures that Alectra Utilities can provide input on distribution system modifications before final designs are implemented, leading to more efficient and cost-effective solutions.
- Impact on Service Reliability: The relocates or reconstructs of equipment in response to Road Authority projects can temporarily disrupt service to customers. Alectra Utilities carefully manages these disruptions to minimize reliability and customer impacts.
- Long-term Planning Challenges: The unpredictability of Road Authority projects makes long-term planning challenging for Alectra Utilities. While some municipalities and regions provide long-term road works programs, many do not, requiring Alectra Utilities to rely on historical trends and known costs for forecasting expenditures. Additionally, posted road works programs are forecasts and are generally not very reliable. The Road Authority typically makes multiple plan changes annually.

By understanding and adhering to the requirements of the PSWHA, Alectra Utilities ensures compliance with legal obligations while striving to minimize costs and maintain service reliability for its customers.

Depending on the nature of the Road Authority's work, Alectra Utilities' Road Authority investments typically fall into two categories:

- Relocation: These investments consist of the relocation of distribution infrastructure to accommodate road works, as contemplated under the PSWHA. This could involve moving existing infrastructure, such as pole lines or duct structures, from one location within the road allowance to another location within the same allowance, either on the same side of the road or across to the opposite side. The configuration and type of infrastructure generally remain unchanged.

- Reconstruction: These investments involve the construction of replacement facilities when a Road Authority requests a change from one form of infrastructure to another. Replacement facilities may also be relocated relative to the location of the original infrastructure. For example, replacing an overhead pole line with an underground duct system. These changes are initiated solely by the Road Authority and are often driven by non-technical factors.

Road Authorities, including Municipalities, the Ministry of Transportation of Ontario (MTO) and regional authorities, establish their road works program for each year, however their work programs often change on short notice, making it difficult for Alectra Utilities to forecast its capital spending for Road Authority projects. Road Authority relocation and reconstruction investments are entirely driven by directives from these third parties and, as such, the timing of when projects start and end is beyond Alectra Utilities' control.

Alectra Utilities mitigates these challenges by participating with the Road Authority, city planners and civil consultants in the preliminary stages of project planning. This ensures that Alectra Utilities can provide comments and recommendations with respect to the distribution system prior to final designs being implemented, with a view to implementing the most efficient and cost-effective designs that meet the relevant needs. Additionally, Alectra Utilities holds regular planning discussions with the various Road Authorities and actively participates in various municipal meetings to better forecast the scope and number of future Road Authority projects.

The Road Authorities within Alectra Utilities' service territory include a range of municipal, regional, and provincial bodies. These include the Region of York, Region of Peel, Niagara Region, Guelph Region, Simcoe County, the MTO, as well as the individual municipalities served by Alectra Utilities.

Costs associated with the projects are dependent on the size, type and complexity of the individual projects, and are divided between the parties as specified in the PSWHA.

Table B11 - 2 Road Authority Investment Expenditures, Drivers and Outcomes

	Historical Spending - NET					Bridge - NET		Forecast Spending - NET				
Year	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Road Authority CAPEX ($MM)	12.0	14.2	5.8	8.5	16.5	14.0	14.8	19.3	15.1	13.2	13.3	13.7
Primary Driver	Mandated Service Obligations											
Outcomes	Reliability, Safety, Efficiency, Coordination and Interoperability, Public Policy											

II Investment Description

Road Authority-Related Investments

A significant portion of Alectra Utilities' overhead and underground infrastructure is installed along road allowances that are under the jurisdictions (owned and managed) of various Road Authorities. Under the *Electricity Act, 1998*, S.O. 1998, c. 15, Alectra Utilities is permitted to occupy public right of ways at no cost to the utility. Per the PWSHA, utilities are mandated to remove, relocate, or reconstruct their facilities to accommodate the specific requirements of the Road Authorities during road related projects.

During Road Authority projects, Alectra Utilities proactively reviews its distribution system requirements to identify opportunities for system enhancements that align with long-term planning objectives, such as addressing future capacity needs driven by intensification and redevelopment. When such enhancements are identified, Alectra Utilities bundles the required Road Authority relocation work with system modifications to complete both scopes of work at the same time. While this approach results in higher upfront costs for Alectra Utilities, since the utility pays for all costs associated with the system enhancements, it avoids the need to return to the same area in the future to install additional infrastructure. As an example, the majority of the costs for relocating an overhead pole line during road widening is driven by labour and equipment, while material costs are less significant. Road Authority relocations are reviewed with System Planning and Asset Management. If the Road Authority project is in an area with a significant load growth, Alectra Utilities reviews the ability for taller poles to be installed, allowing both the relocation of existing circuits and the addition of the new circuits when required. The incremental cost for the taller poles is minimal when compared to the expense of removing and replacing poles with the taller ones, after the Road Authority relocations have been completed.

This bundling strategy creates efficiencies and long-term savings for ratepayers by eliminating redundant work.

Under this model, the Road Authority continues to pay its prescribed share, typically 50% of the labour and labour-saving devices associated with relocating or reconstructing the existing infrastructure. Alectra Utilities continues to bear responsibility for all non-labour related costs associated with the relocation or reconstruction work. In addition, Alectra Utilities assumes full responsibility for any incremental costs related to distribution system improvements, ensuring that

only distribution system-related benefits are recovered through rates. This integrated approach optimizes capital investments while maintaining compliance with the PSWHA and meeting customer and system needs more effectively.

In Alectra Utilities' service territory, there are several ongoing and future large multi-year Road Authority projects as listed in Table B11 - 6.

The specific work involved in any Road Authority project can vary significantly depending on the assets impacted, the nature of the Road Authority request and many other factors (e.g. scope of road widening, traffic and population density, right of way size, number of utilities involved and availability of space to relocate).

To forecast expenditures, Alectra Utilities relies on a combination of historical trends and known costs where possible. Where the details for planned relocations are available, Alectra Utilities can assess an approximate project cost based on the scope of the relocation or reconstruction. For simple overhead to overhead relocations, the costs are calculated based on the initial designs and are directly proportional to the volume of poles, number of dips and taps, and the number of circuits on the poles that are to be relocated. However, Road Authorities often change the scope or details associated with their road layout or construction which can result in significant shifts in Alectra Utilities' designs.

Road Authority projects often present forecasting challenges. For example, a "like for like" approach may not be available where the existing right of way is already utilized and a relocation further away from the traveled portion of the road is not possible due to aerial encroachment, proximity to the road or proximity to the existing buildings. In such cases, the only option is to reconstruct the existing pole line underground which increases the cost associated with the Road Authority project. In many cases, each project must be forecast individually considering the unique variables, including size of the right of way, whether and which other utilities will affect relocations, whether there is space for relocation, whether conversion to underground is required, and future requirements. Based on these factors, an estimate is prepared.

Allocation of Costs

Cost sharing for relocating or reconstructing public utilities within municipal road allowances and provincial highways is determined in accordance with the PSWHA. Section 2 of the PSWHA specifies that a Road Authority and an electricity distribution company may agree upon the apportionment of the cost of labour. In the absence of an agreement, such costs shall be apportioned equally, and all other costs of the work shall be borne by the electricity distribution company. Under Section 1 of the PSWHA, the "cost of labour" is a defined term that includes wages paid to workers as well as other elements, such as the cost of using mechanical labour-saving equipment in the work. These costs are applicable to all activities associated with the project, including construction, external contractors, design, consultants, technical investigations, planning, inspections, permits, legal and other costs. For Road Authority relocation or reconstruction requests, Alectra Utilities must follow the PSWHA and associated regulations. In the absence of a specific cost sharing agreement, Alectra Utilities collects contributed capital of 50% of the labour and labour-saving devices for Road Authority driven projects. As a result, on an overall basis, the total costs of relocating or reconstructing distribution facilities in connection with a typical road widening project are generally allocated 30-40% to the Road Authority and 60-70% to Alectra Utilities. Various factors may affect the final cost of a project, including unforeseen construction activities, such as the removal of abandoned infrastructure that was not identified during Subsurface Utility Engineering investigations, frost charges, and delays caused by other contractors working for the Road Authority.

In certain situations, the Road Authority will incur costs in addition to the PSWHA original relocation costs. As permitted under Section 2 of the PSWHA, Alectra Utilities and the Road Authority may agree on a different apportionment of the cost responsibility for different portions of the relocation project based on the incremental costs of certain requests made by the Road Authority. At the request of the Road Authority, Alectra Utilities may be required for specific portions of the road widening project to relocate some sections underground, install concrete poles with specifications beyond existing standards, or relocate assets at different spacing requirements. Alectra Utilities and the Road Authority may agree to reflect these incremental relocation costs by having the Road Authority fund a greater portion of those costs.

In other situations, Alectra Utilities' may elect to supplement its facilities above and beyond what is required under the Road Authority project. In this case, Alectra Utilities will fund 100% of the additional work.

The most efficient way to relocate assets is initially established by Alectra Utilities. If the Road Authority wants to upgrade from the proposed solution to a more expensive approach, they are required to pay for 100% of the difference in cost between Alectra Utilities' initial solution and the Road Authority's preferred approach.

2.1 Summary of Investment Outcomes and Benefits

Table B11 - 3 summarizes the outcomes and benefits associated with Road Authority investments.

Table B11 - 3 Road Authority Investment Outcomes and Benefits

Outcome	Investment Benefits and Objectives
Customer Value	• This allows for an opportunity for new equipment to be installed, where efficient, to better serve customers.
Reliability	• Helps maintain reliability as aging assets approaching or at end-of-life criteria may be replaced with current standard assets. • System expansion investments may involve the addition of new sub-loops and reconfiguration, thus enhancing system performance.
Safety	• Any new standardized equipment that is installed generally improves safety as compared to older equipment.
Co-ordination / interoperability	• New standards and installation practices allow for safer and easier operations thereby creating better functionality and improved operation requirements.
Public Policy	• Ensures Alectra Utilities' compliance with the PSWHA, the DSC and agreements with Road Authorities.
Efficiency	• In cases where the scope of the Road Authority investment is extended to include system enhancement scope, all work will be designed and constructed simultaneously, thus saving money in mobilization, switching, restoration and overall project management. • All Road Authority projects are coordinated to ensure that work is conducted efficiently and to maximize cost-effectiveness.

III Investment Drivers & Need

3.1 Purpose

As described above, the primary driver of these investments is compliance with legislation that requires Alectra Utilities to relocate or reconstruct distribution equipment within the road allowance, by a specified date, upon direction from a Road Authority.

Table B11 - 4 summarizes the primary and secondary drivers of the program.

Table B11 - 4 Road Authority Investment Drivers

Investment Driver	Reasoning & Investment Benefits
Primary Driver: **Mandated Service Obligations**	• Compliance with the PSWHA requires that all utilities with equipment over, on or under the highway cooperate with the Road Authority and relocate or reconstruct the infrastructure as required to allow for future road construction work.
Secondary Driver: System Enhancements and Efficiency	• Allows for proactive infrastructure upgrades, improved system reliability and alignment with future capital plans. • Bundling enhancement work with mandated relocations increases efficiencies.

IV Investment Timing & Pacing

4.1 Summary of Expenditures

All Road Authority investments are non-discretionary and are required to be initiated and completed in accordance with the direction provided by the Road Authorities.

Many municipalities, the MTO and regional authorities establish road works programs spanning up to 10 years. Many others do not publish any information.

Alectra Utilities' Road Authority group meets with all Municipalities and Regions on an annual basis to discuss the upcoming projects. Each of the projects noted by the Road Authorities are reviewed for their impact on Alectra Utilities' distribution system. The projects affecting the distribution system are included in the road authorities' listing and the C55 Business Cases are adjusted accordingly.

While Alectra Utilities relies on the municipal and regional long-term plans where possible, the specific projects being executed each year are subject to change by the Road Authority, inevitably resulting in variances between forecast and actual costs. Alectra Utilities makes every effort to proactively anticipate any upcoming requests through participating in meetings with the Cities and Regions and through reviewing site plans and zoning amendments.

Table B11 - 5 provides the total annual spending for these investments over the historical, bridge and plan periods, net of capital contributions. This forecast is based on a combination of historical trends and known costs for specific projects identified through coordination with the Road Authorities and through a review of published road works plans from the Regions, Municipalities and the MTO that are within Alectra Utilities' service territory.

Table B11 - 5 Road Authority Historical & Proposed Investment Spending

	Historical Spending - NET					Bridge - NET		Forecast Spending - NET				
Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
CAPEX ($MM)	12.0	14.2	5.8	8.5	16.5	14.0	14.8	19.3	15.1	13.2	13.3	13.7

4.2 Historical Expenditures

4.2.1 Historical Expenditures (2020-2024)

Between 2020 and 2024, there were fluctuations in total net expenditures within the Road Authority projects. In 2020 and 2021, the variance was largely due to the deferral or cancellation of scheduled projects in Brampton, Guelph, and Mississauga. Most of the variance occurred in 2022 and 2023 when spending in the East, South, and Central regions of Alectra Utilities' service territory declined significantly.

A key contributing factor was the reprioritization of capital works by several municipalities and regional governments. In response, several municipalities reassessed their capital programs, delaying or reducing the scope of road infrastructure projects. For the reasons described above, these shifts directly impacted the volume and timing of utility relocation requests submitted to Alectra Utilities. 2024 was the largest year of expenditures in the Road Authority segment for Alectra Utilities ($16.5MM).

4.2.2 Bridge Year Expenditures (2025-2026)

The bridge years of 2025 and 2026 are forecast to have total spending of $28.8MM, with each year having lower spending than in 2024. Investments in Road Authority projects must continue for Alectra Utilities to remain compliant with its mandated requirements.

4.3 Future Expenditures (2027-2031)

Road Authority projects are forecasted in two parts:

- Annual volumes for unspecified projects that arise, which are unknown at the time of budget or DSP creation and for known projects that are below the very large projects (VLP) threshold of $5MM net
- Estimates for known specific projects above the VLP threshold of $5MM net

Aggregated average annual historical expenditures by region were used to forecast the expenditures for unspecified projects and known projects below the VLP threshold. Estimates for known specific VLP projects were developed based on high level estimates for past projects from

2020-2024 that were of similar scope and magnitude. These projects have discrete individual project budgets and individual business cases.

For 2029 to 2031, the annual forecast is based on historical expenditures for unspecified projects of approximately $12.8MM net annually, plus inflationary increases. There is only one known Road Authority VLP which occurs in 2027 and 2028, totaling $7.9MM net (refer to Table B11 - 6). From 2029-2031, Alectra Utilities has no visibility on any VLPs, which results in a drop in the forecasted net spend in these years.

Cost sharing follows PSWHA typically resulting in 35% contributed capital and 65% net amounts for Alectra Utilities. Material Road Authority projects are listed in Table B11 - 6.

4.4 Investment Pacing and Prioritization

Road Authority investments are non-discretionary projects and must be completed according to the timelines stipulated by the Road Authority. In accordance with Section 2(5) of the PSWHA, if Alectra Utilities does not comply with a notice from a Road Authority, it must compensate the Road Authority for any loss or expense incurred by the Road Authority as a result. These projects are high priority since Alectra Utilities must be compliant with the PSWHA. As previously noted, the most efficient way to relocate assets is initially established by Alectra Utilities. If the Road Authority wants to change from one form of infrastructure to another, for example, replacing an overhead pole line with an underground duct system, these changes are initiated solely by the Road Authority. In this case, the Road Authority is expected to pay 100% cost of the difference from Alectra Utilities' initial solution and the Road Authority preferred approach.

Alectra Utilities thoroughly reviews all Road Authority investments and compares all projects against the proposed or future initiatives and projects within the Planned Capital, Industrial, Commercial and Institutional, Transit, Subdivision and Substation portfolios. If Road Authority projects are executed at the same locations as other projects, the Road Authority projects take priority as their completion is driven by the PSWHA. Additionally, any potential cost savings through project coordination are explored.

The pacing and prioritization can be further affected by Road Authority investments that were never previously scheduled and must be designed and constructed within the same year, often impacting spending, budgets and resources.

Scope changes are another risk associated with third party driven projects. Unexpected scope changes can result in multiple iterations of a design, which increases project cost. In addition, since these projects are carried out in the road allowances, unforeseen factors often affect the overall cost. For example, conflicts between the proposed infrastructure and the existing plant which was not installed as per the original design, or the removal of abandoned structures that were not identified on the initial drawings from the Road Authority.

In some cases, a Road Authority may require that Alectra Utilities follow certain conditions that Alectra Utilities would not otherwise provide for in its design because they increase costs. For example, the replacement of an overhead highway crossing with the same infrastructure at a different offset, or the imposition of conditions that will allow another contractor to work in proximity to the new crossing. In cases where the Road Authority requires specific conditions that increase costs, Alectra Utilities constructs the required facilities per the conditions and bills any incremental costs arising from those conditions to the Road Authority.

To manage and mitigate uncertainties in relation to Road Authority projects, Alectra Utilities has ongoing discussions with the municipalities as well as other Road Authorities to make sure it is aware of their plans and can adjust schedule to meet their timelines. In addition, to manage the unpredictable nature of Road Authority projects, Alectra Utilities has retained external contractors under multi-year engineering procurement and construction Master Service Agreements (MSA). This approach ensures that Alectra Utilities has the necessary resources to carry out the work efficiently, even when projects are added or accelerated unexpectedly. Finally, regular progress meetings are held to ensure technical and operational issues are known and resolved promptly.

4.5 Execution Approach

Because Road Authority investments are non-discretionary and entirely dependent on Road Authority timelines, Alectra Utilities will schedule the projects as they are requested subject to having the resources available to complete the scope and having received the construction deposits or purchase orders.

The design for each individual project is started when 60% of the design from the Road Authority consultant is provided to Alectra Utilities. The design is completed, and construction is scheduled at least two months ahead, allowing for the crews' mobilization, the completion of locates, and the acquisition of materials.

The project is then released to the crews or, if internal resources are not available, the project is released to Alectra Utilities' approved contractor for construction. Once the job is completed, Alectra Utilities will invoice or return the difference between the initial estimate and actual final cost for Road Authority's share of the labour costs.

V Options Analysis

As explained above, the scope and timing of Road Authority project investments are non-discretionary. They are mandated by the Road Authority under the PSWHA. Therefore, Alectra Utilities does not have options with respect to completing the scope.

Alectra Utilities does however manage the investments as efficiently as possible within the legislative requirements and Road Authority project conditions. This is accomplished by:

- Actively negotiating with Road Authorities to establish cost-sharing agreements that go beyond the standard 50% labour cost split under the PSWHA where the Road Authority has requested scope changes or imposes conditions that deviate from standard relocation or reconstruction scope.
- Completing an initial scope design that offers the most efficient project solution for the Road Authority's consideration. Road Authorities are incentivized to strongly consider Alectra Utilities' design because they may incur 100% of the costs associated with any additional scope or conditions they impose. Coordinating Road Authority projects with other planned capital, industrial, commercial, institutional, transit, subdivision, and substation projects to reduce costs via shared mobilization, switching, restoration, and overall project management.
- Proactively planning and forecasting Road Authority projects through ongoing discussions with municipalities and other Road Authorities to stay informed about their plans and thus afford Alectra Utilities an opportunity to adjust its schedule to meet Road Authority timelines and mitigate uncertainties.
- Engaging external contractors under MSAs to manage the unpredictable nature of Road Authority projects by ensuring the necessary resources are available, if needed, to carry out the work efficiently.

Alectra Utilities consistently applies these efficiency-related project options wherever possible. However, the non-discretionary nature of Road Authority investments means that Alectra Utilities must proceed with the work as requested.

VI Investment Projects

Since Road Authority projects are non-discretionary and dependent on other parties, the budgets for each year will vary based on the volume and type of project requests. In most cases, like for like relocations are possible. In other cases, Road Authority project conditions render like for like relocations impossible and typically result in additional project scope and costs. Alectra Utilities relocations and reconstructions are contingent on other work performed by the Road Authorities. Some projects may be delayed, accelerated or added to the list of projects for next year.

The material 2027- 2031 Road Authority investments are included in Table B11 - 6.

Table B11 - 6 Road Authority - Material Projects and Initiatives

Project Code	Project Name	CAPEX NET ($MM)	Annual Program
101762	Road Authority Projects- East South	24.5	Yes
150645	Road Authority Projects- Central North (Brampton)	8.6	Yes
152918	Road Authority Projects - West	8.0	Yes
152363	Road Authority Project - Poleline Relocation for Hwy 50 from Mayfield to Coleraine	7.9	VLP
150673	Road Authority Projects - Central South	7.5	Yes
101764	Road Authority Projects - East North	7.2	Yes
151051	Road Authority Projects - West (Guelph)	2.8	Yes
151806	Brampton Road Authority - Mayfield Road	2.3	
152554	Road Authority Project - Steeles Ave from Winston Churchill to Chinguacousy Road	1.5	
152730	Road Authority Project - Poleline Relocation for Lakeshore BRT	1.4	
151807	Road Authority Project - Poleline Relocation for Dixie Rd. widening from Queen to Mayfield	1.2	
152548	Road Authority Project - Intermodal Drive widening from Airport Road to CN tracks	1.1	

Part B: Transit Projects

I Overview

Transit Developments

Alectra Utilities' Transit Projects portfolio comprises the relocations and modifications to distribution infrastructure that are required whenever a transit or rail sponsor — federal, provincial, regional, or municipal — builds new rapid-transit or rail facilities within Alectra Utilities' service territory. These projects are non-discretionary. Once a transit agency establishes its corridor and schedule, Alectra Utilities must move any conflicting assets in accordance with statutes such as the *Building Transit Faster Act* (BTFA), the PSWHA, and applicable agreements.

Sponsors and Project Types

- Provincial transit agency Metrolinx: leading GO Expansion, LRT, BRT, and subway-extension programs across the Greater Toronto and Hamilton Areas.
- Regional transit agencies: smaller commuter or streetcar initiatives that may require utility relocations.
- Federally regulated railways (e.g. CN): freight or passenger rail projects that intersect Alectra Utilities' assets.
- Municipal transit departments: sponsors of corridor-based BRT systems (e.g. Queen St/Highway 7 BRT) and other bus-priority works.

Nature of Work

Transit Projects generally fall into three categories:

- Like-for-current-standard relocations of overhead or underground plant where adequate right-of-way exists.

Overhead to underground conversion in constrained urban corridors with limited right of way space, aerial-clearance issues, or proximity to buildings; or

- Opportunistic modernization, such as upsized conductors, sectionalizing switches, or spare ducts, which is evaluated on case-by-case basis while the corridor is open.

    - **Sponsor-mitigation Upgrades:** If the transit project creates a detriment (restricted equipment access, reduced clearances, loss of redundancy), the sponsor funds the incremental work required to restore pre-project capability.

    - **Distribution System Enhancements:** Where Alectra Utilities can achieve a net system benefit (capacity head-room, automation, future DER readiness) beyond the like-for-current standard relocation, Alectra Utilities will fund the incremental cost. Where distribution system enhancement is recommended, it will first be assessed through Alectra Utilities' capital prioritization process. If system enhancements are deemed to be a priority, Alectra Utilities will defer lower-priority system enhancements and substitute those with the priority system enhancements. This exchange of projects maintains the approved capital envelope and aligns with the transit construction window to capture efficiency gains.

Final cost responsibility is established once detailed design is complete and Transit Projects in conjunction with System Planning confirms whether the upgrade is mitigation (sponsor-funded) or system enhancement (utility-funded). These activities ensure Transit Projects proceed on schedule while maintaining safety, reliability, and regulatory compliance for Alectra Utilities' customers.

Known Transit Project investments that have expenditures within the DSP period are shown in Table B11 - 7.

Table B11 - 7 Summary/Status of Known Projects

Project	Time Period	Length (KM)	Description - location
Hazel McCallion LRT (formerly HuLRT) In-Development	2024-2027	18	Relocations of Alectra assets along Hurontario Street between Port Credit GO and the Brampton Gateway Terminal
Hazel McCallion LRT Phase 2 Prep-Acts Stage	2024-2028	6.4	Relocation of Alectra assets along 2.6KM Rathburn, Confederation Parkway, Burnhamthorpe Road (2.6KM) and on Hurontario/Main Streets (3.8KM) from Steeles to Brampton GO
Dundas Bus Rapid Transit (DuBRT) East Prep-Acts Stage	2024-2028	7.1	Relocation of Alectra Utilities assets along Dundas Street between Confederation Parkway and Etobicoke Creek.
GO Expansion In-Development Stage	2024-2031	N/A	Multiple locations along the Barrie, Kitchener, Lakeshore West and Stouffville GO Corridors requiring Alectra Utilities relocations
Yonge North Subway Extension (YNSE) In-Development Stage	2026-2031	N/A	Multiple locations along the YNSE Corridor require Alectra Utilities relocations/expansions.
HaLRT In-Development Stage	2026-2031	14	Relocations of Alectra assets along Main, King, and Queenston Streets between McMaster University and Centennial Parkway
Hazel McCallion LRT Phase 2 In Development Stage	2029-2031	6.4	Relocation of Alectra assets along 2.6KM Rathburn, Confederation Parkway, Burnhamthorpe Road (2.6KM) and on Hurontario/Main Streets (3.8KM) from Steeles to Brampton GO
Queen Street & Highway 7 BRT Prep-Acts	2024-2031	24	Relocation of Alectra assets along Queen Street in Brampton and Highway 7 in Vaughan
DuBRT West Prep-Acts Stage*	2031+	16.8	Relocation of Alectra assets along Dundas Street. 6KM between Highway 6 and Kerns Road in Hamilton and 10.9KM between Ninth Line and Confederation Parkway
ECWE In-Development*	2031+	N/A	Multiple locations along the ECWE Corridor within Mississauga requiring Alectra relocations
Queen Street & Highway 7 BRT In-Development	2031+	24	Relocation of Alectra assets along Queen Street in Brampton and Highway 7 in Vaughan

Projects listed above and marked with an asterisk ("*") are expected to involve capital expenditures for preliminary work during the 2027-2031 period, but the relevant distribution facilities are not forecast to be put into service before December 31, 2031. They are included for context because early design, permitting, or utility-coordination expenditures may occur during the DSP period. No capital related to these projects is proposed to be added to rate base within the current DSP period, and no capital for those marked projects is included in Table B11 - 9 or Table B11 - 14.

Metrolinx and other transit sponsors are undertaking corridor projects that will support, or in some cases accelerate, both residential and Industrial Commercial Institutional growth across Alectra Utilities' service area during the DSP period. The engineering scope for each relocation is highly situational. It depends on right-of-way width, adjacent land use, traffic density, the number of co-located utilities, and the availability of alternative routes. Expenditure forecasts combine (i) historical unit-cost data, and (ii) project-specific information provided by the sponsor. Where a straightforward overhead-to-overhead relocation is feasible, costs scale with quantities such as poles, dips, taps, and circuits. Where an overhead rebuild is not feasible due to factors such as clearance limits, right of way constraints, or encroachment on buildings or roadways, Alectra Utilities must instead relocate the circuit underground. In those cases, materially higher civil construction and material costs are reflected in the forecast.

Allocation of Costs

Cost responsibility for transit-driven relocations depends on who sponsors the project and where Alectra Utilities' assets are situated.

Table B11 - 8 outlines the cost treatment for each sponsor and context. Table B11 - 9 outlines the net Transit Investment Expenditures, Drivers and Outcomes.

Table B11 - 8 Default Cost Treatment

Sponsor & Context	Cost Treatment*
Provincial (e.g. Metrolinx GO Expansion, LRT, BRT, subway extensions)	Transit agency funds 100 % of relocation costs.
Regional transit agency	Transit agency funds 100 % of relocation costs.
Federally regulated railway (e.g. CN) – Alectra assets inside the railway right-of-way and governed by an existing agreement	Alectra Utilities funds in accordance with that agreement.
Federally regulated railway – Alectra assets outside the railway right-of-way or with no agreement in place	Railway funds 100 % of relocation costs.
Municipal transit departments (e.g. city-led BRT corridor)	Cost sharing follows the PSWHA

***** Actual allocations may be refined through formal agreements, BTFA directives, or PSWHA provisions.

Table B11 - 9 NET Transit Investment Expenditures, Drivers and Outcomes.

	Historical Spending - NET					Bridge - NET		Forecast Spending - NET				
Year	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Transit Projects CAPEX ($MM)	0.5	(0.7)	0.1	(0.3)	(0.1)	0.4	2.1	4.2	4.1	0.0	0.0	0.0
Primary Driver	Project Sponsor Requests											
Secondary Driver	Mandated Service Obligations,											
Outcomes	Customer Value, Reliability, Safety, Efficiency											

* Negative values represent timing differences between expenditures and cost recoveries. In these instances, Alectra Utilities incurred relocation costs in one fiscal year, while the corresponding reimbursement from the transit sponsor was recorded in a subsequent year. Where accruals were missed or later corrected, the adjustment appears to be a negative amount in the year shown.

II Investment Description

Scope and Trigger

Alectra Utilities' Transit Projects portfolio covers the relocation or modification of distribution assets whenever a transit or rail sponsor constructs or expands rapid-transit infrastructure inside Alectra Utilities' service territory. Once a formal notice under the BTFA or a previously established agreement with a right of way owner (ROW Owner) is issued, the work becomes non-discretionary. Table B11 - 10 provides the driver that compels relocation based on the type of Transit Authority.

Table B11 - 10 Relocation Driver by Sponsor

Sponsor Type	Authority / mechanism that compels relocation
Provincial agency (Metrolinx)	Notices under Part IV of the BTFA
Municipal transit department (e.g. City-led BRT)	Municipal or Regional Transit Sponsors (e.g. City-led BRT corridors) — Relocations inside a municipal road allowance are compelled by a Section 2 "Notice to Alter" under the Public Service Works on Highways Act (PSWHA). The Act prescribes the cost-sharing (typically 50 % of labour) and obliges the utility to relocate within the timeframe specified in the notice. Where a transit relocation falls outside the statutory PSWHA framework (for example, on lands that are not part of the public highway), Alectra and the Sponsors execute an Agreement. The agreement contractually obliges Alectra to perform the relocation and sets out cost-responsibility terms.
Federally regulated railway (CN, VIA, etc.)	Existing agreements; if none, the railway funds 100 % of relocations outside its right-of-way

Typical Activities

As detailed in Nature of Work (refer to section above), Transit Projects comprise: (i) like-for-current-standard relocations of overhead or underground plant where right-of-way is available; (ii) overhead-to-underground reconstruction where clearance, boulevard width, or proximity to buildings precludes an overhead rebuild; and (iii) opportunistic modernization undertaken while the corridor is open. Under modernization, sponsor-funded mitigation applies where the transit works create a detriment (e.g. restricted access, reduced clearances, loss of redundancy) and restores pre-project capability; Alectra-funded system enhancement applies only to the

incremental upgrades that provide net system benefits (e.g. capacity headroom, sectionalizing/SCADA, spare ducts). Final cost responsibility is confirmed at detailed design by Transit Projects in consultation with System Planning.

2.1 Summary of Investment Outcomes and Benefits

Table B11 - 11 summarizes the outcomes and benefits associated with the Transit Projects investment.

Table B11 - 11 Investment Outcomes and Benefits

Outcome	Investment Benefits and Objectives
Customer Value	• Relocations are designed and sequenced to maintain service continuity, safety, and power quality for all Alectra Utilities ratepayers
Reliability	• Increase reliability for the corridor by removing older assets that are closer to their end of life. Adding and improving switching will be completed.
Safety	• Replacement of older assets should decrease the potential of failure and reduce possible public safety concerns. Relocation of assets off transit corridors ensures access to manholes/switchgears/transformers from side streets allowing for better traffic control, slower traffic and fewer pedestrians.
Efficiency	• Productivity improvements and efficiency will be gained as part of this investment. For example, the replacement of manual switches with new SCADA-enabled switches that are compatible with a Distribution Automation approach will introduce productivity improvements as field crew workers no longer need to go to the field to manually operate switches.

III Investment Drivers & Need

3.1 Purpose

New or expanded rapid-transit corridors, whether rail, LRT, subway, or BRT often intersect or otherwise interfere with Alectra Utilities' overhead and underground plant. When that occurs, the transit sponsor issues a notice that requires Alectra Utilities to move its assets by a stated date. Three frameworks typically apply. Table B11 - 12 provides the obligations based on the type of Transit Authority.

Table B11 - 12 Alectra Utilities Obligations

Framework	When It Applies	Utility Obligation
Building Transit Faster Act (BTFA)	Metrolinx-led "provincial transit projects" as defined in the BTFA, where Metrolinx determines there is a need for relocation	Alectra Utilities must relocate its facilities in accordance with the notice, by the date specified in the notice
Public Service Works on Highways Act (PSWHA)	Transit projects that involve road works under municipal or regional jurisdiction (e.g. city-led BRT lanes), where road authority determines there is a need for relocation	Alectra Utilities must relocate its facilities in accordance with the notice, by the date specified in the notice
Existing Agreements with ROW Owners	Transit projects that have assets located within or crossing ROW Owner lands (with the exception of Public Highways)	Alectra Utilities must relocate its facilities in accordance with the notice and the language of the existing agreements

Transit

Where a roadway change is incidental to a dedicated transit corridor and the transit agency is the project sponsor, the work is tracked in the Transit Project portfolio. Pure road-widening projects initiated by a Road Authority, with no transit agency involvement, remain in the Road Authority project portfolio.

Funding Logic

- **Like-for-current-standard costs:** (e.g. moving a 500 kVA pad-mount transformer to a new location) are invoiced to the transit sponsor and have no impact on Alectra Utilities' rate base.
- **Incremental "system enhancement" costs**: capacity increases, additional ducts, sectionalizing switches, or other enhancements that exceed the current standard are Alectra Utilities' responsibility. For example, if a project requires a 750 kVA transformer to meet future area load, the sponsor funds the cost of a 500 kVA unit (like-for-current standard) and Alectra Utilities funds only the differential between the two.

Exceptions: Under PSWHA, the sponsor typically funds 50% of eligible labour costs; Alectra Utilities funds the remainder plus materials. The DuBRT East Prep-Acts Stage (City of Mississauga) follows this PSWHA split and therefore has a partial rate-base impact since the project sponsor is a Municipality with rights to utilize the PSWHA.

Investment Drivers

Table B11 - 13 provides a summary of the impact on rates based on the drivers of the project.

Table B11 - 13 Summary of the Impact on Rates Based on Drivers

Driver Category	Applies To	Impact on Rates
Project Sponsor relocation request & Mandated /service Obligations	• **BTFA Utility Work Notices** (Metrolinx) • **Railway or municipal agreements** that oblige the sponsor to reimburse 100 % of like-for-current-standard (LFCS) cost	**Cost-neutral:** Sponsor reimbursement matches like-for-current standard cost.
	• **PSWHA Section 2 Notices** for BRT or road-allowance work (~50 % labour reimbursed; utility funds remaining labour + materials).	**Rate-funded:** Alectra Utilities' unrecovered share enters rate base.
	• **Legacy agreements** that require relocation but provide **no reimbursement** mechanism.	**Rate-funded:** Alectra Utilities' relocation enters rate base.
Incremental system enhancement	Capacity upgrades, additional ducts, SCADA switches added during the relocation	**Rate-funded:** Only the incremental cost above like-for-current standard LFCS.

Relocations are mandatory once a legally binding notice is issued. Alectra Utilities' investment within the DSP period is limited to (i) incremental system enhancement costs that enhance reliability and long-term capacity, and (ii) any unrecovered share under PSWHA-based projects. These expenditures ensure compliance, protect service quality, and leverage sponsor funding to modernize aging assets at the lowest feasible cost to customers.

IV Investment Timing & Pacing

4.1 Summary of Expenditures

Table B11 - 14 provides the year-over-year breakdown of Transit Project investments, including the historical period 2020-2024, the bridge years of 2025-2026, and the future period 2027-2031.

Table B11 - 14 Transit Projects Historical & Proposed Investment Spending

	Historical Spending - NET					Bridge		Forecast Spending - NET				
Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
CAPEX ($MM)	0.5	(0.7)	0.1	(0.3)	(0.1)	0.4	2.1	4.2	4.1	0.0	0.0	0.0

Alectra Utilities capitalizes transit relocations net of contributions received from the project sponsor. In certain years, most noticeably 2021 and 2023, the timing of final cost-recovery invoices and accrual reversals created a situation where sponsor reimbursements booked during the fiscal year exceeded the new relocation costs incurred in that same year. The resulting accounting entry appears as a negative net-capital amount even though the underlying gross construction spending remained positive. These timing differences are routine true-ups and do not affect the total project cost to ratepayers over the life of the program.

4.2 Historical Expenditures

4.2.1 Historical Expenditures (2020-2024)

Between 2020 and 2024, there were consistent annual net expenditures in Transit projects.

4.2.2 Bridge Years (2025-2026)

The bridge years of 2025 and 2026 will have a total spending of $2.5MM, which represents an annual increase from 2024 spending. Alectra Utilities is forecasting during the bridge years to participate in the relocation of assets on the DuBRT project, which has its cost structure through the PSWHA. This results in Alectra Utilities contributing some funding towards that project.

Investments in Transit Projects must continue for Alectra Utilities to be in compliance with its mandated requirements and agreements.

4.3 Future Expenditures (2027-2031)

Transit Projects are forecast based on estimates for known discrete projects. Unlike Road Authority work, which recurs annually across all municipalities and can be projected from historical volumes plus inflation, Transit Projects have no steady-state baseline within Alectra Utilities' service territory. They occur only when a transit sponsor advances a named corridor with defined scope and timing. Accordingly, the forecast is built bottom-up from known, discrete projects for which the sponsor has provided schedules and utility conflict information.

Provincial and federal transit budgets (e.g. Metrolinx, CN) are program-wide and not allocable to Alectra Utilities' footprint in any predictable way, and municipal transit budgets may fund activities that do not require utility relocations. Further, most transit relocations are sponsor-reimbursed at like-for-current-standard, so introducing a generic baseline would risk overstating rate impacts. The rate-funded component arises only from identified items, such as incremental "system enhancement" (capacity, automation, spare ducts) that exceed like-for-current standard, or specific PSWHA shares on projects like DuBRT East. If additional transit projects are initiated mid-period, their like-for-current standard costs are expected to be sponsor-funded. Any Alectra-funded incremental amounts will first be assessed through Alectra Utilities' capital prioritization process. Where justified on a lifecycle basis and without compromising safety or reliability, Alectra Utilities may re-sequence or defer lower-priority system enhancements within the approved capital envelope to align with the transit construction window and capture efficiency gains. Material variances that cannot be accommodated within the approved plan would be addressed through normal regulatory mechanisms in a subsequent application.

The future expenditures are detailed in Table B11 - 15. They reflect Alectra Utilities' commitment to supporting known Transit Projects, with a significant portion of costs expected to be recoverable from project sponsors.

For most of these Transit Projects, Alectra Utilities anticipates that expenditures will be recoverable, as project sponsors, primarily Metrolinx, typically assume the costs associated with relocating utilities to alleviate impacts on Alectra Utilities' rate base. In the case of the *Dundas Bus Rapid Transit (DuBRT) East Prep-Acts Stage*, the City of Mississauga is the Project Sponsor and have the authority to utilize the PSWHA, which requires Alectra Utilities to cover a portion of the costs, specifically those not eligible for PSWHA coverage.

The expected expenditures for Alectra Utilities in 2027-2028 are primarily driven by the DuBRT East Prep-Acts Stage, where a portion of the labour costs (approximately 50%) is covered under the PSWHA, but the remaining costs are borne by Alectra Utilities. Table B11 - 15 provides a listing of future Transit Projects.

Table B11 - 15 Future Transit Projects

Project Name	Time Period	Length (KM)	Gross Spend ($MM)	Funding Responsibility
GO Expansion In-Development Stage	2025-2031	-	7.5	Fully covered by Metrolinx
Queen Street & Highway 7 BRT Prep-Acts	2024-2031	24	3.7	Fully covered by Metrolinx
Hazel McCallion LRT (HuLRT) In-Development	2024-2027	18	83.6	Fully covered by Metrolinx
YNSE In-Development Stage	2024-2031	-	13.5	Fully covered by Metrolinx
HaLRT In-Development Stage	2024-2031	14	92.1	Fully covered by Metrolinx
Dundas Bus Rapid Transit (DuBRT) East Prep-Acts Stage	2028-2031	7.1	16.8	Partially funded through PSWHA, with remaining costs covered by Alectra Utilities
Dundas Bus Rapid Transit (DuBRT) West Prep-Acts Stage	2031+	16.8	0.1	To be determined based on future funding agreements
Hazel McCallion LRT Phase 2 Prep-Acts Stage	2025-2031	6.4	2.2	Fully covered by Metrolinx

4.4 Investment Pacing and Prioritization

The pacing, prioritization and overall timing for the relocation projects will be entirely dependent on project sponsors.

4.5 Execution Approach

All relocation activities will be coordinated between project sponsors and the company who is working with the project sponsor to deliver the transit system upgrades.

V Options Analysis

Transit Project sponsor notices issued under the BTFA, the *PSWHA*, or an agreement compel Alectra Utilities to relocate affected plant by a specified date. Consequently, the decision whether to undertake a transit relocation, and the timing for doing so, is non-discretionary. Alectra Utilities must also coordinate its work with the work being undertaken as part of the underlying transit project. Alectra Utilities' options for how and when the work is executed is therefore limited. Alectra Utilities can, however, maximize the efficiency of Transit Projects within the above legislative and contractual constraints by influencing pacing, the approach to engineering, and the cost-mitigation strategy. Table B11 - 16 summarizes these aspects and the available choices and decision criteria.

Table B11 - 16 Choices and Key Decision Criteria

Area of Limited Optionality	Practical Choices Available to Alectra	Key Decision Criteria
1. Pacing / phasing	• Segment relocations to track the sponsor's construction "critical path" rather than moving the entire corridor at once. • Stage work to match internal resource availability and cash-flow constraints.	• Sponsor milestone dates and right-of-way access windows. • Labour and contractor availability. • Minimizing simultaneous outages or customer impacts.
2. Engineering Approach (Overhead vs. Underground)	• Where right-of-way geometry allows, perform a like-for-current standard overhead shift. • Where clearance, right of way width, or urban-design requirements preclude overhead rebuild, convert to underground duct-bank construction.	• Safety clearances to rail or BRT lanes. • Long-term maintainability and lifecycle cost. • Aesthetics / municipal urban-realm requirements. • Upstream capacity needs (opportunity for system enhancement).
3. Cost-mitigation & coordination	• Early engagement to negotiate joint trenching, shared duct banks, or integrated construction windows. • Recover like-for-current standard costs from sponsor; fund only incremental "system enhancement" (e.g. higher-capacity cable, additional SCADA switches).	• Sponsor willingness to share corridors. • Net present value of system enhancement relative to future reinforcement cost. • Rate-base impact versus sponsor funding.

Rationale for the Preferred Execution Strategy

- **Regulatory compliance:** The chosen approach satisfies BTFA and PSWHA deadlines and avoids penalties or reputational risk for non-performance.
- **Cost Recovery:** Like-for-current-standard relocation costs are invoiced to the sponsor; Alectra Utilities funds only incremental capacity or unrecovered PSWHA shares (e.g. DuBRT East). This limits the burden on electricity customers.
- **Operational Reliability:** Standardized design templates and phased execution minimize customer outages and ensure new assets meet current safety and performance standards.
- **Future Readiness**: Where justified, strategic system enhancements (larger transformers, sectionalizing switches, spare ducts) are added during the relocation, leveraging sponsor civil works to defer future rate-funded capital.

Although the underlying need to relocate assets for transit construction is fixed, Alectra Utilities exercises targeted discretion over scheduling, engineering form, and cost sharing. By optimizing these levers, Alectra Utilities delivers mandatory relocations at the lowest feasible lifecycle cost while maintaining reliability and meeting all statutory obligations.

VI Investment Projects

Transit-driven relocations are non-discretionary and their annual spend varies with the number, size, cost responsibility requirements, and timing of sponsor requests. In most corridors, Alectra Utilities can relocate plant on a like-for-current-standard basis. Where right-of-way constraints or clearance issues prevent an overhead rebuild, the circuit must be reconstructed underground, materially increasing cost.

For most projects where the BTFA applies, the transit sponsor funds 100% of the like-for-current standard cost. Metrolinx generally reimburses Alectra Utilities for all relocation costs in accordance with the requirements of the BTFA, which mitigates impacts on the electricity rate base. Alectra Utility funds only the incremental "system enhancement" portion of relocation costs when it identifies opportunities for efficiencies by installing higher-capacity equipment or additional ducts concurrently with the relocation work.

Where the BTFA does not apply, such as with the Dundas Bus Rapid Transit (DuBRT) East Prep-Acts Stage, a different cost responsibility regime applies. In those circumstances, if the project sponsor is a Road Authority, the PSWHA cost-sharing rules will apply. Specifically, the parties may negotiate a cost sharing agreement; in the absence of an agreement, all labour-related costs will be shared equally between the parties and all other costs will be borne by Alectra Utilities.

Other than the DuBRT project, all other transit relocations forecasts in the 2027-2031 period are expected to be fully sponsor-funded at the like-for-current standard level.

The material Transit Related investments over the 2027 to 2031 period are listed in Table B11 - 17.

Table B11 - 17 Transit Projects - Material Projects and Initiatives

Project Code	Project Name	CAPEX ($MM) - NET
152322	Dundas Bus Rapid Transit (DuBRT) Ph1 - ERZ	8.3

Appendix B12 - Lines Capacity

I Overview

Alectra Utilities distribution system faces unprecedented challenges from rapid urban expansion, intensive downtown redevelopment, and insufficient backup capacity. Immediate action and timely investment are essential for new customer connections and to protect the reliability of service for existing customers. Without timely action, Alectra Utilities faces the risk of service degradation and increased delays in connections for new customers. The planned Lines Capacity investments are needed and are designed to prevent feeder overloading, safeguard power quality, and enable rapid restoration in the event of outages.

The Lines Capacity investments are driven by four key factors. First, rapid urban expansion into rural areas within the Alectra Utilities service area is creating a need for new feeder installations to service greenfield developments. Second, intensification in a number of downtown corridors within Alectra Utilities' service area requires immediate upgrades to support increased load and current service standards. Third, the existing radial configurations which are only connected to one source of electricity need to be replaced with looped systems that are supplied by at least two sources. This configuration will provide a backup feed in the event the main feed is disrupted, or the power line segment is damaged. Lastly, Alectra Utilities plans to construct three new Municipal Substations (MSs) to support growing demand in the communities of Barrie, Alliston, and Mississauga. These substations will be supplied by new 44kV distribution feeders planned as part of the Lines Capacity investments. Together, these initiatives position Alectra Utilities to meet current capacity and reliability requirements as well as prepare for the anticipated new load growth (refer to Figure B12 - 1 for an overview of line capacity investment portfolio factors).

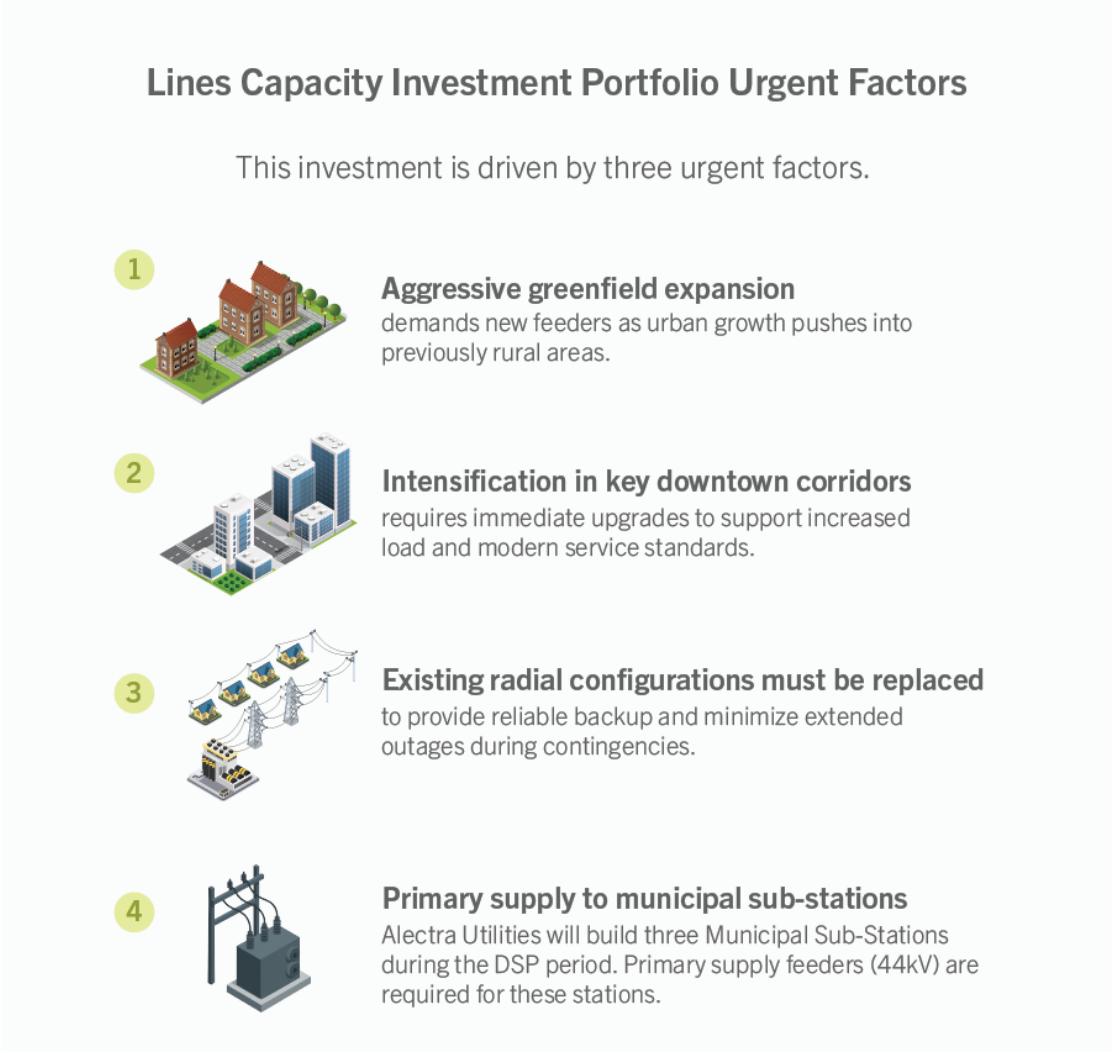


Figure B12 - 1 Lines Capacity Investment Portfolio Factors

I Greenfield Expansion

Alectra Utilities service area spans across seventeen municipalities, several of which are experiencing greenfield expansion. These areas include Markham Future Urban Areas, West Vaughan, Northwest Brampton, and Stoney Creek within Hamilton. These expansions create challenges in connecting new customers as the existing lines in greenfield areas do not have sufficient capacity to serve the load within these new developments. To meet growing demand and maintain system reliability, Alectra Utilities must invest in the construction of new transformer stations, as described in *Appendix B13 – Station Capacity*, as well as additional new feeder lines.

These lines will deliver capacity from both existing and newly built MSs and TSs. Without these supporting investments, the station capacity cannot supply the growing demand.

II Intensification of Downtown Corridors

Alectra Utilities is also experiencing urban intensification and redevelopment in specific areas within its service area. These areas include Square One and Lakeview Developments in Mississauga, Vaughan Metropolitan Centre, Langstaff development in Markham, and Gordon Street intensification in Guelph. The areas of redevelopment include Port Credit in Mississauga and Downtown Hamilton. The existing electrical distribution system serving these areas cannot support the demands of the planned developments. Alectra Utilities needs to expand and upgrade the existing distribution system supply lines (or "feeders") to support new development and accommodate growth, and to maintain safe and reliable service for existing customers.

III Inadequate Back-up Capacity

As per *Chapter 5.3.2 (Section 5.3.2.6.B)*, Alectra Utilities estimates that 232 or 17% of the total 1,371 distribution feeders will exceed their planning limit by 2031.[60] Exceeding a feeder's planning capacity compromises distribution system reliability as it limits load transfer abilities during planned work and system contingencies.

This will ensure safe and reliable operation of Alectra Utilities' distribution system. Without the proposed investments, these feeders will exceed their planning limits, leading to increased risk of equipment failure, more frequent outages, delayed restoration times due to unavailability of capacity for load transfers and insufficient capacity for new customer connections. In the event of a distribution equipment failure on an overloaded feeder section during system peak conditions, Alectra Utilities may be unable to restore power to customers in a timely manner due to the lack of load transferring capabilities offered by new feeder lines.

In addition, there are specific locations in Alectra Utilities' distribution system that are serviced by distribution lines in a "radial" configuration. A radial configuration is a low-cost design for feeders that has no backup provisions, restricting Alectra Utilities' ability to restore power during a planned or unplanned contingency event, resulting in longer outages to customers. The radial configurations will be replaced with looped systems that are connected to two power sources. In

[60] Planning limit of the feeder is 2/3rd of the rating of the maximum capacity of the feeder.

a looped system configuration, if the main source goes down, the power can be supplied from an alternate backup power supply. This makes the system more reliable and resilient. With the planned investments, Alectra Utilities will be able to address 130 feeders (56%) experiencing overloading during the DSP period.

IV Primary Supply to the Municipal Stations

Alectra Utilities plans to build three new MSs[61] that will be supplied by 44kV feeders. The proposed Lines Capacity investment portfolio includes funding to build the new primary feeders required for these stations. These are enablement investments required to make MSs operational and integrate them into Alectra Utilities' grid. Table B12 - 1 provides the total amount of Lines Capacity investment, broken out into each driver category over the forecasted DSP period from 2027 to 2031 and the 2025-2026 Bridge Years.

Table B12 - 1 Line Capacity Investment Portfolio Mix by Driver Category

	Bridge Years		Forecasted Spending					
Driver Category	2025	2026	2027	2028	2029	2030	2031	Total (2027-2031)
I. Greenfield Expansion	11.5	5.1	0.0	18.2	32.1	34.2	21.5	106.0
II. Intensification	4.2	0.0	2.8	12.4	23.2	7.7	27.2	73.3
III. Inadequate Back-up Capacity	1.4	0.0	2.4	4.4	8.0	0.0	2.1	16.9
IV. Primary Supply to MSs	2.2	1.3	0.0	0.0	0.5	0.0	0.3	0.8
Total ($MM)	**19.3**	**6.4**	**5.2**	**35.0**	**63.8**	**41.9**	**51.1**	197.0

1.1 Summary of Planned Investments

Over the forecasted 2027-2031 period, Alectra Utilities plans to invest $197.0MM for Lines Capacity projects. Alectra Utilities has planned feeder expansion and upgrades using a phased approach based on feeder loading requirements paced with development's progress and system utilization. This approach ensures that the necessary infrastructure will be in service when required by customers and minimizes the risk that Alectra Utilities' investments will outpace the growing system needs that drive these expenditures.

[61] Barrie MS, Alliston MS and Webb MS as per *Appendix B13 – Station Capacity*.

Table B12 - 2 Investment Outcomes and Benefits – Lines Capacity Investment Portfolio

	Historical Spending					Bridge		Forecast Spending				
Year	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
CAPEX ($MM)	11.2	7.0	8.9	6.5	5.7	19.3	6.4	5.2	35.0	63.8	41.9	51.1
Primary Driver	Capacity Constraints											
Secondary Driver	Reliability											
Outcomes	Reliability, Customer Value, Efficiency											

Key objectives within the Lines Capacity investment portfolio include:

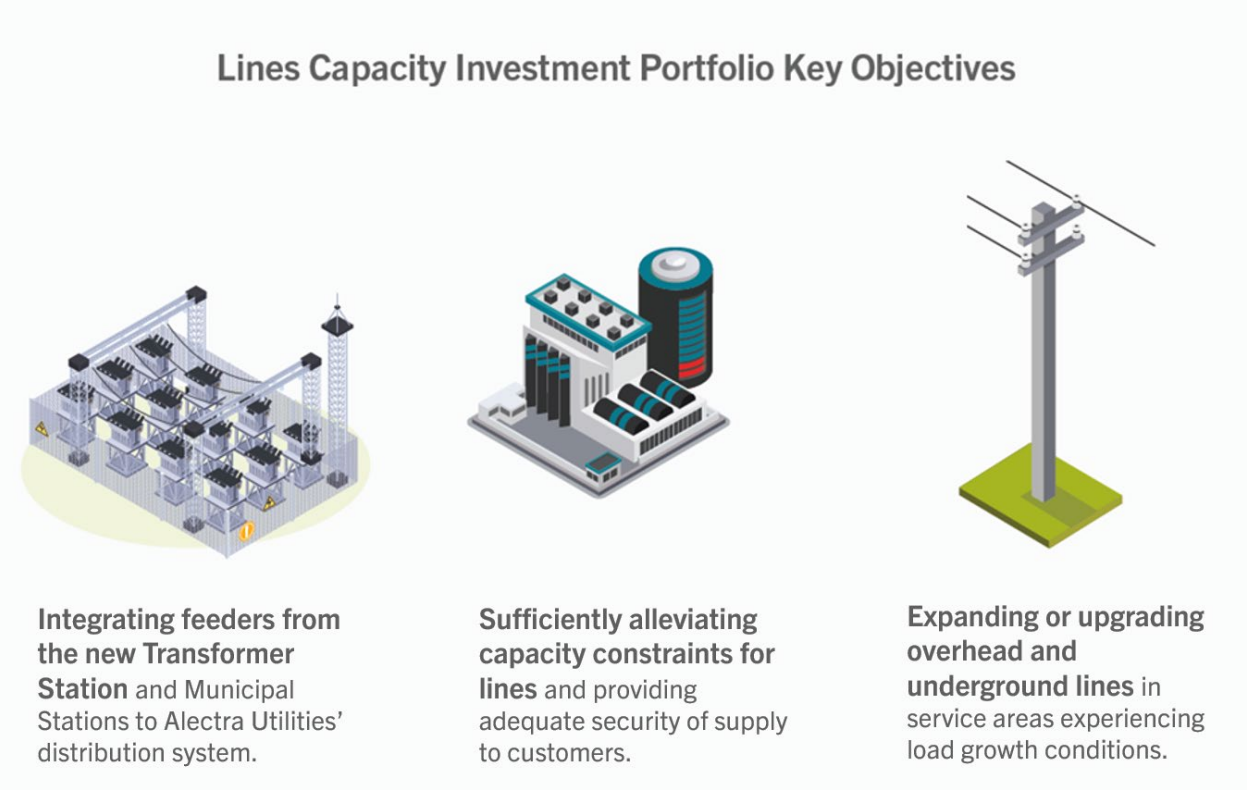


Figure B12 - 2 Lines Capacity Investment Portfolio Key Objectives

II Investment Description

Alectra Utilities' Lines Capacity investment consists of adding distribution capacity from new or existing TSs and MSs to areas of customer growth. The portfolio will also relieve loading constraints and maintain compliance with the Alectra Utilities' planning criteria (refer to *Chapter 5.3.1 Section A 3.1*).

The portfolio includes construction of new feeders, extension or rebuilding existing feeders, and installation of new switching, protection, and monitoring devices.

The Lines Capacity projects are grouped into four categories by the key portfolio factors:

- **Greenfield Expansion** – the construction or upgrade of feeders to connect new residential, commercial and industrial developments to the nearest new or existing TS and MS.
- **Intensification and Redevelopment** – the construction of new feeders or upgrade feeders within existing urban centres where higher densities are driving new load
- **Backup Capability** – adding feeders and sectionalizing ties to restore customers during planned or unplanned outages, and
- **Primary Supply to new MS Stations** – construction of new feeder lines to supply new utility-owned MS.

The following sections describe each category in detail and present representative projects that illustrate the scope and benefits of the proposed investments.

2.1 Greenfield Expansion

The Greenfield Expansion projects provide additional feeder capacity from new or existing TS and MS stations to areas of Greenfield development. New and upgraded lines will transfer station capacity to developing residential, commercial and industrial areas where customer load is growing.

Projects in this category typically extend overhead feeders from stations into growth areas within Alectra Utilities' service territory such as Markham Future Urban Areas, West Vaughan, Northwest Brampton, and Stoney Creek within Hamilton. These investments ensure timely customer connections and support forecast demand increases in each development zone. The load

forecast for each planning zone is detailed in *Appendix J – Load Forecast & System Capacity Adequacy Assessment Report.*

All new or rebuilt lines will be designed to the current Canadian Standards Association specifications (CSA 22.3.No 1-01) for wind and ice loading using a non-linear analysis. Overhead conductors are rated such that they can carry 600 amp during contingency conditions.

Present day standards also incorporate automated switching devices, including automated switches or reclosers, switches at transformers, visible breaks for switches, as well as fault indicating devices for transformers. Constructing the distribution system to present day standards helps ensure efficiency and provides Alectra Utilities with the capability to expeditiously restore service resulting from power outages.

Representative examples of projects within this category of investment include the following:

2.1.1 Example Project: Markham TS#5 Feeder Integration – Part #1

This project is the first part of a multi-part initiative to construct and integrate four new feeders which will provide 80MVA from Markham TS#5 (MTS#5) into the distribution system. The project will deliver additional capacity to the Markham Future Urban Area (FUA) and north Richmond Hill.

Alectra Utilities anticipates that the FUA area will require approximately 65MVA of capacity. The existing feeders in the area are reaching their rated limits and do not have sufficient capacity to accommodate future growth.

The major developments identified in the area that are intended to be supplied by this project include:

Markham Future Urban Area

The City of Markham is working on an Official Planning Amendment that expands the Urban Area of the Town of Markham to both sides of Warden Ave to provide opportunities for urban growth to the year 2031. The north Markham Future Urban Area covers about 1,288 hectares (3,183 acres bordered by Major Mackenzie Drive to the south, the Hydro Corridor and Woodbine Avenue to the west, the northerly City limits and Elgin Mills Road to the north, and the Robinson Creek to the east).

Approximately 675 hectares (1,668 acres) of developable lands are designated for future neighbourhoods, located primarily between Major Mackenzie Drive and Elgin Mills Road.

Approximately 300 hectares (741 acres) located north of Elgin Mills Road are designated for employment uses. In total, the Future Urban Area is intended to accommodate approximately 12,000 residential units with a population of approximately 38,000 persons, and approximately 19,000 jobs. Approximately 60MW of new loads are expected on both sides of Warden Ave north of Major Mackenzie Drive.

The total investment required for this project is $17.4MM with the planned in-service to coincide with the MTS#5 station build.

2.1.2 Example Project - Webb MS Feeder Integration Plan (Phase I)

Feeder Integration Plan (I) covers feeders which will be supplied by the new Webb MS in Mississauga. These four 13.8kV feeders will integrate into the existing distribution system and supply future load growth including two large developments planned for Mississauga (i.e. Block 8 and high-rise expansion) within the DSP forecast period. The existing feeders in the area do not have sufficient capacity to accommodate the future growth.

The major developments identified in the area that are intended to be supplied by this project include:

Exchange District Condo Developments

Exchange District is a master-planned community located in a three-acre development site which includes condominium towers, modern office accommodation, a new hotel and international retailers. The development consists of four towers up to 72 storeys and will add another 12MVA.

Rogers (M-City)

The Rogers M-City will transform a vacant 15-acre lot at the South West corner of Burnhamthorpe Road. This development is projected to house some 6,000 residents and will consist of 10 towers which range from 60 to 75 storeys and will add another 30MW of load. Four towers are constructed and there are plans for additional 4 towers.

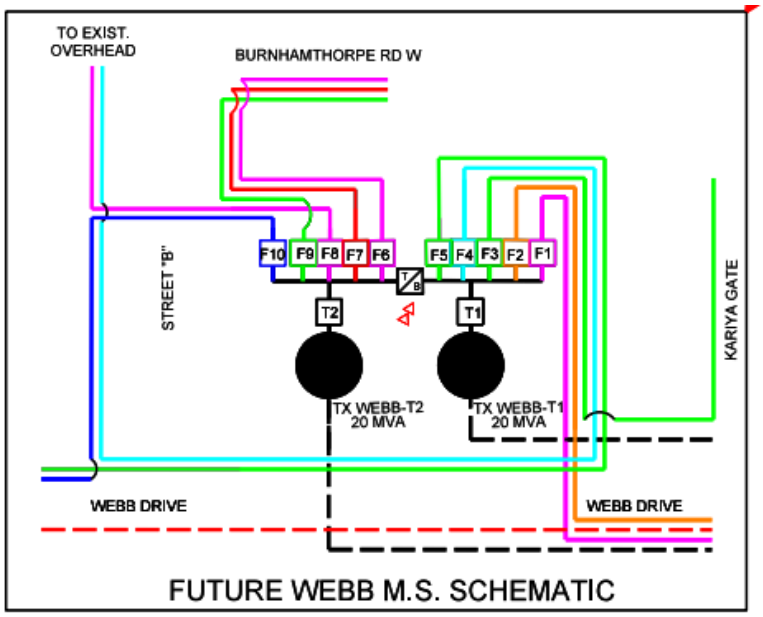


Figure B12 - 3 Webb MS Feeder Integration Plan (I)

The plan will integrate the feeders as follows:

- Webb F1 – Feeder to 1st Customer Gear
- Webb F2 – Feeder to existing gear SG1527
- Webb F3 – Feeder to the first customer gear
- Webb F4 – Feeder from Station to Existing Overhead Line on Burnhamthorpe Road

The total investment required for the Webb MS Feeder Integration Plan (Phase I) is $1.5MM, with a planned in-service within the DSP period.

2.2 Intensification and Redevelopment

The Intensification and Redevelopment category upgrades or builds feeders in existing urban centres where higher population and building density are driving load growth beyond the capacity of the existing network.

Projects focus on reinforcing downtown Mississauga, the Lakeview Area in Mississauga, Vaughan Metropolitan Centre and several areas in Hamilton, as described in more detail in *Appendix J - Load Forecast and System Capacity Adequacy Assessment Report*.

2.2.1 Example Project: St. Catharines' downtown feeder consolidation

The City of St. Catharines' downtown core is supplied by 500MCM and 350MCM PILC underground feeder cables. These 500MCM feeders are rated at 300 amp and do not meet the industry standard. Both capacity and available backup power supply are half the standard 600 amp feeder. The existing feeder lines are heavily loaded, reaching their capacity limits. Once feeders are at full utilization, load shedding will need to be executed during the summer peak period or during contingency conditions to mitigate the risk of failure from overloaded equipment. Supplying customers through highly loaded feeders may impact power quality.

Upgrading feeders to 600 amp industry standard will allow for higher capacity on each distribution circuit bringing it to current standard. It will also free up breakers at Carlton Transformer Station needed for new customers for the development in the North end of the city. This is illustrated in Figure B12 - 4.

In addition, the current cables are undersized (2/0) in the city core and are at or over the planning limit.

There are locations where 2/0 cables are spliced directly to larger cables and cannot supply or backup full capacity. Upgrading the cables and reconfiguration of these circuits will allow organic growth and provide back up capacity in the St. Catharines downtown area.

Planning for Phase 1 of the project will start in 2029, and the final phase will begin in 2031. The total investment required for the St. Catharines downtown Integration is $15.3MM.

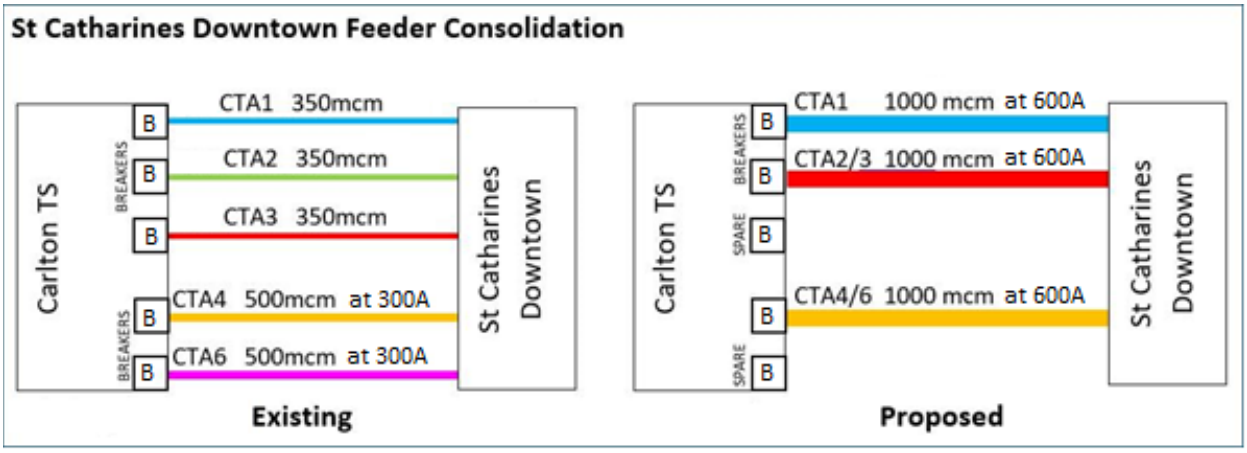


Figure B12 - 4 St. Catharines Downtown Feeder Consolidation Diagram

2.3 Backup Capability

The Backup Capability category constructs new lines to provide adequate backup capability in areas served by single circuits. When a radial supply is out of service, affected customers cannot be switched to an alternative source of supply, resulting in unnecessary extended outages.

Alectra Utilities' network design is an open grid[62] with multiple feeders interconnected via normally open points. Feeders are designed for full backup capability over peak summer loading conditions through the switching of load to an adjacent feeder or multiple adjacent feeders to account for contingency conditions. Each feeder on average serves 400 - 2,500 customers depending on the voltage class of the feeder and size of customers. To facilitate restoration capabilities, Alectra Utilities plans the feeder load to be 2/3rd of the feeder rating.[63] For example, 27.6kV feeder loading will be planned to a maximum of 400 amp under normal operation which is 2/3rd of its 600 amp contingency rating. This approach ensures the feeder operates within safe limits under normal conditions and have room to accommodate the partial or full load of another feeder during a planned or unplanned outage. Alectra Utilities estimates that 232 or 17% of the total 1,371 distribution feeders will exceed their planning operating limit by 2031. Exceeding a feeder's planning capacity compromises distribution system reliability. The overloaded lines limit the ability to connect new customers. In the event of a failure during peak load conditions on some parts of the distribution system, Alectra Utilities would not be able to restore power to customers.

To ensure system reliability, new feeders are required to provide adequate back up capability. Without investment to ensure system contingency, Alectra Utilities' customers that are supplied radially may experience significant outage durations. These customers would be stranded without service until Alectra Utilities is able to make the necessary repairs to the system during power outages. Through the planned investments, Alectra Utilities will address 126 (55%) overloaded feeders by 2031.

[62] Open grid is defined as network of either one or more interconnected feeders with open points with switches in between them which allow redirection of power in planned or unplanned outage situation.

[63] The "egress rating" is the maximum current-carrying capacity of the underground cable connected between the station's breaker and distribution line exiting the station. The contingency rating is the maximum load on the feeder during an N-1 contingency situation. Typically, the overhead feeders are sectionalized such that during contingency condition half the load of the feeder (approximately. 200 amp) can be transferred to other feeders.

2.3.1 Example Project: Install a 4th Feeder from Dundas TS to Waterdown Rd

This project will construct a new 27.6kV feeder from Dundas TS to Waterdown in Hamilton.

The project includes two parts:

[redacted]

- Install a fourth circuit from Dundas TS to Waterdown using the upgraded egress along Olympic Dr. The feeder routing will be along York Rd and Old Guelph Rd such that there would be two separate routings of two feeders to supply Waterdown.

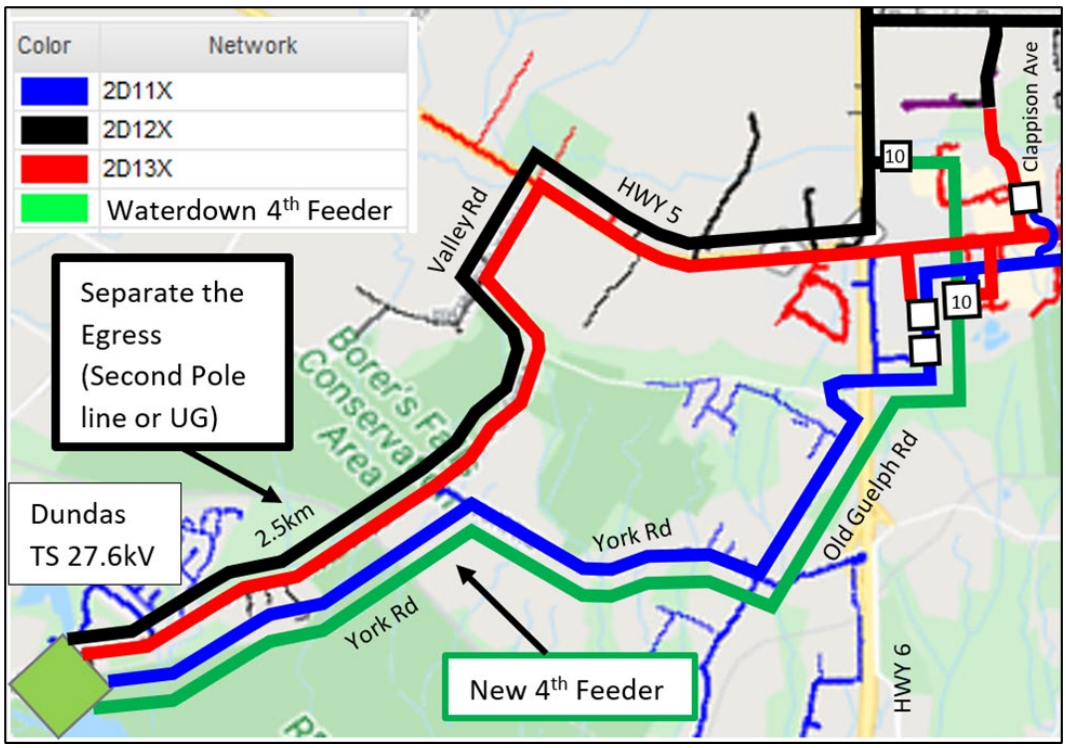


Figure B12 - 5 Install a New 4th Feeder and Egress to Waterdown

2.4 Primary Supply to Municipal Stations

The Primary Supply to MS category includes investments for construction of new 44kV feeder lines to connect new three new municipal substations: Webb MS, Alliston MS, and the new Barrie MS. These line investments are essential for delivering power to each new substation site. The new substations are being developed to support new load growth driven by greenfield expansion, urban intensification, redevelopment, and system redundancy needs.

2.4.1 Example Project: New Barrie 20 MVA Substation - 44kV Supply

This investment involves constructing a 44 kV feeder supply to connect the new 20MVA municipal substation in Barrie. This investment will allow Alectra Utilities to address system capacity needs in Barrie driven by new developments.

South-west Barrie is currently supplied by five 13.8kV municipal stations: MS302, MS303, MS305, MS308, and MS307. The first four substations each have a 20MVA transformer[64] with dual-stage fans with Oil Natural Air Natural (ONAN) and Oil Natural Air Forced (ONAF) ratings of 20.0 MVA and 26.6MVA, respectively. The dual stage fan ONAF/ONAF allows for transformer capacity of 33.2MVA. MS307 is a 10MVA substation with dual-stage fans with ONAN and ONAF ratings of 10MVA and 13.3MVA, respectively. The dual stage fan ONAF/ONAF allows for transformer capacity of 16.6MVA.

Growth projections provided by the City of Barrie indicate that 11,522 residential units and approximately 62,300 square meters of non-residential space developments will be completed over the next ten years.

Following the completion of these developments, MS305, MS308, and MS303 are projected to exceed ONAN ratings during summer peak in 2026, 2028, and 2032, respectively. A new station 44/13.8kV 20MVA is being planned in the Barrie area (refer to *Appendix B13 - Stations Capacity 3.2.1.2 B*). This new station will need to be supplied by 44kV incoming lines.

The investment required for the New Barrie 20MVA Substation - 44kV Supply in 2031 is $0.3MM, which will be completed within a year.

[64] The contingency rating is determined by the cooling capabilities of the transformer, and is equivalent to the highest cooling rating, i.e. ONAN (100% of base rating) for self-cooled transformer units, ONAF (133% base rating) or ONAF/ONAF (166% of base rating) for transformer units with single and dual stage fans, respectively.

2.4.2 Example Project: New Alliston 2 x 20 MVA Substation - 44kV Supply

This investment involves constructing a new 44kV circuit to extend the existing 138M8 feeder by 1.8KM to connect the new 2 x 20MVA substation in Alliston. The new line will deliver a second point of supply to the new MS and will be equipped with three automated switches. This investment is required to ensure the grid can sustain the loss of a major 13.8kV transformer without service interruptions, while also providing the extra capacity needed to support growth from new developments.

The Town of Alliston is currently supplied by two 13.8kV stations: MS330 and MS331. MS330 has a 10MVA single-stage fan transformer rated to 10MVA Oil Natural Air Natural (ONAN)[65] and 13.3MVA Oil Natural Air Forced (ONAF) supplying north-west Alliston. MS331 has two 10MVA transformers each supplying separate parts of Alliston: MS331-T1 feeders supply the east-end of Alliston, and MS331-T2 feeders supply west-end of Alliston. These two transformers have single-stage fans and are rated to 10 MVA ONAN and 13.3MVA ONAF.

Alectra Utilities has identified a need for a new station (refer to *Appendix B13 - Stations Capacity 3.2.1.2 B*). This new station will need to be supplied by 44kV incoming lines.

The investment required for the New Alliston 2 x 20MVA Substation - 44kV Supply is $0.5MM.

2.5 Summary of Investment Outcomes and Benefits

Table B12 - 3 illustrates the outcomes and benefits associated with the Lines Capacity investment portfolio.

Table B12 - 3 Investment Outcome, Benefits and Objectives

Outcome	Investment Benefits and Objectives
Reliability	This initiative will manage system and feeder reliability through: • Ensuring system reliability by reducing the risk of failures due to single-point failure and overloaded equipment through load transfer and planned feeder balancing. • Improving restoration capabilities in the heavily loaded areas and fast growth areas by decreasing the number of heavily loaded feeders.

[65] The contingency rating is determined by the cooling capabilities of the transformer, and is equivalent to the highest cooling rating, i.e. ONAN (100% of base rating) for self-cooled transformer units, ONAF (133% base rating) or ONAF/ONAF (166% of base rating) for transformer units with single and dual stage fans, respectively.

Outcome	Investment Benefits and Objectives
	• Increasing operational flexibility on feeders via the installation of feeder ties to expedite restoration of outages. • Enhancing reliability and resiliency by replacing aging infrastructure as part of feeder capacity upgrades.
Customer Value	• Ensures that Alectra Utilities has adequate capacity to connect customers on time and cost-effectively, without negatively impacting system performance for existing customers. • Improves feeder capacity so more rooftop solar, batteries, and other DERs can connect without overloading the line, while also supporting local two-way power flows when needed. • Ensure adequate capacity to serve new homes, businesses, and growing communities as the population increases.
Efficiency	• Operating feeders within planning criteria maximizes asset life, reduces line losses and ensures required power quality levels. • Enhances system performance and streamlines maintenance operations through the building and upgrading of feeders with modern control systems
Government Policy	• Supports Ontario's climate goals by preparing the grid for more electric vehicles and increased electricity demand through proactive capacity upgrades

1

III Investment Drivers & Need

3.1 Purpose

Under the Distribution System Code (DSC) and the OEB's service quality standards, Alectra Utilities must maintain sufficient distribution system capacity to meet projected load, connect new customers within the prescribed timelines, and preserve reliability, power quality and safety for all customers over the short and long-term.

Meeting these obligations has become increasingly challenging as both greenfield development and urban intensification accelerate across the Alectra Utilities' service territory.

The proposed Lines Capacity investment is required to satisfy these obligations in areas where projected load exceeds the capacity of the existing feeder network.

The primary driver of this investment is to address capacity constraints. Feeder utilization analysis for the 2027-2031 period shows that 232 distribution feeders, 17% of the existing network, will exceed planning capacity limits of the 400 amp planning threshold, as described in *Chapter 5.3.2 Overview of Asset Managed*.

Alectra Utilities plans to target and prioritize critically overloaded feeders. By the end of 2031, through planned investments on new stations and feeder capacity, the forecasted overloading of 126 out of the 232 feeders will be addressed.

Greenfield developments now moving from plans to construction have limited distribution infrastructure. The system, originally designed for lower demand and a more compact service area, must therefore be reinforced to serve both the intensifying urban core and rapidly expanding perimeter developments.

Alectra Utilities plans its feeders to normal summer-peak loading to be the lesser of 2/3rd of the egress-cable rating, or 2/3rd of the 600 amp contingency rating.600 amp contingency rating. Alectra Utilities plans its feeders to normal summer-peak loading to be the lesser of 2/3rd of the egress-cable rating, or 2/3rd of the 600 amp contingency rating. This operating headroom ensures that, under a contingency, an adjacent feeder can assume the loading from the faulted feeder without exceeding its thermal limit. When forecasts indicate that a feeder will exceed this threshold, or when development is approved in an area lacking feeder infrastructure, a capacity

project is initiated. Presently, Alectra Utilities is experiencing growth in a number of areas within its service territory. Notable examples of this trend include:

- **Greenfield developments in Brampton:** Most of the population growth is occurring on the edge of the existing built-up areas in secondary planning areas such as Sandringham-Wellington (SP28), Credit Valley (SP45) and the Vales of Castlemore (SP42). Emerging new growing communities include Bram East (SP41), Bram West (SP40), and Heritage Heights.
- **Intensification of Vaughan Metropolitan Centre**: The Vaughan Metropolitan Centre (VMC), is bound by Highway 407 to the south, Highway 400 to the west, Portage Parkway to the north and Credit Stone and Maplecrete Roads to the east. The total area of VMC is 190 hectares, of which 100+ hectares are developable. Due to the subway line within this area, the Vaughan Metropolitan Centre continues to intensify with vertical growth from new residential condominium properties and commercial developments.
- **Intensification and redevelopment in Mississauga's Lakeview Area and Brightwater redevelopment:** The Lakeview redevelopment project is located on a 177-acre site on Mississauga's eastern waterfront and designed to be a mixed-use community. The site will have 16,000 residential units, and more than 1.5 million square feet of employment space in the area's Innovation Corridor for 9,000 jobs in research and development. The Brightwater is a unique mixed-use development spanning 72 acres from Lakeshore Rd. to the edge of Lake Ontario. The new development is designed for over 3,000 residential units, housing a population of 7,000 residents, and will have 340,000 square feet of retail/commercial space, creating over 1,000 jobs.
- **Expansion of Markham Future Urban Areas**: Markham Future Urban Areas cover approximately 1,668 acres of developable lands designated for future neighbourhoods, located primarily between Major Mackenzie Drive and Elgin Mills Road. Future Urban Area is intended to accommodate approximately 12,000 residential units and will accommodate approximately 19,000 jobs.
- **Redevelopment of Yonge-Steeles and transit expansion along Yonge Street:** The Yonge North Subway Extension (YNSE) will extend the TTC's Line 1 subway

service approximately 8 kilometers from the existing terminus at Finch Station into the City of Richmond Hill. The project runs through the City of Toronto and York Region, including sections within the cities of Markham, Vaughan, and Richmond Hill.

- **Intensification of Mississauga Downtown Core**: The downtown core of the City of Mississauga continues to grow with new condos and expansion of the Square One shopping centre and surrounding retail and commercial development, and the ongoing expansion of City and Regional transportation hubs.
- **Redevelopment and Intensification of Hamilton Downtown**: This area continues to expand with the renewal of downtown Hamilton.

Information regarding these future developments and anticipated load growth has been compiled from municipal planning documents (e.g. official plans), developer inquiries and connection requests submitted to Alectra Utilities, and direct consultations with local economic development offices. Details can be found in *Appendix J - Load Forecast and System Capacity Adequacy Assessment Report*.

Without reinforcement and expansion of the distribution system, Alectra Utilities will be required to operate the distribution system serving these areas beyond the rated equipment capacities, risking equipment failure, voltage violations, and shortened asset lifecycles. Capacity projects are therefore targeted to both supply new greenfield customers and relieve emerging constraints on existing feeders, ensuring that Alectra Utilities can meet its regulatory obligations while supporting development across the region.

The secondary (but no less important) driver is reliability, as the new feeders and technologies to be installed will introduce new operational flexibilities for Alectra Utilities when performing restoration during outage events. These infrastructure upgrades will improve sectionalizing capabilities, enable remote switching, and include real-time system monitoring. With these tools, Alectra Utilities can isolate faulted sections more quickly and restore power to impacted areas faster, while minimizing the duration and scale of outages for customers. Additionally, the added feeder capacity provides alternative pathways for load transfers, which is essential during planned maintenance or unplanned contingencies. Over time, these enhancements will have a positive impact on system reliability and help Alectra Utilities maintain safe and uninterrupted flow of electricity.

The primary and secondary drivers are further defined and summarized in Table B12 - 4.

Table B12 - 4 Line Capacity Investment Drivers

Investment Driver	Reasoning & Investment Benefits
Capacity Constraints	A significant amount of residential and industrial/ commercial/ institutional (ICI) growth is occurring within Alectra Utilities' territory, as urban areas continue to expand within adjacent greenfield areas. Presently, Alectra Utilities has a very limited distribution infrastructure to support growth in such areas with insufficient capacity for future developments. New and upgraded lines will introduce capacity relief. Lines built to present standards enable Alectra Utilities to safely and reliably support new technologies in the form of DER, PV and battery storage that will further introduce localized benefits.
Reliability	By alleviating capacity constraints and overloading within the system, Alectra Utilities plans to mitigate the risk of future outages to the customer. Additional lines with inter-ties enable alternative supply paths to expedite restoration from outages and mitigate impacts of loss of supply events.

Appendix J - Load Forecast & System Capacity Adequacy Assessment Report illustrates the forecast population growth across major municipalities in Alectra Utilities' service territory over the next twenty years. Projections indicate that there will be a significant increase in both population and households within both Brampton, York Region and Guelph areas, along with intensification and redevelopment growth in the Mississauga and Hamilton areas. Alectra Utilities uses this information to develop localized plans considering future developments from municipal planning documents (e.g. official plans), developer inquiries, connection requests submitted to the Alectra Utilities, and direct consultations with local economic development offices.

The planned investment in Lines Capacity will accommodate the impacts of the projected load growth through the installation of new and upgraded feeders between high-growth locations and nearby substations.

Table B12 - 5 shows summary of Lines Capacity projects that are directly correlated with investments in *Appendix B13 - Station Capacity*.

1 **Table B12 - 5 Stations Capacity and Lines Capacity Projects by Area, DSP Forecast (2027-2031)**

Operating Area	Station Capacity Project			Lines Capacity Project			
	Project ID	Project Name	In-Service Date	Project ID	Project ID	CAPEX ($MM)	Investment Driver
East (Alliston, Aurora, Beeton, Barrie, Bradford, Markham, Tottenham, Penetanguishene, Richmond Hill, Thornton and Vaughan)	101488	Build Markham TS #5	2027	101489	Markham TS#5 Feeder Integration - Part 1	17.4	Greenfield
				101490	Markham TS#5 Feeder Integration - Phase 2	16.8	Greenfield
	101542	New Barrie 20 MVA Substation	2032	100461	New Barrie 20MVA Substation - 13.8kV Feeder Integration	2.0	Intensification
	152909	New Alliston 2x20MVA MS	2032	101571	New Alliston 2 x 20MVA Substation - 13.8kV Feeder Integration	1.0	Greenfield
	152762	Vaughan MTS#5-VMC	2033	152763	VTS#5 Feeder Integration Part 1	11.1	Intensification
	Expansion from existing station			100904	Install Double-Circuits Pole Line on Major Mackenzie - Highway 27 to Huntington Rd	3.2	Back up Supply
	Expansion from existing station			100917	Add one additional 27.6kV Circuit on 19th Ave from Bayview to Bathurst St	2.4	Intensification
	Expansion from existing station			100924	Install two additional 27.6kV circuits on Highway 7 from Jane St to Weston Rd	2.2	Intensification
	Expansion from existing station			152749	Rebuild pole line on 19th Ave into two circuits from McCowan Rd to Highway 48	2.0	Greenfield
	Expansion from existing station			152757	Rebuild existing pole line on Keele St into two circuits from Teston Rd to Kirby Rd	1.2	Greenfield
	Expansion from existing station			102386	Rebuild 44kV pole line into two circuits on Tiffin Street from Ferndale Ave to Miller Drive	1.2	Intensification
	Expansion from existing station			150007	Extend 153M10 to Transfer MS322	2.4	Back up Supply
	Expansion from existing station			103633	Install two 27.6kV Circuits on 16th Ave from Highway 404 to Woodbine Ave	1.9	Greenfield
	Expansion from existing station			100281	Build Four 27.6kV Circuits on 19th Ave from Woodbine Ave to Warden Ave	1.7	Greenfield

Operating Area	Station Capacity Project			Lines Capacity Project			
	Project ID	Project Name	In-Service Date	Project ID	Project ID	CAPEX ($MM)	Investment Driver
	Expansion from existing station			152751	Rebuild existing pole line on Nashville Rd into 2twocircuits from Huntington Rd to Highway 50	1.6	Greenfield
	Expansion from existing station			100913	Pole Line Installation Double-Circuits on Major Mack - Huntington Rd to Highway 50	1.5	Greenfield
	Expansion from existing station			101487	Add one Additional 27.6kV Circuits on Major Mack Dr and 9th Line	1.3	Greenfield
Central North (Brampton)	152845	New Goreway 2 TS – Brampton	2032	153068	New 4 Feeders Common Elements - Goreway TS 2	15.2	Greenfield
				152879	Feeder 1 Integration - Goreway TS 2	7.1	Greenfield
				152880	Feeder 2 Integration - Goreway TS 2	3.0	Greenfield
				152881	Feeder 3 Integration - Goreway TS 2	2.4	Greenfield
				152882	Feeder 4 Integration - Goreway TS 2	3.4	Greenfield
				151676	136M10 Feeder Extension Goreway TS to Highway 410	8.4	Intensification
				153073	3 Feeder Integration out of Goreway TS 2 - Along Castlemore Road	3.3	Greenfield
				153111	Feeder 2 integration 4xCircuits Duct bank - Goreway TS 2	1.2	Greenfield
	Expansion from existing station			150716	42M69 Feeder Extension - Williams Pkwy to Heart Lake/Sandalwood	8.9	Intensification
South (Mississauga)	150366	Webb MS New 20 MVA Substation - Mississauga	2030	152890	Webb MS 20MVA Substation - Feeder Integration Plan (I)	1.5	Intensification
				152967	Webb MS 20MVA Substation - Feeder Integration Plan (II)	1.3	Intensification

Operating Area	Station Capacity Project			Lines Capacity Project			
	Project ID	Project Name	In-Service Date	Project ID	Project ID	CAPEX ($MM)	Investment Driver
	152889	TS Station - 230kV/27.6kV Lakeview TS - South Mississauga	2032	152893	Feeder Integration Plan (I) - 27.6kV Lakeview TS - South Mississauga	7.6	Greenfield
	Expansion from existing station			150369	New build – 44kV Feeder Extension York/Meadowpine, Mississauga	2.1	Back up Supply
West (Hamilton and St. Catharines)	152850	New Station - Hamilton South-West (Station)	2033	152865	New Station - Hamilton South-West (Egress)	10.4	Greenfield
	152493	New Station - Newton TS (Capacity)	2031	152853	New Station - Newton TS (Feeder Consolidation)	8.0	Intensification
	Expansion from existing station			152849	New Build - Carlton TS to Martindale Rd/Port, St. Catharines	2.0	Intensification
	Expansion from existing station			150368	New Build - Carlton TS to Linwell Rd/Lake St, St. Catharines	2.1	Intensification
	Expansion from existing station			152852	New Build - Nebo 3101X Extension, Hamilton	2.4	Greenfield
	Expansion from existing station			152496	New Build - Waterdown 4th Feeder, Hamilton	8.8	Back up Supply
	Expansion from existing station			152854	St. Catharines Downtown - Feeder Consolidation	15.3	Intensification
Southwest (Guelph and Rockwood)	Expansion from existing station			152942	New Build - Guelph Downtown	5.9	Intensification
	Expansion from existing station			151238	New Build - Maltby Rd W (Crawley to Gordon), Guelph	1.3	Greenfield

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IV Investment Timing & Pacing

4.1 Summary of Expenditures

Table B12 - 6 illustrates the year-over-year breakdown of Lines Capacity investments, including the DSP historical period from 2020 to 2024, the bridge years 2025 and 2026, and the DSP forecast period from 2027-2031. There is year over year variability in forecast spending as Alectra Utilities paces and prioritizes investments by considering customer demand for additional connections, system demand growth, system reliability and coordination with municipal roadworks, watermain expansions, and other utility construction. Integration feeder builds are timed to follow TS or MS expansions so that downstream capacity is available as soon as the upstream source is in service.

Table B12 - 6 Historical & Proposed Investment Spending

	Historical Spending					Bridge		Forecast Spending				
Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
CAPEX ($MM)	11.2	7.0	8.9	6.5	5.7	19.3	6.4	5.2	35.0	63.8	41.9	51.1

4.2 Historical Expenditures (2020-2024)

Historical expenditures between 2020 and 2024 were $39.3MM. These expenditures focused on feeders from new stations as well as expansion of existing overhead lines to alleviate capacity constraints and address radial configurations.

Most of the spending was on projects related to feeder integration from the new station in Vaughan (VTS#4) which came into service in 2018, addressing capacity constraints in Brampton and Hamilton, and addressing a radial line in Hamilton.

4.3 Bridge Years (2025-2026)

Alectra Utilities Line Capacity investments from 2025 to 2026 are $25.7MM.

Major projects are as follows:

2025:

- $3.2MM is required to rebuild a pole line on McCowan Rd to two feeders to supply a new subdivision development of 1,858 homes in the green field on the north side of 19th Ave between McCowan Rd and Hwy 48 in Markham. The project will address the loading issues of the proposed subdivision both in the short and long term and provide alternate supply route for north-east Markham to increase reliability.
- $1.0MM is required to install duct bank crossing on 16th Avenue in Markham for future new feeders from a new transformer station inside Buttonville TS. The work will be done in conjunction with York Region's 16th Avenue roadway widening project. The new duct bank will allow Alectra Utilities to reroute the 12M10 and 12M11 feeders to 16th Ave to allow a new transformer station MTS5 to be built inside the existing Buttonville TS in the future.
- $5.8MM is required for the Vaughan TS#4 Feeder Integration - Part 3 (Phase 1) project. This project will add four 27.6kV feeders (25M5/25M6/25M7/25M8) from the Vaughan TS#4 and integrate them into the existing distribution system. This will increase supply capacity for greenfield developments on both sides of Highway 400 north of Teston Road.
- $1.6MM is required for a new four-circuits CNR yard overhead crossing on the south side of Hwy 7 Intensification. It will allow 4 more new 27.6kV circuits to be extended from Keele St to Jane St to increase supply capacity to Vaughan Metro Center (VMC) and Vaughan Mills. VMC/Vaughan Mills will be supplied by two 4 circuits pole lines on Highway 7 crossing CN yard. The VMC and Vaughan Mills are major intensification areas in the York Region.
- $1.8MM is required for the 42M71 Feeder extension along Sandalwood from Creditview Road to Mississauga Road which will supply power to the development on that stretch of the line. The investment in the extension will also provide load transferring options and contingency in the future. The existing feeder 42M64 in the area is over the planning limit. There are multiple developments planned in

the area that would require approximately 12MVA. The existing feeder does not have sufficient capacity to connect the anticipated load.

2026:

- $4.3MM Vaughan TS#4 Feeder Integration - Part 3 (Phase 2). This project is the second phase of the 2025 initiative.
- $0.7MM New Build - Campbell TS 36M62 Feeder (Phase 2), Guelph. This project is the second phase of the 2025 initiative.

4.4 Future Expenditures (2027-2031)

Alectra Utilities' Lines Capacity investments from 2027 to 2031 totals $197MM. The proposed new level of Lines Capacity investments is necessary to support the connection of new developments, expedite restoration of outages, and improve Alectra Utilities' capability to safely and reliably integrate DER, PV, and battery systems into the grid.

Over the forecast DSP period, the Lines Capacity investments will address four key drivers: enabling greenfield expansion, supporting urban intensification, resolving inadequate back-up capacity, and providing primary supply to new MS. Also, Alectra Utilities plans to invest in upgrading existing and building new transformer stations, as described in *Appendix B13 – Station Capacity*. These investments are required to meet the growth and the contingency capability in the 17 municipalities that Alectra Utilities serves. The expansion and construction of new distribution feeders is essential for accessing the incremental station capacity. Without the companion Lines Capacity investments, new and upgraded stations cannot be fully utilized.

Over the forecast DSP period, 91% of the Lines Capacity investments ($179.3MM) will fund projects addressing Greenfield Expansion and Intensification. Alectra Utilities needs to build feeders from the new stations and integrate them into the distribution system to support the new urban growth areas in Markham, the redevelopment of Mississauga Lakeshore, Vaughan Metropolitan Centre, and areas in downtown Hamilton, Guelph, and St. Catharines.

4.5 Investment Pacing & Prioritization

Alectra Utilities paces and prioritizes investments by considering customer demand for additional connections, system demand growth, system reliability and coordination with municipal

roadworks, watermain expansions, and other utility construction. Integration feeder builds are timed to follow TS or MS expansions so that downstream capacity is available as soon as the upstream source is in service.

To maximize the efficiency of the planned work, the Lines Capacity investments are coordinated with other infrastructure projects planned by local authorities. By coordinating Alectra Utilities' expansion and renewal plans with municipal and regional authorities' projects, Alectra Utilities can leverage other construction and share infrastructure with other utilities, such as telecommunications providers.

By aligning feeder construction with municipal capital programs, Alectra Utilities can share trenching and restoration costs, minimize disruption to residents and businesses, and complete work before municipalities impose post-construction moratoria on newly rehabilitated corridors. This coordination reduces overall project costs and supports timely delivery of capacity.

Annual spending is paced to match timing of known developments, considering available capacity, and expected peak demand growth, net of conservation and demand side management. Projects are phased according to feeder loading thresholds, funding availability, and the progress of customer development, enabling just-in-time capacity while maintaining rate stability and service reliability for existing customers.

For each Lines Capacity project, Alectra Utilities prepares and ranks a business case in accordance with the capital investment optimization process described in *Chapter 5.3.1 Asset Management Process Overview.* This process confirms system need, optimizes scope and sequences work to balance system performance with prudent use of resources.

Larger projects that take multiple years to build, are broken down into manageable phases to optimize execution resources and mitigate rate impacts, ensuring that capacity is added when and where it is required.

Lines Capacity projects are reviewed on an annual basis to confirm that funds are directed at the right need at the right time. Updated feeder load forecasts and customer driven demands determine whether existing circuits are approaching their planning limits or whether new feeders are required.

Where the process shows that peak shaving through Non-Wires Solutions can temporarily satisfy capacity needs, those NWS resources can be deployed, and the related Stations and Lines Capacity work is deferred or reprioritized.

In the 2027-2031 period, Alectra Utilities plans to procure up to 1,326MWh of demand-response capacity across two TSs and three MSs to achieve these deferrals and associated cost savings (refer to *Chapter 5.3.5 Non-Wires Solutions to Address System Needs*).

4.6 Execution Approach

Approved Lines Capacity projects are designed, scheduled and prepared for implementation in the year preceding construction. Cost estimates for 2025 projects are prepared based on completed detailed designs and current cost data. Estimates for the projects scheduled for 2026 through 2031 are based on high-level designs, considering costs of projects of similar scope and complexity.

Work is delivered through a mix of Alectra Utilities' internal crews and external contractors. This arrangement secures labour availability, protects pricing, and provides flexibility to scale resources to match the annual work program.

Alectra Utilities implemented a formal project management platform to track and manage resource allocation vs. usage, project progress vs. schedule, and financial project performance vs. baseline throughout the entire project execution phase. Regular progress meetings are held to ensure technical and operational issues are resolved promptly. Project metrics are provided and discussed with the project leads to ensure projects track on schedule, on budget, and within scope.

The execution phase follows Alectra Utilities' internal project management methodology, which provides specific guidelines, procedures, work instructions, and industry best practices that allow the project work to be performed in an economically efficient, cost-effective, and safe manner (refer to *Section 5.3.1.3*).

V Options Analysis

The following options were considered when evaluating the Lines Capacity projects:

- Status Quo: Take no action to mitigate the capacity constraints within Alectra Utilities' system
- Non-wires Alternatives
- Construct new feeders to meet system capacity requirements in pace with development, first considering conservation and demand side management impacts

The following subsections provide further details into the results from this analysis.

5.1 Status Quo

Alectra Utilities is required to ensure its distribution system can support projected load growth while maintaining reliability and quality of service for customers on both a short-term and long-term basis, as required by the DSC. Alectra Utilities must be able to connect new customers in a timely manner.

In areas of new development, if new overhead lines are not constructed, it will be physically impossible for Alectra Utilities to connect new customers to the grid.

In the case of feeders which are already loaded and nearing their capacity limits, taking no action will result in feeders becoming overloaded and exceeding their carrying capacity. Once feeders are at full utilization, load shedding will need to be executed during the summer peak period or during contingency conditions to mitigate the risk of failure from overloaded equipment. Supplying customers through highly loaded feeders may impact power quality.

For the reasons stated above, Alectra Utilities rejected the status quo or do-nothing approach.

5.2 Non- Wires Alternatives

Alectra Utilities' peak load forecast process considers the impact of CDM, distributed energy resources and non-wires, which is accounted for as part of the load forecast underpinning the lines capacity projects. For urban expansion projects these options have not been considered, as new feeders are needed to connect the customers to the grid. Alectra Utilities has screened

the lines capacity project as per the criteria developed in *Chapter 5.3.5 Non-Wires Solutions to Address System Needs*. Based on the screening criteria Alectra Utilities did not identify any non wires options for the Lines Capacity project.

5.3 Construct New Feeders

Execution of this investment will alleviate capacity constraints and as well as ensure the availability of sufficient capacity to efficiently connect customers to Alectra Utilities' distribution system. It will allow Alectra Utilities to maintain supply to customers during contingency events and operation flexibility during maintenance and other capital work. This option will help Alectra Utilities maintain service quality and reliability standards for the existing customers as additional load is added to the system. Alectra Utilities plans to construct and configure feeders to present day technical standards to ensure customer choice for integrating distributed generation, electric vehicles and energy storage solutions.

As this is the only option that allows Alectra Utilities to reliably meet forecast connection requirements, it forms the basis of the planned Lines Capacity investments.

VI Investment Projects

The investments from 2027 to 2031 that form the Lines Capacity investments are included in Table B12 - 7.

Table B12 - 7 Material Investments

Project Code	Project Name	CAPEX ($MM)
101489	Markham TS#5 Feeder Integration - Part 1	17.4
101490	Markham TS#5 Feeder Integration - Phase 2	16.8
152854	St. Catharines Downtown - Feeder Consolidation	15.3
153068	New 4 Feeders Common Elements - Goreway TS 2	15.2
152763	VTS#5 Feeder Integration Part 1	11.1
152865	New Station - Hamilton South-West (Egress)	10.4
150716	42M69 Feeder Extension - Williams Pkwy to Heart Lake/Sandalwood	8.9
152496	New Build - Waterdown 4th Feeder, Hamilton	8.8
151676	136M10 Feeder Extension Goreway TS to Highway 410	8.4
152853	New Station - Newton TS (Feeder Consolidation)	8.0
152893	Feeder Integration Plan (I) - 27.6kV Lakeview TS - South Mississauga	7.6
152879	Feeder 1 Integration - Goreway TS 2	7.1
152942	New Build - Guelph Downtown	5.9
152882	Feeder 4 Integration - Goreway TS 2	3.4
153073	3 Feeder Integration out of Goreway TS 2 - Along Castlemore Road	3.3
100904	Install Double Cct Pole Line on Major Mackenzie - Highway 27 to Huntington Rd	3.2
152880	Feeder 2 Integration - Goreway TS 2	3.0
100917	Add one additional 27.6kV Cct on 19th Ave from Bayview to Bathurst St	2.4
152852	New Build - Nebo 3101X Extension, Hamilton	2.4
150007	Extend 153M10 to Transfer MS322	2.4
152881	Feeder 3 Integration - Goreway TS 2	2.4
100924	Install two additional 27.6kV ccts on Highway 7 from Jane St to Weston Rd	2.2
150369	New build – 44kV Feeder Extension York/Meadowpine, Mississauga	2.1
150368	New Build - Carlton TS to Linwell Rd/Lake St, St. Catharines	2.1

Project Code	Project Name	CAPEX ($MM)
152749	Rebuild pole line on 19th Ave into 2 ccts from McCowan Rd to Highway 48	2.0
100461	New Barrie 20MVA Substation - 13.8kV Feeder Integration	2.0
152849	New Build - Carlton TS to Martindale Rd/Port, St. Catharines	2.0
103633	Install Two 27.6kV Ccts on 16th Ave from Highway 404 to Woodbine Ave	1.9
100281	Build Four 27.6kV Ccts on 19th Ave from Woodbine Ave to Warden Ave	1.7
152751	Rebuild existing pole line on Nashville Rd into 2 ccts from Huntington Rdto Highway 50	1.6
100913	Pole Line Installation Double Cct on Major Mack - Huntington Rd to Highway 50	1.5
152890	Webb MS 20MVA Substation - Feeder Integration Plan (I)	1.5
152967	Webb MS 20MVA Substation - Feeder Integration Plan (II)	1.3
101487	Add one Additional 27.6kV Cct on Major Mack Dr and 9th Line	1.3
151238	New Build - Maltby Rd W (Crawley to Gordon), Guelph	1.3
153111	Feeder 2 integration 4xCct Ductbank - Goreway TS 2	1.2
152757	Rebuild existing pole line on Keele St into 2 ccts from Teston Rd to Kirby Sdrd	1.2
102386	Rebuild 44kV pole line into 2 Ccts on Tiffin Street from Ferndale Ave to Miller Drive	1.2
101571	New Alliston 2 x 20MVA Substation - 13.8kV Feeder Integration	1.0

1

Appendix B13 – Station Capacity

I Overview

Over the 2027-2031 period, Alectra Utilities' Stations Capacity investments include land acquisitions for new stations, capacity upgrades at existing substations, and construction of new Alectra Utilities-owned transformer stations. Also included in the investments are Capital Cost Recovery Agreement (CCRA) payments to Hydro One Networks Inc. (HONI) for a new transmission line connection and additional capacity upgrades at HONI-owned stations that supply Alectra Utilities' customers. These investments are required to fulfill Alectra Utilities' obligations identified through the IESO Integrated Regional Resource Planning (IRRP) process, ensuring that Alectra Utilities has sufficient capacity to meet growing electricity demand across its service territory while maintaining a reliable power supply for existing customers. A summary of the capital investment mix is shown in Table B13 - 1.

Table B13 - 1 Stations Capacity Capital Investment Mix Over the 2025-2031 Period

	Bridge		Forecasted Spending					
Investment Type ($MM)	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**Total (2027-2031)**
Transformer Stations (TS)	0.6	15.1	3.9	10.0	43.3	52.1	106.9	216.2
Municipal Stations (MS)	2.9	8.2	3.0	0.0	0.0	2.9	3.9	9.8
MS & TS Land Acquisition	0.0	5.2	15.7	14.1	12.7	0.0	0.0	42.5
CCRA Payments to Hydro One	5.7	5.0	10.0	16.3	16.3	47.5	24.1	114.2
Transmission Line Upgrades	0.8	5.0	5.0	0.0	0.0	0.0	0.0	5.0
MS Expansions	0.6	0.0	1.6	1.6	2.8	6.9	0.0	12.9
Total	**10.6**	**38.5**	**39.2**	**42.0**	**75.1**	**109.4**	**134.9**	**400.6**

As discussed in *Chapter 5.3.2 (Section 5.3.2.1 B.2)*, Alectra Utilities developed its long-term demand forecast using an end-use analysis. This approach incorporates historical system data, regional growth indicators for each of the four Alectra Utilities' Operating Areas (Alectra Utilities East, Alectra Utilities Central, Alectra Utilities West and Alectra Utilities Southwest) and known emerging demand drivers (e.g. Data Centre expansion required for artificial intelligence, cloud computing, storage, adoption of electric vehicles as well as fleet and transportation electrification).

The forecast methodology produces an accurate and transparent forecast that reflects both historic load growth and new trends affecting the distribution system.

Using this methodology, the Alectra Utilities' non-coincident summer peak demand is projected to grow from 5,938MW in 2024 to 7,406MW by 2031, an increase of 1,469MW, representing an average annual growth rate of approximately 3.2%.

The driving factors of this increase are provided in Table B13 - 2.

Table B13 - 2 Forecasted System Load Growth by Driver (2025–2031)[1]

Growth Driver	Current Load (MW) 2024	Forecast Load (MW) 2031	Forecast CAGR Growth 2025-2031	Load Growth Contribution (%) 2025-2031	Load Growth Contribution (MW) 2025-2031
Population, Housing and Employment Growth	5761	6281	1.24%	35%	520
Data Centers (Artificial Intelligence, Storage, Cloud Computing)	115	540	24.7%	29%	425
EVs, Fleet & Transit Electrification	61	586	38.2%	36%	524
Total				**100%**	**1,469**

Increasing population, employment and densities within Alectra Utilities' service area will lead to increased load demand at MS and TS. As discussed in *Chapter 5.3.2 (Section 5.3.2.6.A)*, based on the current load forecast, 13 of 14 Alectra Utilities-owned TSs, and 6 of 241 MSs will exceed their maximum rated capacity by 2031. This highlights the need for targeted investment to address capacity constraints. Without capacity investments, Alectra Utilities will face significant risks to its ability to connect new customers, maintain quality and reliable service for existing customers, potentially resulting in service interruptions, constrained economic growth, and non-compliance with regulated service standards.

The forecast indicates increased peak demand due to fleet electrification and general adoption of EV vehicles in Alectra Utilities service territory. Alectra Utilities has seen a cumulative annual growth rate (CAGR) of 50% in the adoption of electric vehicles in its service territory from 2021-2024. Alectra Utilities projects more than 500,000 electric vehicles in its service area by 2031 as

further detailed in *Appendix J - Alectra Load Forecast and System Capacity Adequacy Assessment Report*.

As discussed in *Chapter 5.3.1 (Section 5.3.1.2 A.3.1)*, Alectra Utilities plans its stations with the goal of ensuring that the stations have the capacity to accommodate the new load growth, while maintaining the operational flexibility to transfer loads when an element of the grid fails, referred to in electrical planning as a “contingency”, minimizing the impact of power outages to customers.

Building a new transformer station is a multi-year process that involves several stages from planning, site selection, Environment Assessment (EA), and regulatory approvals to land acquisition, design, equipment procurement, construction, and commissioning. Typically, the timeline from initial planning to in-service energization is approximately 3 to 5 years for a new MS and 5 to 7 years for a new transmission-connected TS.

The proposed investments in critical infrastructure will increase station capacity across all four operational areas of Alectra Utilities’ service territory. Alectra Utilities expects to add 700MVA of new capacity to its system from projects completed in this rate period and start projects that will contribute to an additional 1442MVA of capacity for rate period 2032-2036.

The listing of material projects planned over 2027-2031 is shown in Table B13 - 3.

1 **Table B13 - 3 Summary of Material Station Capacity Capital Projects by Area, 2027-2031 DSP Period**

Operating Area	Municipalities	Project ID	Project Name	Asset Owner	Investment Type	Cost ($MM)	Purchase / In-Service Date
East	Alliston, Aurora, Beeton, Barrie, Bradford, Markham, Tottenham, Penetanguishene, Richmond Hill, Thornton and Vaughan	152862	Purchase Land for Future Vaughan MTS#5	Alectra Utilities	Land Acquisition	5.1	2027
		152860	Markham MTS#6 Land Purchase and Class EA	Alectra Utilities	Land Acquisition	5.0	2028
		152870	Land Purchase - New Barrie 20MVA Substation - Bryne Dr.	Alectra Utilities	Land Acquisition	1.9	2029
		152934	Land Purchase - New Alliston 2x20MVA MS	Alectra Utilities	Land Acquisition	1.9	2029
		101488	Build Markham TS #5	HONI	CCRA	10.0	2027
		102128	Aurora MS6 Expansion	Alectra Utilities	MS Expansion	2.1	2029
		102455	Melbourne MS322 - 2 x 10 MVA - Bradford	Alectra Utilities	MS Expansion	9.2	2030
		152753	Install Capacitor Banks at VTS1E	Alectra Utilities	MS Expansion	1.5	2027
		101542	New Barrie 20 MVA Substation	Alectra Utilities	New MS	2.3	2032
		152909	New Alliston 2x20 MVA MS	Alectra Utilities	New MS	4.5	2032
		152484	Vaughan TS#6-Build Station	Alectra Utilities	New TS	1.3	2027
		152762	Build Vaughan MTS#5 for VMC	Alectra Utilities	New TS	14.9	2033
		152846	Build Markham TS #6	Alectra Utilities	New TS	2.8	2034
		152758	Build Richmond Hill TS3	Alectra Utilities	New TS	56.5	2030
Central	Brampton, Mississauga	152859	Land Purchase - Brampton - New Heritage TS	Alectra Utilities	Land Acquisition	5.3	2027
		152857	Land Purchase - 230kV/27.6kV Lakeview TS - South Mississauga	Alectra Utilities	Land Acquisition	5.3	2027
		152972	Land Purchase - 230kV/27.6kV - GTAA TS	Alectra Utilities	Land Acquisition	5.4	2028

Operating Area	Municipalities	Project ID	Project Name	Asset Owner	Investment Type	Cost ($MM)	Purchase / In-Service Date
		152844	Land Purchase - 230kV/27.6kV Gateway TS	Alectra Utilities	Land Acquisition	5.5	2029
		152861	Land Purchase - Brampton - New Goreway 2 TS	Alectra Utilities	Land Acquisition	5.2	2026
		152883	230kV UG Transmission Line for TS Heritage 2 - Brampton	HONI	CCRA	53.3	2034
		152723	Pleasant TS - H29 H30 Reconductoring - Transmission	HONI	TX Line Upgrade	5.0	2027
		150366	Webb MS New 20 MVA Substation - Mississauga	Alectra Utilities	New MS	3.0	2030
		152845	New Goreway TS 2 - Brampton	Alectra Utilities	New TS	50.1	2032
		152847	New Heritage TS - Brampton	Alectra Utilities	New TS	13.3	2034
		152888	TS Station - 230kV/27.6kV Gateway TS - North Mississauga	Alectra Utilities	New TS	2.8	2034
		152889	TS Station - 230kV/27.6kV Lakeview TS - South Mississauga	Alectra Utilities	New TS	50.1	2032
		152973	TS Station - 230kV/27.6kV GTAA TS	Alectra Utilities	New TS	4.5	2033
West	Hamilton and St. Catharines	152866	New Station - Hamilton South-West (Land)	Alectra Utilities	Land Acquisition	3.6	2028
		152850	New Station - Hamilton South-West (Station)	Alectra Utilities	New TS	19.8	2033
		152493	New Station - Newton TS (Capacity)	HONI	CCRA	25.5	2031
Southwest	Guelph and Rockwood	152864	New Station - Guelph North-West (Land)	Alectra Utilities	Land Acquisition	3.3	2029
		151147	New Station - Campbell TS Metal Clad Expansion	HONI	CCRA	25.5	2031

The total capital expenditures from the historical period (2020–2024), bridge period (2025-2026) and the forecasted net capital contribution of capital investments (2027–2031) are presented in Table B13 - 4.

Table B13 - 4 Stations Capacity Investment Expenditures, Drivers and Outcomes.

	Historical Spending					Bridge		Forecast Spending				
Year	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Total CAPEX ($MM)	0.5	11.0	0.8	2.5	3.2	10.6	38.5	39.2	42.0	75.1	109.4	134.9
Primary Driver	Capacity Constraints											
Secondary Driver	Reliability											
Outcomes	Ability to service existing and new customers, Reliability, Efficiency, Coordination/Interoperability, Environmental, Grid Modernization											

The total forecasted spending for this program from 2027 to 2031 is $400.6MM, with $174MM expected to be in service at the end of the period.

II Investment Description

Alectra Utilities' proposed Stations Capacity investments from 2027 to 2031 period consisting of multiple critical infrastructure projects, including construction of new TSs, expansion of existing TSs and MSs, and strategic enhancements to the 230kV transmission system. These investments are driven by system needs identified through the Regional Planning process and are necessary to enable timely connection of new loads.

These investments are necessary to ensure that Alectra Utilities' system has sufficient capacity to meet the forecasted peak demand and maintain resilience under contingency conditions. Specifically, the planned upgrades will provide sufficient spare capacity such that, in the event of a failure or outage at one station, adjacent stations can supply the displaced load, minimizing service disruption to customers. This approach is consistent with Good Utility Practice and supports the N-1[66] contingency planning criterion, which is a fundamental principle for ensuring reliability and continuity of supply in a growing distribution grid. Failure to proceed with these targeted investments would materially increase the risk of customer outages and constrain Alectra Utilities' ability to meet projected demand growth. Without these investments, the utility will not have the necessary capacity to support new customer connections in high-growth areas, posing a material risk to system reliability and Alectra Utilities' customer service obligations.

[66] N-1 criterion means that customer loads will continue to be supplied with a major network element out of service. The load at risk of not being supplied is zero.

For each of the stations included within this investment, Alectra Utilities will install and upgrade one or more of the following types of assets and components:

Design Elements

- High voltage breaker
- Power Transformer
- Low voltage main breaker
- Feeder breakers

Power Transformers

- 230kV - 27.6/13.8kV Transformer (100/125/170MVA Transformer)
- 44kV - 13.8kV (20/26.6/33.3MVA Transformers)
- 44kV - 13.8kV (10/13.3/16.6MVA Transformers)

Protection

- Digital (microprocessor-based) relays
- Transformer Differential & Overcurrent Protection
- Bus Differential and Overcurrent Protection
- On-line Transformer temperature monitoring
- On-line Transformer gas monitoring
- Feeder breaker instantaneous and time overcurrent protection
- Feeder reclosing schemes

Control & Monitoring Equipment

- Circuit breakers

The specific projects planned during the DSP period are discussed in *Section 3.2, Section 3.3,* and *Section 3.4*.

2.1 Summary of Investment Outcomes and Benefits

Table B13 - 5 Investment Outcomes and Benefits

Outcome	Investment Benefits and Objectives
Customer Value	Ensure adequate capacity is available to supply new and existing customer loads associated with increasing population and urban intensification (i.e. new residential developments), industrial, commercial and institutional growth, and emerging AI and data centres, through station transformer upgrades and new substations.
Reliability	Maintain reliability by ensuring adequate capacity and continuity of supply during contingency scenarios through station transformer upgrades, new substation builds, and other Stations Capacity investments.
Efficiency	Capacity investments to improve system efficiency by enabling the conversion from legacy 4.16kV infrastructure to a more robust and efficient 27.6kV distribution system supply. This transition is supported by investments in building large, 115kV and 230kV transmission-connected transformer stations, which will distribute power at 27.6kV. The benefit is reduced line losses, improved voltage regulation, and a more robust and scalable grid capable of meeting growing demand and integrating advanced technologies.
Coordination and Interoperability	Capacity investments also enable improved coordination and integration of Distributed Energy Resources (DERs) such as rooftop solar, battery storage, and demand response technologies. By upgrading system infrastructure, Alectra Utilities can support greater two-way power flows and enhance grid interoperability, allowing DERs to be actively managed as part of the distribution system. This improves reliability, optimizes system performance, and aligns with evolving industry standards for a more flexible and resilient grid.
Government Policy	Supporting Ontario's policy goals to reduce greenhouse gas emissions, as outlined in the Made-in-Ontario Environment Plan and the Ontario Vehicle Innovation Network (OVIN) strategy. These initiatives promote fleet and transportation electrification, including the adoption of electric vehicles (EVs), which will increase electricity demand across the province. Proactive capacity upgrades ensure the grid can accommodate the growing load, enabling widespread EV adoption while aligning with the Alectra Utilities' service territory.
Environmental	Investing in distribution system capacity enhances climate resilience by enabling the integration of cleaner, low-carbon energy sources and strengthening the grid's ability to withstand and adapt to extreme weather events linked to climate change.

III Investment Drivers & Need

3.1 Purpose

The planned Station Capacity investments during the 2027-2031 period are driven by capacity constraints on Alectra Utilities' distribution system and the need to provide reliable service. The investment drivers are presented in Table B13 - 6.

Table B13 - 6 Investment Drivers

Investment Driver	Reasoning & Investment Benefits
Primary Driver: Capacity Constraints	The projected increase in load will constrain the ability of the system to provide consistent service delivery. Alectra Utilities has identified capacity constraints that it must address to ensure timely supply to new developments through investment in transformer upgrades and substation construction. New Stations Capacity investments also benefit the system through the additional capacity for customer connections and increased flexibility in system supply configurations. The needs have been identified in the Regional Planning Scoping and Needs Assessment document completed by IESO and HONI.
Secondary Driver: Reliability	To continue meeting minimum reliability, consistent with the N-1 contingency planning standard, Alectra Utilities must make the planned investments in its stations. Failure to make these investments could result in a situation where Alectra Utilities is unable to sufficiently transfer customer load when an element of the grid fails, resulting in significantly decreased reliability in areas of the distribution system.
Secondary Driver: Customer access and Choice	In some areas, there is limited capacity to connect additional DERs. These investments support the growth of distributed renewable generation on the system, that in turn offset generation and transmission investment to the benefit of rate payers and that also create environmental benefits.

3.1.1 Capacity Constraints

The Station Capacity investments are primarily driven by capacity constraints on Alectra Utilities' distribution system. Alectra Utilities serves 17 municipalities with a vast majority being in the urban area which will continue to experience high population and employment growth over the next two decades resulting in significant greenfield growth, redevelopment, and urban intensification.

The increase in peak demand is attributed to the following:

- Organic Growth (New Homes and ICI Growth)
- Data Centre Expansion (Artificial Intelligence, Storage, Cloud Computing)
- Transportation Electrification (Low Duty, Medium Duty and High Duty Vehicles)

3.1.1.1 Organic Growth

There are several Provincial initiatives such as "Places to Grow: Growth Plan for the Greater Golden Horseshoe" plans[67], *Bill 162: The Get It Done Act*, *2024*[68] and *Bill 23: The More Homes Built Faster Act, 2022*[69] which will lead to an upward trend in construction of new homes and ICI growth to support population growth.

Table B13 - 7 illustrates the expected population and household growth across the four Alectra Utilities operational zones from 2021 to 2041. These projections indicate that average population and household growth rates will be 31% and 39%, respectively, between 2021 and 2041. The municipalities that Alectra Utilities serves also establish their growth and employment projections based on the provincial growth targets. Alectra Utilities utilizes the latest growth information (number and type of households, employment) obtained from the municipalities development charge reports to determine the additional load attributed to this growth. Additional information on growth and pacing is obtained from direct discussion and communication with developers for residential and ICI customers.

[67] https://www.ontario.ca/document/place-grow-growth-plan-greater-golden-horseshoe
[68] https://www.ola.org/en/legislative-business/bills/parliament-43/session-1/bill-162
[69] https://www.ola.org/en/legislative-business/bills/parliament-43/session-1/bill-23

1 **Table B13 - 7 Population & Household Growth Forecast – 2021-2041**

City	Population						Households					
	2021	2026	2031	2036	2041	% Increase Population	2021	2026	2031	2036	2041	% Increase Households
Brampton	691,382	751,542	807,875	848,897	889,920	28.72%	247,826	264,478	280,723	295,336	309,950	25.07%
Mississauga	763,300	792,340	818,100	849,680	883,290	15.72%	249,514	262,450	279,850	298,940	317,840	27.38%
Hamilton	584,000	618,000	652,000	692,500	733,000	25.51%	222,540	240,320	258,100	276,635	295,170	32.64%
York	973,024	1,078,997	1,207,649	1,234,573	1,333,680	37.07%	311,657	351,392	394,004	436,977	478,958	53.68%
Guelph	147,000	157,500	168,000	177,000	186,000	26.53%	57,500	62,850	68,200	72,950	77,700	35.13%
Simcoe County	255,310	295,700	337,990	375,780	412,790	61.68%	88,140	104,750	120,790	137,260	153,770	74.46%
St. Catharines	137,886	142,993	148,099	155,982	163,865	18.84%	59,549	62,274	64,999	68,734	72,469	21.70%

Notes:	
1	**Brampton Population and Housing Data (2021-2041):** "Development Charges Background Study, The Regional Municipality of Peel, September 18, 2020, Watson Report"
2	**Mississauga Population and Housing Data (2021-2041):** "Development Charges Background Study, March 4, 2022, Hemson Report"
3	**Hamilton Population and Housing Data (2021-2041):** "City of Hamilton Land Needs Assessment to 2051, December 2020, Lorius Report"
4	**Guelph Population and Housing Data (2021-2041):** "Greater Golden Horseshoe: Growth Forecasts to 2051, August 26, 2020, Hemson Report"
5	York population and housing data (2021-2041):
	Markham:
	2021-2031: "2022 Development Charges Study, City of Markham, March 2022, Hemson Report"
	2031-2041: "2022 YORK REGION OFFICIAL PLAN Office Consolidation | June 2023, York Region Report"
	Richmond Hill:
	2021-2031: "Development Charges Background Study, Town of Richmond Hill, March 26, 2019, Watson Report"

	2031-2041: “Development Charges Background Study, City of Richmond Hill, December 22, 2023, Watson Report”
	Vaughan:
	2021-2031: “Development Charges Background Study, City of Vaughan, June 21, 2022, Hemson Report”
	2031-2041: “2022 York Region Official Plan Office Consolidation | June 2023, York Region Report”
	Aurora:
	2021-2031: “Development Charges Background Study, Town of Aurora, January 24, 2019, Watson Report”
	2031-2041: “2022 York Region Official Plan Office Consolidation | June 2023, York Region Report”
6	**St. Catharines Population and Housing Data (2021-2041):**
	"Development Charges Background Study, City of St. Catharines, June 2, 2021, Watson Report”
7	Simcoe County population and housing data (2021-2041):
	Barrie:
	“Greater Golden Horseshoe: Growth Forecasts to 2051, August 26, 2020, Hemson Report”
	Penetanguishene, Bradford, and New Tecumseth:
	“Growth Forecasts and Land Needs Assessment, March 31, 2022, Hemson Report”
8	York Region- Numbers indicated are for the Alectra Utilities service territory, including Markham, Vaughan, Richmond Hill, and Aurora.
9	Simcoe County –Numbers indicated are for the Alectra Utilities service territory, including Barrie, Bradford, New Tecumseth, and Penetanguishene.

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Table B13 - 8 shows population growth which provides insight into the growth trends within Alectra Utilities' service area.

Table B13 - 8 Population Growth Projections (in %) by Cities/Regions[70]

City/Region	2026	2031	2036	2041
York Region	11%	12%	4%	6%
Simcoe County	16%	14%	11%	10%
Peel Region	6%	5%	4%	4%
Hamilton	6%	6%	6%	6%
City of St. Catharines	4%	4%	5%	5%
Guelph	7%	7%	5%	5%

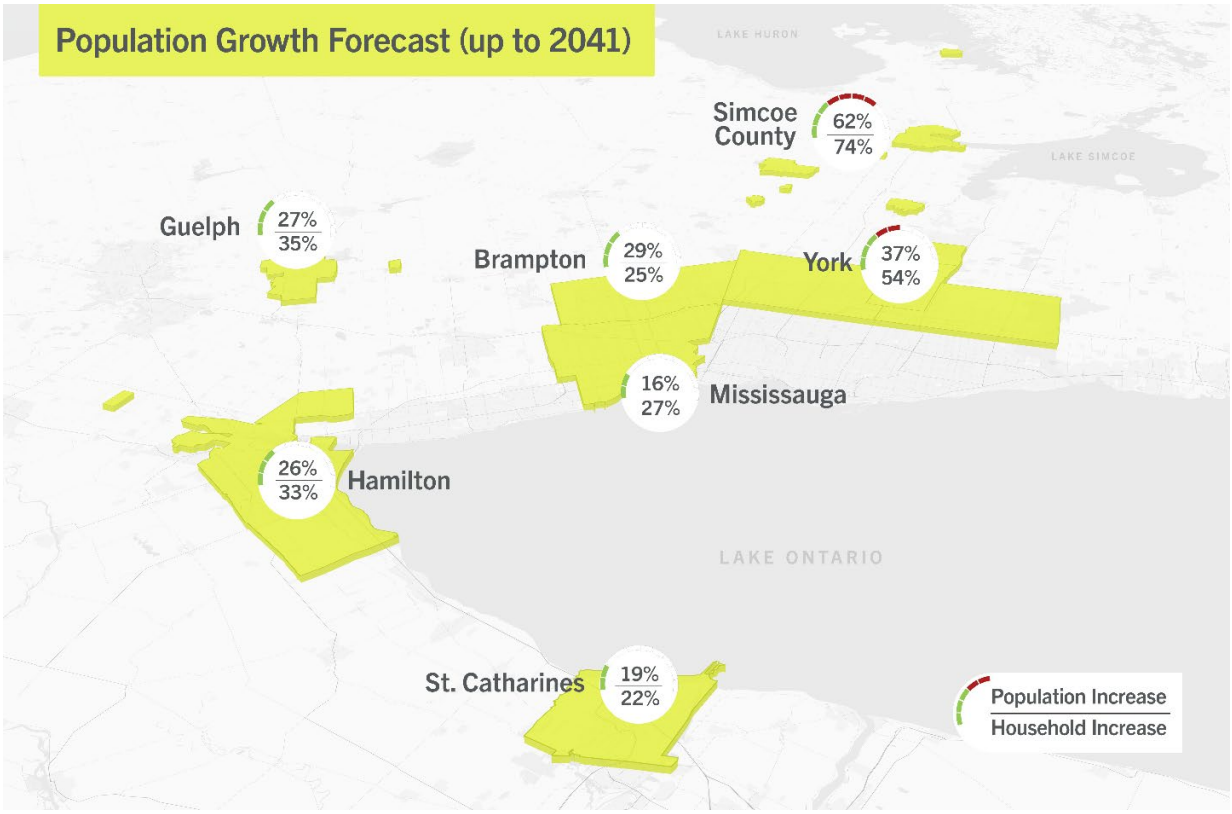

Figure B13 - 1 Population Growth Projections in Alectra Utilities Service Territory

[70] The numbers encompass all municipalities in each respective region (York, Simcoe County, Peel); 5 year period growth % shown

Demographic projections for Alectra Utilities' service territory also reflect significant growth trends.[71] The municipal growth projections illustrate that a population growth of 13% and an average household growth of 18% respectively is expected to occur over the 10-year period from 2026 to 2036. The population growth projections in Alectra Utilities service territory are presented in Figure B13 - 1. Using Alectra Utilities load forecasting processes, the residential, commercial, industrial developments are projected to 'increase the system peak by 520MW from 2024 to 2031.

3.1.1.2 Data Center Expansions

Alectra Utilities' current load from data centers is approximately 115MW and the utility has received customer commitment to connect additional 425MW of data center by 2031. Due to availability of communication infrastructure in its service area, Alectra Utilities will continue to see demand for data centers within its boundaries. Alectra Utilities is in discussion with several data center customers for an additional 500MW; however, without firm commitments, these loads have not been factored in the load forecast, and no investments have been proposed.

3.1.1.3 Transportation

Alectra Utilities has seen an approximately 50% CAGR of EVs in its service area from 2021 to 2024. Alectra Utilities commissioned a study to determine the penetration of electric vehicles in its service area (refer to *Appendix J - Load Forecast and System Capacity Adequacy Assessment Report*). The study projects a CAGR of 33% of EVs in its service area with more than 500,000 electric vehicles in its service area by 2031 which includes Light Duty, Medium Duty and Heavy Duty fleet vehicles. Several of the transit agencies that are in Alectra Utilities service area have plans to electrify their fleet and have been in discussion with Alectra Utilities to provide capacity for their charging facilities. Based on the type of vehicle and their charging demands, Alectra Utilities forecast peak demand of 524MW from EV charging as further discussed in *Chapter 5.3.1 Asset Management Process Overview*.

3.1.2 Reliability

The secondary driver of these investments is reliability. Consistent with utility best practices across Canada, Alectra Utilities plans its distribution system such that the system can continue to

[71] Alectra Utilities relied on data from the Ontario Ministry of Finance, Hemson Consulting, and planning materials for the Peel and York Regions.

operate within normal limits when one element of the grid fails. This is called “N-1 contingent”, since the system is operating with one element less than it normally does. In the context of Municipal substation planning, this means that Alectra Utilities must be able to transfer the loads associated with any given transformer in the substation network to adjacent substations, while remaining within the substation transformers’ contingency ratings.

As load growth occurs, the stations do not have the contingency capacity to carry the load for another station when a major element fails. The planned investments are necessary for Alectra Utilities to maintain system reliability in accordance with the N-1 contingency standard. Table B13 - 9 identifies Alectra Utilities' municipal substations that are projected to exceed capacity utilization, rendering them unable to meet the N-1 contingency reliability standard.

Table B13 - 9 Alectra Municipal Stations Capacity Utilization Exceedance 2031 Forecast

Municipal Substation Element	Ownership	Sub-Planning Zone	Operating Area	Capacity (MVA)	2023 Peak Demand (MVA)	Capacity Utilization	Forecasted Peak Demand (MVA) in 2031	Capacity Utilization in 2031
8th Line (13.8kV)	Alectra Utilities	Bradford	East	13.3	8.88	67%	14.4	108%
Melbourne (13.8kV)	Alectra Utilities	Bradford	East	13.3	9.18	69%	14.1	106%
Reagans (13.8kV)	Alectra Utilities	Bradford	East	13.3	10.9	82%	13.9	104%
Aurora MS5 - T1 (27.6kV)	Alectra Utilities	Aurora	East	16	10.6	65%	16.5	103%

Alectra Utilities’ plan to augment the capacity in Bradford and Aurora during this rate period as further discussed in *Section 3.2.1.1.3* and *Section 3.2.2.2*.

Investments in Station Capacity will accommodate the impacts of the projected load growth through capacity upgrades at the existing stations, as well as the construction of new stations at growth locations. Addressing capacity constraints in key growth areas is crucial as stations approach capacity limits. If not dealt with proactively, these growth trends will impact Alectra Utilities’ ability to connect customers to the distribution system. Without the planned investments to address these load demands, Alectra Utilities may not be able to connect customers in some areas, as well it will restrict Alectra Utilities’ ability to restore customers when a major element, such as transformer, fails.

The planned investments in the stations for each of the operating area are included in *Section 3.2. Section 3.3* discusses the capital contribution (CCRA) payments that Alectra Utilities will be required to make to HONI for transmission connection and capacity upgrades at HONI owned stations. *Section 3.3* discusses investments Alectra Utilities is required to make in relation to Transmitter upgrades. Alternatives to each proposed investment are set out in *Section 5.2*.

3.2 Stations Capacity Investment

The following subsections provide further details on the planned investments by operating areas for the 2027-2031 period.

Alectra Utilities' service area has been organized into four operating areas/regions. These operating areas comprise the following communities:

The four Operating Areas and their Planning Zones are:

- Alectra East: Two Planning Zones including York and Simcoe
- Alectra Central: Two Planning Zones including Central North (Brampton) and Central South (Mississauga)
- Alectra West
- Alectra Southwest

Furthermore, for station capacity analysis, Alectra Utilities considers stations with interconnections to form a study area where loads from one station can be transferred to another station while respecting operational criteria.

3.2.1 Alectra Utilities East Stations Investments

3.2.1.1 York Planning Zone

The York Planning Zone includes two sub-planning zones: Southern York (Vaughan, Richmond Hill, Markham) and Aurora. Vaughan, Richmond Hill, and Markham are primarily supplied from 27.6kV voltage with a small amount of load (approximately 0.5%) supplied at 8.32kV or 13.8kV from MS. Aurora is supplied by five 44kV feeders originating from HONI owned Armitage TS in Newmarket, six 44/13.8kV MS, and two 44/27.6kV MS. Southern York is supplied by 12 Alectra Utilities owned TS and feeders from HONI owned TS at 27.6kV.

Markham and Richmond Hill stations have ten stations in the study area and Vaughan has five stations in the study area.

As part of the regional planning process, the HONI Needs Assessment identified capacity needs in Markham, Vaughan and Richmond Hill as illustrated in Table 5.2.2 - 2 in *Chapter 5.2.2 Coordinated Planning with Third Parties*. Alectra Utilities' analysis identified the need for five additional TS in the York Region between 2028 and 2034 (Table B13 - 10). IESO issued a hand-off letter to Alectra Utilities for implementation of one station in Markham in April 2017. The IESO IRRP for GTA North is currently underway, where Alectra Utilities has presented the need for five additional TSs.

In Markham, the station investment includes the cost of construction of new Markham TS (MTS#5) which is required to be in service by 2028. In addition, it includes the cost of land purchase and conducting Class Environmental Assessment (EA) and preliminary design for new TS (MTS#6) with a planned in-service date of 2034.

In Richmond Hill, the station investment includes the cost of EA, design, and construction of a new Richmond Hill TS #3 (RH-TS#3) with a planned in-service date of 2030.

In Vaughan, the station investments include investment for 2 new transformer stations. The design and construction of a new Vaughan TS #6 (VTS#6) with planned in-service of 2027, and the cost of land purchase, conducting Class EA and preliminary design and procurement of long lead times for Vaughan TS #5 (VTS#5) with a planned in-service date of 2033.

A Markham and Richmond Hill

Markham and Richmond Hill are supplied by seven Alectra Utilities owned transformer stations and one HONI Station, in addition to ties to other stations in Vaughan.

The total capacity of these stations is 1,388MVA, while the existing station loading is 1,282MVA. There is only 108MVA available in Markham and Richmond Hill area. Based on the 2024 Annual Load Forecast and System Capacity Assessment, the system demand is projected to exceed the available total capacity in the Markham and Richmond Hill study area in 2027.

Figure B13 - 2 show the existing station Limited Time Rating (LTR)[72] and major development in Markham and Richmond Hill area.

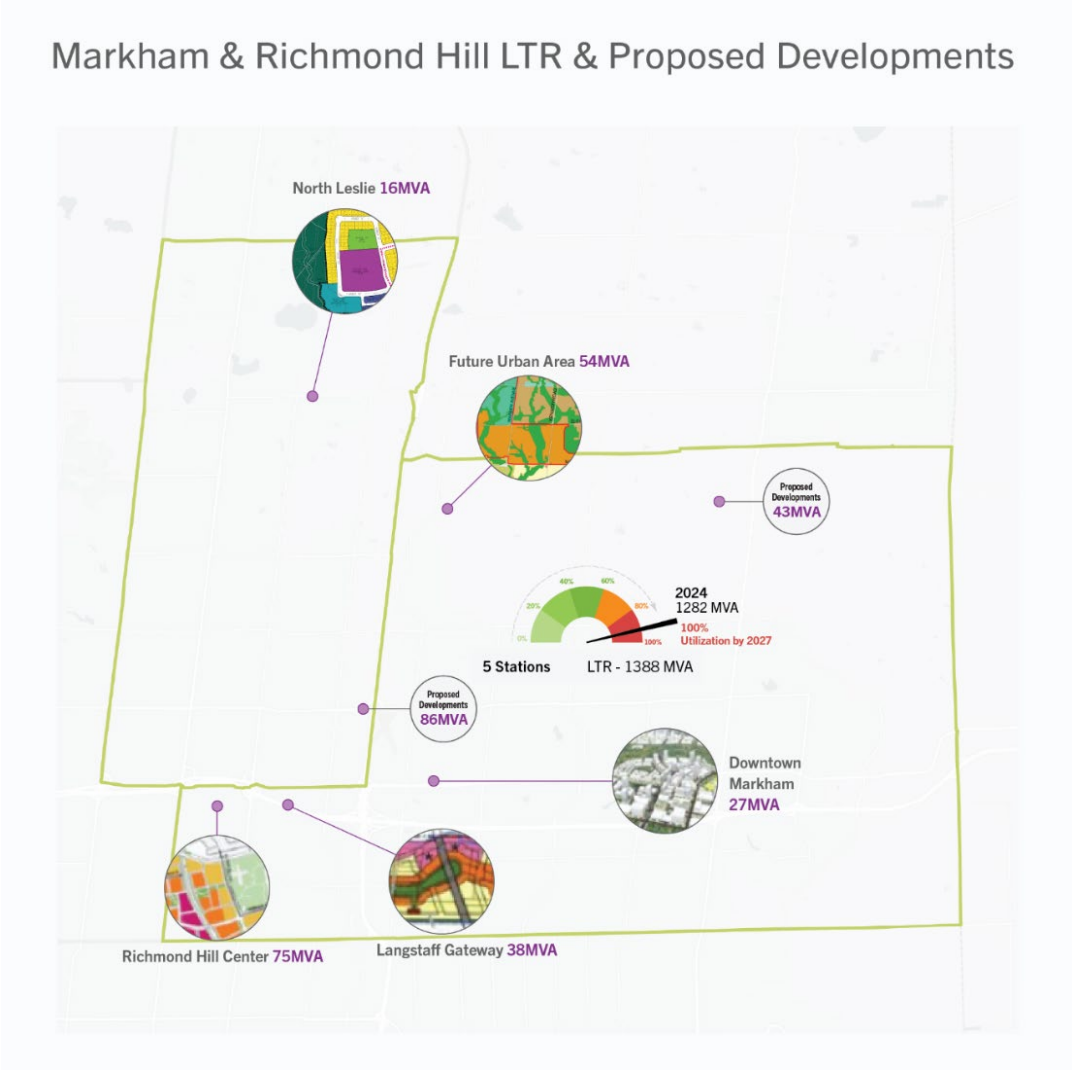

Figure B13 - 2 York Region Station - Markham and Richmond Hill, Ongoing Expansions and Growth Expected to 2035

[72] LTR- The capacity of a DESN station is determined by the "Limited Time Rating" (LTR) of one of the two transformers. This is based on the assumption that one line or transformer could be forced out of service at any time leaving the remaining transformer to carry all of the load. Under this loading condition, an acceptable annual insulation loss of life is 2% or 0.2% per day for 10 days

Figure B13 - 3 illustrates the projected load, LTR capacity for Markham and Richmond Hill TS from 2024 to 2034. Figure B13 - 3 shows that the LTR capacity will be exceeded in 2028.

Table B13 - 10 shows the projected loadings for the existing and new station additions over the period from 2024 to 2034.

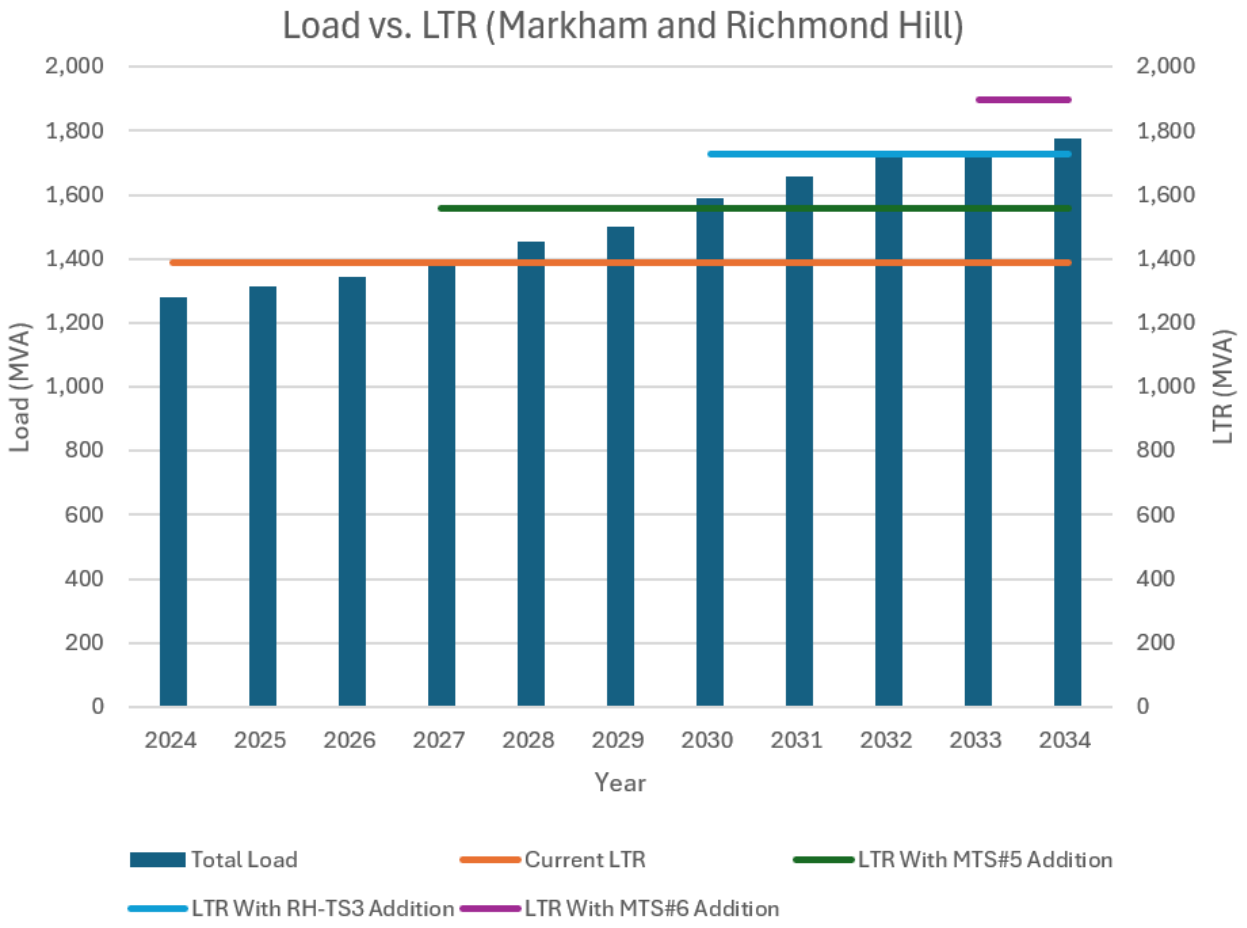

Figure B13 - 3 Load vs. LTR for Markham and Richmond Hill (2024-2034)

Table B13 - 10 Projected Loading and LTR for Existing and New Stations Over Period 2024-2034

Station	LTR (MVA)	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
VTS1	170	170	170	170	170	170	170	170	170	170	170	170
VTS1E	170	170	170	170	170	170	170	170	170	170	170	170
RH-TS1	170	150	170	170	170	170	170	170	170	170	170	170
RH-TS2	112	110	110	112	112	112	112	112	112	112	112	112
MTS1	90	90	90	90	90	90	90	90	90	90	90	90
MTS2	112	112	112	112	112	112	112	112	112	112	112	112
MTS3	112	100	105	112	112	112	112	112	112	112	112	112
MTS3E	112	100	105	112	112	112	112	112	112	112	112	112
Buttonville	170	160	161	170	170	170	170	170	170	170	170	170
MTS4	170	120	120	125	170	170	170	170	170	170	170	170
Total	**1388**	1282	1313	1343	**1388**	**1388**	**1388**	**1388**	**1388**	**1388**	**1388**	**1388**
New Station (MTS#5)	**170**					68	113	170	170	170	170	170
New Station (RHTS#3)	**170**							32	101	170	170	170
New Station (MTS#6)	**170**											47
Total With New Stations	**1898**	1282	1313	1343	**1388**	1456	1501	1590	1659	**1728**	**1728**	1775

Analysis identified the need for three additional TS in the Markham and Richmond Hill area between 2027 to 2034 (Table B13 – 11).

Table B13 – 11 Planned Station Projects – Markham & Richmond Hill

Station Name	Owner	In-Service Year
Markham TS5 (MTS#5)	HONI	2027
Richmond Hill TS3 (RHTS#3)	Alectra Utilities	2030
Markham TS6 (MTS#6)	Alectra Utilities	2034

The following section discusses the growth underpinning each station and proposed investment for each of these stations.

A.1 Markham TS#5

This investment is to support the completion of the construction of the new station Markham TS#5, as identified by the Independent Electricity System Operator's (IESO) Regional Resource Planning Process (IRRP) completed in 2020, refer to *Appendix H06 GTA North (York Region)*. Alectra Utilities' load forecast indicates that the transformation capacity of the distribution system in the Markham/Richmond Hill area will be exceeded by 2028.[73] The projected in-service date for the new station is 2027, as required to meet anticipated load growth.

As of 2024, the area has a population of approximately 575,164 and 15,190 businesses with 259,858 employees.

Between 2024 and 2033, Markham and Richmond Hill are projected to add approximately 47,430 residential units (32,672 units in Markham and 14,758 units in Richmond Hill) and 3.1 million square meters of commercial/industrial space (2.5 million square meter in Markham and 0.6 million square meters in Richmond Hill).

The major developments in the area that are intended to be supplied by this project include:

Markham Future Urban Area (FUA)

The City of Markham is working on an Official Planning Amendment which expands the Urban Area of the Town of Markham to both sides of Warden Ave to provide opportunities for urban growth to the year 2031. The north Markham Future Urban Area covers about 1,288 hectares (3,183 acres bordered by Major Mackenzie Drive to the south, the Hydro Corridor and Woodbine Avenue to the west, the northerly city limits and Elgin Mills Road to the north, and the Robinson Creek to the east.

Approximately 675 hectares (1,668 acres) of developable lands are designated for future neighborhoods, located primarily between Major Mackenzie Drive and Elgin Mills Road. Approximately 300 hectares (741 acres) located north of Elgin Mills Road are designated for employment uses. In total, the Future Urban Area is intended to accommodate approximately 12,000 residential units with a population of approximately 38,000 persons,

[73] Alectra Utilities' forecast reflects current capacity and the expected impact of distributed generation and CDM.

and approximately 19,000 jobs. It is expected approximately 65MVA of new loads are expected on both sides of Warden Ave north of Major Mackenzie Dr.

The development of FUA is well underway; houses are being built in Berczy Glen Secondary plan area bounded by Elgin Mills Road to the north, Warden Ave to the east, Major Mackenzie Drive to the south and HONI corridor to the north.

The Markham Innovation Exchange (Mix)

The Mix will be Ontario's first innovation cluster that connects knowledge and production clusters. Located on 1,920 acres directly adjacent to Highway 404, Mix will create a one-stop destination for research, training and production facilities, and strengthen the domestic supply chain. The total estimated loading for the entire expansion is 120MW.

Due to the load growth from these new developments and other organic growth, the total peak demand in the Markham/Richmond Hill area is expected to grow by approximately 492MVA from 2024 to 2033.

The IESO issued a hand-off letter to Alectra Utilities and HONI concerning the implementation of a wires solution to accommodate the new growth in Markham area. The recommended scope of the project consists of a new 230/27.6kV 170MVA Dual Element Spot Network (DESN)[74] TS in Markham.

Markham TS#5 will be located at the existing HONI owned Buttonville TS, as it has sufficient space to accommodate a new TS. Alectra Utilities will seek to enter in CCRA agreement with HONI to build a new 230/27.6kV 170MVA DESN. Alectra Utilities intends that the class EA screening begins for the new TS in 2025 so that station design can begin in 2026, for an in-service date of 2027/2028.

[74] "Dual Element Spot Network" or DESN is a concept that provides redundancy in the form of duplication for most station components. The DESN transformer station consist of two incoming transmission lines, two transformers and two busses. Any of these components can fail without seriously affecting supply reliability, as the companion equipment is capable of carrying the total station load.

A.2 Richmond Hill Transformer Station - TS#3

This investment supports the construction of the new Richmond Hill TS#3 to meet the load requirements for Metrolinx's Yonge North Subway Extension (YNSE) project, as well as other developments in the Richmond Hill area.

Yonge North Subway Extension

The Yonge North Subway Extension will extend the TTC's Line 1 subway service approximately 8 kilometers from its existing terminus at Finch Station into the City of Richmond Hill. The project spans the City of Toronto and York Region, including parts of the cities of Markham, Vaughan, and Richmond Hill. Four Traction Power Substations have been proposed within Alectra Utilities' service territory. The maximum demand for these four stations is 35MVA, and full supply redundancy is required to meet the reliability requirements of the rail system. Four new dedicated 27.6kV feeders are required to supply these stations in 2029.

Other major developments supplied by this station will include Richmond Hill Center, Langstaff Gateway and Yonge Steeles Corridor Secondary Plan.

Richmond Hill Center

Richmond Hill Center (RHC) is planned to accommodate a population of approximately 23,000 residents, 16,500 jobs, and 13,000 residential units at full build-out within an Urban Growth Centre boundary of approximately 60 hectares. The anticipated load is 50MVA when fully built out.

Langstaff Gateway Secondary Plan Development: Langstaff Gateway Secondary Plan Area projects development of a high-density urban center with up to 15,000 residential units (or a population of approximately 32,000) and approximately 10,000 jobs. The anticipated load for this area is 45MVA when fully built out.

Yonge Steeles Secondary Plan

City of Vaughan's Yonge Steeles Corridor Secondary Plan, as shown in Figure B13 - 4, is an area located along the west side of Yonge Street between Steeles Avenue West and Thornhill Public School and on the north side of Steeles Avenue West between Yonge

Street and Palm Gate Boulevard in the south plan area; and between the Thornhill Golf and Country Club and Longridge Road in the north plan area projects 25,202 residential units and a population of 45,000. The total anticipated load by 2029/2030 is 32MVA and 95MVA when all developments are completed.

Figure B13 - 4 Yonge Steeles Secondary Plan[75]

The projected in-service date for the new station is 2030, as required to meet anticipated load growth and timelines for subway development.

Alectra Utilities' recommended scope of the project includes the construction of a new 230/27.6kV, 170MVA Dual Element Spot Network TS in Richmond Hill. Richmond Hill TS#3 will be located at the existing Richmond Hill TS site. The timeline to build the new station is approximately 3 to 5 years as the new station will be built on existing station land. Alectra Utilities

[75] Sourced from the City of Vaughan's Yonge Steeles Corridor Secondary Plan

intends to complete the EA for the new TS in 2027, allowing station design to begin in 2028, with an in-service date of 2030. Alectra Utilities will receive a partial contribution for this station.

A.3 Markham Transformer Station 6 – TS#6

This investment is to support the construction of the new Markham TS#6, as identified by Alectra Utilities' latest load forecast and in HONI Needs Assessment report. The initiation of the Markham MTS#6 will be in 2028 and the in-service date will be in 2034. The projected in-service date is outside the DSP forecast period. The proposed investment will not have an impact on rates in this DSP period. The major development intended to serve by this project include Markham Future Urban Area, the Mix and other industrial development along Hwy 404 and 16th Avenue.

Between 2024 and 2034, Markham and Richmond Hill are projected to add approximately 47,430 residential units (32,672 unit in Markham and 14,758 units in Richmond Hill) and 3.1 million square meters of commercial/industrial space (2.5 million square meters in Markham, and 0.6 million square meters in Richmond Hill).

Alectra Utilities' peak demand forecast indicates that the continued development will continue to increase the demand in the Markham area and the transformation capacity Markham/Richmond Hill area will be exceeded in 2034.

The timeline to build the new station is approximately 5 to 7 years, including the EA process. Alectra Utilities expenditures during the DSP period include land purchase, completing a class EA and preliminary design of Markham TS#6 for an in-service date of 2034. The exact location of Markham TS#5 will depend on the outcome of the EA, including the associated public consultation process.

B Vaughan

Vaughan is supplied by five Alectra Utilities owned transformer stations.

The total capacity of these stations is 850MVA, while the existing station loading capacity is 724MVA. There is only 126MVA available in Vaughan area.

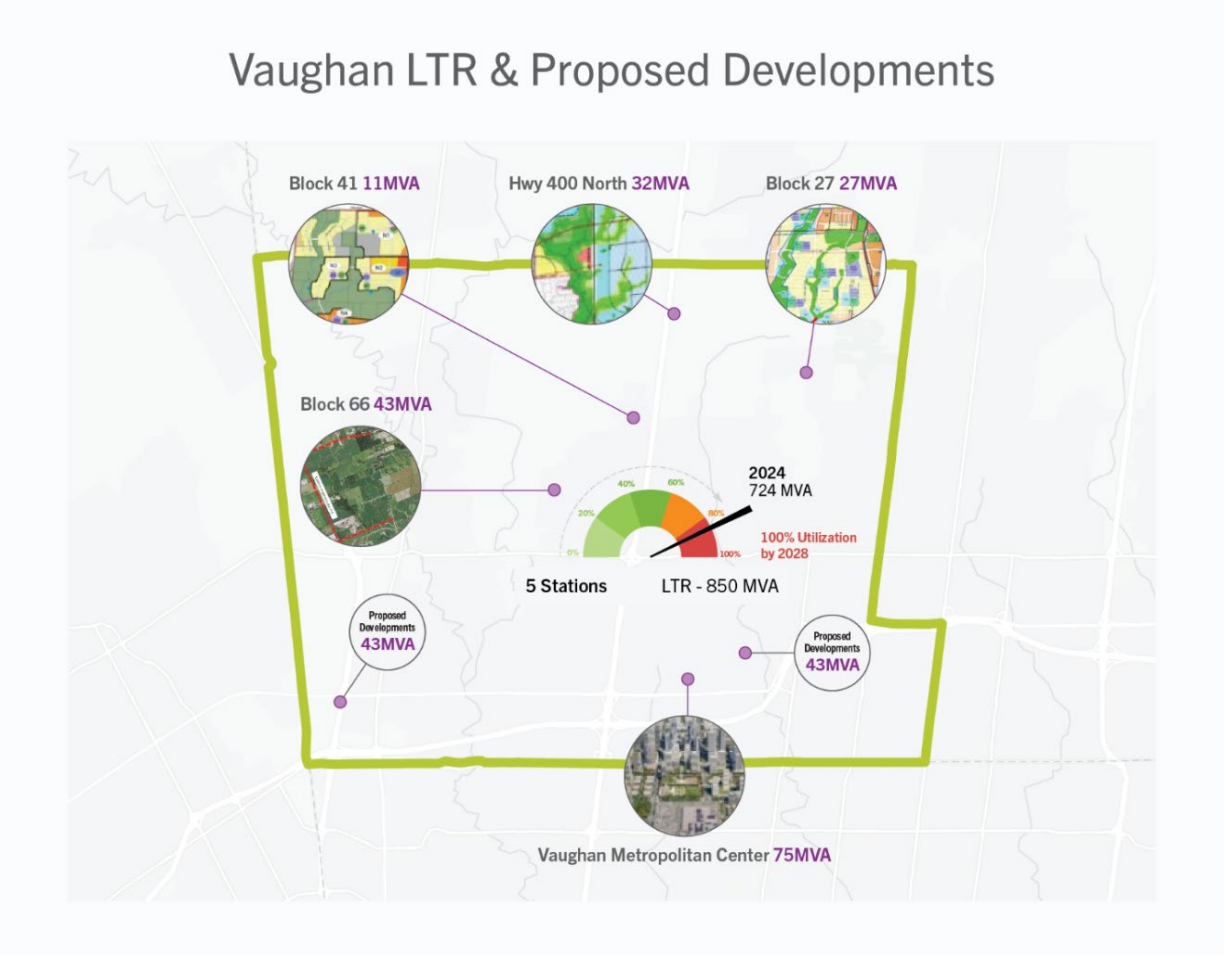

Figure B13 - 5 York Region Station - Vaughan, Ongoing Expansions and Growth Expected to 2035

Figure B13 - 5 illustrates the projected load, LTR capacity for Vaughan TSs from 2024 to 2033. As observed in Figure B13 - 6, the system demand is projected to exceed the available total capacity in the Vaughan area study area in 2028.

Table B13 - 12 shows the projected loading vs. LTR of the current and future stations.

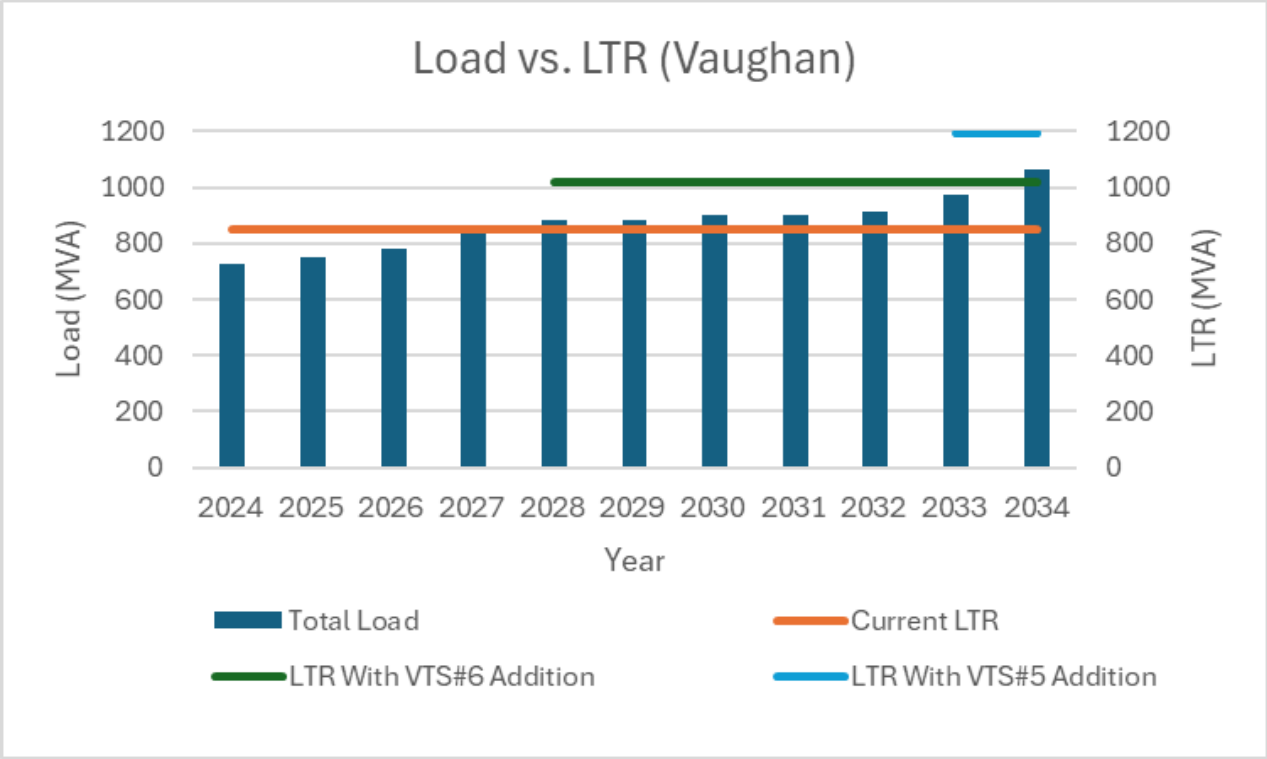

Figure B13 - 6 Load vs. LTR for Vaughan (2024-2034)

Table B13 - 12 LTR Capacity and The Existing and Forecast Load for Vaughan Transformer Stations

Station	LTR (MVA)	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
VTS1	170	170	170	170	170	170	170	170	170	170	170	170
VTS1E	170	170	170	170	170	170	170	170	170	170	170	170
VTS2	170	148	160	170	170	170	170	170	170	170	170	170
VTS3	170	140	150	170	170	170	170	170	170	170	170	170
VTS4	170	96	110	112	158	170	170	170	170	170	170	170
Total	**850**	724	760	792	838	850	850	850	850	850	850	850
New Station (VTS#6)	**170**					33	32	54	53	61	83	95
New Station (VTS#5)	**170**										41	117
Total With New Stations	**1190**	724	760	792	838	883	882	904	903	952	974	1062

Table B13 - 13 illustrates the planned station projects with their planned in-service dates.

Table B13 - 13 Planned Station Projects - Vaughan

Station Name	Owner	In-Service Year
Vaughan TS6	Alectra Utilities	2027
Vaughan MTS5	Alectra Utilities	2033

The following section discusses the growth underpinning the needs for each and proposed investment for each of these stations.

B.1 Vaughan TS#6

An Alectra Utilities' customer is building a data center facility in Vaughan with a maximum demand of 127MVA with a planned operation date of 2027. The customer has requested Alectra Utilities to provide the required capacity supply with 100% redundancy. The area is supplied through one Alectra Utilities owned transformer station (VTS#3) and two HONI-owned TS (Woodbridge TS and Kleinburg TS) which share capacity between HONI and Alectra Utilities' customers. These stations do not have the required capacity to meet this customer's needs.

To fulfill the customer's demand, Alectra Utilities is building a new dedicated 230/27.6kV transformer station with 2x75/100/125MVA transformers. Alectra Utilities will apply the Economic Evaluation policy to determine cost sharing between the customer and the utility. Alectra Utilities has completed the environmental screening for the station, and construction is scheduled to begin in the fall of 2025, with a planned in-service date of 2027.

B.2 Vaughan TS#5

This investment is to support the construction of the new Vaughan TS#5, as identified by Alectra Utilities' latest load forecast and identified in the IESO Needs Assessment report (*Appendix H05 GTA North Region NA July 14, 2023, Page 20*). The initiation of the Vaughan TS#5 will be in 2027 and the in-service date will be in 2033. The projected in-service date is outside the DSP forecast period. The proposed investment will not have an impact on rates in this DSP period. The proposed investment will not have an impact on rates in the current period.

The station will supply the following large development:

Vaughan Metropolitan Centre (VMC)

The Vaughan Metropolitan Centre (VMC) is bounded by Highway 407 to the south, Highway 400 to the west, Portage Parkway to the north, and Creditstone Road and Maplecrete Road to the east. The total area of the VMC is 190 hectares, with over 100 hectares being developable.

The VMC is in the vicinity of five Alectra Utilities owned stations. Table B13 - 12 illustrates the load forecast for the stations. Based on the ongoing development, all stations in Vaughan are expected to reach their LTR capacity by 2028.

The average density of projects continues to significantly exceed those planned in the current VMC Secondary Plan (SP).

Developments and approvals to date are heavily weighted towards residential uses in the form of high-rise condominiums, predominantly consisting of 1-and 2-bedroom units.

Development is proceeding at a greater intensity than anticipated in the 2010 Secondary Plan. Figure B13 - 7 show the relevant development trends. It was planned for 25,000 residents by 2031; however, the latest development trajectory projects a total 129,012 residents and approximately 70,000 units when fully developed.

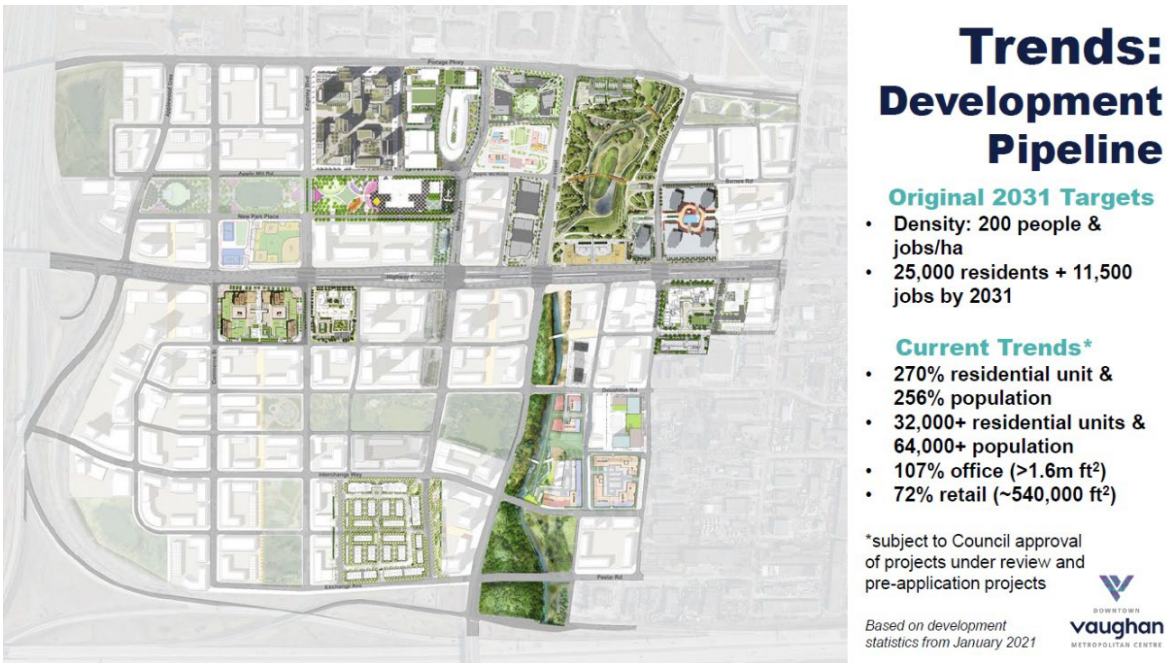

Figure B13 - 7 Population & Employment Initial Target vs. Current Trend for VMC

The total new load in VMC is expected to be 240MVA. Approximately 126MVA is available from the existing system. Based on development applications, it is expected that the capacity will reach LTR under the 1-in-10 weather scenario by 2031. With the new Vaughan TS#6 in service by 2027, an additional 40MVA of capacity will be freed up, which can be utilized to support growth in the Vaughan area.

Alectra Utilities expenditures will include a new 230/27.6kV 170MVA Dual Element Spot Network TS in Vaughan connected by distribution and transmission lines.

The projected in-service date for the new station is 2033, as required to meet anticipated load growth. The Vaughan Station investment includes land purchase, conducting Class EA and preliminary design and procurement of long lead times for a new Transformer. The exact location of Vaughan TS#5 will depend on the outcome of the EA, including the associated public consultation process.

Alectra Utilities forecasts expenditures during the DSP period include land purchase, completing a class EA and preliminary design of station for an in-service date of 2033.

C Aurora MS6 Expansion

Aurora MS#6 has two 10/13/16 MVA 44/13.8kV transformers (T1 & T2) in parallel, and only one can be used at a time. The capacity of the second transformer is not utilized. The peak on MS6 was 11.5MVA and will exceed its max rating of 16MVA in 2029 as load transfer is not feasible.

MS#6 requires new 13.8kV feeders to address low voltage issues on the existing two feeders. New feeders will enable load transfers which will lead to reduce loading on existing feeders and address voltage concerns.

Over 600 new homes are being forecasted in Aurora every year, which amounts to approximately 1.6MVA new load each year. Over 3,000 units have been proposed in Wellington St/Leslie St area. The existing feeders along Wellington St/Leslie St are already loaded and approaching their capacity limits. The additional 13.8kV feeders will be needed in the area.

Aurora MS#6 Expansion project includes the following:

- Adding one 13.8kV main breaker for T2
- Adding two 13.8kV feeder breakers

This project is planned to be energized in 2029, and it will increase supply capacity by 16MVA and solve the summer low voltage issue of existing feeders. It will also provide backup capacity for other stations/feeders.

3.2.1.2 Simcoe Planning Zone

Simcoe planning zone is divided into five subzones: New Tecumseth (Alliston, Beeton, and Tottenham), Barrie, Bradford, Penetanguishene and Thornton. Simcoe area is primarily supplied by HONI owned 44kV transformer stations. Alectra Utilities own the Municipal stations that further step down the voltage to 13.8kV.

Alectra Utilities analysis indicates the need for the Municipal Station capacity augmentation in Alliston, Barrie and Bradford, as illustrated in Table B13 - 14. The In-Service dates are reflective of the deferment that Alectra Utilities has proposed, based on implementing Non-Wires Solutions (NWS).

Table B13 - 14 Planned Station Projects – Simcoe County

Station Name	Owner	In-Service Year
New Alliston MS	Alectra Utilities	2032
New Barrie MS	Alectra Utilities	2032
Melbourne MS Upgrade	Alectra Utilities	2030

The Municipal Stations Capacity investment in Alliston, Barrie includes the costs of land purchase and construction of new MS. The station capacity investment in Bradford includes the cost of transformer upgrade.

A Alliston

Alectra Utilities will be required to build a new Alliston MS 2x20MVA, 44/13.8kV, dual-stage fan, 4-feeder MS to meet the growing demand in this region. The initiation of the New Alliston 2x20MVA MS will be in 2029 and the in-service date will be in 2032. The projected in-service date is outside the DSP forecast period. The proposed investment will not have an impact on rates in the current period.

Without the planned MS, Alectra Utilities would be unable to satisfy the N-1 contingency standard, meaning that customers in this region would face unacceptably high reliability risks. Alectra Utilities forecasts expenditures for land purchase, design, and preconstruction for a new station during the DSP period.

The Town of Alliston is currently supplied by two 13.8kV stations: MS330 and MS331. MS330 has a 10 MVA single-stage fan transformer rated to 10MVA Oil Natural Air Natural (ONAN) and 13.3MVA Oil Natural Air Forced (ONAF) supplying north-west Alliston.[76] MS331 has two 10MVA transformers each supplying separate parts of Alliston: MS331-T1 feeders supply the east-end of Alliston, and MS331-T2 feeders supply west-end of Alliston. These two transformers have single-stage fans and are rated to 10MVA ONAN and 13.3MVA ONAF.

[76] The contingency rating is determined by the cooling capabilities of the transformer, and is equivalent to the highest cooling rating; i.e. ONAN (100% of base rating) for self-cooled transformer units, ONAF (133% base rating) or ONAF/ONAF (166% of base rating) for transformer units with single and dual stage fans, respectively

Another 30 hectares of industrial and commercial development have been approved in the vicinity of Theatre Road and Industrial Parkway. This development includes 12 blocks for industrial purposes and three blocks for commercial use. The load of this development is 8MVA.

A total of 3,162 residential units are to be completed in the Alliston area either in the approved developments or the intensification projects. They include Liberty Development (1.5MVA), Value Centers (2MVA), and Smart Centers (1.5MVA). In some developments, Phase 1 construction has been finished, with the rest to be done over the next few years. Moreover, a total of 3,437 residential units have been either registered or proposed for development.

The projected growth in the Town of Alliston is illustrated in Figure B13 - 8. As shown Table B13 - 15, the MS331-T2 transformer will exceed its normal 10MVA ONAN rating in 2026 and will exceed its maximum 13.3MVA rating in 2031 during the summer peak. Additionally, the MS331-T1 transformer will exceed its normal 10MVA ONAN rating in 2031 during the summer peak. The table also illustrates that the 13.8kV system in Alliston will exceed the system contingency capacity across substation transformers in 2025 upon the loss of a transformer at either MS330 or MS331.

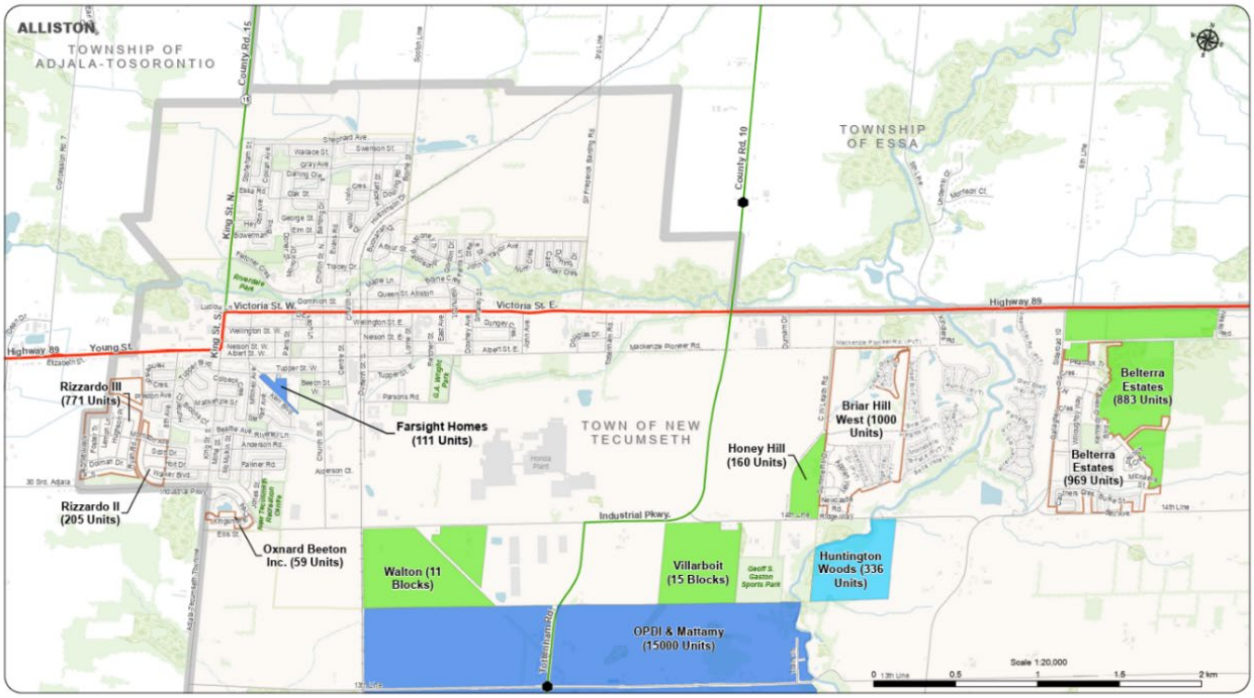

Figure B13 - 8 Town of Alliston and Associated Commercial Developments

Table B13 - 15 Alliston 10-Year Load Growth Projection 13.8kV Municipal Substations

Station Information				Alliston 10-Year Load Projection										
Station ID	Station	ONAN Rating (MVA)	ONAF Rating (MVA)	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
MS330	8th Avenue	10	13.3	7.8	8.0	8.1	8.2	8.4	8.5	8.7	8.8	9.0	9.1	9.4
MS331-T1 (13.8 kV)	14th Line	10	13.3	9.3	9.4	9.5	9.6	9.8	9.9	10.0	10.1	10.2	10.4	11
MS331-T2 (13.8 kV)	14th Line	10	13.3	9.3	9.9	10.5	11.1	11.8	12.5	13.2	14.0	14.9	15.8	16.7
13.8kV Normal Capacity (ONAF):			39.9	26.4	27.3	28.1	28.9	30.0	30.9	31.9	32.9	34.1	35.3	37.1
13.8kV N-1 Contingency Capacity (ONAF):			26.6	26.4	27.3	28.1	28.9	30.0	30.9	31.9	32.9	34.1	35.3	37.1

Alliston's system capacity is 39.9MVA under normal operating conditions, and contingency capacity is 26.6MVA upon a loss of the largest station transformer. The historical loading across all 13.8kV substations in Alliston peaked at 26MVA, leaving only 0.6MVA of contingency headroom. With planned developments, the peak load is projected to reach 27.3MVA in 2025 and 35.3MVA by 2033. These projections are within the system's capacity but exceed N-1 contingency capacity. Alectra Utilities' standards require adjacent substations to provide N-1 contingency. Without the new station, Alliston's transformer capacity would not satisfy N-1 requirements, which would prevent Alectra Utilities from shifting load between feeders and restoring power during outages.

Alectra Utilities has determined that the non-wires option can defer the station investment from 2027-2031 to the next rate period (2032-2037) as presented in *Section 5.2*.

The new substation will provide 2x20MVA of 13.8kV capacity for the industrial/commercial and residential developments. The new substation will also provide contingency backup capacity for the Alliston system upon loss of MS331-T1 or MS331-T2, thereby satisfying the planning criteria for N-1 contingencies.

The Alliston station project consists of purchasing land and the construction of a new 2x20MVA, dual-stage fan, 4-feeder substation which includes engineering design, purchase of station

equipment, approvals, substation construction, equipment installation, and commissioning. The planned in-service date for Alliston MS is 2032.

B Barrie

Barrie is supplied by three HONI stations operating at 44kV. The municipal substations transform the 44kV sub-transmission voltage to distribution voltages of 4.16kV and 13.8kV. There are 26 municipal substations in Barrie; ten 13.8kV MSs and 16 4.16kV MSs.

Alectra Utilities plans to build a new Barrie MS 20MVA to supply the growing demand due to residential, commercial and industrial development. The initiation of the New Barrie 20MVA Substation will be in 2029 and the in-service date will be in 2032. The projected in-service date is outside the DSP forecast period. The proposed investment will not have an impact on rates in this DSP period.

This new substation will allow the utility to relieve the load on the existing substations and maintain system reliability requirements in accordance with N-1 contingency standard. Without the planned MS investment, Alectra Utilities would be unable to supply the forecast load growth or maintain the N-1 contingency standard. As a result, the customers in this region would either not be able to connect or would be exposed to increased risk of power outages and service disruptions. Alectra Utilities forecasts expenditures of $4.2MM on the land purchase and design and preconstruction for a new station during the DSP period.

South-West Barrie is currently supplied by five 13.8kV municipal stations: MS302, MS303, MS305, MS308, and MS307. The first four substations each have a 20MVA transformer with dual-stage fans with ONAN and ONAF ratings of 20MVA and 26.6MVA on single stage respectively. The ONAF/ONAF dual stage fan rating of the transformer is 33.2MVA. MS307 is a 10MVA substation with dual-stage fans with ONAN and ONAF ratings of 10MVA and 13.3MV, respectively. The ONAF/ONAF dual stage fan rating of the transformer is 16.6MVA.

Growth projections provided by the City of Barrie indicate that 11,522 residential units and approximately 62,300 square meters of non-residential space developments will be completed over the next ten years.

Following the completion of these developments, MS303, MS305, and MS308 are projected to exceed ONAN ratings during summer peak in 2024, 2026, and 2028 respectively. The ten-year load growth projection is provided in Table B13 - 16.

Table B13 - 16 Barrie 10-Year Load Growth Projection for 13.8kV Substations

Station Information				Barrie South 10-Year Growth Projection (MVA)										
Station ID	Station	ONAN Rating (MVA)	ONAF Rating (MVA)	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
MS303 (13.8kV)	Ferndale South	20	33.2	21.0	21.6	22.2	22.8	23.4	24.0	24.7	25.3	26.0	26.7	27.3
MS305 (13.8kV)	Holly	20	33.2	19.2	19.9	20.6	21.4	22.2	23.0	23.8	24.7	25.6	26.6	27.5
MS308 (13.8kV)	Park Place	20	33.2	12.9	13.7	14.5	15.4	16.3	17.3	18.4	19.5	20.7	22.0	23
MS307 (13.8kV)	Huronia	10	16.6	8.4	8.6	8.7	8.9	9.1	9.3	9.5	9.7	9.9	10.1	11.2
MS302 (13.8kV)	Saunders	20	33.3	11.8	12.2	12.6	13.0	13.4	13.8	14.3	14.7	15.2	15.7	16.2
13.8kV Normal Capacity (ONAF):			149.8	73.3	76.0	78.6	81.5	84.4	87.4	90.7	93.9	97.4	101.1	105.2
13.8kV N-1 Contingency Capacity (ONAF):			116.5	73.3	76.0	78.6	81.5	84.4	87.4	90.7	93.9	97.4	101.1	105.2

As shown in Table B13 - 16, the MS305 transformer will exceed its normal 20MVA ONAN rating in 2026 and will reach its single-stage ONAF rating of 26.6MVA in 2033 during the summer peak following the completion of the planned developments. MS303 and MS308 will exceed their normal 20MVA ONAN rating in 2028 and 2032. The ability to transfer load from MS303 and MS305 is limited due to there being only one existing feeder interconnection between both substations. Voltage drop issues would also arise in load transfer scenarios, given the long 7.1KM distance between the nearest stations. Voltage drops can cause significant issues for industrial customers since equipment in a facility can trip due to low voltage resulting in outages and lost productivity. To mitigate these conditions, Alectra Utilities could be forced to limit the connection of new loads.

Possible load transfers have been carried out from MS305 to MS308. With the continued growth from ongoing residential, industrial, and commercial developments, MS305 will exceed its ONAF single-stage fan rating of 26.6MVA in 2033. Upon loss of either MS305 or MS308, the load cannot be backed up starting from 2026.

Alectra Utilities has determined that the non-wires option can defer the station investment from this rate period (2026) to the next rate period (2032-2037) as further discussed in *Section 5.2*.

The new Barrie MS 20MVA substation will provide up to 33.2MVA of 13.8kV capacity (dual-stage fan ONAF/ONAF configuration) to supply the industrial and commercial developments along Bayview Drive, Harvie Road, and Concert Way over the next ten years, as well as capacity for 723 new residential unit and two 5-storey apartment blocks in that area. The new substation will provide capacity relief to both MS305 and MS308, while providing backup supply to the neighboring substations under contingency conditions. This will ensure compliance with the planning criteria for single contingency operations.

C Bradford – Municipal Station Upgrade at Melbourne MS

During the 2027-2031 period, Alectra Utilities expects that the demand from forecast residential and Industrial/Commercial developments in Bradford will exceed the utility's capacity. The existing property of Melbourne MS322 substation was leased from the Town of Bradford and has been purchased for expansion to accommodate a new 2x10MVA substation with 4 feeders.

Currently, Bradford is supplied by four 13.8kV MS: MS323 (8th Line), MS322 (Melbourne), MS321 (John), and MS324 (Reagans). Each substation has a 10MVA single-stage fan transformer with a maximum transformer ONAF rating of 13.3MVA.

As shown in Figure B13 - 9, growth projections from the Town of Bradford indicate that 3440 residential homes will be completed, corresponding to approximately 7MVA of additional load. Moreover, there are other industrial and commercial developments along 8th Line, Langford Boulevard, and Professor Day Drive, over the next ten years.

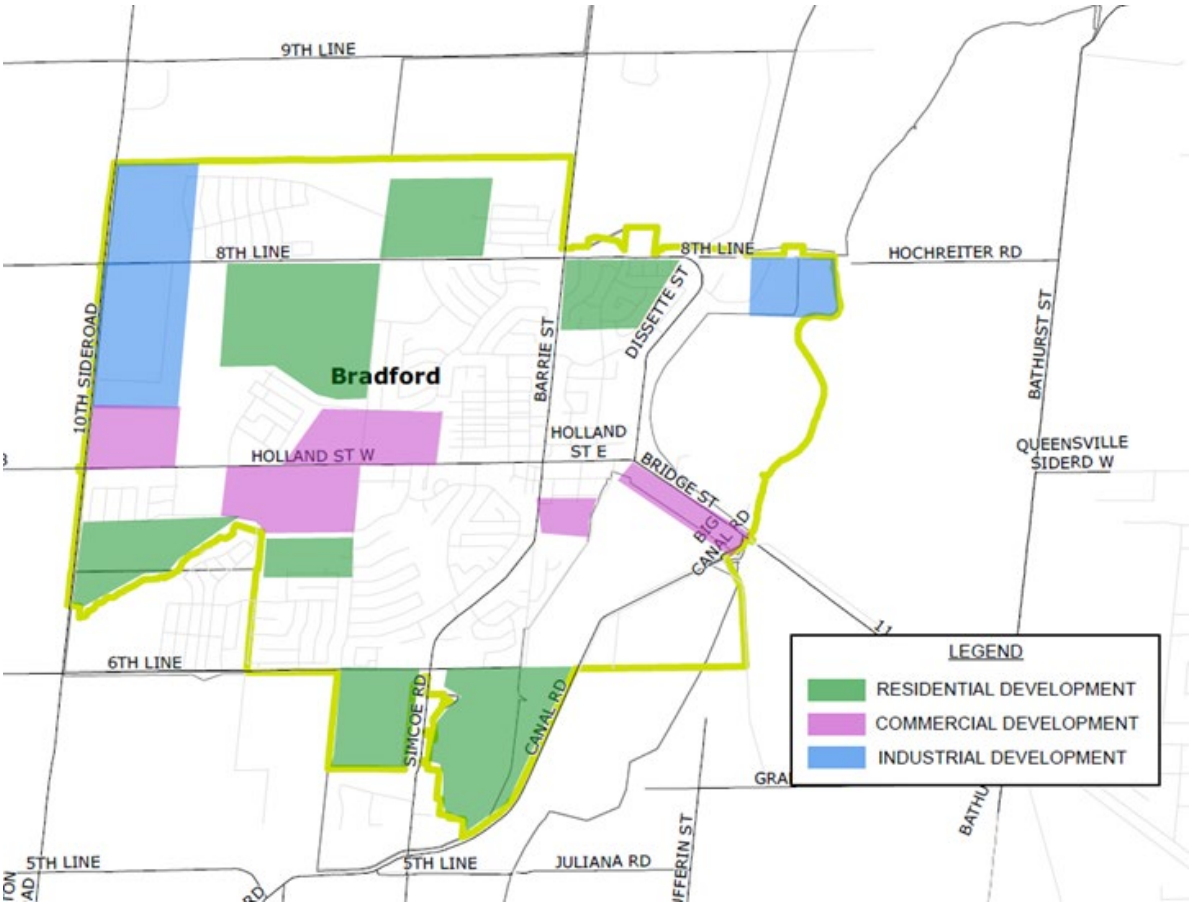

Figure B13 - 9 Town of Bradford Proposed Developments

MS324, MS323 and MS3221 exceeded their ONAN ratings during summer peak loading in 2023. Due to the proposed developments, MS324 will exceed its ONAF rating in 2032. The developments will also result in the single contingency capacity for the Bradford 13.8kV system being exceeded in 2027 upon loss of a substation transformer. The 10-year load growth projection for Bradford is illustrated in Table B13 - 17.

Table B13 - 17 Bradford 10-Year Load Growth Projection

Station Information				Bradford 10-Year Load Projection										
Station ID	Station	ONAN Rating (MVA)	ONAF Rating (MVA)	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
MS321 (13.8kV)	John	10	13.3	10.5	10.7	11.0	11.2	11.5	11.6	11.8	12.0	12.2	12.4	12.7
MS322 (13.8kV)	Melbourne	10	13.3	5.8	5.9	6.1	6.2	6.4	6.5	6.7	6.8	7.0	7.1	7.4
MS323 (13.8kV)	8th Line	10	13.3	11.2	11.5	11.7	12.0	12.2	12.4	12.6	12.8	13.0	13.2	13.6
MS324 (13.8kV)	Reagans	10	13.3	11.1	11.4	11.7	12.0	12.4	12.6	12.9	13.2	13.4	13.7	13.8
13.8kV Normal Capacity (ONAF):			53.2	38.6	39.5	40.5	41.4	42.5	43.1	44.0	44.8	45.6	46.4	47.5
13.8kV N-1 Contingency Capacity (ONAF):			39.9	38.6	39.5	40.5	41.4	42.5	43.1	44.0	44.8	45.6	46.4	47.5

Based on the needs and analysis, Alectra Utilities has determined that utilizing non-wires alternatives can defer this station expansion from 2027 to 2030, as further detailed in *Section 5.2*.

The proposed upgrade of Melbourne MS322 to 2x10MVA substation will provide backup capacity for the Bradford 13.8kV system upon loss of an adjacent substation transformer during summer peak loading, thereby ensuring compliance with the applicable planning criteria for single contingency operations. It will also ensure capacity for the new residential homes in South Bradford, as well as the 13.8kV component of the industrial and commercial developments at 8th Line, Langford Boulevard, and Professor Day Drive over the next ten years. The planned in-service date for the MS322 expansion is 2030.

The project expenditure consists of constructing a new 2x10MVA transformers on existing land at Melbourne MS322. This project includes replacing existing 10MVA end of life 10MVA substation, at including, the purchase of station equipment, obtain approvals, construct the substation and install the equipment installation as well as commissioning the site.

3.2.2 Alectra Utilities Central Stations Investments

Alectra Utilities Central consists of two planning zones (i.e. Central South which comprises of City of Mississauga and Central North which comprises of City of Brampton).

3.2.2.1 Central South (Mississauga) Planning Zone

Mississauga's distribution system has voltages of 4.16/27.6kV,13.8/44kV, and 27.6kV and is supplied by 16 DESNs at 11 Transformer Station locations as well as 67 Municipal Substations. The planning zone is further divided into 44/13.8kV East and West and 27.6/4.16kV in North and South area. Each of the areas are evaluated separately due to differences in voltage levels and lack of load transfer capability due to different voltages and geographic constraints.

As part of the regional planning process, the HONI Needs Assessment identified capacity needs in Mississauga (Bramalea, Erindale, Cooksville, Cardiff) as illustrated in Table 5.2.2 - 7 in *Chapter 5.2.2 Coordination with Third Parties*.

Alectra Utilities' analysis identified the need for three additional TSs and one MS in Mississauga between 2028 and 2034 as illustrated in Table B13 - 18.

For planning purposes, Mississauga has been further divided into North and South due to no interconnection between the sub planning zones.

Figure B13 - 10 and Figure B13 - 11 illustrate the projected load, and LTR capacity for Mississauga North and South respectively from 2024 to 2034. Table B13 - 18 and Table B13 - 19 show the projected loading of the current and future stations for Mississauga North and Mississauga South respectively.

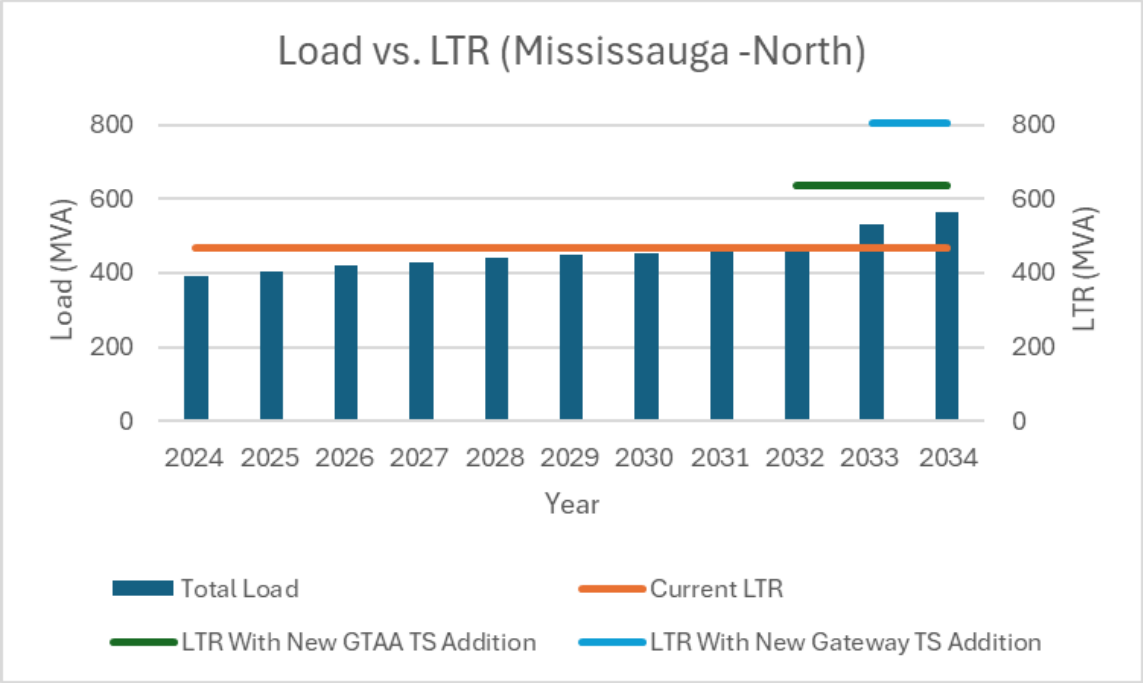

Figure B13 - 10 Load vs. LTR for Mississauga-North (2024-2034)

Table B13 - 18 Projected Loading and LTR for Existing and New Stations Over Period 2024-2034 for Mississauga North

Station	DESN	BUS	LTR (MVA)	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Bramalea TS	T1/T2	BY	99	72	74	75	77	80	82	86	92	98	106	106
Cardiff TS	T1/T2	BQ	126	118	120	122	124	126	126	126	126	126	126	126
Erindale TS	T1/T2	EQ	191	165	170	177	181	185	189	191	191	191	191	191
Richview TS	T5/T6 *	Q	17	11	13	15	17	17	17	17	17	17	17	17
Richview TS	T7/T8 *	BY	33	26	27	29	31	33	33	33	33	33	33	33
Total			**466**	**392**	**404**	**418**	**430**	**441**	**447**	**453**	**459**	**465**	**473**	**473**
New Station (GTAA TS)			**170**[77]										59	70
New Station (Gateway TS)			**170**											20
Total			**636**	**392**	**404**	**418**	**430**	**441**	**447**	**453**	**459**	**465**	**532**	**563**

[77] Dedicated Station

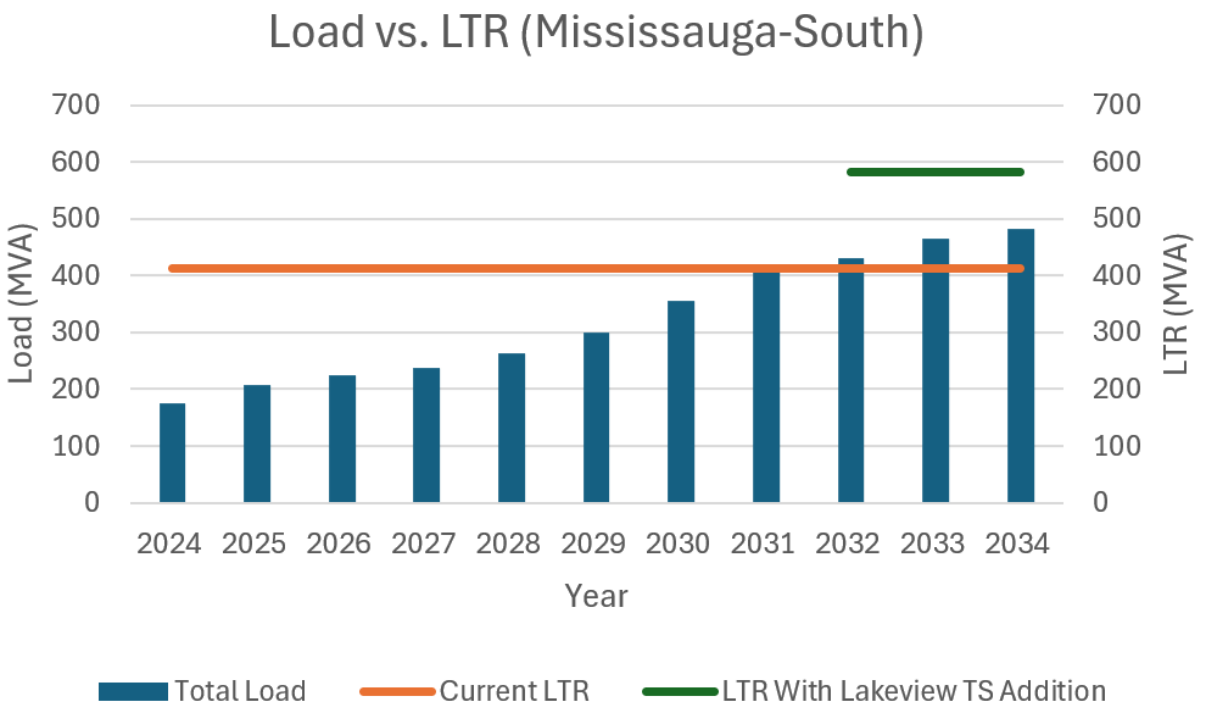

Figure B13 - 11 Load vs. LTR for Mississauga-South (2024-2034)

Table B13 - 19 Projected Loading and LTR for Existing and New Stations Over Period 2024-2033 for Mississauga South

Station	DESN	BUS	LTR (MVA)	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Cooksville TS	T1/T2	EZ	130	47	50	55	57	60	69	84	126	130	130	130
Cooksville TS	T3/T	JQ	130	39	44	50	55	73	94	125	130	130	130	130
Lorne Park TS	T1/T	BJ	152	89	114	119	125	131	138	147	152	152	152	152
Oakville TS[78]	T5/T	EZ	63	34	34	35	36	36	37	39	42	44	48	48
		Total	**412**	175	208	224	237	264	300	356	408	412	412	412
		New Station (Lakeview TS)	**170**									18	53	70
		Total	**582**	**175**	**208**	**224**	**237**	**264**	**300**	**356**	**408**	**430**	**465**	**482**

[78] Oakville TS has been excluded from the LTR calculation as it supplies large customer with dedicated feeders.

Based on the projected load growth and LTR capacity of the existing stations, Alectra Utilities identified a need for one MS and three additional TSs in the Mississauga area between 2028 and 2034 as shown in Table B13 - 20. This addresses the capacity needs in the City of Mississauga stemming from growth and intensification in the City Centre, Lakeview, Pearson Airport, and Uptown areas.

Table B13 - 20 Planned Station Projects - Mississauga

Station Name	Owner	In-Service Year
Webb MS	Alectra Utilities	2030
Lakeview TS	Alectra Utilities	2032
GTAA TS	Alectra Utilities	2033
Gateway TS	Alectra Utilities	2034

The investments for Municipal Stations include the design and construction of a new 20MVA Webb MS (to be located on Webb Drive in the City of Mississauga) with the planned in-service date of 2030.

The investments include the land purchase, completing an Environmental Assessment, and the design as well as the construction of the new Transformer Station (i.e. Lakeview TS) planned be in service by 2032. In addition, the land purchase and completing an EA for Airport TS which will be in service by 2033, and the land purchase, completing an EA and design for Gateway TS which will be in service by 2034.

Figure B13 - 12 shows the stations and growth expected to 2035.

Figure B13 - 12 Mississauga Station, Ongoing Expansions and Growth Expected to 2035

A Webb MS

The City of Mississauga's intensification plans are focused on several areas including the downtown Mississauga core. Mississauga downtown core is supplied by 44/13.8kV system. The 44kV stations (Erindale and Tomken) are owned by HONI which step down the voltage to 13.8kV.

Figure B13 - 13 shows the geographical location of Mississauga's Downtown Core.

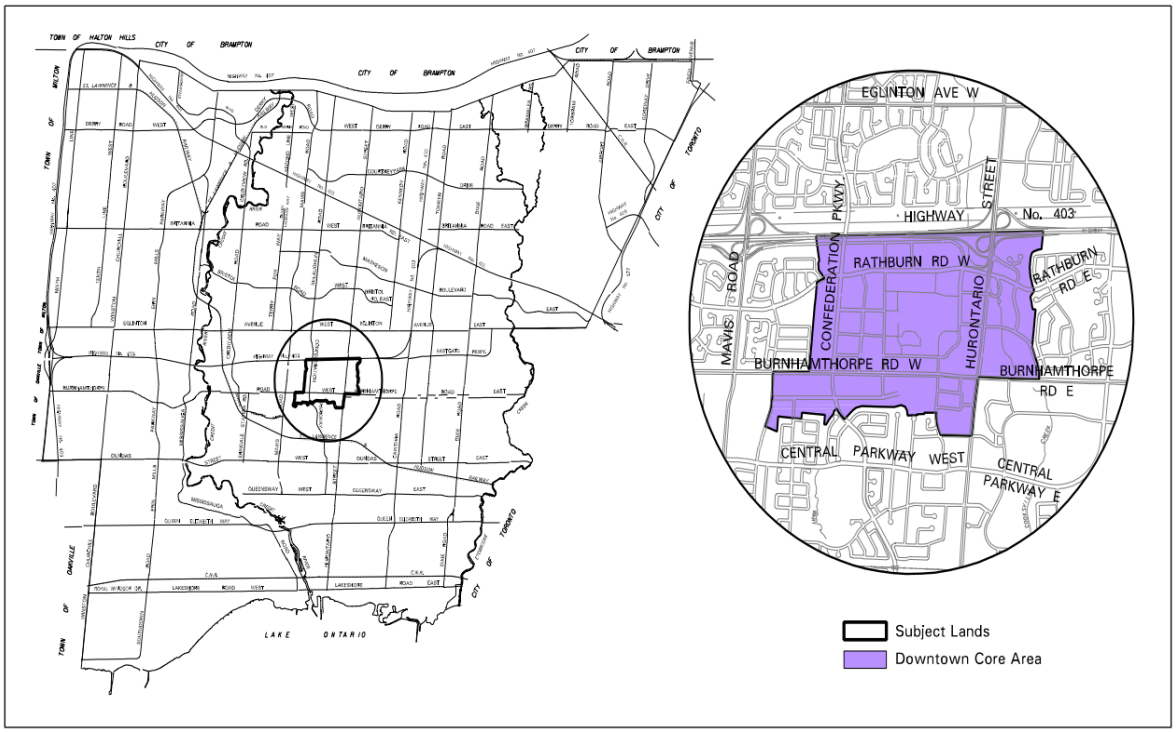

Figure B13 - 13 City of Mississauga Downtown Core

Currently, there are approximately 75 buildings in the Downtown Core and three substations including 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[79] area, especially to Mississauga Valley and Sussex districts. The total connected transformation in the Downtown Core is approximately 130MVA.

[79] DownTown21 area is Mississauga municipal plan which aims to increase density of residential condo towers and buildings in downtown core.

The Downtown Core is supplied by both underground (UG) and overhead (OH) distribution systems that provide the power to residential and commercial customers. The power is supplied to the Downtown Core through a 13.8kV distribution system being fed from five Municipal Stations.

The distribution system in the Downtown Core is supplied by more than two dozen underground and overhead feeders that are interconnected with multiple tie connections to provide reliable power with redundancy capability using the loop feed configuration.

The current capacity available for all districts of Downtown 21 is about 160MVA ONAN/266MVA ONAF. Available capacity allows for short-term growth and N-1 contingency in the Downtown Core. Based on the proposed model and Master Plan provided by the City, it is estimated that upon completion of Downtown 21, the combined transformation will increase to approximately 300MVA.

Table B13 - 21 shows the downtown station loading up to 2033 and capacity on each of the stations in case of loss of the stations. With the load growth, John MS will be over 127% of ONAN and in a contingency situation, there is not enough capacity on the remaining stations to pick up the potential additional loading based on feeder ties. City Center MS has capacity; however, load cannot be transferred to it due to the existing underground infrastructure as Alectra Utilities cannot expand new the feeders from that station. New feeder breakers are required to connect new buildings which will be constructed and come online in the Downtown Core.

Table B13 - 21 Downtown Mississauga Station Loading

Station Information				Downtown Mississauga 10-Year Load Projection										
Station ID	Station	ONAN Rating (MVA)	ONAF Rating (MVA)	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
MS39 (13.8kV)	John	20	33.3	13.4	14.4	16.4	18.4	20.4	21.4	22.4	23.4	24.4	25.4	26.9
MS322 (13.8kV)	City Centre N	60	99.9	24.9	26.4	27.9	30.9	33.9	36.9	38.4	39.9	41.4	42.9	44.9
MS323 (13.8kV)	Woods	40	66.6	22.4	23.9	26.9	29.9	32.9	34.4	35.9	37.4	38.9	40.4	41.9
MS324 (13.8kV)	Confederation	40	66.6	23.2	24.7	27.7	30.7	33.7	35.2	36.7	38.2	39.7	41.2	42.7
13.8kV Normal Capacity (ONAF):			266.4	83.9	89.4	98.9	109.9	120.9	127.9	133.4	138.9	144.4	149.9	156.4
13.8kV N-1 Contingency Capacity (ONAF):			166.5	83.9	89.4	98.9	109.9	120.9	127.9	133.4	138.9	144.4	149.9	156.4

Alectra Utilities will have to expand its infrastructure in the Downtown Core and increase the number of substations to reliably supply power to all the buildings. Figure B13 - 14 shows the downtown Mississauga concept plan.

Figure B13 - 14 Downtown 21 Mississauga Concept Plan

45MVA of new projects are in various stages of construction and energization. The total projected calculated peak demand for 45MVA of connected developments is estimated to be 35MVA. An additional 38 projects are in the site plan application stage which are expected to be energized within a 10-year window with the forecasted peak demand of 70MVA. Based on growth projection and existing infrastructure to connect new buildings, one additional MS is required by 2030.

Alectra Utilities has acquired the land for the Webb MS under a land swap arrangement with the developer. The station will be built at the intersection of Burnhamthorpe Road and Kariya Drive.

This project consists of adding 2x20MVA of capacity by the end of 2030. At completion, the substation will house 2x20MVA power transformer, two high voltage switchgear, two low voltage switchgear units, delivering power via ten 13.8kV feeders.

B Lakeview TS (Mississauga-South)

Mississauga -South is supplied by four HONI-owned stations. The initiation of the Lakeview TS will be in 2027 and the in-service date will be in 2032. The projected in-service date is outside the DSP forecast period. The proposed investment will not have an impact on rates in this DSP period.

Table B13 - 21 illustrates the stations and projected peak demand up to 2033. The entire capacity from Cooksville TS and Lorne Park TS is available to Alectra Utilities, however, only partial capacity from Oakville TS is available. The majority of the capacity from Oakville TS that is allocated to Mississauga is dedicated to supply one large industrial customer.

The medium-term capacity analysis shows a need for a new TS station in Mississauga South by the year 2032. The capacity needs of the area are driven by several large developments.

Trillium Hospital

A new 22 storey hospital (i.e. Peter Gilgan Mississauga Hospital) which will almost triple the size of the current hospital at 260,000 million square meters. The demand is 24MVA with a request for full redundancy. Alectra Utilities is in the process of adding new feeders to Cooksville TS. The hospital load is scheduled to be serviced in 2028/2029.

Lakeview Development

The projected peak demand for the Lakeview Village project is 91MVA to supply 8,000 residential units and 200,000 square meters of commercial area by 2036. This also includes a new district energy system at Lakeview Village which projected a 30MVA requirement. Figure B13 - 15 and Figure B13 - 16 show the Lakeview Village design and phasing plan. Alectra Utilities is currently building two additional feeders to provide 43MVA for the first phase of development.

Figure B13 - 15 Lakeview Village Concept Plan

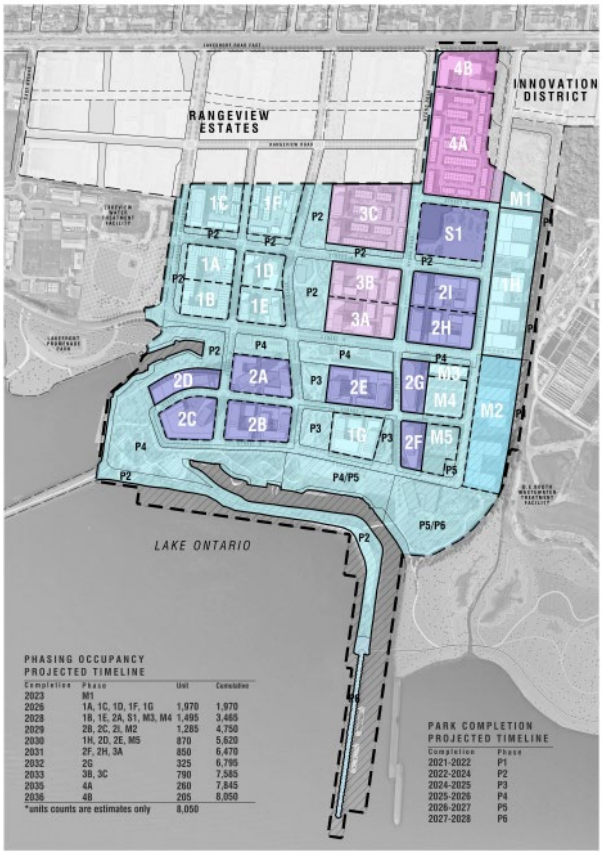

Figure B13 - 16 Lakeview Village Phasing Plan

Brightwater Development

The Brightwater development located in Port Credit (Mississauga South) will transform 72 acres of former industrial lands into residential/commercial neighborhoods. The proposed development will include eight residential towers holding about 3,000 units and over 28,000 square meters of retail and office space. Alectra Utilities projects the power requirements of approximately 10MVA for this development by 2031.

Lakeview Pumping Station

Due to the growth happening in Brightwater, Lakeview, Alectra Utilities has been informed that additional capacity is required at the Lakeview pumping station. An additional 10MW is required by 2030.

The new Lakeview TS will allow the utility to have sufficient capacity for these proposed expansions. The Lakeview TS investment includes land purchase, completing a Class EA, and design and construction for the new TS to be in service by 2032.

Alectra Utilities expenditures during the 2027-2031 period include land purchase, completing class EA, design of the station and station construction for an in-service date of 2032.

C GTAA TS

Alectra Utilities load forecast indicates that there will be a capacity shortfall in 27.6kV North and the system will require additional transformation capacity.

The initiation of the GTAA TS will be in 2028 and the in-service date will be in 2033. The projected in-service date is outside the DSP forecast period. The proposed investment will not have an impact on rates in this DSP period.

The 27.6kV is supplied by HONI-owned transformer stations (Bramalea, Cardiff, Erindale and Richview). Richview is a shared station with another LDC, and limited capacity is available to Alectra Utilities.

Greater Toronto Airports Authority (GTAA) has requested Alectra Utilities to provide additional capacity for its near-term and long-term expansion plan at the Airport. The near-term capacity requirement is approximately 86MVA and long-term needs are 83MVA. The GTAA also requires full redundancy. Greater Toronto Airports Authority (GTAA) needs fully redundant electricity

supply to ensure the continuous and safe operation of Toronto Pearson International Airport. A power failure at a major international hub like Toronto Pearson can have catastrophic ripple effects, impacting millions of passengers and causing significant financial losses. This TS will be a dedicated station to the GTAA to meet their capacity and reliability requirements.

The near-term needs are split between the 44kV and 27.6kV system. About 54MVA will be provided through the 44kV system and 32MVA through the feeders from Richview and Bramalea TSs. There will be no spare capacity left on 27.6kV system for the long-term needs and Alectra Utilities will require to build a new TS to support the GTAA's long-term growth. The new station will be 170MVA 230/27.6kV and will be required to be in-service by 2033. Alectra Utilities will receive a capital contribution for this project from the GTAA. The Economic Evaluation policy will be applied to determine the cost sharing between the customer and the utility.

D Gateway TS

The 27.6kV is supplied by five HONI-owned transformer stations (Bramalea, Cardiff, Erindale and Richview). Richview TS is a shared station, and limited capacity is available to Alectra Utilities. The initiation of the Gateway TS will be in 2029 and the in-service date will be in 2034. The projected in-service date is outside the DSP forecast period. The proposed investment will not have an impact on rates in this DSP period.

The current capacity available at the Erindale TS will be utilized to supply the LRT.

HuLRT (Hurontario Light Rail Transit)

The HuLRT (Hurontario Light Rail Transit) project is under construction which will provide 18KM of rapid transit with 19 stops and will link to GO Stations at Port Credit and Cooksville, the Mississauga Transitway, Square One GO Bus Terminal, Brampton Gateway Terminal, and key MiWay and Brampton Transit routes. Alectra Utilities is committed to providing power to 14 Traction Power Substation (TPSS) and a Maintenance Storage Facility (MSF) of about 26MVA.

The 27.6kV North growth is expected to continue along the Hurontario and Eglinton corridor.

Hurontario/Eglinton Development

The developments along Hurontario Street, including residential high-density condominium buildings and commercial high-density offices, will cause the Mississauga 27.6kV North system to exceed its available capacity. The projected additional peak demand is approximately 30 - 40MVA. The ultimate Master Plan for Hurontario and Eglinton includes an additional 15 high-rise buildings. Figure B13 - 17 shows the Hurontario-Eglinton development concept plan and concept site plan.

Figure B13 - 17 Hurontario-Eglinton Concept Plan

Alectra Utilities will be required to build a new Gateway TS with a projected in-service date of 2034. The new station will enable Alectra to meet the capacity to serve the afore mentioned development.

The Gateway TS investment includes a land purchase, completing a Class EA and preliminary design scheduled be in service by 2034.

3.2.2.2 Central North (Brampton) Planning Zone

Brampton is the 9th largest city in Canada and has the highest growth rate amongst Canada's largest cities. As shown in Figure B13 - 18, most of the population growth is occurring on the edge of the existing built-up areas in the City of Brampton's secondary planning areas such as Sandringham-Wellington (SP28), Credit Valley (SP45) and the Vales of Castlemore (SP42). Emerging new growing communities include Bram East (SP41), Bram West (SP40) and Heritage Heights.

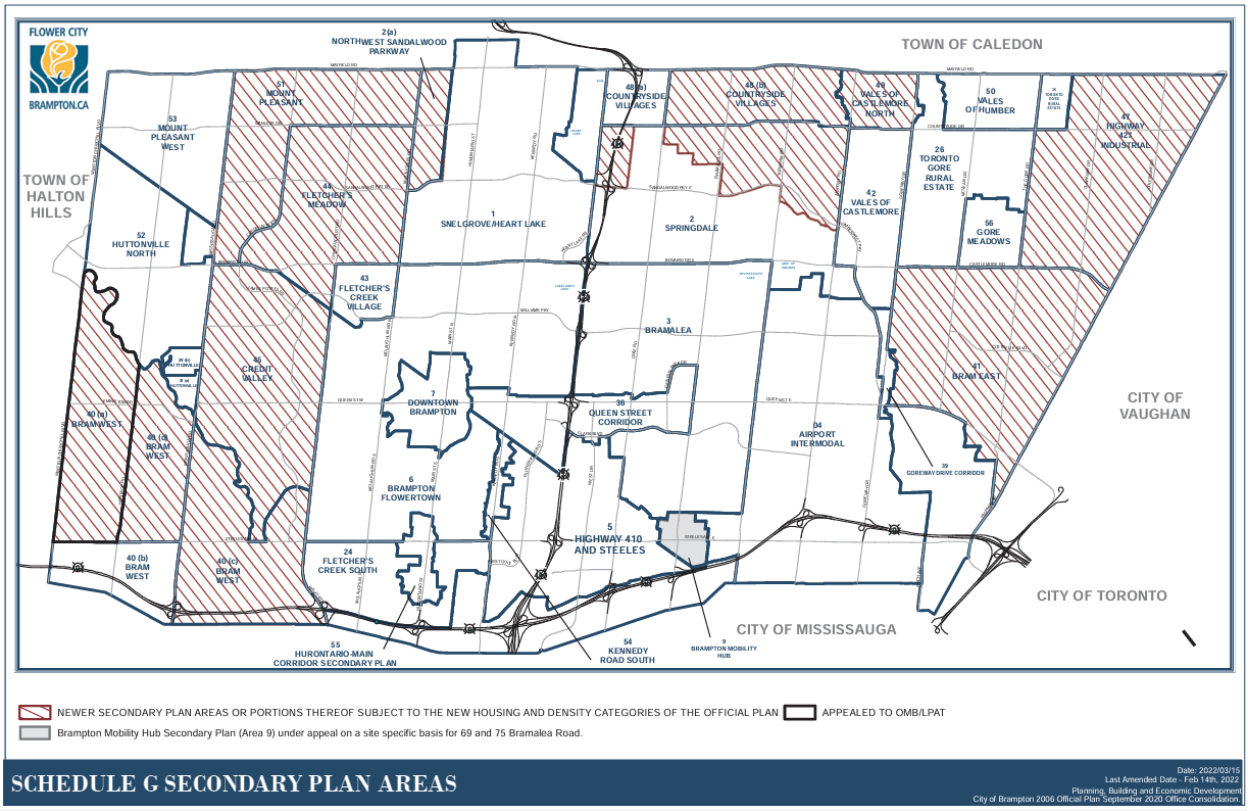

Figure B13 - 18 Brampton Secondary Plan Area

In addition, high density development applications to the city are increasing along the Queen Street Corridor and other parts of Downtown Brampton.

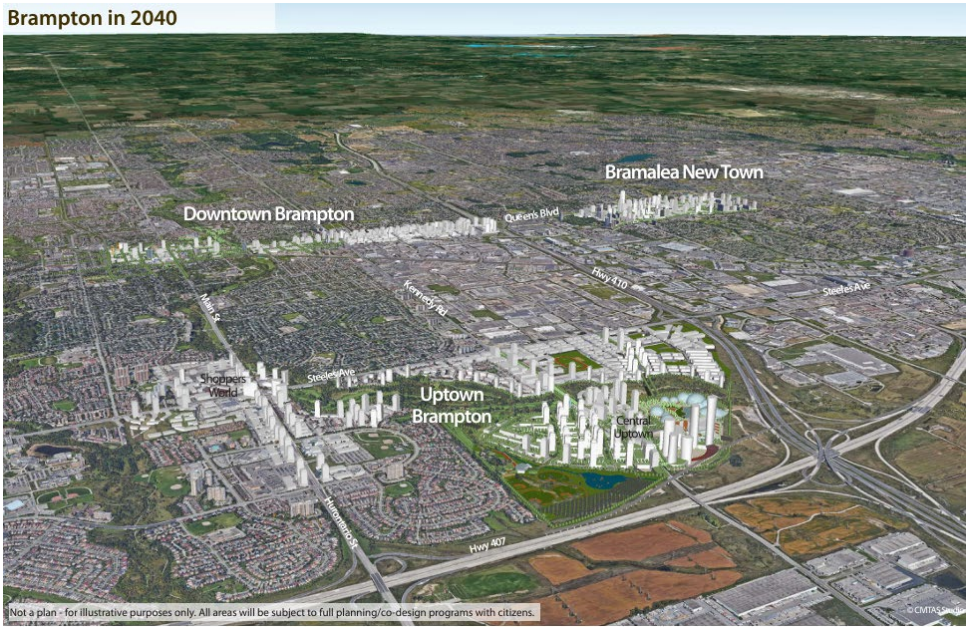

Figure B13 - 19 Brampton 2040 Vision Plan

The following are the details of developments in the City of Brampton which are illustrated in the Brampton Vision Plan (Figure B13 - 19). These major developments drive the need for the additional capacity.

Downtown Brampton

The downtown Brampton area will add 18,000 residential and 550,000 square meters of industrial and commercial space which is estimated to require total capacity of 70MVA by 2040.

Uptown Brampton

The Uptown Brampton area is projected to add 30,000 residential and 560,000 square meters of commercial space which will require a total of 96MVA by 2035.

The Bramalea New Town area is projected to add 10,000 residential and 465,000 square meters of industrial and commercial space which will require a total capacity of 48MVA by 2035.

BramWEST Development

By 2031, BramWEST development could bring approximately 15,132 dwelling units with capacity of 38MVA.

Figure B13 - 20 illustrates the City of Brampton's expected growth by 2035.

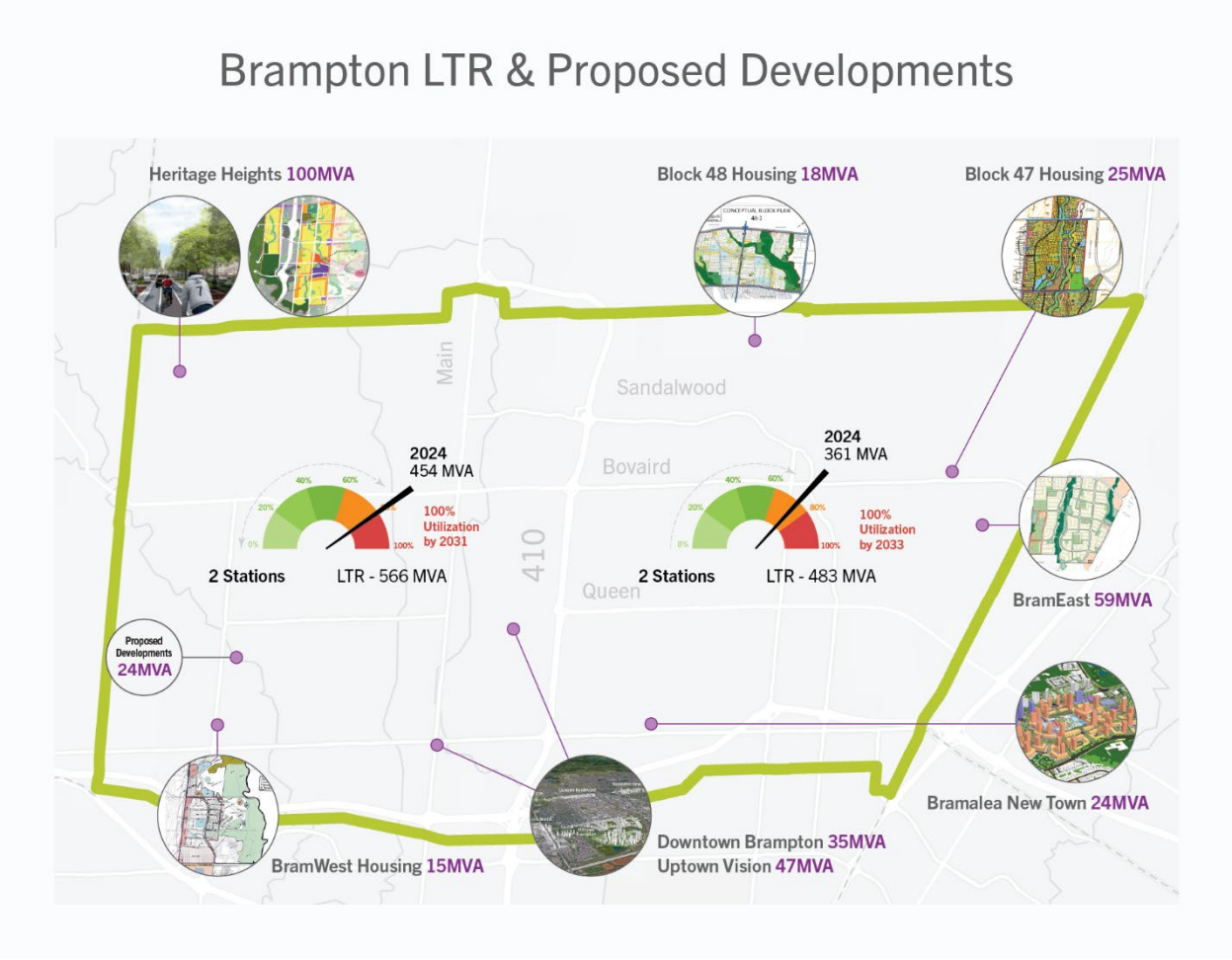

Figure B13 - 20 Brampton Region Stations, Ongoing Expansions and Growth Expected to 2035

The City of Brampton is supplied by ten DESNs at four transformer station locations including three HONI-owned and operated 230kV transformer stations and one Alectra Utilities-owned and operated. The secondary voltages of HONI-owned transformer stations are 44kV and 27.6kV.

Brampton planning zone has been further divided into Brampton-East and Brampton West areas for planning purpose. Four 27.6kV stations, Jim Yarrow and Pleasant TSs, supply the Brampton -West and Bramalea and Goreway TSs supply the Brampton-East.

As part of the regional planning process, HONI Needs Assessment identified capacity needs in Brampton as illustrated in Table 5.2.2 - 7 to *Chapter 5.2.2 Coordinated Planning with Third Parties*.

Alectra Utilities' analysis identified the need for two additional TSs to support the growth in the City of Brampton between 2028 and 2034.

Figure B13 - 21 illustrates the projected load as well as the LTR capacity for existing and future in Brampton East from 2024 to 2033. Table B13 - 22 show the projected loading vs. LTR of the current and future stations for Brampton East area.

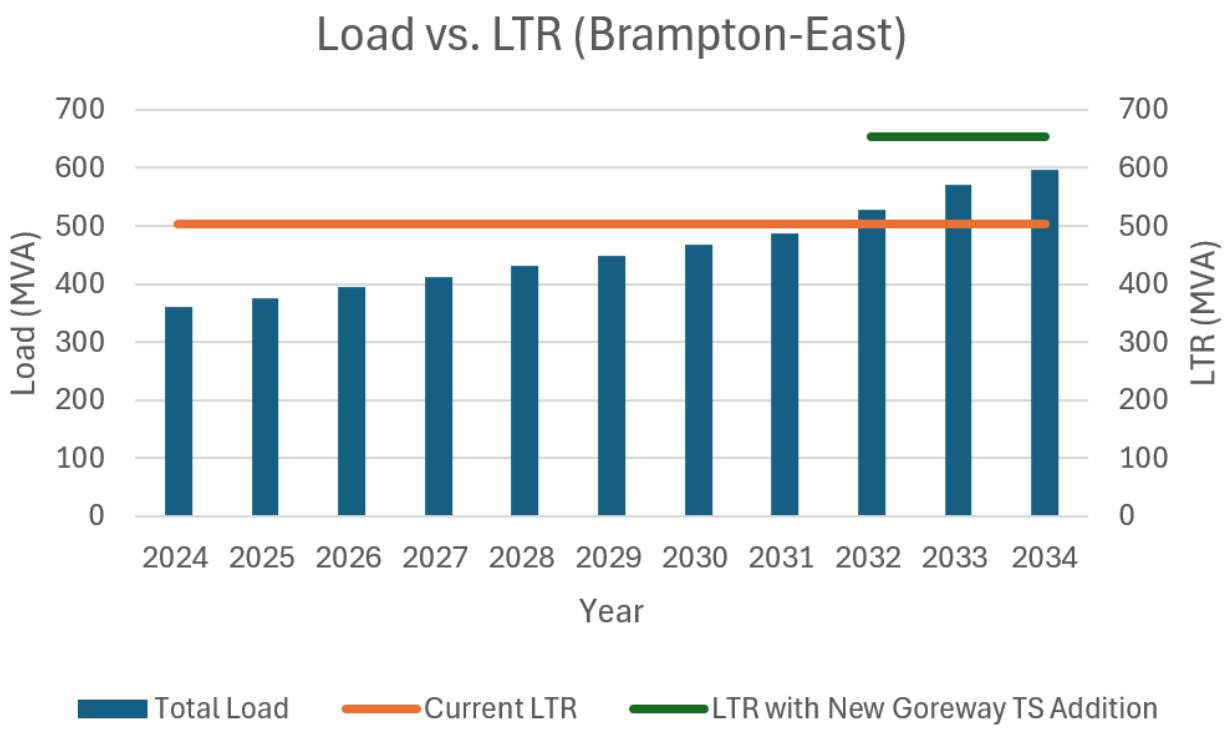

Figure B13 - 21 Load vs. LTR for Brampton-East (2024-2034)

Table B13 - 22 Projected Loading and LTR for the Existing and New Stations over Period 2024-2034 for Brampton East Area

TS Name	LTR (MVA)	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Bramalea TS	120	87	92	98	104	110	116	122	129	135	142	154
Goreway TS T1/T2_JQ & T5/T6_BY	384	274	284	296	308	321	332	345	358	371	385	385
Total	483	361	376	394	412	431	448	467	487	506	527	539
New Station (New Goreway TS)	170									23	44	58
Total with New Station	653	361	376	394	412	431	448	467	487	529	571	597

Figure B13 - 22 illustrates the projected load, LTR capacity for existing and future in Brampton-West area from 2024 to 2033. Table B13 - 23 show the projected loading vs. LTR of the current and future station for Brampton West area.

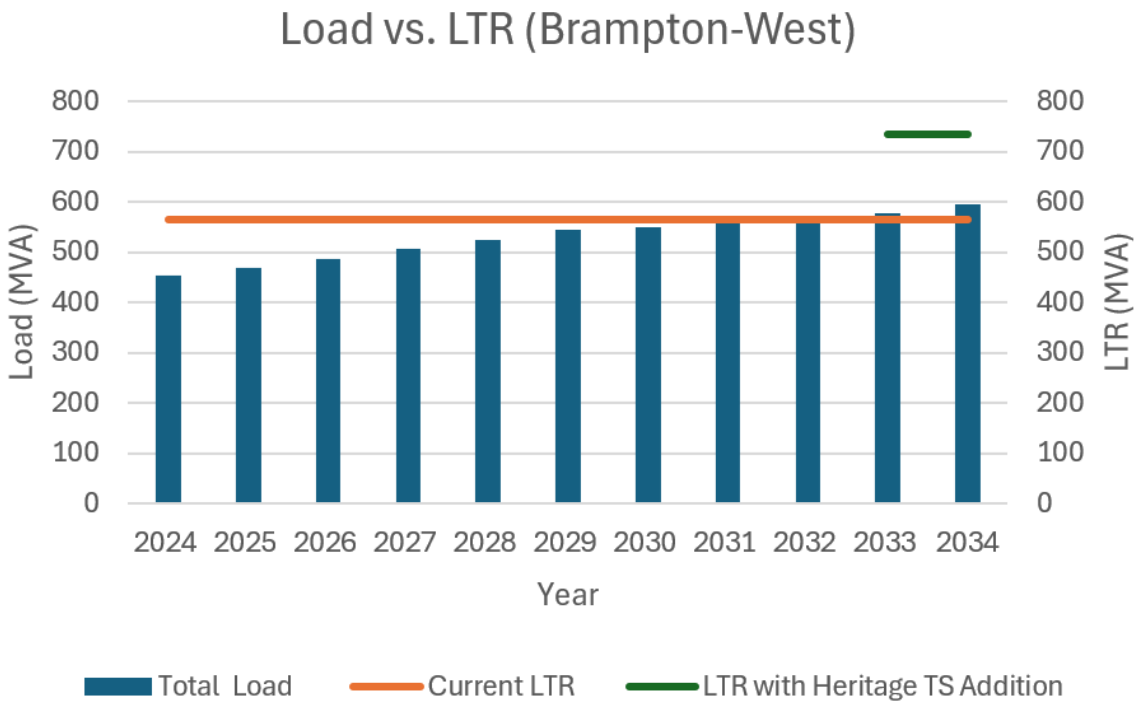

Figure B13 - 22 Load vs. LTR for Brampton-West (2024-2034)

Table B13 - 23 Project Loading and LTR for the Existing and New Station over the Period 2024-2034 Brampton West Area

TS Name Bus	LTR (MVA)	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Jim Yarrow T1/T2_AB	169	145	150	155	161	167	172	172	172	172	172	172
Pleasant TS T5/T6_BY/EZ & T7/T8_FV	397	309	320	332	345	359	372	378	388	395	405	405
Total	566	454	470	487	506	526	544	550	560	567	577	577
New Station (Heritage TS)	170											20
Total with new Station	736	454	470	487	506	526	544	550	560	567	577	597

Based on projected load growth and LTR capacity of the existing station, Alectra Utilities identified a need for two additional TS in Brampton beyond 2031 as shown in Table B13 - 24.

Table B13 - 24 Planned Station Projects - Brampton

Station Name	Owner	In-Service Year
New Goreway TS	Alectra Utilities	2032
Heritage TS	Alectra Utilities	2034

These investments include the expansion of 230kV transmission system, the land purchase, completing an EA, as well as the design and construction of the new Goreway TS in the Northeast area scheduled to be in-service by 2032 and the new Heritage TS scheduled to be in-service by 2034.

A New Goreway TS

The initiation of the New Goreway TS 2 will be in 2026 and the in-service date will be in 2032. The projected in-service date is outside the DSP forecast period. The proposed investment will not have an impact on rates in this DSP period.

The Brampton East area is supplied by three 27.6kV stations. There is 122MVA capacity left on 27.6kV system. The additional new developments in this area will add a total of approximately

210MVA load by 2033. By 2031, loading will exceed the stations' collective LTR of 487MVA. The short-term and medium-term assessments have shown a need in the 27.6kV Brampton East area.

The major developments that are intended to be served by this development are as follows:

Bram EAST (SP41) Development

The subject lands comprise an area of approximately 1,519 hectares (3,754 acres) and are situated between Goreway Drive and Highway 50, south of Castlemore Road and north of the Claireville Conservation Area.

There is ongoing expansion of 60MVA to supply the ICI growth along the Highway 50 and Countryside Drive. Brampton Transit has plans to electrify their fleet and indicated a requirement of an additional 18MVA for their charging facility.

Queen Gore Development

The Gore Road and Queen Street East development is a large parcel surrounded by a diverse mix of land uses. A low-rise residential development is currently under construction, which Alectra Utilities is expanding its system to provide needed 20MVA. To the east side of Gore Road and north of Queen Street East, an application calls for four buildings with seven high-rise towers which range from 23 to 43 storeys in height, adding 2,461 residential units as well as office and retail spaces. This development will add an additional 10MVA load to the distribution system.

Countryside Villages (SP48) Development

Countryside Villages Land Area (Figure B13 - 23), also known as Block Plan 48-2, is approximately 323.76ha (800ac) of the total approximately 645ha (1,600ac) that comprise the Countryside Villages Community, located in north-central Brampton. The site boundaries are Bramalea Road to the west, Airport Road to the east, Mayfield Road to the north and Countryside Drive to the south. The Town of Caledon's boundary is to the north, adjacent to Mayfield Road, consisting of primarily agricultural land. Alectra Utilities received a capacity request of 9MVA for 4,668 residential and commercial units.

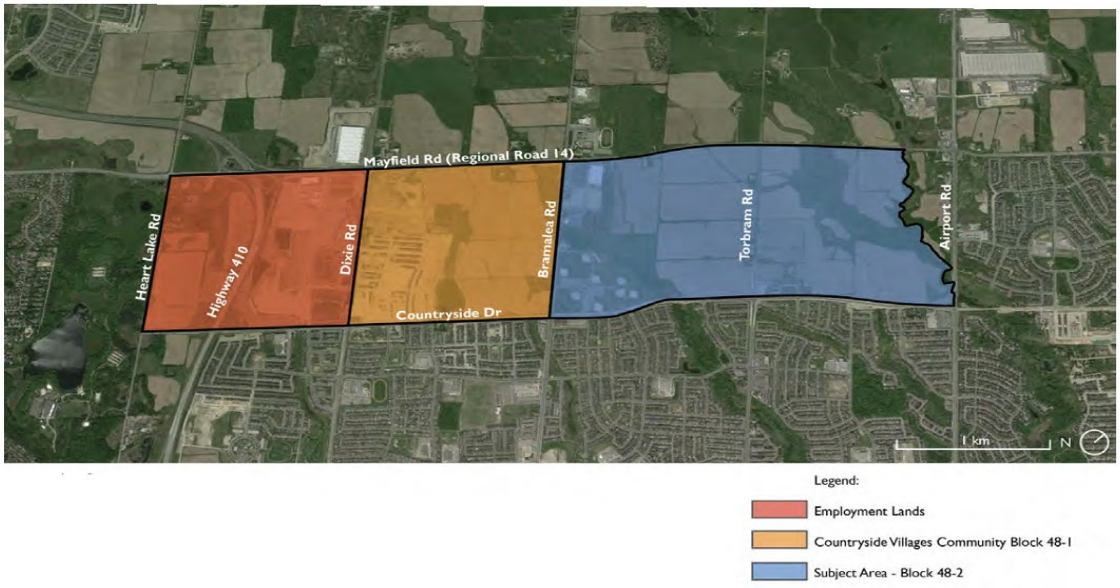

Figure B13 - 23 Countryside Villages (SP48) Development

Block 47-The Gore Road Development

A new residential community plan, Block 47 in the city of Brampton (Figure B13 - 24), is located east of Gore Road between Castlemore Road and Mayfield Road. The community will encompass about 10,360 residential units with an estimated 25MVA capacity. The utility installation is projected to start in 2025.

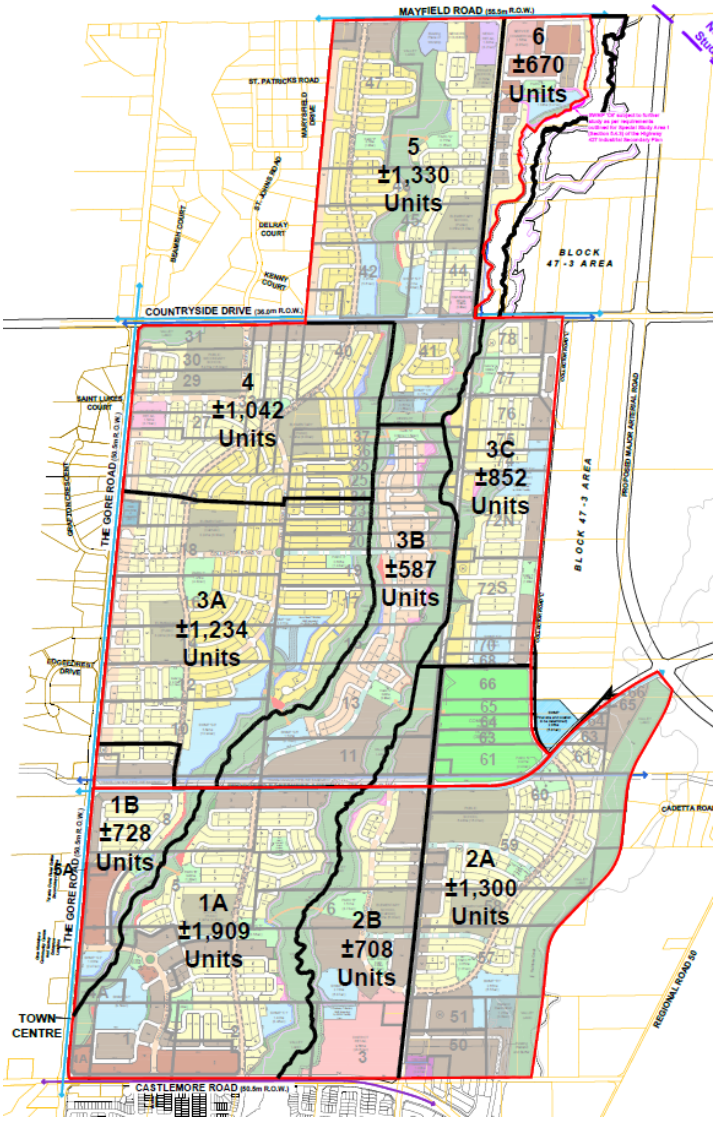

Figure B13 - 24 Block 47 The Gore Road Development Plan

With the ongoing expansion and new capacity requests, all the remaining capacity on the 27.6kV system will be utilized by 2031 and a new station is required to be in service to support the growth.

Alectra Utilities has determined that the optimal site for the TS would be in along the Goreway drive.

Alectra Utilities' expenditures during the 2027-2031 period would include the land purchase, completing a class EA, the design and construction of the TS for an in-service date of 2032.

B Heritage TS

The initiation of the New Heritage TS will be in 2027 and the in-service date will be in 2034. The projected in-service date is outside the DSP forecast period. The proposed investment will not have an impact on rates in the current period.

The western area of the City of Brampton is supplied mostly by the Pleasant and Jim Yarrow TSs at 27.6kV while several large industrial customers are supplied at 44kV. Jim Yarrow TS has 24MVA remaining capacity available. There is an ongoing expansion off Jim Yarrow TS to supply 24MVA to a data center which will lead the station to reach LTR in 2024.

There is 112MVA of transformation capacity available on Pleasant TS. Alectra Utilities is in the process of designing four feeders from the Pleasant TS to supply the 80MVA for Heritage development for Block 52-1 and 52-2. This will utilize all of the feeders currently available at Pleasant TS.

In addition, there are a few developments, as well as organic growth which will add approximately 51MVA of load on the 27.6kV system. This will put the TSs stations beyond their LTR by 2033.

The major development that is intended to be serviced by the proposed Heritage TS is Heritage Heights.

Heritage Heights

The subject area encompasses approximately 987 gross hectares (2,439 gross acres) of land located within a large future urban growth area in the City of Brampton. The lands are bounded by Mayfield West Road to the north, Winston Churchill Road to the west, the Credit River to the south and Mississauga Road to the east. Heritage Heights represents that largest undeveloped greenfield area in the City of Brampton. The land will also be the home for new provincial Highway 413 (Figure B13 - 25).

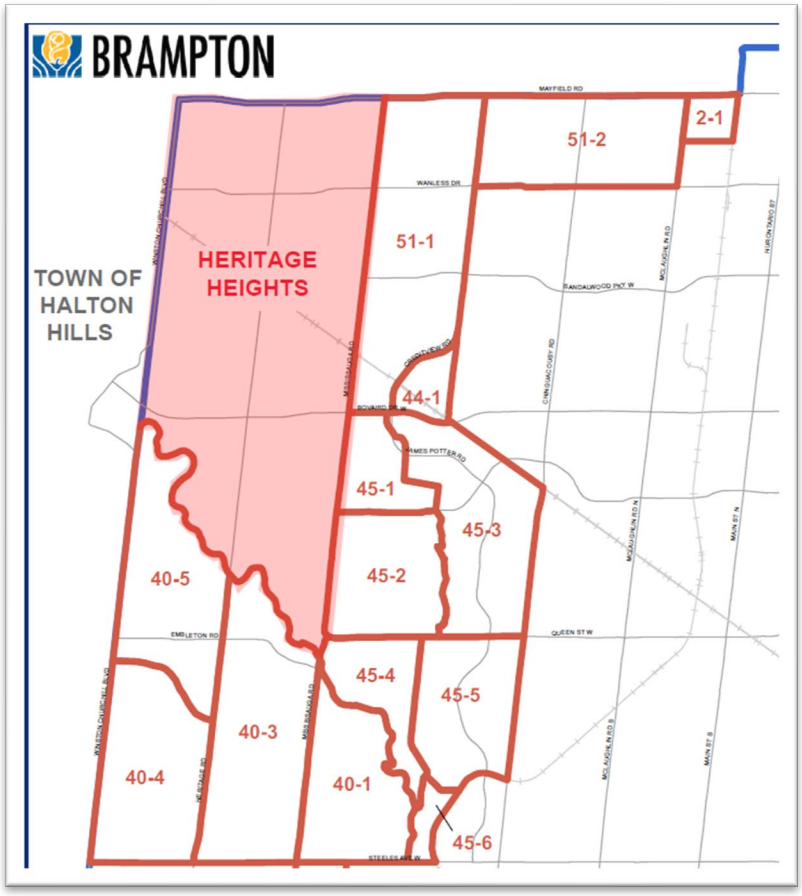

Figure B13 - 25 Heritage Heights Development Plan

By 2040, the development will be comprised of 13,655 low density, 11,225 medium density and 10,975 high density dwelling units as well as mixed-use commercial space of 1.4 million square meters.

This will add a total of approximately 180MVA of load. The four feeders from Pleasant TS with 80MVA will only supply the Block 52-1 and 52-2 development of the Heritage Heights.

There is no space at existing Pleasant TS to build a new station. Alternatively, the location of the new station was considered at South-East of Highway 407 and Winston Churchill Blvd, adjacent to Meadowvale TS.

It is also challenging and costly to expand new feeders across Highway 407 to the new developments North-West of Brampton. HONI's transmission line T38B/T39B has a constraint on the capacity and new DESN cannot be connected.

Alectra Utilities has determined that the optimal site for the TS would be near the Heritage and Bovaird intersection. This will be within the corridor for new Highway 413, providing easy access for the maintenance and operations.

A new 230kV transmission connection will be required from the existing H29/H30 transmission line at Pleasant TS, approximately 7KM west to the station site. Currently, there is a capacity constraint on the Pleasant TS transmission line which will be reconductored by 2029.

Alectra Utilities expenditures during the DSP period include the land purchase, completing class EA, design and construction of the station with an in-service date of 2034.

The connection of this transformer station to HONI's 230kV transmission system would require expansion of their transmission system. The time needed to build the new transmission infrastructure is approximately five years, including the EA process. Alectra Utilities intends to start the process for new line and station in 2030 for an in-service date of 2034. Further details are in *Section 3.3*.

3.2.3 Alectra Utilities West Stations Investments

3.2.3.1 West Planning Zone (Hamilton sub-planning zone)

The City of Hamilton is the 10th largest city in Canada, and 5th largest in Ontario. Its population is expected to increase to 692,500 by 2036, up by 19% from its 2021 population.

The City of Hamilton is supplied by 19 DESN at Thirteen stations are HONI-owned and operated. The City of Hamilton has two distribution voltages: 13.8kV which supplies the center (urban) areas and 27.6kV which supplies the (semi urban) areas. The escarpment divides the city into an upper and a lower section due to an elevation change of 100 meters at many locations. The vertical drop creates limited ability to transfer electrical capacity between the upper and lower sections of the City. New growth and expansion are occurring in both sections.

The City of Hamilton's secondary plan is shown in Figure B13 - 26, with the escarpment depicted by a green line.

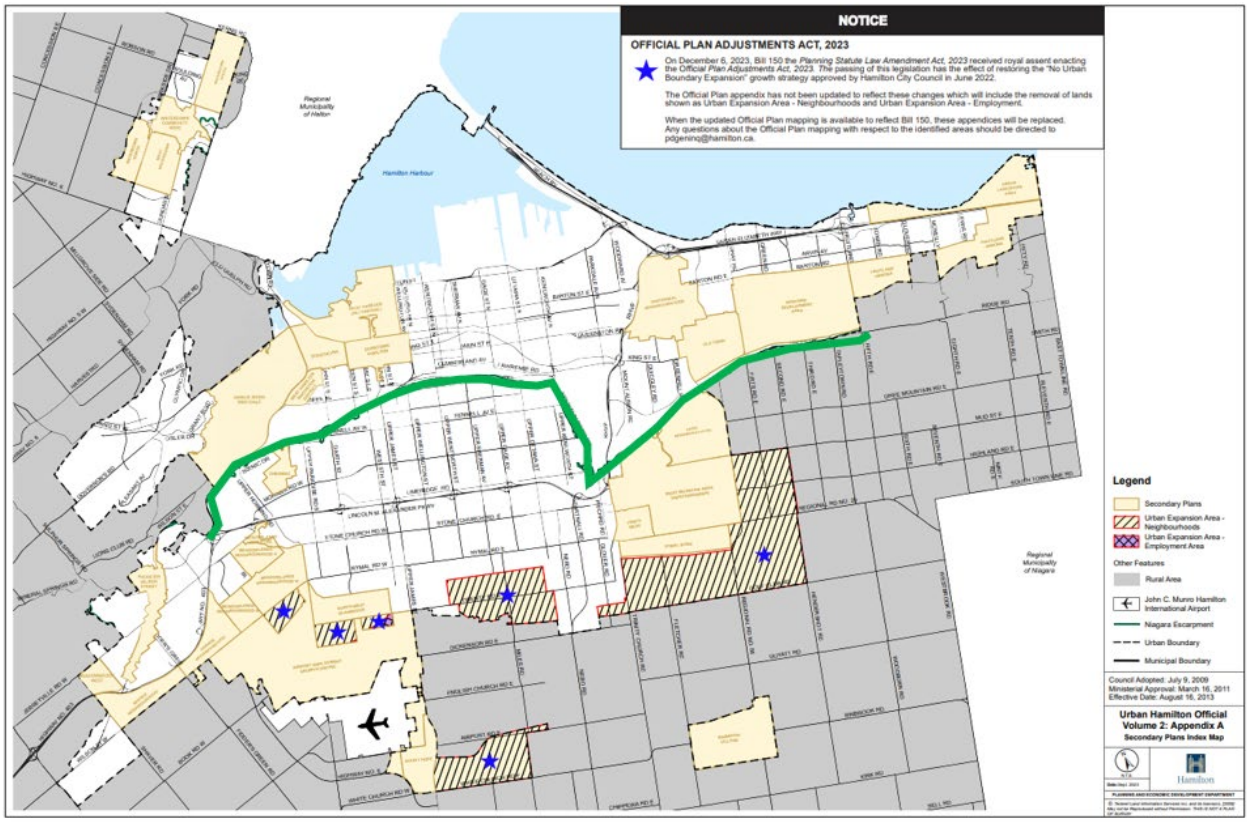

Figure B13 - 26 Hamilton Secondary Plan

As part of the regional planning process, HONI's Needs Assessment identified capacity needs at both Nebo and Newton TSs as illustrated in Table 5.2.2 - 9 in *Chapter 5.2.2 Coordinated Planning with Third Parties*.

Alectra Utilities' analysis identified capacity needs at Newton TS and Nebo TS areas in 2028 and 2026, respectively as shown in Table B13 - 25

Figure B13 - 27 and Figure B13 - 28 illustrate the projected load, LTR capacity for Newton TS and Nebo TS area respectively from 2024 to 2034. Table B13 - 25 and Table B13 - 26 show the individual station projected loading and LTR for Newton TS and Nebo TS.

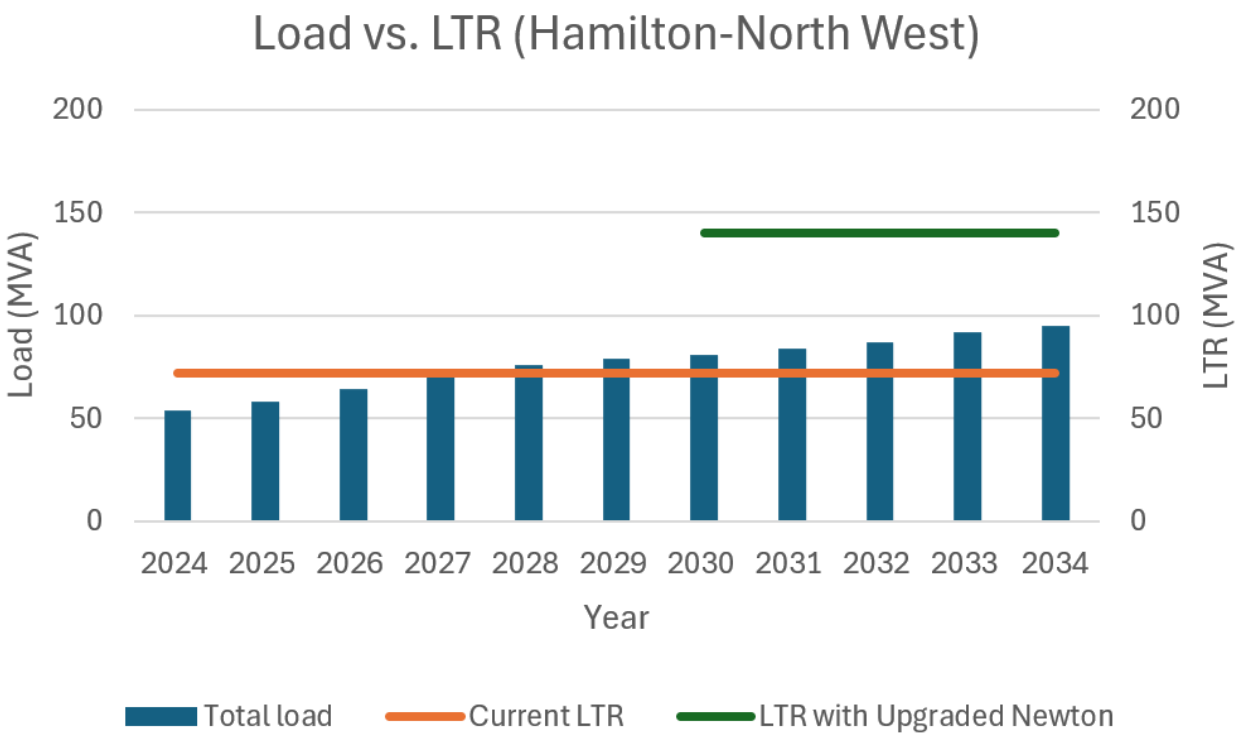

Figure B13 - 27 Load vs. LTR for Hamilton-North West (2024-2034)

Table B13 - 25 Project Loading and LTR for the Existing and New Station over the Period 2024-2034 for Hamilton North-West Transformer

Station	LTR (MVA)	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Newton B (13.8kV)	36	27	29	32	34	36	36	36	36	36	36	36
Newton Y (13.8kV)	36	27	29	32	36	36	36	36	36	36	36	36
Total	72	54	58	64	70	72	72	72	72	72	72	72
Additional load on Upgraded (Newton TS)	**68**				3	4	7	9	12	15	20	23
Total With New Station	**140**	54	58	64	73	76	79	81	84	87	92	95

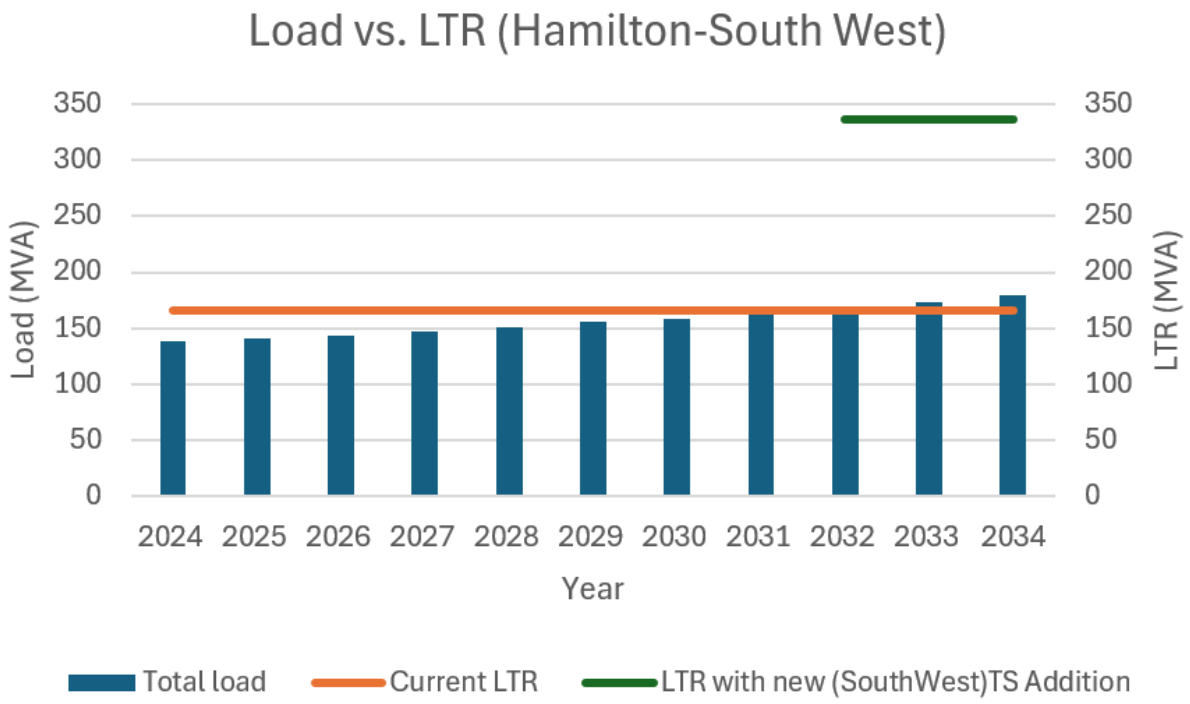

Figure B13 - 28 Load vs. LTR for Hamilton-South West (2024-2034)

Table B13 - 26 Project Loading and LTR for the Existing and New Station over the Period 2024-2034 for Hamilton Southwest Transformer Stations

Station	LTR (MVA)	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Mohawk B1B2 (13.8kV)	55	37	38	39	40	41	42	43	44	47	50	53
Mohawk Y1Y2 (13.8kV)	55	46	47	48	49	51	52	53	54	55	55	55
Nebo QJ (13.8kV)	56	56	56	56	56	56	56	56	56	56	56	56
New Station (SouthWest TS) (13.8kV)					2	3	6	7	9	11	13	16
Total South (13.8kV)	166	139	141	143	147	151	156	159	163	169	174	180
Nebo BY (27.6kV)	68	50	51	52	54	56	57	59	60	61	63	66

Based on projected load growth and LTR capacity of the existing stations, Alectra Utilities identified a need for two additional TSs in the Hamilton between 2030 and 2034 (Table B13 - 27).

Table B13 - 27 Planned Station Projects

Station Name	Owner	In-Service Year
Newton TS Upgrade	HONI	2031
New South-West (Nebo) TS	Alectra Utilities	2033

The investments include expansion of existing Newton TS by 2031, the land purchase, completion of an EA, preliminary design Engineering, and long lead items procurement for new TS. This station is scheduled to be in-service by 2033.

Figure B13 - 29 shows the stations, ongoing expansions and the growth expected to 2035.

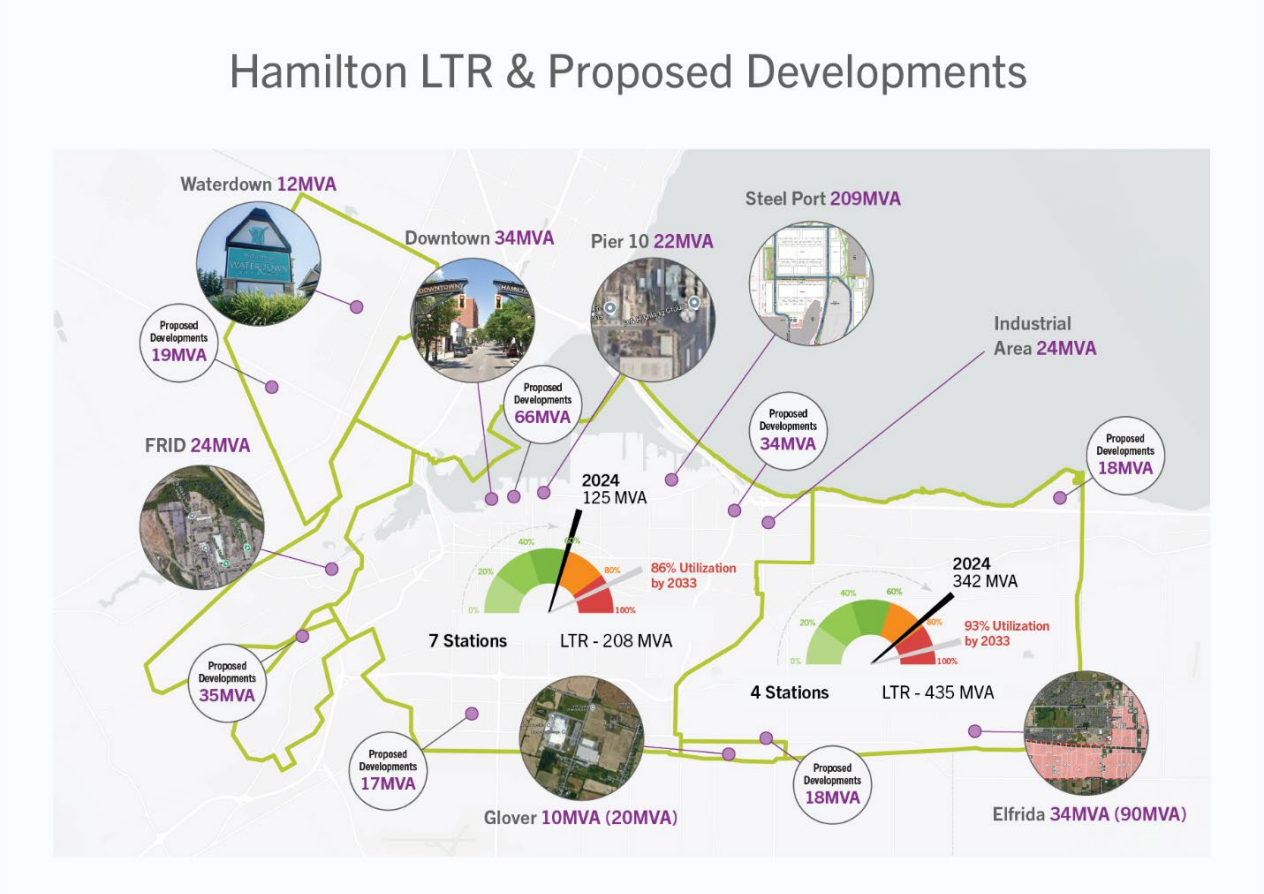

Figure B13 - 29 Hamilton Region Stations, Ongoing Expansions and Growth Expected to 2035

The large developments within the City of Hamiton are:

Steelport Area

A large industrial and commercial development in the lands formally occupied by large steel manufacturer will be under redevelopment with a total requirement of 200MVA.

South Mountain Area

Glover Rd and Pritchard Rd Corridor - The greenfield area of Glover Rd and Pritchard Rd running South/North of Rymal Rd has had large requests for increased loading. Large growth is being seen in this area with requests as high as 14MVA in this 27.6kV area.

Elfrida Development - The Neighborhood of Elfrida is in the South-East side of Upper Hamilton. Greenfield development of 1,136.9 hectares of land splits ownership to Alectra Utilities 437.12Ha (38%) and HONI 699.78Ha (62%). The projection of 30,000 Units 60/20/20 Single/Town/Apartment is expected to have loading of 84+ MVA with Alectra Utilities supplying 32MVA of load.

A Newton TS

The medium-term stations assessment has shown a need for new capacity at Newton TS. By 2028, the existing Newton TS will not have the capacity to supply additional load due to new residential, commercial, and industrial developments.

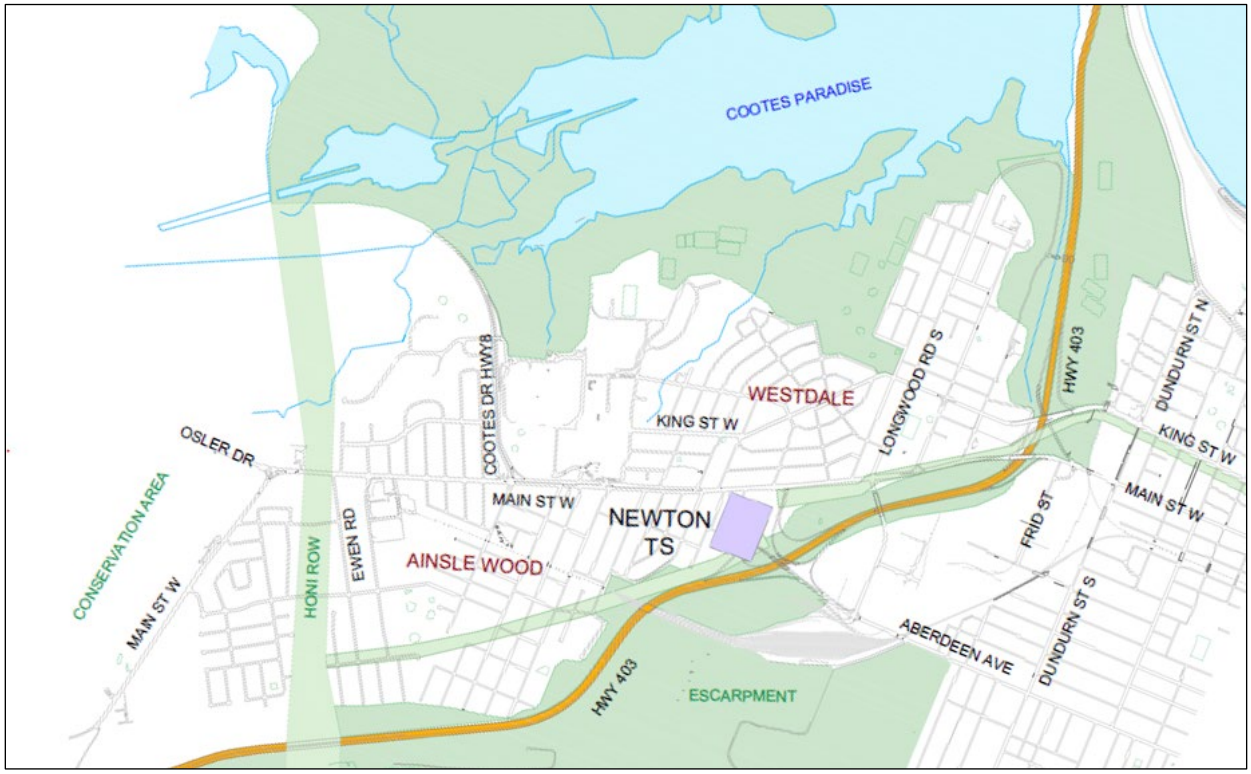

Figure B13 - 30 Hamilton Newton TS Area

Newton TS supplies the geographical areas of Westdale and Ainsle Wood in Hamilton which contains McMaster University along with residential, commercial, and industrial customers. Limited options exist for connecting to other station feeders due to Highway 403 crossing on the east, the Hamilton escarpment on the south, conservation lands in the west, and Lake Ontario to the North, as shown in Figure B13 - 30.

Newton TS and Elgin TS serve the developments in Northwest Hamilton; however, connections between the two stations are limited due to challenges in crossing Highway 403. Expected load transfer ability from Newton TS to Elgin TS is 6MVA.

Alectra Utilities plan to defer the station capacity requirement from 2028 to 2030 by utilizing a non-wires alternative and request HONI to upgrade the Newton TS capacity by 2030, further detailed in *Chapter 5.3.5 Non-Wires Solutions to Address System Needs.*

Newton TS will supply the following developments:

Hamilton Light Rail Transit (LRT) OMSF

Hamilton LRT will connect key areas, destinations and institutions along Main Street, King Street and Queenston Road and lead to secondary growth through intensification along the corridor. The Operations Maintenance Storage Facility (OMSF) will require 7.2MVA of capacity.

McMaster Growth

McMaster Innovation Park (MIP) has indicated their current loading requirement of 15MVA and an additional 6MVA in the future.

Frid Street Developments

Alectra Utilities has been approached to provide an additional 22MVA for developments on Frid street. Locations further south off Frid St have also requested additional capacity of over 20MVA. These developments will be supplied from Newton TS.

Newton TS is a HONI-owned transformer station with a summer LTR rating of 72MVA. Alectra Utilities will utilize a non-wires option to defer a station upgrade from 2028 to 2030.

Alectra Utilities plan to enter into a CCRA agreement with HONI to upgrade the existing transformer station to have a Summer LTR of 140MVA. This upgrade will provide additional 60MVA for development.

The timeline to upgrade the station is approximately three years. Alectra Utilities plans to initiate the upgrade in 2028 for an in-service date of 2031.

B Hamilton South-West (Nebo) TS

The initiation of the New Hamilton South-West (Nebo) Station will be in 2028 and the in-service date will be in 2033. The projected in-service date is outside the DSP forecast period. The proposed investment will not have an impact on rates in this DSP period.

The southwest area of Hamilton is supplied by three 13.8kV transformer stations, Horning, Mohawk, and Nebo TSs. Nebo TS is a dual voltage station with the 27.6kV servicing the lands in southeast Hamilton.

The combined limit of Nebo TS (13.8kV) and Mohawk TS will exceed their LTR in 2030. There are limited options for balancing load between the two stations with a 7MVA expected load transfer ability from Nebo TS to Horning TS (3MVA) and Mohawk TS(4MVA) respectively. Growth on Nebo QJ will result in reaching LTR in 2026, after using load transfer capability.

The new load on Nebo QJ, exceeding the LTR, will be supplied by a non-wires alternative through to 2032, as further detailed in *Section 5.2*).

Nebo TS (27.6kV) will reach its LTR after 2033; however, less than 20MVA of capacity is currently available. This capacity will be quickly eliminated if one large customer wished to connect in this area. Large individual load requests at Glover Rd (10MVA) and Elfrida (32MVA) as well as smaller organic growth will be accommodated on the new TS.

Coinciding with the Nebo TS (27.6kV) capacity needs, Alectra Utilities plans to invest in a new TS to meet the load growth in the southwest area of Hamilton.

The timeline to design and construct the new TS is approximately five years Alectra Utilities intends to complete the new TS land purchase in 2027 in order that the EA can begin in 2028, with an in-service date of 2033. Alectra Utilities has determined that the optimal site for the new TS would be south of Rymal Road along the 230kV Right of Way.

Service reliability will improve when the new station is in service. System capacity will increase an additional 140MVA.

3.2.4 Alectra Utilities Southwest Stations Investment

Alectra Utilities' southwest planning zone covers two sub-planning zones, the City of Guelph and the Village of Rockwood. The City of Guelph is supplied by five DESNs at three separate HONI-owned Transformer Station sites (i.e. Hanlon TS, Cedar TS, and Campbell TS) and one Alectra Utilities-owned Municipal Transformer Station (i.e. Arlen MTS). Cedar TS, Hanlon TS and Arlen MTS each step-down the 115kV transmission supply to 13.8kV while Campbell TS steps-down the 230kV transmission supply to 13.8kV.

3.2.4.1 Southwest planning zone (Guelph sub-planning zone)

A Guelph

According to a 2021 census, Guelph is the 38th largest city in Canada, and 17th largest in Ontario. The population of Guelph is expected to increase to 177,000 by 2036, up by 20% from 2021. Population growth is occurring in the greenfield areas with intensification forecast in Guelph's downtown core. Figure B13 - 31 shows the City of Guelph's downtown secondary plan.

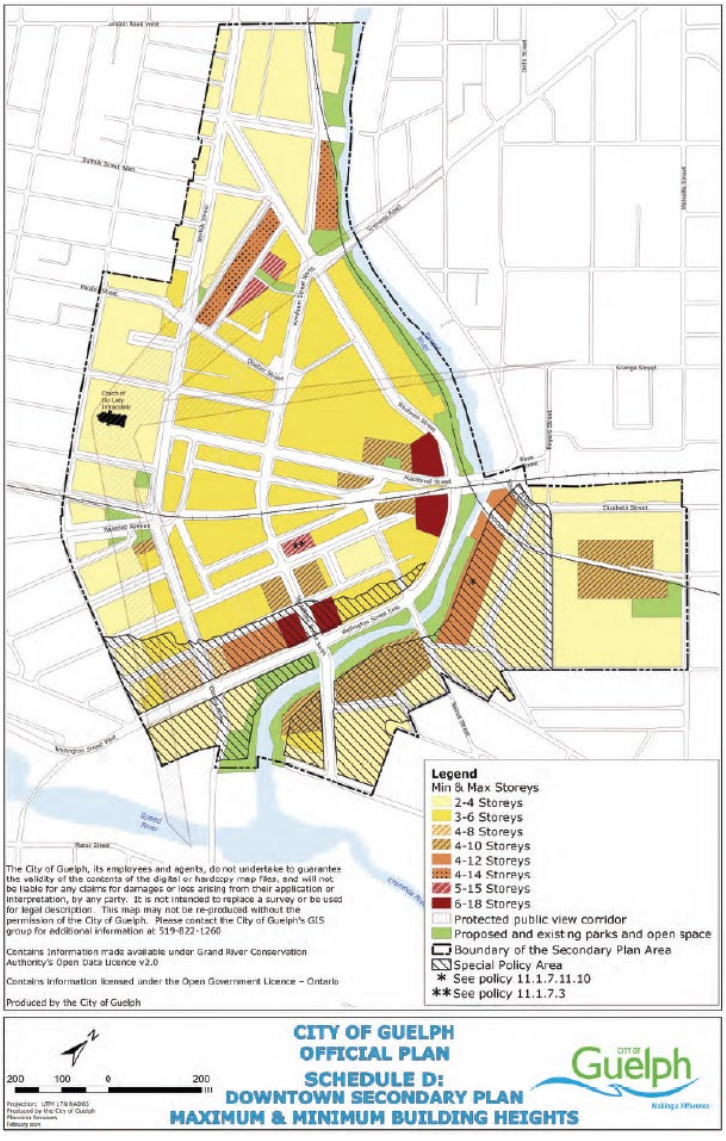

Figure B13 - 31 Guelph Downtown Secondary Plan

Figure B13 - 32 illustrates the growth expected up to 2035.

Figure B13 - 32 Guelph Region Stations, Ongoing Expansions and Growth Expected to 2035

As part of the regional planning process, HONI's Needs Assessment identified capacity needs on Campbell and Cedar TSs as illustrated in Table 5.2.2 - 10 in *Chapter 5.2.2 Coordinated Planning with Third Parties*. Alectra Utilities' analysis also identified need for additional capacity in the City of Guelph. Figure B13 - 33 illustrate the projected load, LTR capacity for the Guelph area from 2024 to 2034. Table B13 - 28 shows the individual station projected loading and LTR for Guelph area.

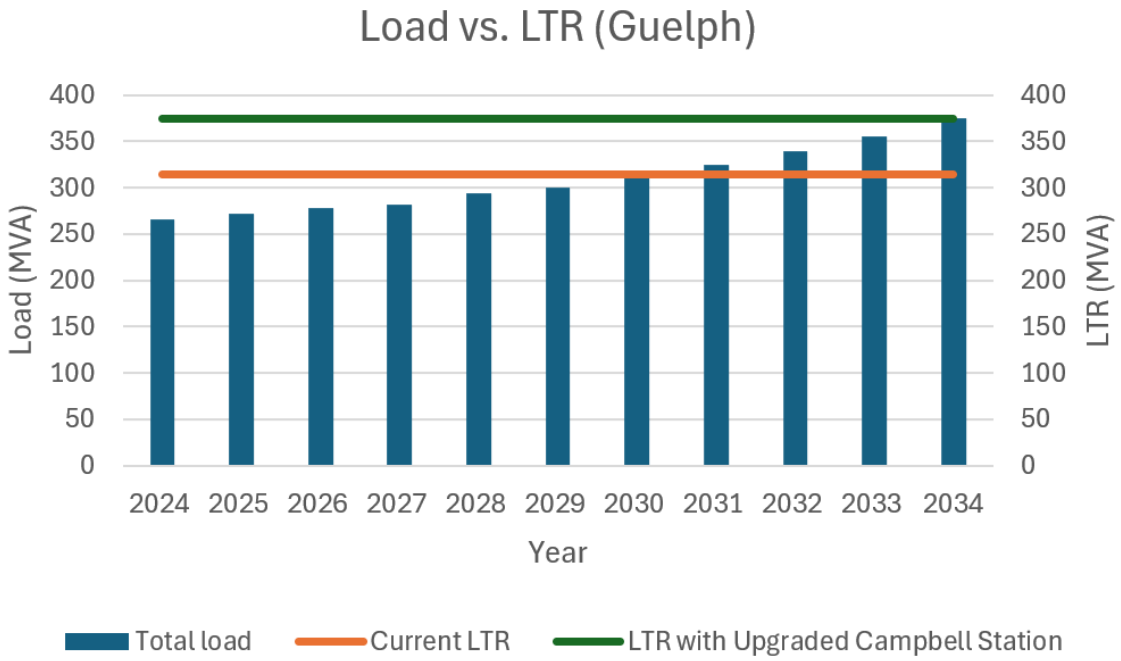

Figure B13 - 33 Load vs. LTR for Guelph (2024-2034)

Table B13 - 28 LTR and Existing Capacity and Load Forecast Load for Guelph's Transformer Stations by 2033

Station	LTR (MVA)	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Cedar TS (T1/T2)	111	86	88	90	91	98	100	109	111	111	111	111
Cedar TS (T7/T8)	43	35	37	39	40	41	42	43	43	43	43	43
Campbell TS (T1/T2)	101	92	93	94	95	98	100	101	101	101	101	101
Campbell TS (T3/T4)	60	53	54	55	56	57	58	59	60	60	60	60
Total	315	266	272	278	282	294	300	312	315	315	315	315
Additional Capacity from Upgraded (Campbell TS)	60								10	25	40	60
Total after Upgrade	375	266	272	278	282	294	300	312	325	330	355	375

Based on projected load growth and LTR capacity of the existing stations, Alectra Utilities has identified two TS capacity needs in the City of Guelph between 2031 and 2034 (Table B13 - 29).

Table B13 - 29 Planned Station Projects - Guelph

Station Name	Owner	In-Service Year
Campbell TS Upgrade	HONI	2031
New Guelph Station/BESS (North West)	Alectra Utilities	2034

The Guelph area investments include the upgrade of Campbell TS by 2031 and the land purchase for a new station or Battery Energy Storage System BESS to be in-service by 2034.

A.1 Campbell TS

The north side of the City of Guelph is supplied by two HONI-owned transformer stations (i.e. Campbell TS, and Cedar TS) (Figure B13 - 34). The north-west area in the City of Guelph contains a large portion of the industrial/commercial load and the Campbell TS has exceeded its LTR limit. The proposed downtown intensification and greenfield growth in the north-west area will create load growth on both Campbell and Cedar TSs.

Alectra Utilities' feeder work is being done to balance the load however geographic constraints limits the ability to transfer loads, and the combined the capacity of the Campbell and Cedar TSs will reach LTR in 2034 as a result of the new residential, commercial, and industrial developments. Alectra Utilities has previously constructed additional ties between Campbell TS and Cedar TS for load transferability. Currently, 6.0MVA of load is transferable.

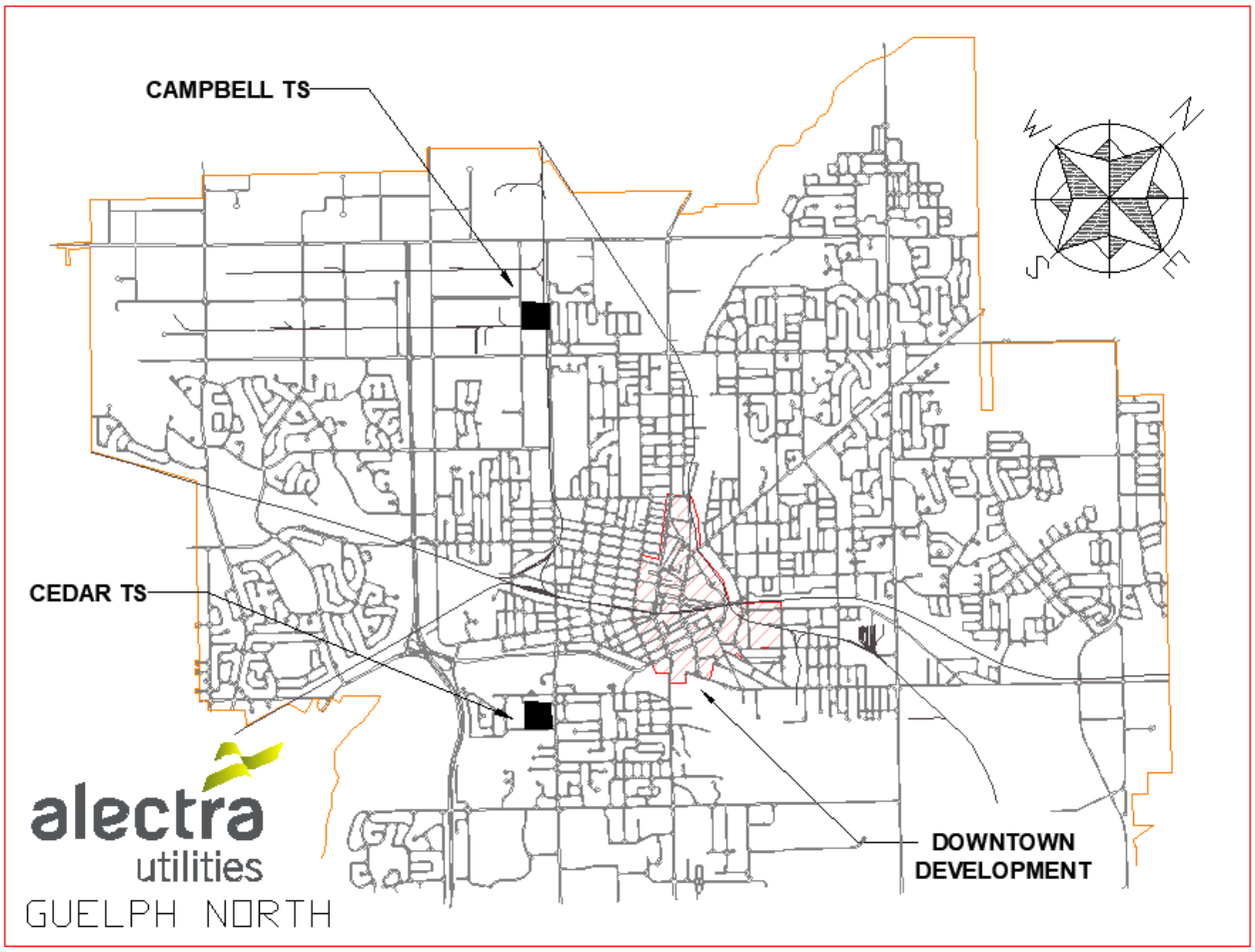

Figure B13 - 34 Campbell and Cedar Stations Guelph North

Campbell TS expansion will serve the following new developments:

North-West Side Developments

The north-west side of the City of Guelph is highly commercial/industrial, with growth occurring near Speedvale Avenue West and Woodlawn Road West. Greenfield areas in the south, such as Laird Rd, are seeing growth and intensification at Southgate Drive, Stone Road, St Clair to Maltby, and Watson Road.

A large amount of ongoing expansion is occurring in the north side of the City of Guelph, and potential future load from new electric initiatives in transportation and decarbonization of heating.

Electric Transit & Decarbonized Heating

> Guelph is focused in supporting the use of zero and low-emission vehicles. The city is planning the conversion of the city bus system to electric with need of charging infrastructure. Additional load growth (EV charging - 17MVA) identified by the City of Guelph which will be needed to connect to Cedar TS.

Alectra Utilities plan to engage HONI to upgrade Campbell TS to add new capacity in north area of Guelph. The TS upgrade is to increase add capacity within T1/T2 and T3/T4. Campbell TSs T1/T2 transformers were upgraded to 140MVA; however, the existing bus maximum limits the rating to 96MVA. With the JQ bus upgrade the LTR would increase to 118MVA. Campbell TSs T3/T4 transformers have an existing capacity of 60MVA (56MW). The LTR is to be revised to 103MVA (96MW).

The timeline to upgrade the new TS is approximately 3 years, and work will begin in 2028 for an in-service date of 2031.

Following the expansion of the Campbell TS, Alectra Utilities forecasts continued load growth in Guelph area, and it is expected that station capacity will be exceed in 2034. During the DSP period, Alectra Utilities plans to purchase land in 2029 that can be used for either wires or non-wires infrastructure.

3.3 CCRA Payments

When a distributor seeks a capacity upgrade, it must enter into a Connection Cost Recovery Agreement (CCRA) with the transmitter (HONI). Under the CCRA, Alectra will provide an initial capital contribution equal to the difference between the total capital cost and the present value of forecasted incremental transmission revenues.

During the DSP period, Alectra Utilities will be required to enter CCRA agreements with HONI on several stations and line expansion projects.

3.3.1 230kV Expansion in Brampton

The projected in-service date for 230kV transmission line expansions will be 2034 which is outside of the DSP forecast period.

Section 3.2.3 details the TS requirements in the City of Brampton. There are no lands available on the existing 230kV corridor which are close to the load centers in which Alectra Utilities can construct new stations. Alectra Utilities will engage HONI to expand the 230kV system. Alectra Utilities will need to enter into CCRA contracts with HONI for the expansion of the 230kV system in the east and west areas of the City of Brampton.

The investment is to support the construction of 230kV underground transmission lines for the two planned stations.

- H29/H30 expansion to the new Heritage TS at Bovaird and Heritage Road
- V42/V43H expansion to the new Goreway TS

3.3.2 Markham TS#5

Refer to *Section 3.2.1.1 A.1*.

3.3.3 Newton TS Expansion

Refer to *Section 3.2.3.1 A*.

3.3.4 Campbell TS Capacity Expansion

Refer to *Section 3.3.4*.

3.4 Transmitter Related Upgrade

3.4.1 H29/H30 Reconductoring

The circuits identified as H29 and H30 form an 8.5KM, 230kV double-circuit supplying Pleasant TS, as shown in Figure B13 - 35. The capacity of these lines is 448MVA.

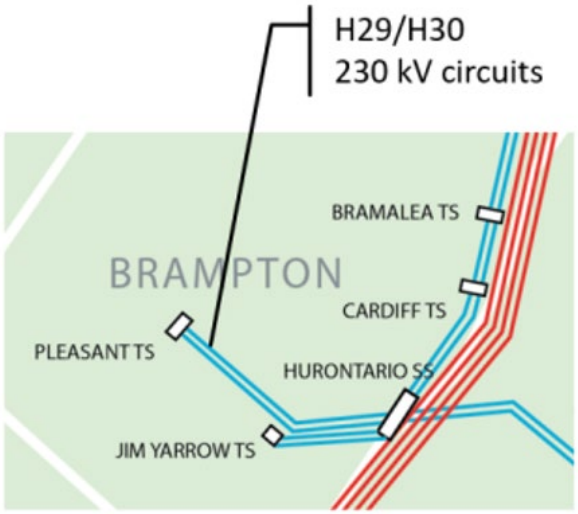

Figure B13 - 35 H29/H30 Conductor Upgrade

Due to load growth forecasted by Alectra Utilities, HONI (Distribution) and Halton Hills Hydro Inc, the 230kV circuits H29/H30 supplying Pleasant TS will not have sufficient capacity to meet the demand at Pleasant TS anticipated in 2028.

To accommodate the forecasted load growth, the GTA West Integrated Regional Resource Plan IRRP and Regional Infrastructure Plan (RIP) recommended to reconductor circuits H29/H30.

This need was originally identified in the IESO's 2015 Northwest GTA IRRP. In this report, upgrading the H29/H30 circuits with conductors of a higher rating was recommended. In addition, it was recommended that the load at Pleasant TS should be monitored and the reconductoring work should be pursued when demand reaches approximately 430MVA.

The station at Pleasant TS was forecasted to reach the peak of 448MVA by 2027. However, circuits H29/H30 out of Pleasant TS have observed significant load growth with a summer 2020 peak of 441MVA. If one circuit is out of service, there is a potential for overload in another circuit. The load is forecasted to grow significantly over the years due to the combined load of all utilities served from the line and upgrade to the conductor is required. Alectra Utilities, Halton Hills Hydro and HONI (Distribution) have engaged HONI (Transmission) to start the process to upgrade the conductor. Alectra Utilities will be required to make a capital contribution to the upgrade based on the capacity required from the circuit. The proposed project will commence in 2026 and is planned to be completed by 2027 to 2028.

IV Investment Timing & Pacing

4.1 Summary of Expenditures

Table B13 - 30 and Table B13 - 31 illustrate the year-over-year breakdown of the Stations Capacity investments, including the historical period from 2020-2024, and the DSP period from 2027 to 2031.

Table B13 - 30 Historical & Proposed Investment Spending

	Historical Spending					Bridge		Forecast Spending				
Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Stations Capacity	0.7	5.3	0.1	0.3	0.8	4.1	28.5	24.2	25.7	58.8	61.9	110.8
CCRA	0.0	5.5	0.7	0.0	0.0	5.7	5.0	10.0	16.3	16.3	47.5	24.1
Transmitter Related Upgrades	(0.2)	0.2	0.0	2.2	2.4	0.8	5.0	5.0	0.0	0.0	0.0	0.0
Total ($MM)	**0.5**	**11.0**	**0.8**	**2.5**	**3.2**	**10.6**	**38.5**	**39.2**	**42.0**	**75.1**	**109.4**	**134.9**

Table B13 - 31 DSP In-Service by Year

	In-Service by Year				
Year	2027	2028	2029	2030	2031
Stations Capacity	18.6	0.0	2.3	77.0	0.0
CCRA	20.0	0.0	0.0	0.0	50.9
Transmitter Related Upgrades	5.0	0.0	0.0	0.0	0.0
Total ($MM)	**43.6**	**0.0**	**2.3**	**77.0**	**50.9**

4.2 Historical Expenditures (2020-2024)

Historical expenditures primarily consist of land purchases for the Melbourne MS and Webb MS which are planned to come into service in 2030, as further detailed in *Section 3.2.1.2* and *Section 3.2.2.3*.

4.3 Bridge Year and Future Expenditures (2025-2031)

Bridge Years' 2025-2026 expenditures will total $49.1MM and future expenditures from 2027-2031 will total $400.6MM. These expenditures are primarily driven by land purchase and new

Transformer and substation construction and capacity upgrades at existing stations. These investments have year over year fluctuations because Alectra Utilities plans the station investment based on load growth and contingency capacity requirements, and not on recurring patterns of spending. The increase in expenditures in 2028-2030 includes Richmond Hill TS, Markham TS#5, and land purchases for Markham TS#6 and Nebo TS in 2028, the Richmond Hill TS build and land purchase for Gateway TS in 2029, and a CCRA payment in 2030 related to the transmission line expansion for Heritage TS and Goreway TS.

4.4 Investment Pacing and Prioritization

Alectra Utilities uses a deterministic approach to plan station capacity, which means that with a network element out of service all loads will continue to be served until that network element is repaired or replaced. Under this planning methodology, in the event of a contingency, such as the loss of a transformer at a TS or at an MS, all customer loads served by the affected station must be fully supported (or "backed up") by another station within the same planning zone. This ensures continuity of service, maintaining system reliability and avoiding customer outages during such events.

Alectra Utilities' annual load forecast reflects historical load patterns and expected service growth based on regional, municipal and customer long-term plans. It also accounts for other influences and factors such as CDM and distributed generation programs, weather correction and large anticipated loads that are known to Alectra Utilities.

The land purchases and station construction are based on the load growth while considering future CDM/DG contributions as well as coincide with known and forecasted development.

4.5 Execution Approach

Alectra Utilities will utilize contractors to complete the design and construction of its stations. The Execution phase will follow Alectra Utilities' internal project management methodology which provides specific guidelines, procedures and work instructions, that allow the project work to be performed in an economically efficient, cost-effective, and safe manner.

Alectra Utilities has standardized its TS and MS designs and has experience in completing station projects. The most recent example is the completion of 170MVA DESN station in Vaughan (VTS#4) and the completion of York MS in Mississauga.

V Options Analysis

Alectra Utilities has considered different options for each component of the Stations Capacity portfolio as detailed below.

5.1 Status Quo/ "Do Nothing"

There is insufficient capacity on the system to meet the load growth and the contingency requirements in each of the project areas identified herein. Therefore, the Status Quo option is not recommended. Alectra Utilities has also examined the risk of not securing land for the relevant stations and determined that the pace of rapid development and increasing scarcity of suitable parcels (both in size and location) favour the timely acquisition of land in the upcoming DSP period. If this investment is deferred into the future, Alectra Utilities is likely to incur higher costs associated with the land purchase as well as significant 27.6kV and 13.8kV feeder integration costs.

5.2 Utilizing Non-Wire Alternatives

Alectra Utilities has strengthened its internal capability to evaluate NWS within this DSP and has drafted a preliminary NWS Framework that is consistent with the OEB's Non-Wires Solutions Guideline[80] as further detailed in *Chapter 5.3.5 Non-Wires Solutions to Address System Needs*. In its current planning cycle, Alectra Utilities evaluated its 30 stations capacity projects to determine if any could be addressed using NWS.

Applying the preliminary NWS Framework, Alectra Utilities identified five stations (encompassing five station capacity, three land- acquisitions, and four material lines projects) with potential to be addressed through NWS. For these station projects, preliminary BCA results under conservative assumptions indicated positive outcomes, supporting a deferral path during the DSP period. Further detail on NWS Framework results is provided in *Chapter 5.3.5 Non-Wires Solutions to Address System Needs*.

Additional work will be required to confirm uncommitted DER availability, develop locational DR tariffs, and quantify resource reliability under multiple operating scenarios. Alectra Utilities will

[80] Non-Wires Solutions Guidelines for Electricity Distributors (formerly CDM Guidelines for Electricity Distributors) | Ontario Energy Board

advance the NWS through locational market engagement (RFI/RFP/RFQ [81] and, where appropriate local auctions) timed to the enabling- infrastructure investments described in *Appendix B14 - Enabling Resiliency and Modernization*. These investments are expected to reduce execution risk and enable broader application of NWS across the grid.

[81] RFI – Request for Information, RFP – Request for Proposal, RFQ- Request for Quotation)

VI Investment Projects

The investments from 2027 to 2031 that form the Stations Capacity investments are included in Table B13 - 32.

Table B13 - 32 Material Projects

Project Code	Project Name	CAPEX ($MM)
152758	Build Richmond Hill TS3	56.5
152883	230kV UG Transmission Expansion in Brampton	53.3
152889	TS Station – 230/27.6kV Lakeview TS - South Mississauga	50.1
152845	New Goreway TS - Brampton	50.1
152493	New Station - Newton TS (Capacity)	25.5
151147	New Station - Campbell TS Metal Clad Expansion	25.5
152850	New Station - Hamilton South-West (Station)	19.8
152762	Build Vaughan MTS#5 for VMC	14.9
152847	New Heritage TS - Brampton	13.3
101488	Build Markham TS #5	10.0
102455	Melbourne MS322 - 2 x 10MVA - Bradford	9.2
152844	Land Purchase – 230/27.6kV Gateway TS - North Mississauga	5.5
152972	Land Purchase – 230/27.6kV - GTAA TS	5.4
152859	Land Purchase - Brampton - New Heritage TS	5.3
152857	Land Purchase – 230/27.6kV Lakeview TS - South Mississauga	5.3
152862	Purchase Land for Future Vaughan MTS#5	5.1
152723	Pleasant TS - H29 H30 Reconductoring - Transmission	5.0
152860	Markham MTS#6 Land Purchase and Class EA	5.0
152973	TS Station – 230/27.6kV GTAA TS	4.5
152909	New Alliston 2x20MVA MS	4.5
152866	New Station - Hamilton South-West (Land)	3.6
152864	New Station - Guelph North-West (Land)	3.3

Project Code	Project Name	CAPEX ($MM)
150366	Webb MS New 20MVA Substation	3.0
152846	Build Markham TS #6	2.8
152888	TS Station – 230/27.6kV Gateway TS - North Mississauga	2.8
101542	New Barrie 20MVA Substation	2.3
102128	Aurora MS#6 Expansion	2.1
152870	Land Purchase - New Barrie 20MVA Substation - Bryne Dr.	1.9
152934	Land Purchase - New Alliston 2x20MVA MS	1.9
152753	Install Capacitor Banks at VTS1E	1.5
152484	Vaughan TS#6-Build Station	1.3

1

Appendix B14 - Enabling Resiliency & Modernization

I Overview

Alectra Utilities is modernizing its electricity distribution system to improve reliability, resiliency, safety, and customer experience while meeting regulatory and market requirements. The Enabling Resiliency & Modernization Program (the "Program") brings together coordinated investments in operational technologies, field automation, system control and telecommunications, customer-facing digital tools, and targeted rebuilds of high-risk rear lot infrastructure. The Program enables automation and resilience on distribution feeders, equips the control room to manage a modern, DER-rich network, provides the governed data and analytics backbone for planning and asset management, and ensures improved customer experience.

The Program consists of four coordinated segments presented in the sections that follow: Supervisory Control and Data Acquisition (SCADA), Automation and System Control (Section II); Rear Lot Conversions (Section III); Grid Modernization (Section IV); and Customer Service Technologies (Section V).

Grouping these segments in a single Program ensures that field automation and telecommunications, targeted rebuilds of constrained plant, foundational data and control platforms, and customer-facing capabilities are delivered in a sequenced, mutually reinforcing manner. Taken together, these investments:

- Enable faster, safer restoration in adverse weather via fault detection, isolation, and service restoration, enhanced telecoms, and control room capabilities with added operational flexibility (SCADA, Automation and System Control, Grid Modernization)
- Remove inherently hazardous, inaccessible rear lot plant, replacing it with standardized, accessible, and resilient front lot infrastructure (Rear Lot Conversions)
- Strengthen the grid's foundational data, model management, and work execution (Grid Modernization)

- Improve customer service quality outcomes and cost-effective delivery through paced investments in digital transformation and automation (Customer Service Technologies)

In the DSP Period, the Enabling Resiliency and Modernization Program totals $240.9MM. As summarized in Table B14 - 1, the investment mix balances foundational platforms with field execution: SCADA, Automation and System Control ($102.1MM), Rear Lot Conversions ($86.6MM), Grid Modernization ($41.1MM), and Customer Service Technologies ($11.1MM).

Table B14 - 1 Enabling Resiliency and Modernization Investment Mix Over the 2025-2031 Period

	Bridge		Forecast Spending					
Investment Type	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**Total (2027-2031)**
SCADA, Automation and System Control	12.2	10.5	9.6	18.4	26.2	26.8	21.1	102.1
Rear Lot Conversions	0.7	0.0	0.0	0.0	20.3	32.7	33.6	86.6
Grid Modernization	2.4	3.9	2.5	5.3	7.5	13.2	12.6	41.1
Customer Service Technologies	3.1	1.0	2.2	2.0	2.9	2.0	2.0	11.1
Total ($MM)	**18.4**	**15.4**	**14.3**	**25.7**	**56.9**	**74.7**	**69.3**	**240.9**

Within this total, SCADA, Automation and System Control provide $102.1MM to densify feeder automation, modernize control-room capabilities, and strengthen the supporting telecommunications. This reduces the frequency and duration of outages through automated protection and Fault Detection, Isolation and Restoration (FDIR). It also scales safe operations under adverse weather and equips the control room to manage a more automated, flexible, DER-rich network.

Rear Lot Conversions provide $86.6MM to remove a concentrated source of safety risk and extend restoration by rebuilding inaccessible rear lot assets to accessible, standardized front lot configurations with appropriate sectionalizing and pad-mounted equipment. This improves public and worker safety, shortens restoration times, and creates the conditions for future automation, where access constraints currently limit performance.

Grid Modernization investments include $41.1MM to establish and develop the core platforms that make Distributed Energy Resources (DER)-readiness and automation practical and safe, advancing a governed single utility data model, deploying an Advanced Distribution Management System (ADMS), improving Planning Tools and Automation (PTA), enabling DER Wholesale Market Preparedness (DWMP), and utilizing Enterprise Asset Management (EAM) platform so that planning, operations and maintenance work from consistent, high-quality data and standardized processes.

Customer Service Technologies provides $11.1MM to complete the modernization of customer-facing capabilities by enhancing the MyAlectra portal, replacing the legacy New Connections portal, adding webchat/chatbot functionality, and modernizing collections and payments. Customers will also experience improvements in reliability and resiliency through an integrated outage map, timely and accurate notifications, accessible self-service, and an enhanced customer experience for customer connections.

Table B14 - 2 summarizes the investments in the Enabling Resiliency and Modernization Program from 2020-2031, including actual expenditures in the 2020-2024 historical period, 2025-2026 bridge year expenditures, and 2027-2031 forecasted capital expenditures.

Table B14 - 2 Enabling Resiliency and Modernization Investment Expenditures, Drivers and Outcomes

	Historical Spending					Bridge		Forecast Spending				
Year	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
CAPEX ($MM)	11.4	14.0	19.2	17.5	24.2	18.4	15.4	14.3	25.7	56.9	74.7	69.3
Primary Driver	Reliability, Safety, Functional Obsolescence, Resilience to Adverse Weather											
Secondary Driver	Failure risk, Substandard performance, Customer Experience, Business Operations Efficiency											
Outcomes	Customer Value, Reliability, Safety, Efficiency											

The sections that follow set out, for each Segment, the investment description, drivers and needs, options considered, and timing and pacing.

The proposed integrated approach aligns delivery sequencing with resource capacity and value-risk priorities and ensures early platform benefits support subsequent deployments and customer-facing improvements.

II SCADA, Automation and System Control

2.1 Overview

Alectra Utilities' SCADA, Automation and System Control segment features investments that enable a more flexible grid, limit the impact of power interruptions, improve operational effectiveness and safety, and reduce restoration times when outages occur. These investments will support the remote monitoring and control of the Alectra grid via the SCADA system and will enable the flow of grid information that is essential for Grid Modernization platforms such as the ADMS. The segment includes three categories of investment:

- **Feeder Automation and Sectionalizing:** Adds remotely operable switches and intelligent reclosers at mid-line and tie locations, with Trip Savers at transient-fault hotspots, so feeders are subdivided into practical, switchable blocks with dependable alternate supply paths.
- **Fault Location and Feeder Sensing:** Deploys remotely monitored communicating fault circuit indicators and line sensors on long laterals and underground corridors, enabling the control room to identify faulted areas restore healthy sections more quickly in the event of a power outage.

Station Protection and Communications: Renews end-of-life relays with modern microprocessor-based protection and communication devices, adds online monitoring to provide real-time information on the health of critical assets, and strengthens and expands Alectra-owned telecommunication networks that sustain SCADA monitoring and control of the grid. This will also provide the backhaul for transporting billing and operational data from Advanced Metering Infrastructure 2.0 (AMI 2.0) meters. The key driver of the investments in this segment is reliability. The deployment of automated switching and protective devices has yielded significant reliability benefits, with SAIDI improving by roughly 14-16 minutes in recent years. Continued automation of the grid with automated device deployments will result in further reliability gains by expanding the reach of SCADA control to feeders that presently lack automation and remote sectionalizing capability. Moreover, increased grid automation will lay a solid foundation for the co-ordinated deployment of FDIR (self-healing) schemes, which will further enhance system reliability. A number of Transformer Stations (TS), which are critical hubs in the Alectra distribution system, contain legacy relays that have reached the end of their useful life. These relays also have limited

functionality, and do not provide optimal protection selectivity or information on system events. The targeted replacement of these protection schemes will reduce the possibility of failure, with consequent potential power outages and risks to Station and distribution assets due to a loss of protection. Moreover, the installation of modern, microprocessor-based protection and control systems will improve system protection and further limit the scale of outages when faults occur. These devices will also provide real-time and event data that will enhance system operations. Investments in telecommunication networks will result in robust, reliable communication systems that are critical for the transportation of real-time system data between remote devices and the Control Room, thereby enabling remote monitoring and control of the Alectra grid.

During the 2020-2024 period, Alectra Utilities invested $38.3MM in SCADA and Automation and $22.4MM in System Control to deploy automated switching and protective devices in the field, implement SCADA and Outage Management head-end systems, and install telecommunications infrastructure. During 2025 and 2026, investments are being made in relay renewals and wireless telecommunication network installations. Over the 2027-2031 period, $72.8MM in SCADA and Automation and $29.3MM in System Control will fund approximately 530 additional SCADA-controlled devices, 50 Trip Saver locations, and 300 remotely monitored line sensors at 100 three-phase locations. Investments will also be made to replace end-of-life protection systems at five TSs, as well as the installation of real-time asset health monitoring systems (e.g. dissolved gas analysis (DGA) and temperature monitoring on power transformers, and partial discharge monitoring devices on high-voltage bushings). Telecommunications investments include the installation of 11 new Worldwide Interoperability for Microwave Access (WiMAX) hubs to expand and strengthen the reach of the wireless WiMAX backbone, two fibre-optic expansion projects to connect the East and Central North fibre networks and to extend the Alectra fibre network to Central South Region, and six localized Mesh Networks to support distribution automation and fault indicator deployments.

By the end of the DSP Period, the planned investments will result in greater feeder sectionalizing capability to limit exposure during fault conditions. The addition of more automated devices will provide greater ability to isolate faulted feeder sections and restore power to unaffected sections, while System Controllers will have more flexibility to respond to emerging system constraints by swiftly performing load transfers. Key TSs operate with modern protection and control systems that provide improved system protection and system data to support system operation and event

analysis. Fibre-optic and wireless telecommunication networks will be expanded and strengthened to effectively support the transportation of operational and billing data, while also allowing for a transition away from third party networks. This will reduce third-party leasing costs while also enhancing cybersecurity by reducing exposure to third-party networks, enabling consistent encryption and authentication protocols, standards, and supporting real-time monitoring of control signals for anomalies.

The investments during 2027-2031 period will yield tangible benefits in reliability and operational effectiveness and will establish a durable data transport foundation to support future centralized grid operation functions with an ADMS and other grid modernization platforms.

2.2 Investment Description

During the 2027-2031 period, Alectra Utilities plans targeted investments that expand real-time remote monitoring and control capability, improve feeder sectionalization capability, and enable speedier outage restoration. At the same time, day-to-day operations will be prepared for a more automated and DER-capable grid. The investments advance three integrated Categories: Feeder Automation and Sectionalizing, Fault Location and Feeder Sensing, and Station Protection and Communication. The work is sequenced so that the capabilities deployed are immediately useful on their own, and enabling the Grid Modernization and Customer Service Technologies segments.

2.2.1 Feeder Automation & Sectionalizing

Distribution automation will be expanded with automated switches and intelligent reclosers strategically placed on targeted feeders to create additional feeder sectionalizing and feeder intertie capability. These devices provide remote supervision and control through SCADA and serve as the physical nodes that enable remote fault detection, isolation, and restoration at the feeder and Station levels. They reduce diagnostic time when faults occur and reduce feeder patrol times to identify fault locations. In day-to-day operations, the addition of remotely controlled devices provide additional flexibility to balance loads, reconfigure feeders, and optimize the use of available capacity. In practice, the additional deployments of automated devices will break feeders into smaller, switchable sections with multiple alternative supply paths, thereby allowing power interruptions to be confined to the smallest possible line section. Moreover, the additional

remotely controlled devices will provide greater capability to quickly restore healthy feeder sections, thereby improving reliability and enhancing customer experience. Alectra's past distribution automation deployments have already contributed measurable improvements in SAIDI, reducing average customer outage duration by 14 to 16 minutes in each of 2023 and 2024 as further detailed in *Section 2.3*). Additionally, the Distribution Automation deployments over the Forecast Period will provide a foundation for the targeted implementation of automated FDIR (self-healing) schemes, further developing an intelligent grid with less reliance on manual intervention to respond to system faults.

At a more localized level, Trip Savers will be installed at sites where recurring transient faults have occurred, typically due to animal contacts or weather. Trip Savers are self-resetting devices that clear temporary faults and automatically restore power in approximately one minute, eliminating the need for truck rolls to replace blown conventional fuses.

Over the 2027-2031 period, Alectra Utilities plans to invest $72.8MM in SCADA and Automation programs. These investments primarily consist of installing new SCADA-enabled distribution switches, switchgear, and reclosers, remote fault indicators, and Trip Savers. The summary of the investment is shown in Table B14 - 3.

Table B14 - 3 SCADA and Automation Investments

Project Code(s)	Project Name	Bridge Years 2025 to 2026 ($MM)	DSP Forecast 2027-2031 ($MM)
152947	Automated Switchgear Installation for the customers on 85F4 -SG1490 to SG1491 from Feeder 85F8	0.0	1.3
151104	Distribution Automation - Central North	2.1	6.4
151092	Distribution Automation - Central South	2.5	7.5
100886	Distribution Automation - East	3.5	11.6
151391	Distribution Automation - Guelph	0.7	2.2
150334	Distribution Automation - West	7.6	24.6
152957	Installation of automated devices on Aurora Feeders on A-1F3, A-2F1, A-2F3, A-3F4, A-5F1, A-5F2 and A-5F3	0.0	2.1
152953	Installation of automated devices on Greenwood TS1 and TS2 on 20M3, 20M5, 20M9, 20M21, 20M22 & 20M23	0.0	1.6
152929	Installation of automated pad mount reclosers - Central South	0.0	2.9
152726	Installation of automated pad mount reclosers at the overhead to underground transitions.	0.0	1.7
152832	Installation of S&C Trip Saver in West Region	0.2	1.2
152796	Installation of S&C Trip Savers at various locations in Central South	0.4	1.6
152904	Reliability Improvements to Beeton and Tottenham	0.0	2.9
Multiple	Other (non-material projects)	0.0	5.2
	Total	**17.0**	**72.8**

Over the 2027-2031 period, Alectra Utilities plans to invest $70.0MM in deployment of 530 SCADA-enabled Switching Devices that include automated switches, reclosers, and switchgears. These deployments will be co-ordinated with the installation of sensors, controls, and telecommunication networks to form a cohesive distributed automation system that will monitor, control, and optimize the performance of the grid while minimizing human intervention.

As part of the deployment strategy, Alectra Utilities will replace some of its existing manual switches, selected for replacement in *Appendix B01 - Overhead Asset Renewal* (shown in Figure B14 - 1), with new SCADA-enabled switches (shown in Figure B14 - 2). SCADA-enabled devices

are remotely monitored and controlled by the Control Room and provide real-time system data back to the SCADA system. As the utility increases grid automation, it must also invest in telecommunication and IT infrastructure to support it. Automated systems rely on fast, reliable data communication to operate effectively, so a robust and reliable telecommunication infrastructure must be in place to enable data transmission. Investments in telecommunication networks are described in *Section 2.2.3*.

Figure B14 - 1 Manual Load Break Operation

Figure B14 - 2 Control Box

In addition to the installation of new DA-compatible, SCADA-enabled devices, this investment will also include the deployment of remotely monitored fault indicators and trip savers. Remote fault indicators provide real-time telemetry to automate the process of identifying where a fault/failure has likely occurred, allowing for speedier isolation of the problem area and service restoration to the remaining customers. The continued development of Alectra Utilities' DA network of SCADA-controllable switching devices, intelligent fault indicators, and telecommunication networks will also provide a solid basis for the development of automated Fault Detection, Isolation, and Restoration (FDIR) systems.

Over the 2027-2031 period, Alectra Utilities plans to invest $2.8MM to deploy approximately 60 S&C Trip Saver devices. A Trip Saver is a self-resetting fuse used in overhead distribution

systems. It combines the functionality of a fuse and a recloser to automatically clear temporary faults (like those caused by lightning, animal contacts, or tree branches) without requiring a utility crew to intervene to replace a conventional fuse. These Trip Savers will be placed in locations that experience frequent temporary faults. In such situations, customers can be interrupted for a few hours while line patrols are conducted and restoration undertaken. Installing Trip Savers at these locations would significantly reduce outage durations. These devices detect faults, briefly open to clear them, and restore power within a minute, eliminating the need for crew intervention. The Trip Savers also communicate status updates to the system control room, providing data that is used by Alectra Utilities' reliability team, identify patterns and develop action plans to address areas that experience frequent outages.

Trip Savers, therefore, offer a cost-effective means to improve reliability, while providing important system data that can be analyzed to address localized reliability issues.

2.2.2 Fault Location and Feeder Sensing

The second workstream improves the speed of fault sensing and isolation by installing remotely monitored Fault Circuit Indicators (FCI) and line sensors on long overhead laterals and underground conductors where visual patrols are time-consuming. These FCIs are placed at strategic points along main feeders where their siting is co-ordinated with automated switching devices that also provide fault information. During the 2027-2031 period, Alectra Utilities plans to install these line sensors at approximately 100 locations, a total of about 300 sensors. Communication paths will be provided using Alectra Utilities' mesh network where available and third-party commercial cellular elsewhere (with a long-term objective to migrate more sensing to utility-owned communication).

In parallel with the installation of line sensors, Alectra Utilities plans to deploy fault indicators on both overhead and underground circuits throughout its service territory to enhance fault detection and reduce outage duration. This dual deployment approach ensures broad coverage for basic fault identification while targeting advanced monitoring capabilities where they are most effective and cost-efficient.

Fault indicators provide a visual indication confirming the presence and direction of faults, enabling field crews to locate and isolate issues quickly. In addition to traditional fault indicators, the deployment of SCADA-enabled line sensors in strategic locations will deliver real-time data

on current line disturbances and fault events to the system control operators. Together, these devices enhance the utility's ability to accurately pinpoint fault locations, reduce outage durations, and support faster power restoration. The continuous monitoring capability of SCADA devices will improve visibility into the distribution grid, supporting proactive maintenance, load management, reliability analysis, and long-term system planning. Overall, the investment in deploying fault indicators and SCADA-enabled line sensors will enhance field crew efficiency and support speedier fault locating and power restoration, supporting supports Alectra Utilities' commitment to improving reliability and grid modernization.

During the 2027-2031 period, Alectra Utilities plans to make a $4.9MM in capital investment to improve its fault detection capability by installing new fault indicators, replacing non-functional or outdated units and deploying new SCADA-enabled line sensors. The investment will be prioritized based on system performance data, focusing on areas where improved fault detection will provide the most reliability and customer service benefits.

Alectra Utilities plans to install fault indicators and SCADA-enabled line sensors in the following types of circumstances:

- Strategic locations where enhanced fault detection will improve fault location in overhead circuits, circuit interconnections, and underground cable systems
- Overhead circuits with recurring "unknown" outages, where enhanced visibility will help diagnose root causes
- Locations identified during inspections as missing or inoperable fault indicators
- Sites where crews are already performing work, such as cable injection or replacement projects, to streamline installation and improve cost efficiency

The deployment of SCADA-enabled line sensors requires SIM cards and connections to wireless telecommunications networks, resulting in higher ongoing operating costs where third-party commercial cellular networks must be utilized. Alectra Utilities will prioritize installations in areas where existing Alectra Utilities-owned wireless communications infrastructure is already in place. This approach reduces incremental operating costs. This targeted investment approach reduces outage investigation time, improves grid monitoring capabilities, and contributes to grid modernization and overall system reliability.

2.2.3 Station Protection and Telecommunications

The third workstream consists of three components: 1) the renewal of station protection and control systems; 2) the deployment of real-time monitoring systems for critical assets; and 3) the expansion and reinforcement of Alectra telecommunications networks that transport critical operational and billing data.

The first component in this category is the replacement of end-of-life protection and control systems at Transformer Stations (TS).

TSs are critical nodes in Alectra's distribution grid. They form an interconnection between the Hydro One transmission grid and Alectra distribution systems, supply significant amounts of load, and supply downstream Municipal Stations (MS). They contain large assets such as power transformers and high-voltage breakers and switching components. It is essential, therefore, that TS assets be sustained in optimal operating condition. This also extends to the protection and control systems at TSs. Relaying systems at TSs protects critical assets within the stations and also protect distribution feeders supplied from the stations. Because of the interconnection with Hydro One's transmission system, the protection schemes in Alectra stations also play a role in protecting the Hydro One grid from faults that may occur on Alectra's systems. Moreover, TS protection and control systems also provide critical protection and remote monitoring functions for large, distributed generators connected to TS feeders. It is therefore imperative that TS protection and control systems be sustained in an optimal operating state. In the Alectra TSs targeted for protection systems renewal, end-of-life relays are at risk of failure and no longer provide optimal protection. The functionality of these legacy relays is limited, and do not support the needs of a modernized grid for critical system data. Investments during the 2027-2031 period, therefore, are being made to replace end-of life protection and control systems with modern microprocessor-based systems. Legacy electromechanical and early solid-state devices will be replaced with modern microprocessor-based devices that provide enhanced protection, control, and communication capability. The new relays will improve protection selectivity and provide time-synchronized sequence-of-events, oscillography, and secure communications, improving protection co-ordination with upstream and downstream devices, and providing critical system data to assist Control Room operators with making real-time decisions. Event data will also be provided to assist with post-event analysis. Renewal decisions are driven by age, functionality, and supportability rather than a composite health score. The assets in scope are 18-43 years

old, and in most cases well beyond the industry useful-life guidelines (e.g. 30 years for electromechanical/solid-state and 15 years for first-generation microprocessor relays). Between 2027 and 2031, protection upgrades are planned at five TSs.

The second component of this investment category is the deployment of online monitoring for critical station assets such as power transformers and high-voltage bushings. These are costly assets, and their failure would have significant financial and reliability impacts. Conventionally, the health of these assets would be assessed via periodic inspection and testing routines. Online monitoring of these assets provides real-time information about the health of these assets and allows for prompt remedial action to be taken should risks to their health be identified.

During the 2027-2031 period, real-time DGA monitors are being added to power transformers to detect insulation decay and incipient faults. Transformer temperature monitors will be deployed on power transformers to capture real-time winding and oil temperatures for thermal modeling and automated cooling control. High-voltage bushing monitoring is installed to detect partial discharge and deterioration well before failure. The program prioritizes regions with sparse instrumentation today, expanding DGA and temperature monitoring to Mississauga stations and replacing unreliable bushing monitors at six transformer stations in Vaughan, Richmond Hill, and Markham. These online monitoring systems provide information that is critical to assessing the health of key assets on an ongoing basis. These investments will shorten post-event triage and support condition-based maintenance, reducing the likelihood of asset failure, and consequently unplanned outages, and the costs of emergency asset replacement. The third component of this investment category is the expansion and reinforcement of Alectra Utilities telecommunications networks to provide robust, reliable infrastructure that is essential for the reliable transportation of operational and billing data to support effective grid monitoring and control and revenue collection. Investments during the DSP period will expand and reinforce telecommunication networks and enhance path diversity for SCADA, Distribution Automation (DA), and AMI 2.0 traffic. Reliable telecommunications networks also underpin grid modernization initiatives, as the efficient transportation of real-time system data is essential for effectively operating a grid that incorporates a high level of automation and distributed generation sources.

In its present state, Alectra Utilities-owned telecommunication networks feature a variety of systems, aside from fibre-optic networks. [redacted]

[redacted]

[redacted] The fibre-optic and WiMAX networks are complemented by inter-regional microwave communication links. [redacted] Alectra's fibre-optic and WiMAX networks form the backbone of Alectra Utilities' telecommunications infrastructure, as they provide high-speed, broadband paths that are capable of speedily transporting large amounts of data. In recent years, Alectra Utilities has also developed local-area Mesh networks for transporting AMI 2.0 and DA data. [redacted] In areas where Alectra Utilities-owned networks do not exist, third-party telecommunication networks (fibre or cellular) are utilized.

In the 2025-2026 Bridge Period, Alectra Utilities will install one WiMAX hub to strengthen coverage in areas that currently rely on third-party links. During 2027-2031, Alectra Utilities plans to install eleven additional WiMAX hubs (approximately $10.6MM) to extend coverage to strengthen the wireless network canopy and provide a robust, resilient network with more alternate paths for data flow at critical nodes. The wireless Mesh network program will provide localized capacity and provide support for DA and fault indicator deployment as well as the future integration of DA and AMI 2.0 networks. Investments are also being made to expand and strengthen the fibre-optic system. [redacted] The investments in telecommunications networks will also enable a transition away from leasing 3rd party networks, leading to reduced operating costs. Owner-quality remediation at select stations is included where market or interconnection requirements demand. At Kenilworth TS, a capacitor installation will correct the poor power factor flagged by the IESO improving power quality for more than 50MVA of load. This work is coordinated with Hydro One's refurbishment program, with Hydro One designing, installing, owning, and maintaining the capacitor bank. Alectra Utilities funds the capital costs of design, equipment procurement, and installation; execution is planned for the 2025-2026 window. Similar site-specific interventions will proceed

only where compliance or customer impacts justify the investment and will be scheduled to align with station outages required for protection renewals.

The combined Station Protection and Communication segment totals approximately $29.3MM in the 2027-2031 period, following $5.7MM in the bridge years. Investments are distributed to achieve three objectives: improved protection and control, enhanced visibility into the health of major assets, and the continued development of a resilient telecommunications network to meet the needs of automation, SCADA, AMI 2,0, and grid modernization.

By making these investments, Alectra Utilities will ensure that its protection, control, and telecommunications networks continue to operate at an optimal level while meeting the needs of SCADA, the future ADMS, AMI 2.0, and grid modernization. Modern relays will limit the geographical extent of interruptions and provide critical system data to support real-time operation and post-event analysis. Investments in online monitoring systems will provide information critical to assessing the health of major Station assets, and telecommunications networks will provide a resilient platform for the reliable transportation of data critical to day-to-day operations and revenue streams. Together, these investments keep Station Protection and Communication systems at par with the growth in SCADA endpoints, Distribution Automation, AMI 2.0, and grid modernization. These investments will be essential for the development of a modern, intelligent, flexible grid that meets the needs of consumers and generators.

2.2.4 Investment Outcomes and Benefits

These investments provide the data, analytics, and controls needed to plan and operate a modernized grid: automated switching devices and sensors working to provide information and control capability to the SCADA system; upgraded protection and control schemes providing improved protection and functionality in addition to critical operating information; intelligent devices monitoring asset health; and robust telecommunications networks enabling the transportation of data to support SCADA, DA, and AMI 2.0. The same architecture positions Alectra Utilities to integrate ADMS capabilities in the next stage, so that the DA platforms being built can be further leveraged to develop FDIR (self-healing) systems.

Delivering on these investments closes observable gaps in situational awareness and grid controllability. Sensors and SCADA provide governed observability, which improves outage detection and customer communications. Upgraded protection schemes reduce the extent of

outages, while remotely operable devices shorten restoration times. Additionally, utility-owned telecommunication networks enable these actions to occur safely and consistently in real time, during both day-to-day operations and major events. The same architecture forms a platform that is compatible with the planned ADMS and will operate in conjunction with the ADMS to further modernize the Alectra grid.

Table B14 - 4 summarizes the outcomes and benefits of the SCADA, Automation, and System Control investments.

Table B14 - 4 Summary of SCADA, Automation and System Control Investment Outcomes and Benefits

Outcome	Investment Benefits and Objectives
Reliability	Reduce the number of customers affected and the duration of outages by adding remotely operable sectionalizing/tie devices on targeted feeders, coordinating modern switches and reclosers, and using communicating FCIs/line sensors to localize faults quickly. Selective station protection and upgraded SCADA head-end/telecoms support safe, timely switching. Outages on trunk sections are converted from sustained to momentary where feasible; healthy sections are restored within minutes. Maintain remote operability and rapid sectionalization during day-to-day operations and emergency events by strengthening utility-owned data communication pathways, modernizing station relays, and deploying online monitoring to provide real-time visibility into the health of critical assets. This reduces the possibility of asset failure, limits the geographical extent and duration of customer impact when outages occur, and accelerates post-event restoration.
Safety	Reduce worker and public exposure by performing switching remotely; de-energize quickly in public-contact events (e.g. customer contact with lines via vehicle or cut down tree, critical injury, fire or explosion); reduce on-site manual operations and patrols.
Customer Value	Fewer sustained interruptions on automated feeders and faster partial restoration; more accurate outage detection and information on restoration times as SCADA/FCIs feed OMS/ADMS workflows and customer-facing tools.
Efficiency	Shorten triage and reduce unnecessary truck rolls with positive device status and sensor-driven fault location; improve operator throughput and field crew productivity as SCADA/AMI/sensor telemetry is integrated into operational and outage management workflows and, later, ADMS.

2.3 Investment Drivers & Needs

Alectra Utilities plans a co-ordinated, targeted program of feeder automation, station protection and monitoring, and utility-owned telecommunications to address clear gaps in real-time situational awareness, controllability, and operational resilience. The combined segment is structured to solve the following operating problem: faults and abnormal conditions must be detected quickly, isolated safely, and healthy load restored promptly (under day-to-day conditions and during wide-area events) using systems that Alectra Utilities can govern, secure, and sustain over the long term. Absent these investments, restoration will continue to depend on time-consuming field patrols and third-party communications; outage minutes will remain higher than necessary; legacy relays and limited station telemetry will constrain protection selectivity and post-event analysis and present the risk of widespread outages; and emerging Grid Modernization use cases will lack the data and transport they require to function reliably.

Coverage of remotely operable sectionalizing points and feeder-level telemetry remains uneven. A defined subset of feeders has either no or limited mid-line automation, which limits remote feeder sectionalizing, selective isolation and back-feed restoration. Underground corridors and long overhead laterals often require full patrol to pinpoint faults, extending outage duration and increasing field exposure. At the station level, several sites lack online asset monitoring (e.g. DGA, temperature, bushing condition) and still rely on end-of-life electromechanical/early solid-state relays that provide limited event records and hinder selective clearing. Communications backhaul to many field and station endpoints relies on single-path, third-party services whose performance and availability degrade under storm loads or other factors (outside Alectra Utilities control) that impact the third-party network. Control-centre SCADA capacity must scale to supervise additional endpoints and maintain operational effectiveness as the number of SCADA-controlled devices grows

Maintaining service reliability and responding rapidly to power outages is an important priority as identified Alectra Utilities' customers in the first phase of customer engagement as detailed in *Exhibit 1, Tab 5, Schedule 2 Application-Specific Customer Engagement*). When combined with an effective DA system, SCADA-enabled switches provide rapid transfer of loads in emergencies, reduce restoration time, which improves reliability, provide flexibility to reconfigure the system to avoid feeder and station overloads when system constraints occur, and provide real-time system information that is essential for real-time operations and post-event analysis.

The primary driver for these investments is reliability and resiliency. On radial feeders without adequate sectionalizing, a single permanent fault can interrupt a large segment of customers until crews locate and isolate the fault. DA-enabled switches and reclosers at judiciously selected points, paired with feeder interties, reduce the number of customers exposed to any one event and enable the control room to restore healthy sections within minutes. Communicating fault indicators and line sensors supply the diagnostic context to narrow patrol and confirm isolation, particularly on underground cable systems and long overhead lines. At stations, modern protection improves clearing selectivity and reduces the propagation of momentary events, which is increasingly important for sensitive commercial and multi-unit residential customers.

Extreme weather events are occurring more frequently and with greater geographic impact. While vegetation management and targeted system hardening reduce fault frequency, automation and resilient communications directly reduce the duration and geographic extent of outages during storms. Resilient, multi-path, utility-owned telecommunication networks allow local schemes to continue to function if a backhaul is impaired. Dual-path communications and utility-owned transport improve the probability that remote operations remain available; and online station asset monitoring reduces the possibility of asset failure.

Safety is also a key driver of these investments. Remote supervision and control, combined with reliable telemetry, reduces live-line manual switching, feeder patrols, field crew exposure to traffic.

The planned SCADA and Automation investments will reduce the risk of personnel injury due to travelling and operating equipment. These investments will specifically improve safety during winter conditions, where equipment may be difficult to access due to snowfall and placement (e.g. snow removal piling snow near Alectra Utilities' equipment, thus restricting access). Automated devices are self-contained and reduce the risk that non-functional manual switches may cause.

These investments will also improve operational efficiency. As outage volumes fluctuate and access constraints tighten in dense urban areas, automation and dependable communications sustain service levels while reducing truck rolls. Remote operations displace multiple field trips; accurate fault corridors derived from aligned sensor indications shorten patrols; and standardized edge schemes at ties compress the interval from event detection to restoration. Online station monitoring supports condition-based maintenance, allowing maintenance windows to be planned rather than triggered by equipment failures. Resilient telecommunications infrastructure is a

prerequisite for dependable SCADA/DA operations. Utility-owned wireless (such as WiMAX) and fibre links provide deterministic performance, governance over change, and higher availability during storms than public networks. The use of commercial cellular or fibre systems remains appropriate as a secondary path or where utility networks are unavailable or impractical to deploy, but experience shows that sole dependence on third-party services introduces latency, variability, and availability risks precisely when restoration needs are greatest. Expanding utility-owned telecommunications networks also displaces recurring 3rd party lease fees with capital assets that can be engineered and secured to Alectra Utilities' standards, supporting SCADA/DA growth and AMI 2.0 transport on common infrastructure.

Validated, time-synchronized telemetry and event records are necessary for present Outage Management System (OMS)/Distribution Management System (DMS) workflows and for future centralized functions (e.g. Fault Location, Isolation, and Service Restoration (FLISR) supervision, switching safety checks, distribution state estimation) as enterprise ADMS capabilities come into service. Field automation, modern station relays, and reliable backhaul together produce the data density and quality that these functions require. Without systematic investment across these layers, advanced applications cannot perform consistently or safely at scale.

Load growth and service expansions are increasing feeder complexity. In densely populated municipalities, field access, traffic management, and scarcity of outage windows constrain manual switching. Mixed Overhead/Underground topologies complicate visual fault location. Automation, sensing, and station-level selectivity provide a scalable response that maintains restoration performance despite these constraints. Where new ties are built under System Service portfolios, concurrent automation ensures they yield immediate restoration value instead of operating as manual assets.

Alectra Utilities is advancing SCADA, Automation, and System Control to shorten the timeline from fault event to restoration and to contain the geographical extent of outages. Recent experience demonstrates the value of this approach. Based on a review of outages, automated devices improved SAIDI by approximately 14.21 minutes in 2023 and 15.51 minutes in 2024. Absent these devices, relying only on manual field switching, system performance would have been materially worse in those years. Extending remote operability and selective protection to more feeders is, therefore, a practical way to replicate and scale those gains.

The immediate need on many circuits is finer, controllable segmentation with practical ties to adjacent feeders. In several areas, ties exist but remain manual; when a sustained fault occurs, restoration is delayed by patrols, access constraints, and switching windows in dense urban settings. The plan addresses this gap by adding DA-compatible switches and intelligent reclosers to create switchable blocks with at least one alternate supply path. The deployment trajectory is deliberate and deliverable: 100 SCADA-enabled switches per year in 2027 and 2028 and 110 per year in 2029-2031, with a total of 530 new locations added during this period. Placement follows a feeder-by-feeder logic on 44/27.6kV and 13.8kV networks, with approximately 3.5 devices per 44/27.6kV feeder and 2.5 per 13.8kV feeder, serving as a planning goal. Adjustments are made for topology, access, and existing automation.

Alectra Utilities' long-term goal is to enable distribution automation on all feeders. Accomplishing this would require the company to deploy 2,865 automated switches. The utility plans to reach 82% progress towards this target by the end of 2031. Figure B14 - 3 shows the steady pace of DA device installation during the 2020-2031 period and progress towards the target.

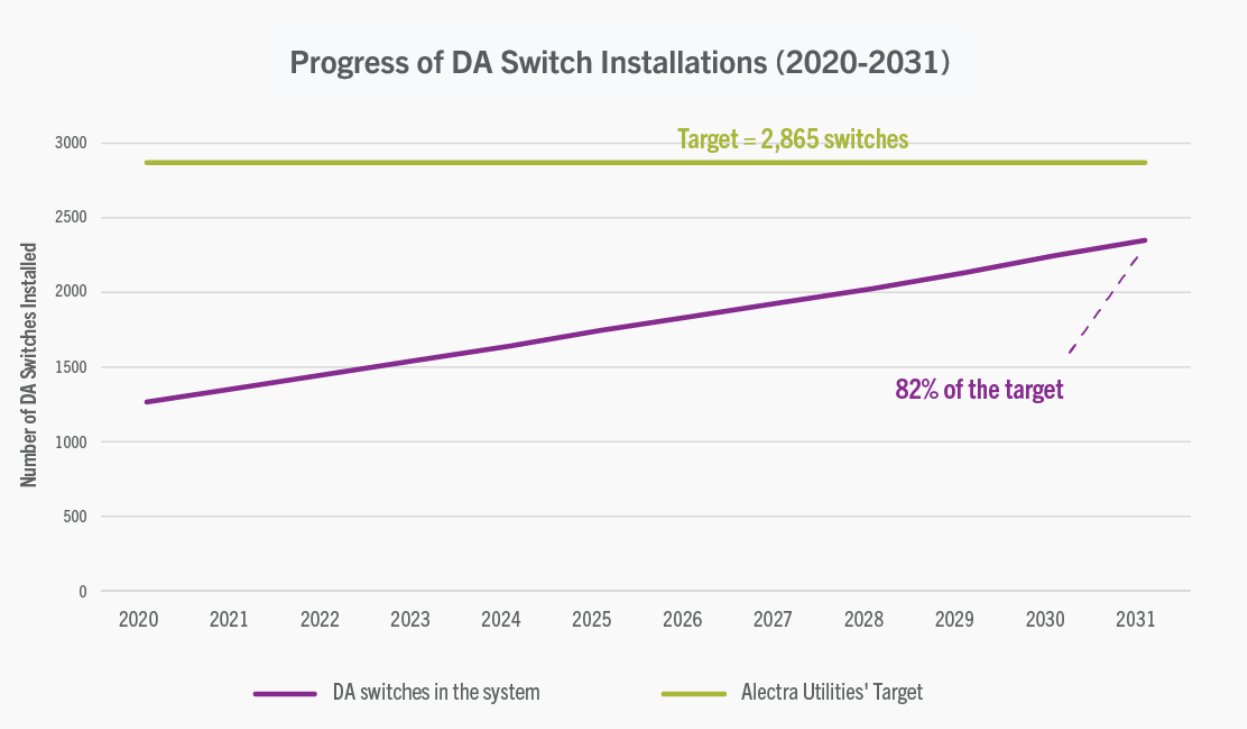

Figure B14 - 3 Progress of DA-switches Installations, 2020-2031

Feeder automation is an effective and immediate solution to address reliability issues, predominantly with duration of outages, where poor feeder performance is not tied to any one significant cause. Instead, the overall condition and operating context of the feeder has made it susceptible to multiple issues such as equipment failure, foreign interference, adverse environment, and vulnerability to adverse weather. In situations where reliability impacts have multiple causes, Alectra Utilities has found that DA is the most cost-effective way to improve reliability. Though DA will not address the outage frequency for the affected customers, it may reduce the duration of each outage. As technologies have advanced and costs have decreased, automation has become an effective, medium-term solution to reliability challenges, enabling utilities to locate faults and restore service to most customers more quickly. However, DA is not intended to replace core renewal efforts. Alectra Utilities is proposing significant System Renewal investments to address deteriorating infrastructure, including overhead line rebuilds, replacement of aging switches, and mitigation of animal contact. Together, these coordinated investments provide a cost-effective and responsible path to maintaining a safe, reliable, and distribution grid.

Where transient faults drive recurrent fuse operations, the gap is different: customers experience avoidable sustained interruptions while crews travel to replace fuses. Trip Savers are deployed at these locations, so temporary faults clear and service returns in roughly a minute, eliminating the typical two-hour restoration and associated truck rolls. The plan targets approximately 50 Trip Saver sites by 2031, prioritizing them based on fault history and short-circuit levels.

By 2031, 50 Trip Savers would be installed across locations where customers have been experiencing frequent, sustained outages due to transient faults. The sustained outage is due to the time taken to replace the blown fuse. Additionally, the Trip Savers are installed at locations with a short-circuit level of less than 6.3 kA and require a minimum load to power the device.

On long underground corridors and extended overhead laterals, outage localization is the bottleneck; visual patrols are slow, and the control room lacks discrimination between branches. Communicating fault circuit indicators and line sensors address this by time-stamping current/voltage disturbances at branch points along the main while avoiding overlap with automated devices that already provide fault indication. Alectra Utilities is installing roughly 12-15 locations per year and expects about 100 locations, or approximately 300 sensors, by 2031. Sensors connect to the Alectra Utilities mesh where available, otherwise via secure third-party

cellular, with a long-term plan to migrate more endpoints to Alectra Utilities-owned backhaul as coverage expands.

At stations supplying these feeders, legacy protection equipment and limited online condition monitoring remain a constraint. Many relays slated for renewal are 18-43 years old and lack communication, oscillography, or reliable event capture. They may still trip under fault conditions, but they hinder selective operation, post-event forensics, and integration with modern feeder automation. The planned replacements are prioritized on age and functionality. Station-level monitoring (e.g. transformer/bushing) is added where instrumentation is lacking to improve real-time asset monitoring capability and reduce the possibility of asset failure.

The efficacy of grid automation and remote monitoring/control depend on the reliable flow of information between the field and SCADA system. Thus, resilient telecommunications pathways are necessary to realize the benefits of automation and grid modernization. The plan, therefore, reinforces utility-governed transport, licensed-spectrum wireless hubs and towers at critical nodes and targeted fibre-optic extensions, so that remote supervision and control remain available for day-to-day operations, in outage situations, and during adverse weather. Planned investments in Alectra Utilities-owned telecommunications will also enable a migration away from 3rd party networks, with a resulting reduction in operating costs. Representative projects include new WiMAX nodes, localized mesh networks, and fibre-optic links between regions.

These targeted actions close specific, documented gaps in the system. Automation converts existing ties into actionable restoration, Trip Savers remove sustained interruptions caused by temporary faults, sensors bring precision to fault location where patrols are slow, station protection restores selectivity and event visibility, and backhaul resiliency preserves the ability to operate remotely when storms arrive. Together, they also build the pre-conditions for the next control-room platform: centralized FLISR is planned as part of ADMS in the 2030s following vendor selection in 2028-2029, and it will rely on the controllability and observability established by this segment.

Delaying the investments in this segment would preserve longer outage durations on affected circuits, maintain higher exposure counts under single contingencies, and retain avoidable switching risk. New feeder ties would operate as manual assets, limiting restoration leverage; station reinforcement and renewal programs would under-deliver due to limited selectivity and

sparse telemetry; and reliance on single-path, third-party communications would persist through future storm seasons. Over time, the cost and risk of supporting legacy relays, radios, and controllers would rise, and future Grid Modernization functions would be delayed or deliver inconsistent results.

Combining field automation, station protection/monitoring, and utility-owned telecommunications under one segment reflects how reliability is achieved in practice: communications enable telemetry; telemetry enables control; modern protection makes that control selective; and automation turns control into timely restoration. The same assets that minimize day-to-day interruptions are crucial during storms and provide a durable data foundation for future centralized capabilities. As such, the segment represents a least-regrets, prudent response to Alectra Utilities' operational needs over the plan term.

2.4 Options Analysis

Alectra Utilities considered technical and delivery alternatives across each layer of the combined segment. The recommended approach is a coordinated program of targeted and prioritized DA-enabled sectionalizing and sensing, modern station relays, online monitoring, and ultimately a utility-owned telecom backbone.

2.4.1 Segment-Level Alternatives

- **Status Quo** (manual switching, limited telemetry, and third-party communications where available).

  This alternative theoretically represents the lowest near-term capital but fails to meet reliability, safety, or storm-readiness objectives. Restoration remains dependent on field patrol and access; ETR accuracy remains limited; and single-path, third-party telecoms are least reliable during wide-area events. This alternative will require increases in recurring OM&A, will not scale under wide-area events, and will not reduce safety switching risk. The approach does not address customer priorities and fails to close grid gaps, resulting in a less economical and less safe solution over the asset's life, and is therefore unacceptable.

- **Rapid Deployment** (accelerated rollout of SCADA-enabled sectionalizing and sensing).

  This alternative would provide immediate benefits in restoration time reduction. However, it poses financial and resource constraints due to the large up-front capital and resourcing requirements, and raises execution risk, increasing the chance of sub-optimal implementation.
- **Capacity/hardening instead of automation** (additional ties, conductor upgrades, cable renewal, and vegetation programs).

  This option would focus on building feeder ties, conductor upgrades, cable renewal, and vegetation programs to reduce fault frequency and increase transfer paths, but they do not localize faults or execute restoration. This option is complementary, not substitutive.
- **Targeted Moderate Deployment – Recommended** (keeping pace with deployments of automated devices, expansion of network communications, and keeping pace with ADMS deployment).

The recommended option installs remote-operable sectionalizing and sensing where they deliver the most value, renews protection where it limits operations, scales communications in step with device density, and delivers steady improvements while keeping cost and delivery risk in check.

2.4.2 Category-specific alternatives and rationale

Alectra Utilities considered three approaches for feeder automation and sectionalizing. Remaining with manual switching and no sensors offers the lowest near-term cost but fails to address reliability and resiliency needs because restoration would continue to depend on patrols. Accelerating a system-wide rollout delivers immediate benefits but requires large up-front capital and resourcing, heightening execution risk and increasing the likelihood of sub-optimal implementation. The preferred path is a targeted, moderate deployment that prioritizes feeders with the highest reliability impact, adds DA-enabled sectionalizing and sensing where they deliver the most value, and sequences work with related renewals. Hence, benefits arrive steadily while keeping delivery risk and lifecycle cost in check.

For communications, doing nothing would leave Alectra Utilities exposed to functional obsolescence and reliability risks, while relying solely on third-party networks lowers initial cost

but creates external dependency and elevates security and availability risks. The end-state preference is a dedicated closed network under utility control. In the near term, Alectra Utilities will operate a hybrid posture with utility private networks as the primary path and secure third-party networks as secondary or site-specific primary, then migrate to dedicated utility transport on critical endpoints and high-value routes where prudent.

At stations, run-to-failure or single-measure fixes (relay-only or monitoring-only) are not prudent. The lifecycle intervention at priority sites combines modern microprocessor protection (to restore selectivity and event visibility) with online monitoring where instrumentation is lacking.

On balance, the preferred alternative is a coordinated approach that expands automation and remote feeder sectionalizing capability, adds remote fault indication and sensing to address localized reliability issues, replaces end-of-life protection systems, adds real-time-monitoring of critical stations assets, and continues to develop a resilient telecommunications network. Altogether, these investments will improve reliability, enhance grid monitoring and control, and deliver value to customers while supporting grid modernization initiatives.

2.5 Investment Timing & Pacing

Table B14 - 5 provides the year-over-year breakdown of investments, including the Historical Period from 2020 to 2024, the Bridge Period 2025 to 2026, and the DSP Forecast Period from 2027 to 2031.

Table B14 - 5 Historical & Proposed Investment Spending

	Historical Spending					Bridge		Forecast Spending				
Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
SCADA and Automation	3.4	9.0	8.7	8.0	9.2	8.3	8.7	8.7	9.2	15.2	21.6	18.1
System Control, Comm'ns & Performance	5.5	4.2	4.4	3.3	5.0	3.9	1.8	0.9	9.2	11.0	5.2	3.0
Total ($MM)	**8.9**	**13.2**	**13.1**	**11.3**	**14.2**	**12.2**	**10.5**	**9.6**	**18.4**	**26.2**	**26.8**	**21.1**

Alectra Utilities continued to build its automation base at a steady pace throughout the Historical Period of 2020-2024. Over that time, SCADA and Automation expenditures were $38.3MM, while

System Control and related communications were $22.4MM. The investments expanded the penetration of remote-operable devices and wireless telecommunications infrastructure.

The Bridge Period (2025-2026) continue that investment, averaging $11.4MM in each year.

The 2027-2031 plan increases device deployments and supporting infrastructure by investing $72.8MM over that period in SCADA and Automation, and $29.3MM in System Control. The increase is necessary to deploy additional DA-enabled devices, replace deteriorating P&C and communication assets, improve network reliability, and support the need for reliable, robust communication networks to support the increased demand for data transportation for SCADA/ADMS and AMI 2.0 needs.

Alectra Utilities will continue to install automated devices, at an annual pace of 100 to 110 units annually. This trajectory increases sectionalizing density and the availability of remote tie operations across the served districts.

Trip Saver deployments are designed to address feeders with frequent fuse operations resulting from transient faults. Engineering criteria include the observed fuse operation frequency, a short-circuit level below approximately 6.3 kVA, and a minimum load to power the device. The plan installs roughly 50 locations by 2031, at which point the highest-value candidates will have been treated; further installations will continue as a proactive reliability measure.

Communicating FCIs and line sensors continue at a measured rate (about 12-15 locations per year), scaling to about 100 locations by 2031, coordinated with automated switch placements so that sensing fills information gaps rather than duplicating telemetry.

The plan includes the replacement of end-of-life relays and communications equipment, improving storm availability, and supporting the higher point counts and bandwidth associated with SCADA/ADMS and AMI 2.0. Over the DSP period, Alectra Utilities will renew protection and control assets at five transformer stations, install ten new WiMAX wireless hubs, and build two fibre links: one tying the East SONET ring into the Brampton fibre network and a second connecting Brampton to the Derry Road office.

Looking beyond 2031, centralized FLISR is expected to be implemented as part of the ADMS deployment following a sequenced roll-out. The edge automation and head-end improvements proposed in this plan are the necessary precursors to realize those future benefits.

Alectra Utilities utilized Copperleaf to determine the optimal timing and pacing of proposed investments, using a multi-variable capital investment optimization tool to optimize projects based on value and risk across the entire capital investment portfolio for the DSP period. For more information on the process, refer to *Chapter 5.3.1 Planning Process*. The projects identified are optimized based on the available funding and the values and risks in the given year.

Specific locations for work are prioritized considering outage data, fuse-operation frequency, feeder configuration, and access constraints. The work is coordinated with *Appendix B01 - Overhead Asset Renewal*, *Appendix B02 - Underground Asset Renewal,* and Rear Lot Conversions in *Section III* for efficiencies and to avoid re-work.

By the end of the DSP period, priority feeders will have sufficient remote-operable sectionalizing and automated ties to limit customer exposure to modest segments; communicating fault indicators and line sensors will instrument long laterals and underground corridors that have historically driven patrol time; priority stations will operate with modern microprocessor relays and online condition monitoring; and the telecommunications infrastructure will be reinforced with Alectra fibre and licensed radio-frequency networks complemented by third-party systems where warranted. This position sustains restoration improvements and provides the data and communication prerequisites for supervising selected schemes centrally as enterprise ADMS capabilities are brought into service.

III Rear Lot Conversions

3.1 Overview

Alectra Utilities' Rear Lot Conversions segment replaces legacy distribution that runs through private backyards with standardized front lot underground supply in municipal road allowances. The Segment removes energized plant from rear yards, installs pad-mounted, switchable transformers and primary cable in conduit with sectionalizing points, and cuts over customers to new underground services. Once cut over, rear-yard conductors, poles, porcelain top-ties, pole-mounted transformers, and service drops are de-energized and removed. Designs adhere to current standards, ensuring that isolation and restoration are supported, and access for operations is restored to the road allowance.

The need is established by condition, performance, and safety. The asset assessment indicates that approximately 43% of poles in rear lot areas will be in poor or very poor condition or beyond useful life by 2031. Rear lot feeders experience higher outage frequency and materially longer duration than non-rear lot feeders on a non-MED basis, and they are disproportionately affected during Major Event Days. These characteristics reflect poor accessibility and heavy tree contact in backyards. Eliminating rear lot plant removes the hazard from private property and restores safe work envelopes for crews. Alectra Utilities discontinued conversion designs that leave energized assets in rear yards following a 2022 incident and restrictions from the Electrical Safety Authority at locations with pools near rear lot plants.

The portfolio addresses a defined set of rear lot areas and is sized to make progress through the plan period. Twenty-four areas have been identified across Alectra Utilities' service territory. Fifteen are scheduled for conversion during 2027 to 2031, with the balance to follow. The spending profile reflects a measured ramp to align with resource capacity and prerequisite civil staging. Forecast capital for rear lot conversions totals $86.6MM in 2027-2031.

This segment is a key pillar of the Enabling Resiliency and Modernization Program. Converting rear lot neighbourhoods reduces the geographic extent and duration of interruptions by restoring controllable access, enabling sectionalizing on the road network, and removing exposure in backyards. It improves public and worker safety by taking energized equipment out of recreational spaces and returning work to bucket-truck accessible locations. It also prepares

these areas for grid modernization by applying today's standards for isolation and restoration and by using pad-mounted equipment and underground loops that can support future automation. The portfolio will reduce rear lot exposure by 2031, while refining an approach to complete the remaining areas thereafter.

3.2 Investment Description

Alectra Utilities proposes a systematic program to convert legacy rear lot distribution to standardized front lot underground supply in targeted neighbourhoods. The work replaces the plant that traverses private backyards with new equipment installed within municipal road allowances. The scope includes pad-mounted, switchable transformers, underground primary cable in conduit with sectionalizing points at practical intervals, standardized polymeric insulation, meter base relocations as required, and new underground secondary services to each premise. Once customers are switched over, the rear lot assets are de-energized and removed, eliminating the hazard at its source. Designs adhere to current standards, enabling future isolation, restoration, and automation to be supported from the outset.

Over the 2027 to 2031 period, Alectra Utilities plans to invest approximately $86.6MM in rear lot conversions. While designs, easements, and municipal coordination will be advanced in 2027 and 2028, the execution will ramp in 2029 through 2031 as multiple neighbourhoods proceed in parallel.

After a 2022 incident due to a previously completed hybrid rebuild installation, and multiple wire-down events into customer pools (since 2020), Alectra Utilities discontinued any design that would leave energized assets in rear lots. The new standard relocates both primary and secondary to the road allowance and restores clear, code-compliant working envelopes for crews and the public. The Electrical Safety Authority also flagged locations where pools could not be used due to proximity to rear lot plant, confirming the safety exposure that this program removes.

Delivery is organized by neighbourhood to bring benefits forward and to manage construction risk. Projects are staged in phases sized to the neighbourhood, balancing customer impact, municipal coordination, and construction efficiency. Civil construction comes first. Ducts, vaults, service laterals, and surface restoration are completed before electrical installation and cutovers proceed in planned waves. Early engagement with homeowners is built into the schedule because the work occurs next to private property. Easements, meter moves, and driveway or

landscaping restoration are coordinated before field work begins. This approach mirrors Alectra Utilities' practices for area conversions and is scalable across multiple districts.

Rear lot conversion is a renewal with resiliency benefits. Rear lot customers experience disproportionate impacts. For example, during the December 2013 ice storm within the Alectra East operating area, rear lot customers accounted for 17% of total customer minutes interrupted, while representing only 0.01% of customers. Limited access and heavy tree contact lengthened patrol and repair times. Relocating the plant to the street reduces exposure and restores controllable access, which shortens outage duration during major events and day-to-day faults. Climate analysis indicates that high-wind events will intensify. The 2022 derecho that brought down more than 100 poles is projected to recur about once every four years as stated in *Appendix G - Climate Risk and Vulnerability Assessment*. Converting rear lot areas is therefore a targeted resiliency measure.

The program addresses functional obsolescence and access constraints that make like-for-like renewal impractical. Legacy porcelain top-tie insulators require full isolation before work and are prone to contamination and flashover. Rear lot poles are congested with multiple attachments and often ladder-only access. Conductor sizes are undersized in many locations, including #4 and #6 copper and older ACSR spans that must be fully isolated before work. Street relocation removes these constraints and restores standard maintenance methods with bucket-truck access.

Standardized front lot infrastructure also supports modernization and customer connections that rear lots cannot efficiently accommodate. Pad-mounted equipment, vaults, and meter bases on the road allowance provide clearances and work envelopes for service upgrades and distributed energy resources. This puts these neighbourhoods on the same operating platform as the rest of the system, making them ready for the automation capabilities described in *Section V*.

For a number of investments Alectra Utilities is implementing a hybrid design that combines overhead plant along the road allowance with underground service laterals to the residences. This approach is used only where site conditions support safe, economical construction and long-term maintainability. Favourable conditions include minimal tree cover or a non-mature treeline, existing overhead support structures in the road allowance such as streetlight or telecommunications poles, or underground corridors that are already congested. Figure B14 - 4

illustrates a location suitable for a front lot overhead solution, while Figure B14 - 5 shows a location where overhead front lot conversion would not be appropriate. Where these conditions are not present, the standard is full front lot underground relocation. The use of a hybrid design does not alter the program objective of removing energized plants from rear yards and restoring safe, controllable access from the street.

Figure B14 - 4 Front Lot Conditions Suitable for Overhead Infrastructure

Figure B14 - 5 Front Lot Conditions Not Suitable for Overhead Infrastructure

Execution must be proactive. Alectra Utilities has more than forty rear lot areas across the system and waiting for deterioration with multiple failures would create a growing backlog that cannot be addressed through emergency work. Reactive rebuilds in backyards are impractical and potentially unsafe, and they do not scale to the volume of locations that must be converted. The program therefore adopts a rolling, multi-year pipeline that plans neighbourhood conversions in advance, aligns the utility's resources and permits, engages customers early, and steadily reduces rear lot exposure each year. This approach ensures that rear lot areas are ultimately rebuilt to standard, rather than being addressed piecemeal after failures.

The segment structure reflects both need and deliverability. Alectra Utilities supplies approximately 15,000 customers with overhead rear lot infrastructure and about 18,000 with rear lot underground infrastructure. Much of this plant is at least 40 years old and runs through backyards near pools and other public-facing spaces. 24 rear lot areas have been identified for relocation, with 15 scheduled between 2027 and 2031. The 2027 to 2031 work will materially reduce exposure but will not eliminate it, which confirms the prudence of pacing and the need to continue the program after 2031. A detailed list of the 15 projects is provided in *Section 3.5* and repeated in the project list in *Section VI*.

Table B14 - 6 summarizes the outcomes and benefits of the Rear Lot Conversion investments.

Table B14 - 6 Summary of Rear Lot Conversions Investment Outcomes and Benefits

Outcome	Investment Benefits and Objectives
Customer Value	• Increases customer satisfaction by eliminating the need to access private customer property for maintenance and inspections. • Eliminates overhead electrical lines directly within their private property and updates the distribution system to present-day standards. Removal of overhead electrical plant eliminates the risks of customer safety and property damage in the event of an overhead system failure. • Provides standard front lot meters and service layouts that support future customer upgrades and DER connections.
Reliability	• Replacing aging rear lot assets with modern infrastructure improves reliability by meeting current standards. • Underground pad-mounted switches and switchable transformers enhance sectionalizing and restoration, reducing outage durations. • External disruptions from animals, trees, and human contact are minimized with underground systems. • Front lot equipment allows faster crew access, significantly reducing restoration times compared to rear lot assets, where outage frequency and duration have been 30% to 40% higher than the Feeder Average Interruption Frequency Index over the past three years during regular conditions, and materially worse during the Major Event Days. • Front lot design creates resilient grid and addresses storm-driven reliability exposure that produces disproportionate impact on rear lot customers.
Safety	• Ends partial rebuilds and removes energized plant from recreational spaces. • Retires porcelain top-ties and undersized conductors prone to safety issues. • Homeowners no longer have to worry about potential safety risks posed by rear lot infrastructure and can obtain greater enjoyment and flexibility in their backyards.
Efficiency	• Standard equipment and road access reduce truck rolls and reactive maintenance. • Proactive, phased delivery avoids repeated mobilizations and stranded work. • Permits operational improvements (e.g. enhanced switching and sectionalizing within underground loops, visible breaks within underground pad-mounted switches, as well as enhanced fault-indicating devices installed at transformers, switches, and wood poles).

3.3 Investment Drivers & Needs

Rear lot assets are functionally obsolete. They exhibit poor reliability and elevated public and worker safety risk given their location behind residences, frequent proximity to pools and decks, and adjacency to mature vegetation. The rear lot topology impedes fault location and restoration and prevents the use of standard equipment such as bucket trucks and drilling rigs. Congested poles with multiple attachments exacerbate access hazards, while legacy porcelain insulators and undersized conductors necessitate full isolation before any work proceeds. As the plant ages beyond expected useful life, the likelihood and consequence of failure increase, particularly during extreme weather events. These characteristics collectively justify replacing it with a standard front lot configuration that is accessible, can be sectionalized, and is inherently safer.

Asset condition data demonstrate a material gap between the current state of rear lot infrastructure and other configurations, leading to elevated standards for safety, reliability, and operability risks. Across the planned portfolio, a significant proportion of poles are in poor condition and beyond their useful life. Rear lot feeders consistently experience higher outage frequencies and longer durations than non-rear lot feeders under normal operating conditions and are disproportionately impacted during Major Event Days (MEDs). Removing rear lot exposure by relocating supply to the front lot closes this gap by: (i) eliminating energized assets from private recreational spaces; (ii) restoring safe, efficient access for inspection and maintenance; and (iii) reducing outage duration through improved sectionalization and restoration practices.

Rear lot infrastructure is widespread across Alectra Utilities' service territory, and it is aging. Alectra Utilities supplies approximately 15,000 customers from overhead rear lot plant and about 18,000 from rear lot underground, primarily in older neighbourhoods with assets now 40 years or more in service. These circuits traverse private backyards near pools and buildings, which complicates access and elevates risk to the public and crews. Rear lot assets present a material condition gap; across the twenty-four planned rear lot conversion areas, at least 43% of poles will be beyond useful life or in poor or very poor condition by the end of the DSP Period.

Public and worker safety is a primary driver. Since 2020, there have been multiple wire-down events into residential pools, including one with occupants present. The Electrical Safety Authority directed customers at two locations not to use their pools due to proximity to an energized plant. Figure B14 - 6 visualizes similar conditions with rear lot plant near the swimming

pools. Near-miss records also document hidden condition issues, such as severely rotted rear lot poles discovered during planned work, as well as hazards during backyard tree activities. Relocating primary and secondary to the road allowance removes these hazards from private property and returns crews to bucket-truck access methods rather than ladder-only work in confined spaces.

Figure B14 - 6 Example of Rear Lot Infrastructure Near Customer's Pool

The secondary driver for Rear Lot Conversion Program is reliability. Reliability under day-to-day conditions is measurably worse on rear lot circuits. On a non-MED basis, Feeder Average Interruption Frequency Index (FAIFI)[82] for feeders that have rear lot sections was 42% higher in 2022-2024, compared with non-rear lot feeders over the same years. Feeder Average Interruption Duration Index (FAIDI) for rear lot feeders was 36% higher and total customer interruption hours were 126% higher versus non-rear lot feeders. This demonstrates persistent frequency gaps and longer durations on rear lot feeders, which the proposed investments are designed to address.

The other secondary driver for Rear Lot Conversion Program is resiliency to adverse weather events. Resilience during storms is a distinct need. The 2013 ice storm illustrates how topology

[82] The customer count per feeder is held constant for the 2022–2024 calculations, based on 2023 actual data.

and access compound impacts. In the Alectra East operating area, rear lot customers accounted for about 29.8 million Customer Minutes Interrupted (CMI), or 17% of system CMI, while representing a tiny fraction of the customer base, 0.01%. Climate Risk and Vulnerability Assessment Study work indicates the 2022 Derecho, which downed more than 100 poles, is consistent with a high-wind event expected roughly once every four years, as illustrated in Figure B14 - 7. This trend poses a significant risk to the overhead distribution system as discussed in *Appendix G - Climate Risk and Vulnerability Assessment*).

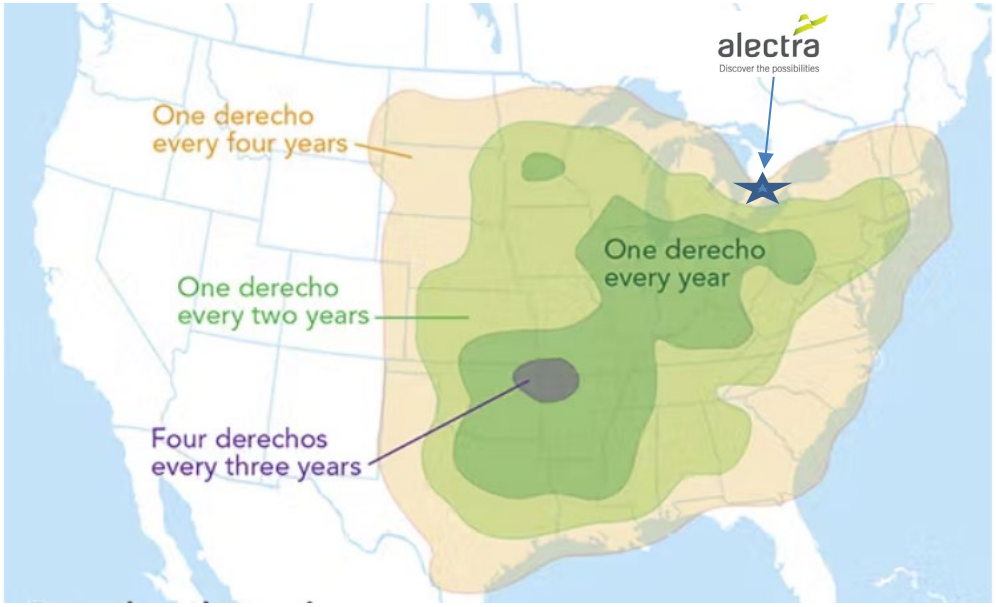

Figure B14 - 7 Derecho Event Occurrence Rate[83]

MED averages confirm the disproportionate effect on rear lot circuits; for example, 2022 rear lot FAIDI averaged 14.32 hours versus 5.51 for non-rear lot, and in 2024, 29.98 hours versus 1.00. Table B14 - 7 below shows the comparison of reliability data during Major Event Days in 2022 and 2024 (2023 did not have any MED days). Moving the plant to the street shortens patrols, enables sectionalizing, and reduces restoration time when adverse weather escalates into wide-area events. Moving the substandard infrastructure from rear lots to front lot design moves the utility to a resilient modern grid. It will provide rear lot customers with a standard performance experience similar to that of other customers in Alectra Utilities' service territory.

[83] https://www.tdworld.com/grid-innovations/distribution/article/20964810/storm-hardening-the-grid

Table B14 - 7 FAIFI and FAIDI, MED Reliability Comparison of Feeders With and Without Rear Lot Sections, 2022-2024

Average MED Data	Average FAIFI			Average FAIDI		
Feeder Type	2022	2023	2024	2022	2023	2024
Feeders with Rear Lot Sections	1.40	N/A	3.40	14.32	N/A	29.98
Non-Rear Lot Feeders	0.80	N/A	0.78	5.51	N/A	1.00

Operability and cost-to-serve are also drivers. Rear lot layouts impede switching and maintenance, often relying on obsolete porcelain top-tie hardware and undersized conductors that require full isolation before work can be done. Access disputes and tree activity in backyards create restoration delays and safety exposures. Figure B14 - 8 through Figure B14 - 10 illustrate rear lot areas that contain unsafe conditions, with limited access (tree conflicts, proximity to pools and buildings, and multi-party attachments), which impede routine inspection, preventive maintenance, and switching, and lengthen restoration times when failures occur. As the plant ages, deterioration compounds the access constraints and increases the likelihood of contact incidents, which in turn affects service reliability for customers served from these locations. Standard front lot designs enable visible breaks, pad-mounted switching, and practical sectionalizing points that align with the automation approaches in the SCADA, Automation and System Control segment, improving day-to-day operations and positioning these areas for future ADMS-supervised functions.

Figure B14 - 8 Tree-house Close to Pole and Energized Primary and Secondary Conductors

Figure B14 - 9 Inaccessible pole in Very Poor Condition (Cracked and Rotten)

Figure B14 - 10 Rear Lot Equipment Surrounded by Vegetation

Rear lot configurations also constrain service upgrades and distributed energy resource connections. Non-standard layouts and restricted working clearances slow panel upgrades, meter changes, and interconnection work. Relocating meters and primary equipment to the road allowance standardizes service interfaces, restores safe, code-compliant working envelopes, and provides clear access for crews and inspectors. The result is faster and more predictable connection timelines for EV charging, heat pumps, solar, and storage, and a neighbourhood built to the same standards used elsewhere on the system. This supports growth and DER enablement and aligns with broader grid modernization objectives, including consistent infrastructure and dependable access to deploy automation and customer-facing tools.

Finally, scale requires a proactive program. Twenty-four rear lot areas have been defined; fifteen are scheduled for 2027-2031, and the balance are planned to follow after 2031. More than forty rear lot neighbourhoods exist across the system, which confirms the gap will not be fully closed within this DSP. Reactive rebuilds are not deliverable at this scale because emergency access, permitting, and customer coordination cannot be secured after deterioration has progressed. A rolling conversion program reduces the exposure each year and ensures that rear lot assets are rebuilt to standard rather than addressed piecemeal after failures.

3.4 Options Analysis

The utility evaluated three practicable courses of action to address rear lot risk, informed by experience since 2018 and refined after 2022. Those are summarized below.

3.4.1 Increased vegetation maintenance (status quo with enhanced trimming)

Targeted tree trimming can temporarily mitigate tree contacts, the leading trigger for rear lot outages, and can be used tactically to stage investment. However, this course of action does not eliminate energized plants from backyards, does not resolve access constraints, and increases operating expense. It defers rather than resolves safety and reliability risks. A sample location for increased tree-trimming is shown in Figure B14 - 11.

Figure B14 - 11 Tree-trimming candidates close to Pole and Energized Conductor

3.4.2 Targeted Spot Replacements

Condition-driven pole and component replacements (e.g. wood pole renewals informed by inspection and testing) can reduce localized risk and facilitate a transition to a conversion. This course of action improves short-term resilience while preserving the rear lot topology and its inherent access and safety constraints. It is not a substitute for conversion and is best used to manage pacing.

3.4.3 Rear lot to front lot conversion (Selected)

Comprehensive conversion relocates all energized plant to the front lot, enabling standard maintenance practices, sectionalization, and rapid restoration. This course of action eliminates exposure of energized assets to private recreational spaces and removes the root causes of prolonged restoration following faults or storms. Prior to 2022, a limited "partial relocation" approach (moving only primary circuits) was occasionally used; however, that practice has been discontinued due to an unacceptable residual safety risk from leaving secondary/service conductors in the rear lot.

The rear lot conversion course of action best addresses the drivers of functional obsolescence, safety, and reliability. It provides enduring risk reduction and aligns with customer feedback, prioritizing reductions in outage duration during extreme weather. Increased Vegetation Management and Targeted Spot Replacement remain supporting tools for pacing and risk management but do not close the fundamental gap caused by rear lot topology.

3.4.4 Options to Proceed

Once setting the course of action to address the risks associated with rear lot infrastructure, Alectra Utilities has considered whether the utility would take the Status Quo approach with no proactive remediation, or the utility would remediate the rear lot infrastructure by converting the feeders to the front lot:

I. Option 1: Status Quo / Do Nothing / Run to Failure
II. Option 2: Rear Lot Conversion

After evaluating each option, Alectra Utilities proposes funding investments as selected by portfolio optimization using Copperleaf C55 as detailed in *Chapter 5.3.1 Planning Process* and supported through customer engagement. No pacing alternatives were provided, though the optimization of the budget investments was allocated within the 2027-2031 period based on the value they provide to customers. Additionally, the proposed investments were included in customer engagement, where Overhead Renewal, in particular, received significant endorsement.

The "do-nothing" or status quo approach is not a reasonable option because Alectra Utilities can not continuously defer investment in these smaller sub-categories relative to the benefits they provide customers in terms of reliability, safety, storm resilience, and compliance.

3.5 Investment Timing & Pacing

Table B14 - 8 provides the year-over-year breakdown of investments, including the historical period from 2020 to 2024, the bridge years from 2025 to 2026, and the DSP period from 2027 to 2031.

Table B14 - 8 Historical & Proposed Investment Spending

	Historical Spending					Bridge		Forecast Spending				
Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Rear Lot Conversions	2.4	0.1	1.0	0.1	0.1	0.7	0.0	0.0	0.0	20.3	32.7	33.6

The spending profile ramps over the 2027-2031 period, with significant delivery beginning in 2029 as customer engagement, municipal permitting, and resource capacity are sequenced to support execution.

Rear lot conversions over the 2020-2024 period totaled $3.7MM, primarily driven by investment in 2020 for two projects. Funding for rear lot conversions was reduced in comparison to cable renewal investments primarily due to the high dollar to lower customer impact. Over this same period the safety risk was also reevaluated and hence a push for a multi-year investment in rear lot conversions.

Bridge years' investment is centered on a project in Brampton, for $0.7MM in 2025.

Rear lot conversion will need to ramp up significantly over the 2027-2031 period as Alectra Utilities returns to addressing rear lot assets in the system. The significant capital requirements needed for rear lot conversions have been scheduled to start in 2029 to allow for customer engagement, municipal permitting and resource capacity optimization.

There are 15 projects from across the different areas of Alectra Utilities' service territory that contribute to the spending need over the forecast period.

- Rear Lot Renewal Project - Royal Orchard - North, Markham

- Rear Lot Renewal Project - Main Street / Unionville / Carlton, Markham
- Rear Lot Renewal Project - Marsdale Dr, St. Catharines
- Rear Lot Renewal Project - Royal Orchard - South, Markham
- Rear Lot Renewal Project - Bluebird
- Rear Lot Renewal Project - Riverview Blvd and Northcliffe
- Rear Lot Renewal Project - Strathcona Dr
- Rear Lot Renewal Project - Richelieu Dr and Trelawne Dr, St. Catharines
- Rear Lot Renewal - (199) - Douglas St, Guelph
- Rear Lot Renewal - (HAM) - St. Andrew's Drive
- Rear Lot Renewal Project - Steeles and Henderson, Markham
- Rear Lot and Voltage Conversion - Dickson Park Crescent, Mississauga
- Rear Lot Renewal Project - Bayview and Steeles, Markham
- Rear Lot Renewal Project - Aurora Heights, Aurora
- Rear Lot Renewal Project - Highway 7/ McCown (SE) - Markham

Rear lot conversion projects are engineered and delivered using a phased, feeder-based approach. Projects proceed in sequenced phases sized to the neighbourhood, balancing customer impact, municipal coordination, and construction efficiency, and to bring early reliability and safety benefits to the first cohorts while downstream phases proceed through design, engagement, and civil works. Civil construction (e.g. conduits, chambers, service laterals) is scheduled first and generally constitutes the larger share of cost; electrical installation and customer cut-overs follow. This staging manages risk and maintains service continuity.

Annual selections are driven by Alectra Utilities' capital planning process as detailed in *Chapter 5.3.1 Asset Management Process Overview*, based on multi-variable optimization that considers factors such as asset condition, reliability performance, resiliency, safety exposure, and others.

Because work occurs adjacent to private property, projects require early notifications, easement validations, and frequent coordination with homeowners to arrange access and schedule service cut-overs. Where customer meters are relocated, work is sequenced to minimize disruption and completed to current standards. The program maintains a dedicated outreach stream to manage inquiries, arrange site meetings, and coordinate restoration of landscaping and hardscapes.

Designs employ standardized pad-mounted, switchable transformers and sectionalizing cabinets to enhance isolation and shorten restoration times. Primary cable is installed in duct with adequate spare capacity for future sectionalizing points and automation. Obsolete materials (e.g. porcelain insulators and undersized #4 / #6 conductors) are eliminated. Standardization supports parts availability and simplifies operations.

IV Grid Modernization

4.1 Overview

Alectra Utilities' Grid Modernization segment builds the data, analytics, control, and work-execution foundations needed to improve operational efficiency, enable flexible customer connections, and support a more automated and electrified grid with increasing DER uptake.

These investments align with various policy instruments including the OEB's Benefit-Cost Analysis (BCA) Framework[84], Non-Wires Alternatives (NWA) Handbook, Non-Wires Solutions Guidelines[85], the Distributed Energy Resources Connection Procedures (DERCP)[86]/Electric Vehicle Charging Connection Procedures (EVCP) procedures[87]. They also advance priorities set out in the Pathways to Decarbonization (2022)[88], the Electrification and Energy Transition Panel Report (2023)[89], and the IESO's DER Roadmap[90] and Market Vision and Design Project[91], which mandate greater DER participation in Ontario's IESO wholesale market.

The segment is delivered as a coordinated portfolio of five projects. Hence, each capability lands on standardized data, integrates once, and produces reliability, safety, efficiency, and customer outcomes under the Enabling Resiliency and Modernization Program. The projects include those summarized below:

[84] Benefit-Cost Analysis Framework for Addressing Electricity System Needs – May 2024 – https://oeb.ca/sites/default/files/uploads/documents/regulatorycodes/2024-05/OEB_BCA_Framework_FINAL-AODA.pdf
[85] Non-Wires Solutions Guidelines for Electricity Distributors (formerly CDM Guidelines for Electricity Distributors) – March 2024 – https://oeb.ca/sites/default/files/uploads/documents/regulatorycodes/2024-04/OEB_2024%20NWS%20Guidelines_20240328.pdf
[86] Distributed Energy Resources Connection Procedures (DERCP) – March 2022 – https://www.oeb.ca/sites/default/files/DER-Connection-Procedures-DERCP-20220914.pdf
[87] Electric Vehicle Charging Connection Procedures – February 2024 – https://www.oeb.ca/sites/default/files/Electric%20Vehicle%20Charging%20Connection%20Procedures%20%28EVCCP%29_20240216.pdf
[88] IESO's Pathways to Decarbonization Report – 2022 – https://www.ieso.ca/-/media/Files/IESO/Document-Library/gas-phase-out/Pathways-to-Decarbonization.pdf
[89] Report of the electrification and energy transition panel – December 2023 – https://www.ontario.ca/files/2024-02/energy-eetp-ontarios-clean-energy-opportunity-en-2024-02-02.pdf
90 IESO's DER Roadmap – July 2024 – https://www.ieso.ca/Get-Involved/Innovation/Distributed-Energy-Resources/DER-Roadmap
[91] "Distributed Energy Resources (DER) – Market Vision and Design Project", Pages 24, 25, 32, 35, 36, 37, 39, 40, 41 – January 2023 – https://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/dermvdp/dermvdp-20230125-presentation.pdf

- **Advanced Distribution Management System (ADMS):** This investment provides a single integrated platform for Control Rooms functions to execute safe switching, automated restoration, and voltage optimization against live topology
- **Integrated Network Model (INM):** This investment provides a single, unified "source of truth" of data used for planning and operation, which enhances advanced grid analytics and operational efficiency.
- **DER Wholesale Market Preparedness (DWMP):** This investment enables DER registration, telemetry aggregation, evaluation of the distribution system's ability to accommodate bids within IESO market timeframes, dispatch execution, and settlement data exchange, functions that scale in step with IESO market timelines to ensure reliable DER participation in the wholesale market
- **Enterprise Asset Management (EAM):** This investment links condition and performance to risk-based plans, supports efficient scheduling and execution through Workforce Management, and optimizes maintenance effort to reduce repeat outages, extend asset life, and lower long-term costs for customers.

Alectra Utilities plans to deliver this Program in a sequence designed to avoid stranded functionality and to match system readiness. INM is implemented first to reconcile, cleanse, and harmonize data from various disparate operational and planning systems, including asset demographics and network connectivity (Geographical Information System - GIS), system loading (Data Historian), planning data (CYME network models and forecast data), system metering (CMDE), reliability, outage, and asset inspection data (OMS/GIS), Customer Information System (CIS) and Enterprise Resource Planning (ERP) records, and customer connection data (CXP). INM merges this data into a unified data model and acts as the system of record for subsequent platforms and operational systems, ensuring consistency, accuracy, and scalability across planning, operations, and market functions. PTA leverages the unified data model to conduct unbalanced three-phase time-series analyses, probabilistic hosting capacity assessments, non-wires screening, and automated interconnection assessments. ADMS then modernizes the control room by consolidating SCADA/OMS/DMS/Advanced Capabilities and Distributed Energy Resource Management Systems (DERMS) functions. During the 2027-2031 period, the focus is on establishing the new SCADA core and prioritizing integrations, with OMS modernization scheduled for later. DWMP establishes minimum viable capabilities in system analysis, telemetry,

registration, and dispatch exchange so that DER participation can scale prudently in step with IESO wholesale market timelines. EAM optimizes asset lifecycle and work management, linking condition and performance to risk-based plans and streamlining field execution.

The Grid Modernization segment directly supports the other segments. It makes SCADA, Automation and System Control investments ADMS-ready. It enables targeted rebuilds under Rear Lot Conversions to operate on standardized, front lot designs that can be sectionalized. It improves customer experience by providing the data required for accurate outage communications and by accelerating interconnection decisions through automated studies.

Grid Modernization will deliver tangible outcomes. It will improve reliability through model-driven switching, distribution automation readiness, selective protection, and faster fault localization. It will further strengthen safety by building on existing work protection procedures with enhanced interlocks and accurate topology. It will raise efficiency by standardizing studies, automating assessments, and digitizing work management, allowing cycle times to decrease and throughput to grow without requiring proportional staffing. It will improve customer value through quicker restorations, clearer outage information, and timely, consistent interconnection decisions. It will also preserve vendor optionality through standards-based interfaces, and its singular, governed data model will allow planning and operations systems to draw on the same trusted source, so benefits allowing cycle times to decrease and throughput to grow allowing benefits across planning, operations, and asset management.

4.2 Investment Description

Alectra Utilities' Grid Modernization Segment outlines the core platforms needed to plan and operate a more automated, data-driven grid, while aligning with the Program's focus on resiliency, reliability, operational efficiency, and customer value. As described above, the segment comprises five coordinated projects that collectively provide the data, analytics, and controls necessary for planning and operating the system, while also ensuring compliance with external regulatory and policy drivers:

i. **ADMS** modernizes and extends control-room capabilities by consolidating SCADA, OMS, DMS, and DERMS/Advanced Capabilities functions. Within the 2027-2031 period, the focus is on establishing the new SCADA core, common network, and asset models, as well as prioritizing integrations needed for reliable

real-time control. By 2028 Alectra Utilities will conduct vendor selection and mobilize the first ADMS workstream, followed by capital investments of $0.7MM in 2029, $5.3MM in 2030, and $7.3MM in 2031 for SCADA deployment and to commence OMS implementation planning. OMS modernization proceeds as a later phase beyond 2031, while the OMS bridge remains in place during the DSP period to support outage management and switching until the unified platform is commissioned as described in *Appendix B09 - Information Technology Systems*.

ii. **INM** establishes the single, governed asset and network connectivity model that other Grid Modernization projects consume. The platform is aligned with the Common Information Model (CIM). It reconciles topology and attributes from core systems of record, including asset demographics and network connectivity (GIS), system loading (Data Historian), system metering (CMDE), reliability, outage, and asset inspection data (OMS/GIS), CIS and ERP records, planning data, and customer connection data (CXP) for consuming systems. INM is implemented first, ensuring there is a single authoritative data model that downstream systems can trust and integrate with. This lowers integration cost, reduces duplication of data handling, and mitigates operational risk when ADMS, PTA, DWMP, and EAM are introduced. In the bridge years, INM establishes the canonical model, ingests data from critical systems of record, and implements automated data-quality rules for topology, phasing, and attribute completeness. During the plan period, ingestion extends across remaining assets and INM provides relevant data to (i) ADMS required for system management and operations, to (ii) PTA for unbalanced time-series studies and standardized hosting capacity, to (iii) DWMP for real time grid evaluation (in market timeframes) as well as DER registration and telemetry alignment, and to (iv) EAM for asset life-cycle management and planning. In the bridge years, Alectra Utilities plans platform stand-up and initial onboarding for INM with $1.2MM in 2025 and $1.4MM in 2026. From 2027 to 2031, with a total of $6.0MM in capital expenditures, the project continues to systematize data ingestion, refine data quality processes, and publish CIM-compliant data profiles, delivering an authoritative, consolidated network model early and reusing it across other systems.

iii. **PTA** delivers advanced planning analytics and workflow automation. Capabilities include unbalanced three-phase time-series analysis, flexible hosting capacity, automated interconnection assessment, and consideration for non-wires solutions. These tools standardize and accelerate planning studies, increasing the transparency of evidence used to support capital and NWS analysis. PTA also automates technical steps in the connection process, allowing the utility to manage rising DER volumes and connection requests without degrading service levels. Further, PTA ensures compliance with recent OEB requirements, including the Distribution System Code, Non-Wires Solutions Guidelines, Filing Guidelines for Third-Party DERs, the Benefit-Cost Analysis Framework, and the DER Connection Procedures, while streamlining CIA reviews so engineers can manage rising DER applications without degrading service levels. [92] The planned 2027-2031 investment of approximately $6.3MM enables these functions and improves responsiveness in planning and interconnection.

iv. **DWMP** prepares Alectra Utilities to meet provincial expectations for DER participation in the IESO wholesale markets by establishing minimum viable capabilities for transmission and distribution coordination. The project includes real-time system assessment, DER registration, telemetry aggregation, integration, dispatch orchestration, and secure exchange with the market operator. Integration with SCADA and INM ensures that dispatch respects system limits and live topology, allowing operators to work from a governed view of the network state. In the bridge years, Alectra Utilities plans $1.2MM in 2025 and $2.3MM in 2026 to stand up DWMP core capabilities. During 2027-2028, Alectra Utilities plans a combined $1.6MM to complete implementation and integration so DWMP is in

[92] Distribution System Code (DSC) – May 2024 - https://www.oeb.ca/regulatory-rules-and-documents/rules-codes-and-requirements/distribution-system-code-dsc
Filing Guidelines for Incentives for Electricity Distributors to Use Third-Party DERs as Non-Wires Alternatives – March 2023 - https://www.oeb.ca/regulatory-rules-and-documents/rules-codes-and-requirements/filing-guidelines-third-party-ders
Non-Wires Solutions Guidelines for Electricity Distributors (formerly CDM Guidelines for Electricity Distributors) – March 2024 - https://www.oeb.ca/regulatory-rules-and-documents/rules-codes-and-requirements/nws-guidelines-electricity
Benefit-Cost Analysis Framework for Addressing Electricity System Needs – September 2023 - https://www.oeb.ca/consultations-and-projects/policy-initiatives-and-consultations/benefit-cost-analysis-framework
Distributed Energy Resources Connection Procedures (DERCP) – March 2022 - https://www.oeb.ca/sites/default/files/DER-Connection-Procedures-DERCP-20220914.pdf

service by 2028, with no additional capital in 2029-2030, and a planned $0.4MM upgrade in 2031 to align with ADMS release sequencing and market changes.

v. **EAM** implements a single platform for asset lifecycle and work management. It standardizes asset registers and hierarchies, links condition and performance to risk-based plans, and digitizes field execution from planning to close-out. This enhances data quality, reduces the total cost of ownership of assets, and improves planning and execution efficiency. A centralized, integrated asset management platform is needed to govern data quality, support inspections and defect elimination, and streamline compliance reporting. Alectra Utilities plans preparatory design and readiness activities in 2027 and full implementation in 2028-2031 for a total of $12.3MM over the DSP period.

The Grid Modernization plan is sequenced to match system readiness and to avoid stranded functionality. Early-period work advances INM data governance, implements PTA workflows, and mobilizes EAM. ADMS and DWMP are staged to align with field automation density, telecommunications capacity, and market milestones. Across the 2027-2031 period, the segment totals $41.1MM in capital, reflecting ADMS at $13.3MM, INM at $6.0MM, PTA at $6.3MM, DWMP at $2.0MM, and EAM at $12.3MM. This mix aligns with dependencies and pacing and supports measurable reliability, safety, and customer outcomes under the Enabling Resiliency and Modernization Program.

Table B14 - 9 shows the investment detail for Grid Modernization Program.

Table B14 - 9 Grid Modernization Investment Summaries

	Bridge		Forecast Spending				
Year	2025	2026	2027	2028	2029	2030	2031
ADMS	0.0	0.0	0.0	0.0	0.7	5.3	7.3
INM	1.2	1.4	1.1	1.2	1.6	1.4	0.7
PTA	0.0	0.0	0.0	0.1	2.0	3.4	0.8
DWMP	1.2	2.3	0.9	0.7	0.0	0.0	0.4
EAM	0.0	0.0	0.2	2.7	3.0	3.1	3.3
Others	0.0	0.2	0.3	0.6	0.2	0.0	0.1
Total ($MM)	**2.4**	**3.9**	**2.5**	**5.3**	**7.5**	**13.2**	**12.6**

Table B14 - 10 summarizes the outcomes and benefits of the Grid Modernization Segment.

Table B14 - 10 Summary of Grid Modernization Investment Outcomes and Benefits

Outcome	Investment Benefits and Objectives
Customer Value	• Faster, more accurate outage information and restoration through ADMS. • Transparent, standardized planning studies and streamlined DER connections through PTA. • Improved responsiveness and field execution using EAM work management. • Facilitation of participation of DER Assets in Wholesale Markets via DWMP.
Reliability	• Automated workflows in PTA and EAM reduce manual effort and rework. • A standards-based integration approach preserves vendor optionality and lowers long-term integration cost. • Portfolio design drives cumulative benefits across planning and operations.
Safety	• Automated workflows in PTA and EAM reduce manual effort and rework. • A standards-based integration approach preserves vendor optionality and lowers long-term integration cost. • Portfolio design drives cumulative benefits across planning and operations.
Efficiency	• INM will reduce manual data management tasks and provide operational efficiencies. • Automated workflows in PTA and EAM reduce manual effort and rework. • A standards-based integration approach preserves vendor optionality and lowers long-term integration cost. • Portfolio design drives cumulative benefits across planning and operations.

4.3 Investment Drivers & Needs

Without Grid Modernization, Alectra Utilities would be constrained by aging, fragmented SCADA and OMS platforms that cannot keep pace with electrification, DER growth, and climate risks. The result would be slower and less safe restoration, backlogs of interconnection requests, higher lifecycle costs from manual rework, greater cybersecurity and compliance exposure, and limited ability to plan or deploy non-wires solutions. By contrast, the proposed portfolio (INM, PTA, ADMS, DWMP, and EAM) delivers capabilities the status quo cannot: a single governed network model, automated switching and faster restoration, probabilistic planning and automated interconnection assessment, scalable DER coordination and market readiness, and asset

lifecycle management that sustains reliability and efficiency without disproportionate substantial labour resources.

The current environment relies on legacy SCADA and OMS, which serve as separate sources of network truth, as well as manual planning and asset workflows. These conditions create risk to switching safety and restoration, extend study and interconnection cycle times, and increase lifecycle cost. Platform obsolescence and support timelines must be addressed before capability erodes. Functional obsolescence limits the ability to automate, analyze, and coordinate feeders across districts.

The Grid Modernization Program also responds to the need to enhance reliability and resilience through the increased deployment of Distribution Automation (DA)-enabled switches, which communicate providing consistent services when addressing emerging market and regulatory requirements, including transparent planning, non-wires solution screening and planning and integration, and Transmission-Distribution (T-D) coordination, to improve reliability and resilience with higher penetration of DA-enabled switches, communicating Fault Circuit Indicators (FCIs) and field sensors. There is a need to maintain a safe, reliable grid with acceptable power quality when accommodating rising electrification, DERs that introduce time-varying and bi-directional power flows, utilizing non-wired solutions, and implementing flexible connections for DERs (as mandated by the OEB). Alectra Utilities will need to continue to provide consistent services when addressing emerging market and regulatory requirements for transparent planning and non-wires solution considerations and integration, and T-D coordination to enable DER participation in the IESO Wholesale market.

The rest of the section describes the drivers for Grid Modernization investments.

4.3.1 SCADA and OMS obsolescence

Alectra Utilities needs to modernize its control-room platforms to sustain safe operations and deliver reliable service through the 2027-2031 period. The company currently uses Survalent SCADA with outdated hardware across the service territory and several legacy OMS instances that are already more than 9 years in service and require upgrades to maintain functionality and security. By the time the ADMS project replaces OMS, the current systems will be 19 years old. The lack of a unified platform creates operational complexity and drives up the cost and risk of

integrating any new capability. These issues will become more acute as electrification and DER penetration increase the variability and complexity of distribution operations.

The current mix of systems is increasingly difficult to keep up to date. Outdated or unsupported components create a direct operational risk. Each integration requires bespoke work across several solutions rather than a single, governed interface. This fragmentation limits the pace at which Alectra Utilities can introduce automation and analytics in day-to-day operations and during storms.

ADMS consolidates SCADA, OMS, DMS, and DERMS/Advanced Capabilities under a single architecture, allowing operators to work from a unified view of the network state with model-driven switching, restoration, and analytics. The core functions Alectra Utilities aims to deploy are network visualization and alarm processing; outage analysis and management with mobile support; state estimation, Fault Location, Isolation and Service Restoration (FLISR), optimal power flow and voltage optimization; and DER program and dispatch capabilities. These functions are required to manage a more dynamic grid, operationalize non-wires resources, and reduce outage duration through faster, safer switching.

Alectra Utilities plans to deploy the new ADMS system using a phased approach that begins with SCADA in the 2027-2031 period, then beyond 2031 proceeds to OMS, DMS and finally DERMS/Advanced Capabilities. The risk of component obsolescence and security exposure rises if Alectra Utilities remains on aging SCADA and OMS technologies. A phased ADMS program mitigates that risk by replacing the base control layer first and then retiring the OMS and DMS silos as the unified platform comes online.

Data governance is a prerequisite because ADMS relies on a single, accurate network model to enable safe model-driven switching and advanced automation. INM provides this governed, reconciled source of truth, enabling ADMS functions to scale reliably and at lower risk. In contrast, without it, the cost of integration and data clean-up increases, and some functionality becomes ineffective. The Integrated Network Model is implemented ahead of ADMS. Hence, there is one authoritative, CIM-aligned model that reconciles asset demographics and network connectivity (GIS), system loading (Data Historian), system metering (CMDE), reliability, outage, and asset inspection data (OMS), CIS and ERP records, and customer connection data (CXP). This lowers integration cost and reduces operational risk when ADMS and related applications are introduced.

During the transition, Alectra Utilities will maintain current systems in a safe and supportable state while ADMS is procured and implemented. These maintenance activities continue in parallel and are addressed in *Appendix B09 - Information Technology Systems*, however, they do not eliminate the underlying need for platform renewal.

In summary, Alectra Utilities' ADMS plan will replace an aging, fragmented SCADA/OMS environment with a unified, model-driven platform; equip the control room with FLISR, optimal power flow and voltage optimization so restoration is faster, and switching is safer; operationalize DER coordination and market participation; and reduce lifecycle cost and cyber risk by converging to a single, supported architecture.

The phased approach, with SCADA first, followed by OMS, DMS, and DERMS/Advanced Capabilities, aligns with dependencies on INM and the maturity of field automation and communications. This approach ensures that new capabilities are introduced on a governed data foundation and can scale across the service territory.

4.3.2 Reliability and Resilience

Keeping the lights on and restoring service quickly can become increasingly challenging as the grid becomes more complex and weather-related risks increase. Rising DER penetration introduces bi-directional and time-varying flows that make fault location, isolation, and reconfiguration more challenging. Major events are more frequent and more severe as concluded by *Appendix G - Climate Risk and Vulnerability Assessment*, so restoration must be faster, safer and more repeatable.

Alectra Utilities' distribution system relies on aging SCADA and legacy OMS that are harder to keep within support windows and are not designed for model-driven operations. Failure or loss of support in these platforms would impair situational awareness, delay switching, and increase the risk of operating error. The ADMS program addresses this by giving operators a single operational picture and by using model-driven switching and automated fault location, isolation, and service restoration on prioritized feeders. Integration with the Integrated Network Model ensures the live operating model reflects as-built topology and device settings. Volt-Var Optimization improves voltage performance where feasible and supports power quality during restoration. Together, these capabilities shorten the path from fault to restoration during day-to-

day outages and during storms, protect operator safety through enforced interlocks and work protection, and deliver measurable reductions in interruption frequency and duration.

4.3.3 Electrification and Time-varying Constraints

The electrification of transportation and heating, combined with the increasing adoption of DERs, creates load shapes that vary by time of day and season, shifting with customer behavior. Deterministic, worst-case studies no longer isolate true constraints or reveal where non-wires solutions are practical. Planning will require a probabilistic forecast of load growth at the feeder and station level and three-phase, time-series analysis that reflects DER operating characteristics and coincidence.

The investments in this program respond to these planning requirements related to electrification. PTA delivers these capabilities and adds dynamic hosting capacity capabilities, automated interconnection assessment, and scenario tools that define, evaluate, and optimize different non-wires solutions to determine their economic and technical suitability, comparing them against traditional solutions. INM supplies the reconciled network model, ensuring results are accurate and repeatable. ADMS then operationalizes the limits and recommended envelopes, ensuring that day-to-day operations respect what planning has established. The result is faster and more consistent interconnection decisions, capital that is right-sized and timed to actual need, and credible pathways to defer traditional upgrades with non-wires options where they provide better value.

4.3.4 DER Integration and Bi-Directional Power Flow

As an increasing variety of DERs are connected to a distribution system, enhanced monitoring, control, and network modeling are required. DER adoption is increasing and now includes behind-the-meter solar and storage, controllable loads, community assets, and aggregated portfolios. DERs can relieve constraints and improve resilience, but without accurate visibility and coordination, they can also create back feed, voltage excursions, or thermal overloads. Dynamic hosting capacity, interconnection study throughput, and operational coordination are core needs.

PTA enables dynamic hosting capacity analysis and automates interconnection assessments, ensuring timely and transparent decision-making. INM ensures studies use consolidated network models from the same source. In operations, ADMS provides visibility to DER impacts on voltage

and loading and enforces operating limits. DWMP prepares the utility to model the ability of the distribution system in real time to accommodate DER participation in the market (in market timeframes), exchange telemetry and dispatch instructions with the IESO as a market operator and aggregators. This allows DER flexibility to be coordinated prudently and safely, where products and rules permit, and sets the foundation for non-wires portfolios where they are economically and reliably feasible.

Alectra Utilities must also account for the scale of potential DER growth. The IESO-commissioned DER Potential Study[93] indicates several gigawatts of provincial distribution-side potential by 2032 across scenarios. Based on size and customer base, Alectra Utilities estimates that 15 to 25 percent of provincial potential could be located within its service territory over time. Alectra Utilities currently has 6,340 DERs and approximately 343MW connected as of 2023. For near-term planning, the utility estimates a potential realization of approximately 120 to 130MW of new participating DERs in the system within the 2027 to 2031 horizon. This reinforces the need for standardized, scalable tools and governed data.

4.3.5 Market Readiness and T-D coordination

Provincial expectations are that DERs participate in the IESO wholesale markets with appropriate T-D coordination, telemetry, registration, aggregation, and dispatch orchestration. Distribution operators must ensure that market actions respect distribution-level constraints and safety requirements. Manual exchanges and ad hoc processes are unsustainable at scale and fail to meet audit requirements.

The IESO's Market Rules and operating procedures obligate distributors, including Alectra Utilities, to promptly comply with evolving requirements for the IESO-controlled grid and wholesale market. Through its DER Market Vision and Design Project and DER Roadmap, the IESO has set a 2027/28 target for T-D coordination protocols that enable DER participation in the wholesale market. These initiatives[94] require LDCs to provide accurate digital network models, load and

[93] Distributed Energy Resources (DER) Potential Study – January 2024 - https://www.ieso.ca/Sector-Participants/Engagement-Initiatives/Engagements/DER-Potential-Study

[94] List of rules, procedures, protocols and initiatives is the following:

- https://www.ieso.ca/-/media/Files/IESO/Document-Library/Market-Rules-and-Manuals-Library/market-manuals/system-operations/so-SystemsOperations.pdf

DER forecasts, real-time power flow visibility, telemetry aggregation, and coordination platforms with the IESO and DER aggregators.

DWMP establishes a minimum viable set of capabilities that mature alongside market timelines. It delivers a DER registry, telemetry integration, dispatch exchange patterns, and operating playbooks. This prepares the utility to model the ability of the distribution system in real time to accommodate DER participation in the market (in market timeframes) for coordination with the IESO. INM provides the topology context to determine operating limits, and ADMS records switching states, enforcing those limits. This alignment keeps market participation grounded in accurate models and operating procedures and creates a path to scale as volumes increase.

4.3.6 Foundational Data Quality and Model Governance

Planning, operations, and asset management require a single, digitized, accurate, and timely representation of the network and its assets. This requires organizing data from across the enterprise into a governed, reusable digital model that brings planning, operations, and asset information together. While current manual processes are adequate today, rising volumes and complexity will demand more analysis, more automation, and faster cycle times. This unified model enhances analysis speed, enables model-driven automation, and minimizes manual reconciliation and rework. It improves operational efficiency by allowing programs to integrate

- IESO's DER Roadmap – July 2024 – https://www.ieso.ca/Get-Involved/Innovation/Distributed-Energy-Resources/DER-Roadmap
- "Distributed Energy Resources (DER) – Market Vision and Design Project", Pages 24, 25, 32, 35, 36, 37, 39, 40, 41 – January 2023 – https://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/dermvdp/dermvdp-20230125-presentation.pdf
- https://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/tdwg/tdwg-20240328-presentation.pdf
- "TDWG Meeting #8 Introduction" Presentation by IESO – https://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/tdwg/tdwg-20231027-introduction-and-feedback-summary.pdf
- https://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/tdwg/tdwg-20231027-sow-a-coordination-protocols-oct-27.pdf
- https://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/tdwg/tdwg-20231027-sow-b1-functional-assessment-oct-20.pdf
- https://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/tdwg/tdwg-20231027-sow-b2-communication-assessment-oct-20.pdf
- https://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/tdwg/tdwg-20231027-sow-b3-shared-platform-oct-27.pdf
- https://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/tdwg/tdwg-20231027-sow-b4-architectural-assessment-oct-27.pdf
- "OEB-IESO OEB-IESO Joint Study of Distributed Energy Resources (DER) Incentives" – Fall 2024 – https://www.ieso.ca/Sector-Participants/Engagement-Initiatives/Engagements/OEB-IESO-Joint-Study-of-Distributed-Energy-Resources-DER-Incentives (to be updated once report is released)
- IESO's DER Roadmap – July 2024 – https://www.ieso.ca/Get-Involved/Innovation/Distributed-Energy-Resources/DER-Roadmap

once with a single source of truth, rather than building one-off links. It helps teams do more with less by reusing vetted data and analytics across workflows. Most importantly, it shifts us from reactive work on our system to proactive, data-informed decisions and interventions.

Today, persistent challenges, include quality assurance and reconciliation gaps that allow errors to persist (requiring manual reconciliation), limited linkage between data from disparate sources, reliance on manual preparation and drill-down investigations, limited traceability or auditing of data, and minimal visualization or analytics capabilities. Each system maintains a view, and updates from design or field execution propagate with latency. These issues drive additional work and studies, and constrain automation because the absence of a consistent, reusable digital view of the system. INM resolves this by delivering a canonical, CIM-aligned network and asset model with automated data-quality rules, reconciliation processes, traceability, and stewardship workflows. It becomes the authoritative source for ADMS, PTA, DWMP, and EAM, so each program integrates once with INM rather than building custom links to multiple sources.

INM also enables compliance with emerging planning and market expectations by providing scalable, canonical data for studies, reporting, and real-time operations, thereby facilitating the faster enablement of DERs and non-wires alternatives. It centralizes a reconciled and time-versioned model that supports repeatable analyses and timely, evidence-based decisions. It provides standardized inputs, transparent assumptions, and rerunnable results for benefit-cost analyses. It enables consistent screening and verification for third-party non-wires services. It supports systematic screening of qualifying investments with a defensible rationale. It provides time-versioned models, data lineage, and standardized artefacts that make filings repeatable and defensible. It also exports CIM-compatible datasets for regional planning, ensuring that inputs remain synchronized across utilities and over time.

4.3.7 Operational Efficiency and Workforce Enablement

Alectra Utilities requires a single platform to manage asset data and work at scale. Today, there is no EAM. The current mix of systems (e.g. station assets are managed in Cascade as a CMMS, while distribution relies on a Structured Query Language (SQL) database and Alteryx workflows) has been effective in meeting needs, but they are inherently fragmented and require reconciliation across systems. EAM addresses this by establishing a governed asset registry with a cradle-to-grave approach, standardized hierarchies and attributes, and linked work histories and costs.

Core capabilities include lifecycle and reliability modelling, asset condition assessment, inspections and maintenance planning, and compliance tracking.

Alectra Utilities' current operational platforms are fragmented, with aging SCADA and OMS systems, duplicate data entry, and limited integration across tools. These conditions create avoidable effort to maintain data quality, slow the preparation of switching orders, studies, and interconnection assessments. During storm events, skilled staff are diverted to manual reconciliation rather than higher-value analysis. Customer-facing workflows also involve multiple handoffs, which will not scale with rising DER requests without adding staff.

Grid Modernization investments in INM, ADMS, PTA, and DWMP address these operational challenges by standardizing models and workflows, automating technical assessments and study production, and digitizing work from planning to field execution. Interconnection screening is automated under governed rules, ensuring timely and consistent decisions. Hosting-capacity analysis and real-time system evaluation enable DER penetration and keep the grid under control.

The outcome is shorter cycle time from need identification to executed work, lower duration of work execution and rework, and a planning and operations workforce that can meet rising demand without a proportional increase in labour resources. In combination, the Grid Modernization projects allow throughput to increase. They are expected to result in 20-50% efficiency gains in key engineering tasks across engineering and control room operations, as well as a more targeted deployment of field journeypersons.

4.3.8 Safety, Compliance, and Auditability

Extreme weather is becoming more frequent, and the grid is becoming increasingly complex, with bi-directional flows and rapidly changing operating states. Outdated OMS and SCADA systems make it harder to view the system at scale, assess risk quickly, and direct safe and effective restoration. Limited situational awareness and fragmented models increase the chance of switching error, extend outage windows, and raise the risk to field crews and the public. Potential errors rise with higher proliferation of the DERs in the system. If dispatch or switching decisions are made on an inaccurate view of the network, a control action could energize into an open point or overload equipment, with the potential for serious injury or death.

Compliance expectations also continue to increase. The utility must demonstrate conformance with ESA audits, maintain complete and timely records of switching and work protection, and meet environmental tracking requirements for SF_6 gas and PCB oils. Alectra Utilities must replace grid control platforms before support and cyber patching lapse, to operate from a single, validated network model that underpins model-driven switching and interlocks, and to maintain configuration control and complete work histories that are traceable from finding to corrective action. These capabilities allow the control room to maintain safe clearances under stress, give field staff accurate instructions backed by current topology, and provide auditable evidence of compliance and environmental stewardship.

4.3.9 Cybersecurity and Vendor Supportability

Critical operational systems must remain within vendor support windows with timely patches, tested upgrades, and appropriate access controls and segmentation. Legacy versions and bespoke integrations increase cyber exposure and complicate incident response. The investments in the Program will allow Alectra Utilities to maintain a modern, supportable platform set and to reduce exposure from custom interfaces and one-off data movements. ADMS modernization and the INM integration layer address this by updating core platforms and shifting integrations to secure, documented interfaces. EAM introduces configuration control and change tracking for assets and systems.

4.3.10 Customer and Stakeholder Expectations

Municipalities, large customers, and DER developers expect timely and transparent information on capacity and interconnection feasibility. Customers expect accurate outage communications and steady improvement in restoration performance. PTA's enabling of NWS planning, dynamic capacity and automated interconnection outputs, ADMS outage analytics, and the governance established through INM and EAM provide consistent, repeatable data for stakeholders. These tools improve engagement quality, reduce back-and-forth on data accuracy, and align expectations on timelines and constraints.

4.3.11 Consequences of Not Proceeding

If Grid Modernization is deferred, the utility will face a rising risk that SCADA and OMS reach end-of-support during the period when ADMS should be implemented. Fragmented models will

continue to limit automation, slow restoration during major events, and constrain DER coordination. Interconnection studies will still be completed; however, additional staff or third parties will need to be retained as volumes increase. Operational risk and cybersecurity risk exposure will increase as legacy platforms age. Lifecycle cost will grow due to manual work and fragmented workflows. The ability to identify and adopt non-wires solutions will be constrained by model fidelity and tool limitations. These outcomes challenge reliability objectives, market readiness, and value for money.

The proposed Grid Modernization projects address these risks in a sequenced manner. INM is established first to create a singular, consolidated, canonical network model. PTA equips planners with the technical capabilities, analytics, and automation needed for NWS, electrification, and DER growth. ADMS introduces the unified control-room foundation with SCADA first and OMS to follow on a planned path. DWMP enables market coordination. EAM digitizes asset and work management, so improvements are sustained, and evidence is transparent. This is a practical and paced response to clear drivers and needs.

4.4 Options Analysis

Alectra Utilities assessed alternatives at the Segment level and for each Grid Modernization project. The analysis weighed customer outcomes, lifecycle cost, delivery risk, and interoperability. Evidence from current sustainment costs, support windows, and delivery capacities informed the recommended path. For example, maintaining the current mix of control-room systems incurs recurring vendor costs each year that do not address functional gaps or mitigate the risk of obsolescence.

4.4.1 Segment-level alternatives

- **Status quo / Managed deterioration**. Defer modernization and maintain legacy systems with minimal upgrades. Near-term capital is lowest, but this does not address reliability, DER coordination, or market readiness. Risks include vendor end-of-support, rising cyber exposure, and increasing operating costs.
- **Minimum-compliance sustainment**. Execute mandatory patches and limited enhancements to satisfy basic compliance. This reduces initial spend, but

preserves silos, constrains automation, and limits non-wires adoption. Customer outcomes and long-term value are inferior.

- **Phased modular modernization (recommended)**. Implement ADMS, INM, PTA, DWMP, and EAM as a coordinated set of projects with staged releases. INM provides the canonical model. ADMS delivers safe switching and restoration. PTA introduces probabilistic planning and automated interconnection assessment. DWMP establishes real-time system assessment for market timeframes, telemetry and dispatch exchange. EAM governs asset and work execution. This approach balances cost, risk, and benefits and preserves vendor optionality through open standards.

4.4.2 Project-specific Alternatives and Rationale

Advanced Distribution Management System (ADMS)

- **Status Quo**. Continue with Survalent SCADA and multiple legacy OMS platforms that are aging and, in several cases, out of support. Sustainment spend persists while unacceptable fragmentation, cyber exposure, and functional gaps remain.
- **Phased ADMS Implementation – 10-year sequence (Recommended)**. Procure ADMS, complete vendor selection and mobilization in 2027-2028, implement the SCADA core in 2029-2031, and begin OMS preparation in 2031, with DMS and DERMS/Advanced Capabilities following on the planned path.
- **Phased ADMS Implementation – 6-7 year sequence.** Procure ADMS, complete vendor selection and mobilization in 2027 and implement core systems after 2031.

Phased ADMS, with 10 years of sequenced implementations and staged releases, places the control-room foundation on a governed INM model, retires OMS silos in sequence without building a new OMS on top of legacy telemetry, enables model-driven switching, FLISR, and voltage optimization when most feeders have sufficient devices in place. This approach reduces rework, aligns landing with field automation and communications readiness, spreads capital over several years to moderate rate impacts, and avoids the integration and cutover risks inherent in accelerated OMS-first schedules. It also acknowledges the need to sustain legacy OMS during the transition while addressing the higher-value operational risks first.

Integrated Network Management

- **Status Quo.** Continue manual blending. Keep separate models in GIS, SCADA, OMS, planning tools, and asset systems, and assemble extracts for each use case. This will be slower, have limited auditability and will not meet planning needs.
- **Build in-house**. Develop and maintain custom modules and rules, requiring dedicated staff and added software costs. This increases lifecycle risk and dependency on bespoke code.
- **Accelerated INM to 2029**. Delivers sooner at a higher cost due to compressed timelines (similar scope to Phased INM to 2031, just implemented at an accelerated rate to be completed by 2029).
- **Phased INM to 2031 (recommended)**. Implement a rules-based, CIM-aligned canonical model with automated QA, reconciliation, and stewardship, timed with dependent projects.

The phased, vendor-based INM is the lowest-risk approach to replacing manual data assembly and supporting ADMS, PTA, DWMP, and EAM with a single source of truth.

Planning Tools and Automation

- **Status quo**. Keep existing point tools and spreadsheets. Work can proceed only with three to five times more effort per technical assessment for Connection Impact Assessments (CIA), load balancing, and capacity upgrades. Backlogs and inconsistency would grow.
- **Stand up two key tools over two years, starting in 2028 (recommended)**. Deploy the distribution planning and forecasting tools, leveraging the data model from INM. This meets throughput needs, supports scaling with existing resources, and enables dynamic hosting capacity and automated interconnection.
- **Stand up the same two tools over four years.** Lower delivery intensity but slower relief of study volumes and interconnection cycle times. Prolongs reliance on manual methods and delays non-wires screening at scale.

- **Build workarounds inside current tools**. Adds scripts and templates to legacy workflows. Limited and temporary gains, higher maintenance effort, and continued dependence on uncontrolled data extracts.

The integrated PTA option over two years is the only viable path to meet throughput and transparency needs identified for coordination and non-wires screening.

DER Wholesale Market Preparedness

- **Status quo**. No operational capability to register, exchange telemetry, or coordinate dispatch with the market operator.
- **Minimum-viable DSO functionality, shorter implementation**. Establish telemetry, power-flow checks within market timeframes, secure protocols with IESO and aggregators, and dispatch or curtailment capability on an accelerated schedule.
- **Minimum-viable DSO functionality, longer implementation (recommended)**. Same functional scope, delivered on a schedule that aligns with INM landing, reducing integration risk and cost. This is identified as the most cost-effective option while meeting coordination requirements.

The longer, sequenced DWMP build delivers required capabilities with lower delivery risk and aligns with dependent platforms.

Enterprise Asset Management

- **Status quo**. Continue with manual, labour-intensive processes using Cascade for stations and SQL/Alteryx for distribution. Meeting workload would require additional labour resources, and productivity gains are foregone.
- **Incremental changes to existing systems**. Add scripts and reporting while tightening business processes and attempting defect-management workflows in-house. Requires enhancements to Cascade, GIS, and other systems, with a heavy reliance on internal resources. Processes remain manual and benefits are limited and not scalable.

- **Enterprise EAM integrated with Workforce Management (recommended)**. Implement a single, governed asset register with standard hierarchies and attributes. Reduce outages and lower long-term costs for customers by transitioning to risk-based plans that support inspections, maintenance, and defect elimination. Improve environmental tracking for SF_6 and PCB assets and strengthen incident and compliance reporting. Integrate with Workforce Management for efficient scheduling and mobile execution, enabling faster repair cycles and fewer repeat outages. Deliver in phases, starting with pilot scope, then rolling out by asset group and region to control risk and build capability.

The integrated EAM option best addresses productivity, evidence quality, and compliance obligations.

The segment-level choice is between deferring modernization, patching the current environment, or delivering a coordinated, phased program. Deferral and minimal sustainment present lower near-term capital requirements but carry increasing risks throughout the period, including vendor end-of-support in the control room, heightened cyber exposure, constrained restoration performance, and limited ability to coordinate DERs or evaluate non-wires solutions. Those paths also preserve manual rework and bespoke integrations, which raise lifecycle cost and push work onto staff rather than into governed systems.

The preferred phased modernization balances cost and risk by sequencing common foundations first, then layering operational and planning capabilities as the system is ready. INM is delivered early, allowing every system to integrate once and leverage a canonical network model. This enables studies and operations to be repeatable and auditable. PTA lands on that model to automate interconnection and dynamic hosting capacity, which improves customer service and supports non-wires screening. ADMS replaces the control-room foundation in stages, so restoration and switching safety improve in step with field automation and communications. DWMP aligns with the IESO market timelines. EAM digitizes asset and work management.

This sequencing moderates rate impacts by spreading capital over several years, reusing the same data and integration services across projects, and avoiding large, simultaneous cutovers. It also reduces delivery risk because each release has a defined scope, a stable test environment, and clear entry criteria for operations. On balance, the preferred option closes the core gaps:

ensuring safe restoration under increasing weather risk, addressing obsolescence in SCADA and OMS, accommodating rising DER volumes that require coordinated planning and operations, and meeting the need for auditable, governed data, while managing costs and preserving optionality.

4.5 Investment Timing & Pacing

Table B14 - 11 provides the year-over-year breakdown of investments, including the historical period from 2020 to 2024, the bridge years 2025 to 2026, and the DSP period from 2027 to 2031.

Table B14 - 11 Historical & Proposed Investment Spending

	Historical Spending					Bridge		Forecast Spending				
Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
ADMS	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.7	5.3	7.3
INM	0.0	0.0	0.0	0.0	0.4	1.2	1.4	1.1	1.2	1.6	1.4	0.7
PTA	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	2.0	3.4	0.8
DWMP	0.0	0.0	0.0	0.0	0.2	1.2	2.3	0.9	0.7	0.0	0.0	0.4
EAM	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	2.7	3.0	3.1	3.3
Others	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.3	0.6	0.2	0.0	0.1
Total ($MM)	**0.0**	**0.0**	**0.0**	**0.0**	**0.7**	**2.4**	**3.9**	**2.5**	**5.3**	**7.5**	**13.2**	**12.6**

The Grid Modernization segment is sequenced to deploy capabilities when the system is ready and to avoid stranded functionality. Across the 2027-2031 period, the segment totals $41.1MM, allocated as follows: ADMS $13.3MM, INM $6.0MM, PTA $6.3MM, DWMP $2.0MM, and EAM $12.3MM. This mix reflects the dependencies among platforms and the pacing needed to deliver measurable reliability, safety, and customer outcomes under the Enabling Resiliency and Modernization Program. Capital expenditures are the following:

- Advanced Distribution Management System:
  - Bridge years (2025-2026). Planning and procurement readiness activities proceed, with no capital in the bridge years.
  - DSP Period (2027-2031). 2027-2028 focus on vendor selection and mobilization. Investments are focused on SCADA deployment with $0.7MM in 2029, $5.3MM in 2030, and $7.3MM in 2031. OMS preparation begins late in 2031 as the unified platform is established.
- Integrated Network Model:

- Bridge years (2025-2026). Platform stand-up and priority ingestion are delivered with $1.2MM in 2025 and $1.4MM in 2026.
- DSP Period (2027-2031). INM extends ingestion and automates data quality and publication of profiles for ADMS, PTA, DWMP, and EAM systems. Planned investments are $1.1MM in 2027, $1.2MM in 2028, $1.6MM in 2029, $1.4MM in 2030, and $0.7MM in 2031.

- Planning Tools and Automation:
  - Bridge years (2025-2026). No material capital expenditures.
  - DSP Period (2027-2031). PTA stands up advanced analyses and automated interconnection workflows. Investment increases as modules go into service. The plan totals $6.3MM across the period, with investment of $0.1MM in 2028, $2.0MM in 2029, $3.4MM in 2030 and $0.8MM in 2031.
- DER Wholesale Market Preparedness:
  - Bridge years (2025-2026). DWMP stands up core capabilities with about $1.2MM in 2025 and $2.3MM in 2026.
  - DSP Period (2027-2031). Integration and market coordination are completed with $0.9MM in 2027 and $0.7MM in 2028. No capital is planned in 2029-2030. A small upgrade of $0.4MM in 2031 aligns with ADMS release sequencing and market changes.
- Enterprise Asset Management:
  - Bridge years (2025-2026). No segment capital is required.
  - DSP Period (2027-2031). EAM mobilizes in 2027 and implements in 2028-2031 for a total of $12.3MM, including $0.2MM in 2027, $2.7MM in 2028, $3.0MM in 2029, $3.1MM in 2030, and $3.3MM in 2031 to complete modules, integrations, and rollout.

Project delivery follows a standard Alectra Utilities project governance model. The implementation approach for all projects is phased, and the plan is designed to manage integration risk while bringing customer-facing benefits forward.

V Customer Service Technologies

5.1 Overview

Alectra Utilities proposes continued investment in Customer Service Technologies to enhance service quality outcomes and accessibility at a reasonable cost over the 2027-2031 period. Within the Enabling Resiliency and Modernization portfolio, this segment advances the utility's digital transformation strategy and delivery of a digital-first, omnichannel service model.

The segment comprises four integrated projects that deliver a unified, digital-first experience and reduce manual intervention in Contact Centre and back-office processes: (i) Customer Portal Enhancements (MyAlectra); (ii) Legacy SilverBlaze (New Connections Portal) replacement; (iii) Customer Care Webchat & Chatbot; and (iv) Collections & Payment Enhancements. These initiatives are scheduled and funded across the Bridge (2025-2026) and DSP (2027-2031) periods, with a clear line of sight to scope and outcomes.

The Customer Portal Enhancements program sustains and extends the MyAlectra Customer Portal following the 2024 base application release, adding features required for regulatory compliance initiatives and to enhance customer choice through improved customer insights and functionality and proactive notifications (e.g. rate plan comparison tools, usage alerts), improving outage communications, and integrating Alectra Utilities' eMobility platform to support electrification-related insights and enquiries. The program is structured as ongoing annual application enhancements after the initial base system implementation to keep pace with OEB compliance changes, customer insights, and data expectations in support of informed customer energy decisions.

The SilverBlaze New Connections Portal replacement mitigates end-of-life system and vendor support risks with the application, while introducing an integrated self-service appointment booking for customers, progress tracking for connection and upgrade requests, and integration to enterprise systems. The solution is expected to streamline workflows, reduce manual handoffs, and enable higher customer request volumes while reducing staffing growth, with an estimated cumulative $4.8MM in operational savings by 2031.

Customer Care Webchat & Chatbot. Over the DSP time horizon, Customer Service will invest $1.7MM in webchat and chatbot solutions as part of its digital customer transformation and

automation strategies to drive operational efficiency. In 2025, chatbots were implemented, improving customer accessibility by providing 24/7 customer support. These chatbots answer customer enquiries across five main customer journeys, triage requests for further follow-up, and provide documented conversation transcripts. Web chat will also be implemented, enabling real-time, personalized assistance from Customer Service Representatives (CSR). By 2027, more Generative AI chatbots will be implemented, enabling greater automation of workflows, increased call deflection, and enhanced customer experience. These tools combined will reduce call wait times and Average Speed of Answer (ASA), reducing operational costs by an estimated cumulative $6.4MM in operational savings by 2031 and freeing CSRs to focus on complex, value-added tasks. The implementation of chat and webchat will also enhance service levels, improve accessibility in accordance with the Accessibility for Ontarians with Disabilities Act (AODA), and enhance customer satisfaction by ensuring a consistent experience across all platforms while allowing customers to engage through their preferred methods.

Collections & Payment Enhancements broaden secure digital payment options and introduce analytics-based segmentation and propensity-to-pay, targeting reductions in arrears, write-offs, and call volumes through automated arrangements within the MyAlectra portal. Planned benefits include measurable write-off reductions and third-party contact centre cost savings from 2029 onward, estimated at $2.26MM by 2031.

Pacing reflects that the heavy build occurred in 2020-2024, with modest spending in the bridge years followed by measured enhancements in the 2027-2031 period, aligned to scoped deliverables and benefits tracking.

In summary, Customer Service Technologies is a focused, integrated program that (i) enhances digital-first customer experience, (ii) sustains compliance and customer choice as rates and programs evolve, and (iii) delivers evidenced OM&A efficiencies, thereby maintaining service quality, accessibility, and customer affordability.

5.2 Investment Description

Alectra Utilities proposes investment in Customer Service Technologies to continue the digital customer experience program initiated in the last plan period and to maintain compliance with service quality requirements while containing operational and maintenance, and administration (OM&A) costs. The scope modernizes high-volume customer journeys, shifts routine transactions

into digital self-serve, and equips staff with integrated tools so complex requests are handled faster and more consistently. These investments are aligned to outage communications, new connections, billing and payments, and contact channels that together handle more than 600,000 calls and 150,000 outage inquiries annually. They also support 1.1 million customers and the full suite of Customer Service functions across a non-contiguous service territory.

The segment comprises four integrated projects that simplify high-volume transactions, enhance outage communications, and redirect routine enquiries from voice to lower-cost digital channels. These projects are:

- Enhancements to MyAlectra portal
- New Connections Customer Portal replacement
- Customer Care Webchat and Chatbot
- Collections and Payment Enhancements

Together, they deliver a unified, self-serve experience and reduce manual handling in the Contact Centre and back office.

Customer Portal Enhancements sustain and extend the MyAlectra platform that went live in 2024. Digital experience enhancements focus on features that reduce avoidable calls and improve customer communications during outages. Planned work includes incorporating landlord and property management profiles into the portal, as well as improving the management of multi-premise accounts. An improved outage map with proactive notifications is also planned, improving customer communications and reducing the number of outage calls from a base of 150,000+ annually. The integration of eMobility content will also enhance functionality for EV customers, allowing them to understand the benefits of EVs, bill impacts, and optimal rate choices, as well as the location of public chargers within Alectra's territory, along with home charging considerations. The aim is to move high-volume, low-complexity interactions to digital self-serve and to support SQRs such as Telephone Service Accessibility and First-Call Resolution.

Services implemented to date with the portal include digital registration up for paperless billing, including ability to view bills online, receive text and email notifications when the bill is ready, ability to set up a digital wallet and make credit card payments via the portal, view billing and payment transaction history, view electricity usage insights, complete routine requests via smart

forms including stop service and request to switch rate plan, or join Equal Payment Plan, as well as allowing eligible customers to set up a payment arrangement. The roadmap for the next several years will enhance smart form functionality, including allowing customers to complete service start online, expanded billing and payment notifications, and usage alerts, such as high-bill notifications. Additionally, it will include improved outage maps and notifications, landlord and property-management profiles for multi-account management, and a mobile app.

The New Connections customer portal replaces an end-of-life, legacy portal (SilverBlaze NCCP). It implements a modern platform with online appointment booking, end-to-end status tracking of requests, guided digital intake, and embedded web chat. The new portal integrates with the incoming field work management solution, customer information system, enterprise resource management, project management, and geographical information system, and provides dashboards and reporting for operational key performance indicators. This project closes vendor support challenges and security gaps, reduces manual handoffs, and improves both the customer journey and staff productivity in the connections process.

Customer Care Webchat and Chatbot - In 2025, chatbots will be implemented, improving customer accessibility by providing 24/7 customer support. These chatbots will answer customer inquiries, including FAQs, triage requests for further follow-up, and provide documented conversation transcripts. Web chat will also be implemented, enabling real-time, personalized assistance from Customer Service Representatives (CSR). By 2027, more Generative AI chatbots will be implemented, enabling greater automation of workflows, increased call deflection, and enhanced customer experience. These tools combined will reduce call wait times and Average Speed of Answer (ASA), reducing operational costs by an estimated cumulative $6.4MM in operational savings by 2031 and freeing CSRs to focus on complex, value-added tasks. The implementation of chat and webchat will also enhance service levels, improve accessibility in accordance with the Accessibility for Ontarians with Disabilities Act (AODA), and enhance customer satisfaction by ensuring a consistent experience across all platforms while allowing customers to engage through their preferred engagement channels.

Collections and Payment Enhancements broaden secure digital payment options to improve customer choice and convenience and enable analytics-based collection segmentation and propensity-to-pay scoring to improve the effectiveness of collections strategies and customer

communications. Eligible customers can now set up their own payment arrangements within the portal. These features reduce arrears-related calls and lower write-offs and bad debt.

These investments align with the Enabling Resiliency and Modernization goals. They improve resiliency by reducing call congestion during storms through proactive, self-serve outage communications and by presenting consistent ETR's as Grid Modernization and ADMS mature. They enhance customer value and choice by providing additional self-serve functions and information on electricity usage, billing, payments, rate options, and ways to reduce costs. These investments improve operational efficiency by reducing manual handling and promoting higher digital adoption.

Capital expenditures for Customer Service Technologies total $11.1MM in 2027-2031 period. Within that total, Customer Portal Enhancements are $8.9MM; the New Connections portal replacement is $0.4MM; Customer Care Webchat & Chatbot is $0.5MM; Collections and Payment Enhancements are $1.3MM.

The summary of the investment is shown in the Table B14 - 12.

Table B14 - 12 Customer Service Technologies Investments

Project Code(s)	Project Name	Bridge Years 2025- 2026	DSP Forecast 2027-2031
152563	2.1.4.1 - Customer Portal Enhancements (SEW Applications)	1.1	8.9
152361	2.1.4.3 - SilverBlaze Replacement (New Connections)	1.7	0.4
153046	2.1.4.4 - Customer Care Webchat & Chatbot	1.2	0.5
153048	2.1.4.5 - Collection & Payment Enhancements	0.0	1.3
	Others	0.1	0.0
	Total ($MM)	**4.1**	**11.1**

Table B14 - 13 summarizes the outcomes and benefits of the Customer Service Technologies investments.

Table B14 - 13 Summary of Customer Service Technologies Investment Outcomes and Benefits

Outcome	Investment Benefits and Objectives
Customer Value	• Customers receive additional billing, payment, rate option and usage insights, proactive notifications, and tools helping customers manage their electricity bills as electrification increases customer adoption of EV's heat pumps and other electric end uses. • These investments will also enhance real-time outage communications, including proactive notifications and improved information on ETR's provides improved account management tools for landlords and property managers makes it easier for these customer segments to manage multiple accounts. • With increased utilization of smart devices, investment in a mobile app increases accessibility of the portal by providing the same experience on smartphones. • In total, these features improve satisfaction and reduce effort for common tasks.
Reliability	• Improved outage maps and notifications provide unified, timely status and ETR's, reducing repeat calls and supporting restoration communications during events. • Integration paths anticipate future ADMS capabilities so customer-facing information can reflect live network state as systems converge.
Safety	• Consistent outage status and alerts reduce unnecessary field visits and help customers and staff make informed, safe choices during events. • Digital and guided workflows integrated with workforce management improve field efficiency and reduce errors from manual handoffs in connections.
Efficiency	• Webchat and chatbot deflect routine call inquiries while improving customer experience; the connections portal automates steps and deflects calls by enabling customers to book their own appointments and track status of their request and integrates to core systems; MyAlectra portal reduces third-party contact center and billing costs through increased adoption of e-billing. • Collectively, these capabilities enable higher throughput without proportional staffing growth.

5.3 Investment Drivers & Needs

Alectra Utilities must serve a growing customer base through more frequent extreme-weather events and a shift to electrification while keeping service levels steady and costs prudent. Total annual customer interactions are forecast to increase from approximately 0.82 million in 2025 to 1.08 million by 2031, as EV adoption, service upgrades, DER connections, and population growth add new touchpoints as detailed in *Exhibit 4, Tab 2, Schedule 7 Customer Service*. The Customer Service Technologies segment addresses these pressures by shifting high-volume, repeatable tasks to digital self-serve and assisted-digital channels, modernizing end-of-life systems, and improving collections effectiveness so that customer experience improves as volumes rise.

5.3.1 Storm and Outage Communications

Climate projections indicate a higher risk of derechos, tornadoes, and extreme wind events, with the 2022 derecho serving as a representative, high-impact scenario (refer to *Appendix G - Climate Risk and Vulnerability Assessment*). These hazards increase the frequency and severity of major events and the associated surge of outage inquiries beyond the current base of more than 150,000 calls in active years. Customers expect timely and accurate restoration updates, as well as a single point of contact to track progress. The plan upgrades the MyAlectra outage experience with an integrated outage map, proactive notifications, improved status presentation, and a preference management option so customers can subscribe to their channel of choice. The design anticipates alignment with future ADMS, so estimated restoration times and device states reflect live network conditions as Grid Modernization proceeds. The intent is to reduce repeat calls during events, improve the transparency of restoration, and improve communications via straightforward updates that customers can self-serve. Together with other digital solutions, the outage communication upgrades will reduce peak call congestion with the third-party outage management service provider and improve customer satisfaction with restoration communications.

5.3.2 Digital Channels to Manage Rising Customer Interaction Volumes

Total customer interactions will increase from approximately 0.82 million in 2025 to 1.08 million by 2031, an increase of 32%. Without a channel shift, the utility would either need to lengthen wait times and degrade service quality levels or add additional internal and external customer

service resources. Alectra's digital-first strategy plans to expand digital and self-serve options. As presented in *Exhibit 4, Tab 2, Schedule 7 Customer Service*, Webchat and Chatbots are estimated to shift close to 181,000 customer inquiries by 2031, or about 17% of total inquiries from non-digital channels. Automated transactions, such as starting and stopping services, are expected to increase from 41,000 in 2025 to 106,000 by 2031. Digital interactions that do not require a CSR increase from 41,000 in 2025 to 197,000 by 2031, raising the digital share from 5% to 18% and decreasing the CSR-handled share from 95% to 82%. Agent concurrency in chat enables multiple simultaneous conversations, further improving throughput without requiring proportional staffing.

These channel shifts have quantified benefits. Webchat and Chatbots (the virtual assistant) together are expected to impact OM&A by approximately $6.4MM over the plan horizon as eligible inquiries are resolved digitally, with associated reductions in third-party contact-centre usage.

Together, these measures maintain steady service levels while interactions increase and contain operating costs by redirecting high-volume, low-complexity work to channels that customers prefer.

5.3.3 New Connections Modernization Facilitates Growth in Service Requests

Population growth, EV adoption, and small-scale DERs are accelerating service-upgrade and connection requests. Alectra Utilities load forecast shows EVs rising from 70,908 in 2025 to over 500,000 by 2031, along with additional DER-connected capacity on the order of 120MW-130MW through the early 2030s. Panel upgrade requests alone are forecast to grow from approximately 13,000 in 2025 to 95,500 by 2031. Processing that workload with the current toolset and resources would create delays and additional manual back-office handling.

The New Connections portal replacement addresses end-of-life system risk in the existing SilverBlaze NCCP platform and introduces streamlined digital intake capabilities, allowing customers to book their own appointments and receive automated status updates. Customers will receive additional, convenient payment options via a digital wallet, reducing delays while payments are processing and the need for customers to follow up on project status. The need to replace SilverBlaze is immediate: the original software vendor was acquired by a larger vendor entity, and support for Alectra Utilities' fully customized application has been exceptionally limited and will be discontinued.

Alectra Utilities estimates a net OM&A benefit of approximately $4.8MM from the portal replacement and process changes. These savings are embedded within the Customer Service program forecast of costs. They are primarily attributable to realizing a 3 FTE reduction in 2026, driven by self-serve appointment booking, status lookups, and digital payments for deposits and upgrade fees. Customers also gain clearer instructions and real-time status, which reduces back-and-forth and rework for both parties.

5.3.4 Adding Convenient Payment Options and Enhancing Collections Performance

Phase One of the Collections Enhancement Project will expand the digital wallet functionality within the MyAlectra Portal, introducing multiple, convenient payment options, including Apple Pay, Google Pay, and PayPal. Additionally, automated payment arrangements will be enhanced to allow customers to set up their own payment plans directly through the portal. Customers will also gain the ability to make payments via Interactive Voice Response (IVR) or a secure text link, further simplifying the payment process.

Phase Two will leverage data analytics and machine learning to deliver more proactive and personalized payment communications, such as tailored reminders, alerts, offers, and assistance. Advanced propensity-to-pay models and predictive scoring will assess customer-specific credit risk by analyzing historical data, customer behavior, and external factors, optimizing collection efforts, and improving revenue recovery.

The Collections Enhancement Project is expected to significantly improve collection rates, reduce arrears, and minimize write-offs while providing a seamless customer experience. By 2029, enhanced payment functionality and segmentation strategies are projected to reduce write-offs by $0.1MM, growing to a cumulative benefit of $1.9MM by 2031. Additionally, the expansion of automated payment arrangements will eliminate the need for 9,200 customer service calls annually, reducing third-party contact center costs by $0.4MM from 2029 to 2031.

5.3.5 Meeting Rising Customer Expectations

Usage of digital online service channels continues to grow year-over-year. Residential research found that the vast majority of customers try to solve issues online before calling. Commercial and industrial customers show the same pattern and prefer digital for routine transactions, including new service inquiries. Customers are using digital channels more than phone calls and

are more satisfied when they do. In 2024, for example, 44% of customers reported contacting Alectra Utilities about a service request, question, or to seek general information, with 38% doing so through digital channels, including the My Alectra portal, website, email, social media, text, or outage chat, in order of preference. Digital web traffic analysis further supports this trend, with over 2 million visits and more than 4 million pageviews across Alectra Utilities' online platforms in 2024 (Google Analytics, alectrautilities.com).

Alectra's digital-first strategy ensures Alectra's services adapt to evolving customer needs and regulatory requirements, while delivering a seamless and responsive customer experience. Satisfaction results reinforce this digital-first shift. J.D. Power insights show significantly higher customer satisfaction among customers using digital channels compared to those requiring phone support (Customer Care Satisfaction Index score of 767 versus 728). E-billing users similarly report more positive experiences (Billing and Payment Satisfaction Index of 794 vs. 736). E-billing also encourages greater use of the My Alectra portal, improving visibility into consumption and billing patterns and supporting increased confidence and satisfaction with monthly costs (Price Satisfaction Index of 651 vs. 603). Refer to *Exhibit 1 Tab 5, Schedule 1 Ongoing Customer Engagement* for additional analysis on Alectra Utilities' customer research supporting additional investments in digital channels.

The MyAlectra enhancement project will deliver rising customer expectations for digital services by integrating real-time billing, payment, and electricity usage insights. The portal will also offer increased self-serve functionality through smart form functionality to automate start/stop customer journeys, expand digital wallet capabilities, enable digital wallet features, deploy landlord multi-account tools, integrate eMobility functionality, and introduce a mobile app, so that the same tasks are available natively on smartphones.

Chatbots will initially support five major customer journeys: Moving (start/stop services), Accounts & Billing, Outages & Safety, Save Energy & Money, and MyAlectra registration), each designed to guide customers to the appropriate online resources or service areas. While the chatbot will not perform transactions or resolve issues directly, it helps users efficiently navigate, locate forms, tools, and information for tasks like transferring service, viewing bills, reporting outages, accessing energy-saving tips, and managing account settings. This navigational design streamlines customer journeys, reduces call centre traffic, and lays the groundwork for future enhancements that could enable more direct self-service capabilities. Additionally, Web Chat

enables live, real-time conversations between customers and CSRs through an online chat interface, providing an alternative to phone calls for immediate assistance.

The intent is to give customers accurate information and shorter paths to resolution, which improves satisfaction while reducing avoidable customer contacts.

5.3.6 Data, Regulatory Change and Sustainment Needs

MyAlectra portal is now a core enterprise system alongside the CIS. It requires ongoing testing, maintenance, and enhancements to ensure accurate, 24/7 bill and usage presentation, functioning smart forms, automated payment arrangements, and digital wallet operations as vendor releases and regulatory changes occur. Discovery during the initial rollout confirmed the need for robust data governance and regression testing because interval and billed data must reconcile for customers to trust the platform. Continued investment ensures the platform remains compliant with new rate structures and program rules, thereby avoiding the re-emergence of manual workarounds. All additions to functionality will continue to pass through formal IT security assessments and comply with legislative and regulatory requirements.

5.3.7 Consequences of Not Proceeding

If these investments do not proceed, Alectra Utilities would face increasing customer contact volumes requiring additional OM&A investments in third-party contact center resources beyond the OM&A 2025-2031 plan presented in *Exhibit 1, Tab 6, Schedule 5 Productivity*. These include $6.4MM from Chat/Webchat, $4.8MM from New Connections modernization, and $2.26MM from the Collections Enhancement Project.

In addition, during major weather events, outage-related calls would queue longer, repeat calls would increase, and customer satisfaction with restoration communications would decline. Without replacing the unsupported SilverBlaze NCCP portal, there would be an increased system risk, as occasional application errors, connectivity issues, and system controls would limit application functionality or cause a full system failure. In addition, the capability to support increased customer connection requests would decrease without an increase in OM&A resources, and work backlogs and connection delays would increase.

5.4 Options Analysis

Option 1 – Status Quo / Managed Deterioration.

Under this option, Alectra Utilities would maintain the base customer-facing systems and existing processes with no material enhancements. The analysis shows that this would miss the process improvements required to meet new business demands and customer expectations and would forego the efficiencies that the modern platform is designed to deliver. Under this option, there would be an increased risk that customer-facing systems would not be able to support new regulatory requirements (e.g. add new rates to rate option comparison tools). In collections, arrears are expected to grow materially with electrification, and related growth in electricity consumption, and without the Collections Enhancement Initiative, bad debt is expected to increase by $1.9MM, For New Connections, the legacy SilverBlaze is at end-of-life, has limited vendor support, and is not scalable beyond basic interactions. This option does not meet the segment's objectives.

Option 2 – Status Quo / Minimal Enhancements.

This option would keep systems current and implement only the minimum change requests needed for regulatory compliance. It reduces short-term change risk but limits the ability to deliver customer-facing enhancements and to keep pace with technological changes. This option also constrains operational efficiency gains and, by reducing digital self-serve options, would likely reduce customer satisfaction, as customer research has demonstrated higher satisfaction scores with expanded digital options (refer to *Exhibit 1 Tab 5, Schedule 1 Ongoing Customer Engagement* for additional analysis on Alectra Utilities' customer research supporting additional investments in digital channels.

Option 3 – Integrated Omnichannel Modernization (Recommended).

This option continues the phased enhancement of the MyAlectra portal, replacing the end-of-life New Connections portal. It implements chat and webchat channels at scale, deploys collections and payment enhancements as integrated modules, and provides sustainment capital to keep the platform secure and current. Implementation of chat and chatbots will improve service quality indicators, operational efficiency, and customer

satisfaction. The MyAlectra portal enhancements will improve resiliency and modernization through enhanced outage management and customer communications capabilities. The New Connections project retires SilverBlaze, replacing an unsupported tool with a scalable portal that enables customers to book and track service appointments. This portal will integrate with workforce management tools to modernize workflow. In collections, this option enables propensity-to-pay collection segmentation, proactive omni-channel collection campaign management, and expanded digital payment options. In summary, this option future-proofs the customer experience, enables value stacking of additional modules through competitive business cases, and curtails the complexity of integrating and maintaining disparate systems.

The recommended Option 3 directly improves service quality metrics and OM&A efficiency with quantified benefits, including expected cumulative operational savings. It also aligns with sector practice to adapt channels and workforce tools to a digital-first approach, meeting customer expectations for expanded digital services and supporting electrification. It is the only option that closes the identified gaps at scale while managing rate impacts through staged delivery, while demonstrating OM&A savings in collections (reduced bad debt), customer connections (lower OM&A resource requirements) and implementation of web chat and chatbots (lower OM&A resource requirements).

5.5 Investment Timing & Pacing

Table B14 - 14 provides the year-over-year breakdown of investments, including the historical period from 2020 to 2024, the bridge years from 2025 to 2026, and the DSP period from 2027 to 2031.

Table B14 - 14 Historical & Proposed Investment Spending

	Historical Spending					Bridge		Forecast Spending				
Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Customer Service Technologies	0.1	0.7	5.1	6.1	9.2	3.1	1.0	2.2	2.0	2.9	2.0	2.0

Alectra Utilities sequences Customer Service Technologies to increase service quality as interaction volumes rise, lower the cost-to-serve by shifting routine work to digital channels, and

enhance outage communications for more frequent major events. Historical spending established the base platform. Bridge-year investments enhance base functionality and replace the end-of-life New Connections tool. Plan-period investments extend self-serve, digital capacity, and collections effectiveness in measured releases that the organization and its vendors can support.

From 2020 to 2024, Alectra Utilities invested approximately $21.2MM, driven by establishing functional and technical requirements during the discovery phase, build, and go-live of the new MyAlectra platform. This investment reflected the complexity of integrating CIS, meter data, change management, and training to support the transition. This investment established the foundation for the 20252031 program to build upon.

The 2025-2026 capital expenditures will focus on completing immediate platform enhancements and retiring end-of-life tools. The plan replaces the legacy SilverBlaze New Connections portal with a modern digital intake and workflow solution and completes the initial rollout of enterprise webchat and a production virtual assistant. MyAlectra portal enhancements address early customer feedback, improve bill and usage presentation, automate common move-in and move-out (stop/start service) journeys, and introduce digital wallet options. Total bridge capital is about $4.1MM across three workstreams. The outcome is a stable, supported platform that can absorb growth in EV and DER-driven requests, along with digital capacity that begins to shift customer engagement out of the voice queue before the plan period ramps up.

Across 2027-2031, the Customer Service Technologies segment invests $11.1MM to scale the capabilities introduced in the bridge years and sustain the core portal through controlled annual releases as summarized below:

- **MyAlectra portal** enhancements (of $8.9MM) extend self-serve across high-volume tasks, integrate outage map and outage notifications, expand multi-account tools for landlords and small businesses, integrate with e-mobility tools and keep the portal aligned with evolving rate options and regulatory rules. Enhancements are grouped into measured releases that prioritize adoption and contact avoidance.
- **New Connections** requires limited capital in the plan period, of $0.4MM, to sustain the new portal. The replacement delivered in the bridge years removes end-of-life risk and enables cycle-time and staffing benefits as EV and DER related upgrades grow.

- **Webchat and chatbots** through modest annual releases, of $0.5MM, that add new customer journeys and maintain knowledge libraries while introducing authenticated flows for common account tasks. These digital channels reduce reliance on third-party contact-centre capacity and preserve service levels as interactions rise. By 2031, digital interactions that do not require a Customer Service Representative will increase to 25% of customer inquiries.
- **Collections and Payments** implement analytics-driven collection treatment paths and expanded digital payment methods for $1.3MM of capital. The work introduces predictive scoring, portal-based arrangements, proactive reminders, and secure payment options such as Apple Pay and Google Pay. The expected result is improved recoveries, lower write-offs, and fewer inbound calls for payment arrangements.

This pacing aligns with the broader Enabling Resiliency and Modernization plan, which positions Customer Service Technologies alongside grid automation and control investments to improve customer communication during outages and service events. Benefits from contact deflection, shorter cycle time, and improved collections are realized progressively as features deployed.

VI Investment Projects

The material Enabling Resiliency and Modernization Program investments from 2027 to 2031 are included in Table B14 - 15.

Table B14 - 15 Material Projects and Initiatives

Project Code	Project Name	CAPEX ($MM)
Multiple	Distribution Automation	52.3
152542	Advanced Distribution Management System	13.3
152935	Enterprise Asset Management	12.3
152673	Rear Lot Renewal Project - Bayview and Steeles, Markham	12.0
150329	Rear Lot Renewal Project - Main Street / Unionville / Carlton, Markham	11.3
152677	Rear Lot Renewal Project - Aurora Heights, Aurora	11.3
150330	Rear Lot Renewal Project - Marsdale, St. Catharines	10.8
152563	CX project Enhancements (SEW Applications)	8.9
150397	Rear Lot Renewal Project - Riverview Blvd and Northcliffe	7.3
152467	Rear Lot Renewal - (HAM) - St. Andrew's Drive	7.3
153094	Planning Tools and Automation	6.3
152543	Integrated Network Management	6.0
152843	Rear Lot Renewal Project - Highway 7/ McCown (SE) - Markham	5.3
150383	Rear Lot Renewal Project - Bluebird	4.3
150399	Rear Lot Renewal Project - Richelieu Dr and Trelawne Dr, St. Catharines	4.1
150398	Rear Lot Renewal Project - Strathcona Dr	3.6
152503	Rear Lot Renewal Project - Steeles and Henderson, Markham	3.6
152929	Installation of automated pad mount reclosers - Central South	2.9
152904	Reliability Improvements to Beeton and Tottenham	2.9
Multiple	Fault Indicator Installation and Replacement	2.3
Multiple	New Wireless FAN to Improve SCADA Communications	2.2
150047	Rear Lot Renewal Project - Royal Orchard - North, Markham	2.1
152957	Installation of automated devices on Aurora Feeders on A-1F3, A-2F1, A-2F3, A-3F4, A-5F1, A-5F2 and A-5F3	2.1
152545	DER Wholesale Market Preparedness	2.0
152260	Expand Alectra Utilities Dark Fiber Network - JYTS to Derry Rd	2.0

Project Code	Project Name	CAPEX ($MM)
152726	Installation of automated pad mount reclosers at the overhead to underground transitions.	1.7
152953	Installation of automated devices on Greenwood TS1 and TS2 on 20M3, 20M5, 20M9, 20M21, 20M22 & 20M23	1.6
152796	Installation of S&C Trip Savers at various locations in Central South	1.6
150331	Rear Lot Renewal Project - Royal Orchard - South, Markham	1.6
153048	CX Collection & Payment Enhancements	1.3
150507	230kV TS Transformer Primary Bushing Monitoring Enablement-BPD Elimination - Transformer Stations	1.3
152947	Alternate supply for the customers on 85F4 -SG1490 to SG1491 from Feeder 85F8	1.3
153009	New Communications Tower and Wireless Communications Node - King MS	1.2
153010	New Communications Tower and Wireless Communications Node - RHTS1 , Richmond Hill	1.2
152832	Installation of S&C Trip Saver in West Region	1.2
Multiple	Flood Detection/Prevention for Underground Installations	1.1
151896	Rear Lot Renewal - (199) - Douglas St, Guelph	1.1