ATTACHMENT I

Facilities Assessment – St. Thomas

(2024)

September 12

135 Edward Street, St. Thomas

2024

BUILDING CONDITION REPORT

Submission by:
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ENTEGRUS™

320 Queen Street
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INDEX

Building Condition Review

135 Edward Street

Building Condition Review

CONSULTANT TEAM MATRIX

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Executive Summary

ROA Studio Inc, along with associated consultants, was engaged to provide observations and report the physical conditions of the property located at 135 Edward Street, St Thomas, Ontario. This review addresses item that are significant for the continued operations of the facility in its current usage and occupancy, consistent with comparable properties of similar age.

The report observes the general physical condition of the subject property, material systems and components, and identifies deficiencies and any unusual features or inadequacies.

The consultant team visited the site on July 10, 2020 conducted a visual inspection of building systems.

The following building systems were reviewed and the following is our professional opinion of the found condition of the building:

Building Exterior	☑ Good	☐ fair	☑ Poor
Windows & Doors	☑ Good	☑ fair	☐ Poor
Roofing | Skylight	☑ Good	☑ fair	☐ Poor
Interior finishes	☑ Good	☐ fair	☐ Poor
Structural systems	☑ Good	☑ fair	☐ Poor

Refer to attached Mechanical, Electrical and Civil reports for further information

Opinions of Probable Costs

These opinions of probable costs are to assist the client in developing a general understanding of the physical condition of the subject property.

The following summarizes the cost per building systems.

Site Services	$	2,250.00
Site Elements	$	27,000.00
Building Exterior	$	14,500.00
Windows & Doors	$	10,000.00
Roofing | Skylights	$	0.00
Interior finishes	$	17,000.00
Structural Systems	$	7,500.00
Fire Protection	$	0.00
Plumbing Systems	$	95,000.00
Natural Gas	$	4,500.00
HVAC Systems	$	200,000.00
Electrical Systems	$	70,000.00
Fire Alarm Systems	$	0.00
Total	$	447,750.00

Opinions of probable costs should only be construed as preliminary budgets.

SECTION 1 PROJECT DETAILS

1.1 Purpose

ROA Studio Inc, along with associated consultants, was engaged to provide observations and report the physical conditions of the property located at 320 Queen Street, Chatham Ontario. This review addresses item that are significant for the continued operations of the facility in its current usage and occupancy, consistent with comparable properties of similar age.

The intent of this report is to determine anticipated capitol and maintenance cost over a five (5) to ten (10) year period. All inspections were non-destructive and based on visual inspections of representative portions of the various systems. This report should not be considered a guarantee or warranty of any kind. Unexpected repairs should still be anticipated.

1.2 Scope of Work

Observe the general physical condition of the subject property, observe material systems and components, and identify deficiencies and any unusual features or inadequacies observed by conducting specific or representative observations, as appropriate. Visually inspect the building systems based on representative samples to be review include but not limited to:

Site - Asphalt Paving, Concrete Curbing and sidewalks, Parking and exterior egress.

Site Services- Conduct a site inspection related to the existing servicing infrastructure and trench drain system. Determine possible causes of sewer back-ups into trench drain system and offer possible solutions to correct existing problems.

Building Envelope - facades and curtain wall system, glazing system, exterior sealants, exterior loading docks, doors, stairways, etc.

Roofing - Identify and observe the roof systems (exposed membrane and flashings) including, parapets, slope, drainage, etc. Observe for evidence and/or the need for material repairs, evidence of significant ponding, or evidence of roof leaks.

Interior Elements - common areas including, but not limited to, lobbies, corridors, assembly areas, offices and restrooms. Identify and observe typical finishes for flooring, ceilings, and walls.

Structural Systems - Perform structural design spot checks. Observe the building substructure, including the foundation system, building's superstructure and structural framing (floor framing system and roof framing systems).

Electrical Systems - Main electrical service, electrical panels, emergency lighting, fire alarm systems and emergency power systems.

Written Report - Subsequent to the visual inspection, prepare a comprehensive list of deficiencies and provide photo evidence of such deficiencies. A estimated budget cost to be associated with any corrective work required over a 5-10 year period.

Opinions of Probable Costs - are to be prepared for the suggested remedy of the material physical deficiencies observed. These opinions of probable costs are to assist the client in developing a general understanding of the physical condition of the subject property.

Opinions of probable costs are provided for material physical deficiencies and not for repairs or improvements that could be classified as: (1) cosmetic or decorative; (2) part or parcel of a building renovation program or tenant improvements/finishes; (3) enhancements to reposition the subject property in the marketplace; (4) for warranty transfer purposes; or a combination thereof.

Opinions of probable costs should only be construed as preliminary budgets. Actual costs may vary from the consultant's opinions of probable costs depending on such matters as type and design of suggested remedy, quality of materials and installation, manufacturer and type of equipment or system selected, field conditions, whether a physical deficiency is repaired or replaced in whole, phasing of the work (if applicable), quality of contractor, quality of project management exercised, market conditions, and whether competitive pricing is solicited.

1.3 Exclusions to Scope of Work

Providing an environmental assessment or opinion on the presence of any environmental issues such as asbestos, hazardous wastes, toxic materials, the location and presence of designated substances or mould.

Preparing engineering calculations (civil, structural, mechanical, electrical, etc.) to determine any system's, component's, or equipment's adequacy or compliance with any specific or commonly accepted design requirements or preparing designs or specifications to remedy any physical deficiency.

1.4 Conventions Used in this Report

GOOD - Indicates the component is functionally consistent with its original purpose but may show signs of normal wear and tear and deterioration.

FAIR - Indicates the component will probably require repair or replacement anytime within five years.

POOR - Indicates the component will need repair or replacement now or in the very near future.

MAJOR CONCERNS - A system or component that is considered significantly deficient or is unsafe and in need of prompt attention.

1.5 Documents Provided

The documents made available to the consultants by Entegrus to assist in the preparations of this report are as follows:

- Construction Drawings by Hira Ltd dated June 1993.

1.6 Interview of Associated Persons

During the Site visit, Mr. Gary Aitkins was made available to provide information regarding history of work on premises.

1.7 Project Site & Building History

The project site is located on the south side of Edward street in St. Thomas, Ontario. The site neighbors commercial properties to the North and West, a park to the East and railroad tracks to the South. The site has One (1) main structure, that includes the main office and garage. The facility was built in approximately 1993 and has had renovations to the main office area.

1.8 Building Description | Data

Main Office

- 1993 building includes partial basement, first floor warehouse space and Garage

Building Areas

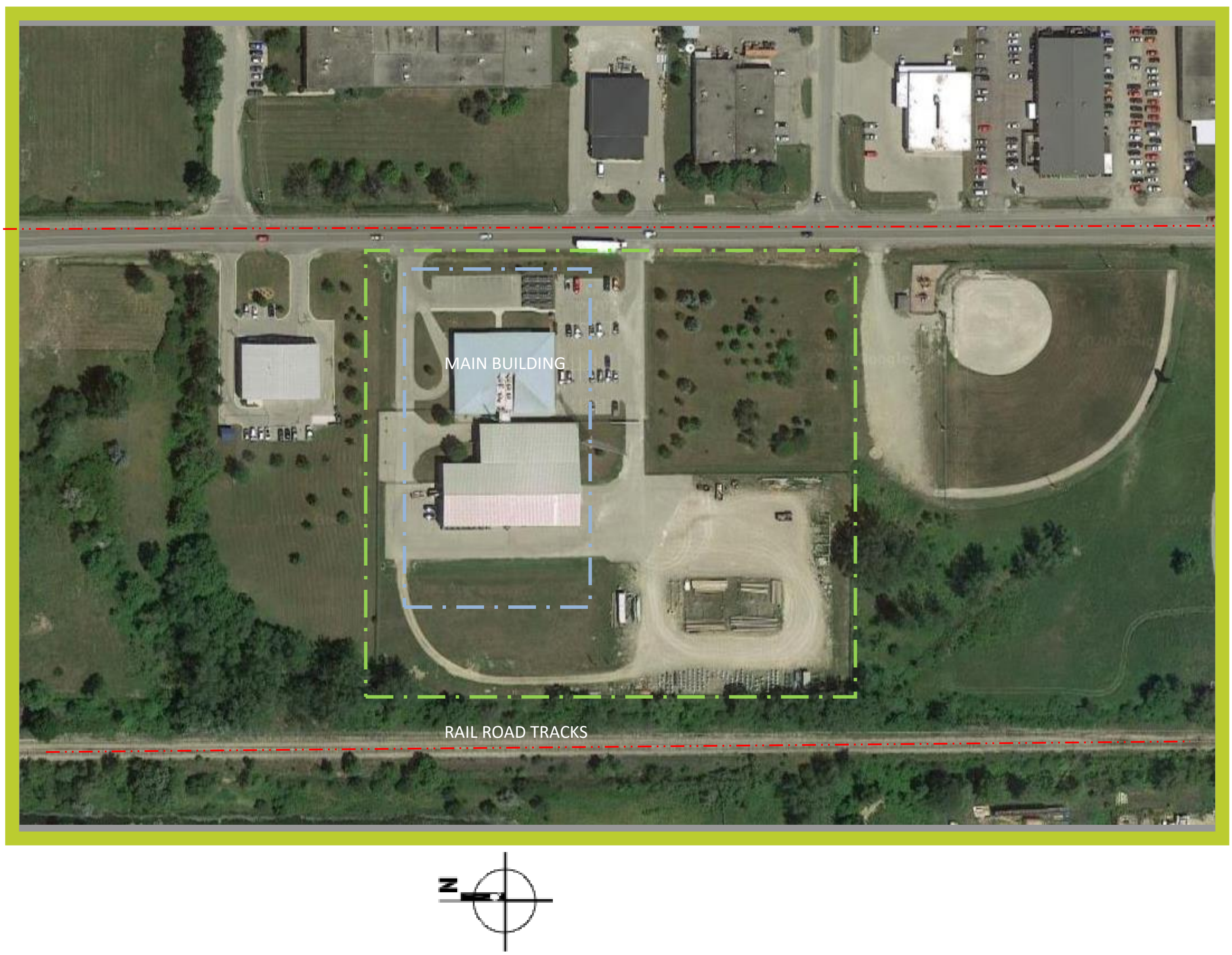
Main Floor Office	1,100 m²
Shop & Stores	2,000 m²
Total	3,100 m²

OBC Classification

Group D - Office
Group F Division 2 - Garage

1.9 Site Survey Date & Conditions.

ROA Studio, along with consultants, visited the site on July 10, 2020. Temperatures had a high of 34°C and dry. Minimal rain to no rain occurred a week before the inspection.



SECTION 2 BUILDING SURVEY

2.2.1 Building Exterior

Description
This section reviews the exterior cladding including wall coverings, eaves, soffits and flashings.

Masonry Veneer	☑	Good	☐	fair	☐	Poor
Pre-fin Metal Siding	☑	Good	☐	fair	☐	Poor
Masonry Block	☑	Good	☐	fair	☐	Poor
Facia & Downspouts	☑	Good	☐	fair	☐	Poor
Sealants & Caulking	☑	Good	☐	fair	☑	Poor

General Comments
The exterior of the building is in generally good condition. The architectural block had minor cracking and a few areas on the metal siding had some damage. Caulking at windows was in good shape however a few control joints on the Garage were deteriorated and needs repair.

Recommendations | Observations

- Discolouring of architectural block. Recommend cleaning and monitoring.
- Minor mortar cracking by pay window
- Siding damaged above Stores loading dock
- Caulking at control joint failing
- A few penetrations did not have sealant
- Metal platform and stairs at loading dock rusting

Opinion of Probable Cost
Allow $6,000 to clean and monitor architectural block
Allow $2,500 for masonry repointing
Allow $2,500 for new sealants
Allow $3,500 for Exterior Paint

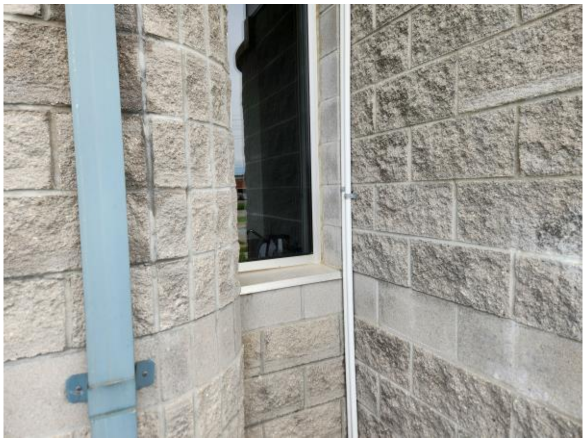
Images

Sample of Soffit – Main Entrance

Efflorescence on Split Face Block – Main Entrance

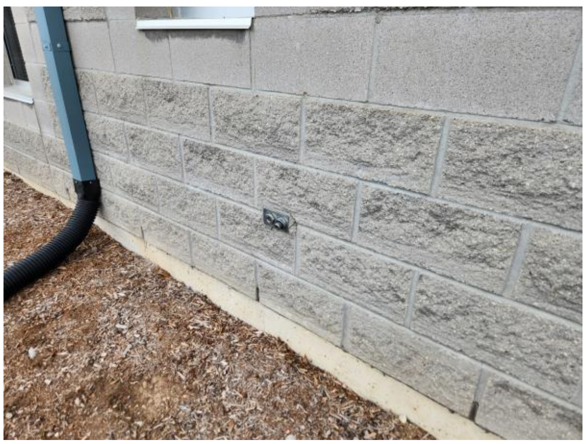
Sample of split face block – Main Entrance

Images

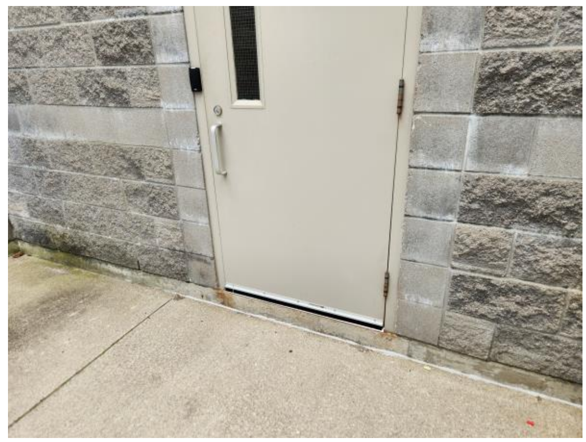


Sample of split face block

Sample of Metal Soffit Bay



Sample of split face block



Efflorescence on Split Face Block – Back Entrance

Control joint sealant failing - Sample

Paint deterioration (minor) on eaves and gutter.

Images

Guard rusting and to be painted.

Loading dock Entrance requires painting

Repair: Control Joint Failing
Location: Garage

Rusting appearing on Loading Dock
Location: Garage

Metal Siding
Location: Garage Building

Siding and Block Sample - courtyard

2.2.2 Windows | Exterior Doors

Description
This section reviews current state of the windows and doors in the buildings. This includes a visual inspection of the frames, sealing, glazing and hardware.

Window Frames	☑	Good	☑	fair	☐	Poor
Glazing	☑	Good	☐	fair	☐	Poor
Door & Frames	☑	Good	☐	fair	☐	Poor
Over Head Door & Frames	☑	Good	☐	fair	☐	Poor
Sealants | caulking	☐	Good	☑	fair	☐	Poor

General Comments
The aluminum and hollow metal window frames are original. Majority of the frames are in good conditions. The sealed units are original. The majority of the hollow metal doors are starting to show deterioration, most of the weather stripping is in fair condition.

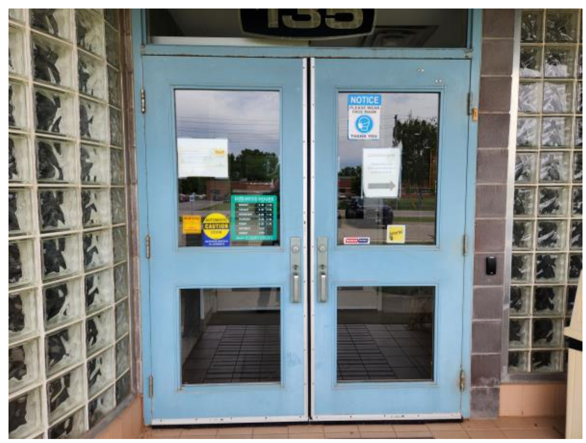
Recommendations | Observations

- Minor wear at loading dock overhead door frame, monitor and repaint.
- Door and door frames in several areas are showing signs of minor rusting.
- Aluminum Window Framing are in good condition

Opinion of Probable Cost
Allow $5,000 for bollard, door and frame painting
Allow $5,000.00 for new hollow metal door and frame in Garage

Images

Glass Block
Location: Main Office



Monitor: Rust forming on window framing (Repaint)
Location: Main Office

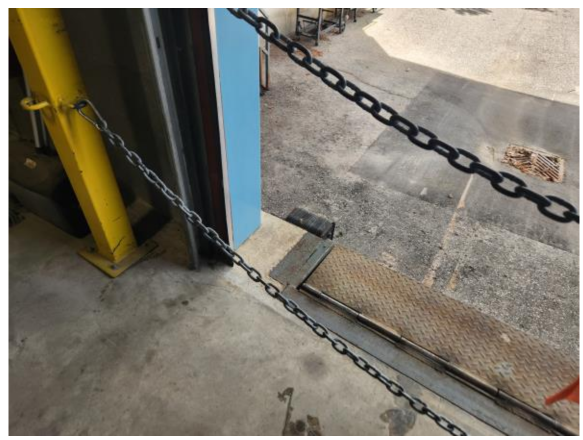
Monitor: Rust forming on window framing (Repaint)
Location: Main Office

Images

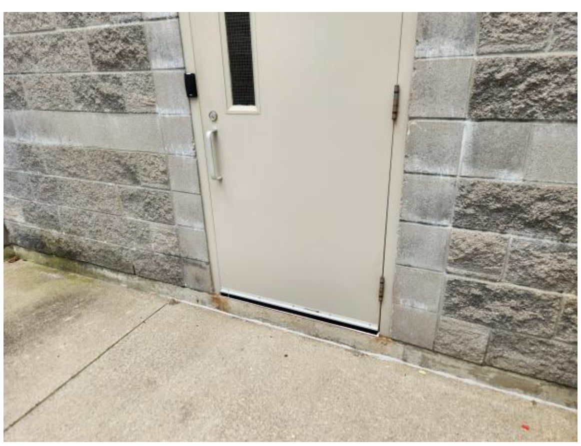
Sample: Thermal Units in good conditions
Location: Main office

Sample of Aluminum Windows and Sill
Location: Main office

Exterior doors paint peeling
Location: Main Office



Sample: Overhead door at Loading Dock
Location: Shop



Exterior frames starting to rust
Location: Main Office

Minor wear on Overhead door jambs
Location: Loading Dock

Images

Frame rusted out
Location: Garage

Sample: Overhead door opening
Location: Garage

Sample: Hollow Metal door required painting
Location: Main Office Building

2.2.3 Roofing | Skylights

Description
This section reviews current state of roofing including the roofing material, parapets and drainage.

Single Ply Membrane	☐	Good	☑	fair	☐	Poor
Metal Roofing	☐	Good	☑	fair	☐	Poor
Parapets	☐	Good	☑	fair	☐	Poor
Scuppers	☐	Good	☑	fair	☐	Poor
Skylights	☑	Good	☐	fair	☐	Poor

General Comments - Main Office

The roof of the building is majority pitched metal roofing with partial flat roof with single ply membrane. The roof is appears to be original to the building and is in fair condition. No Sign of leaks were observed inside the building. The roof over the staff outdoor patio was observed to be in fair condition.

Skylights were observed from the ground and interior and appear to be in good condition.

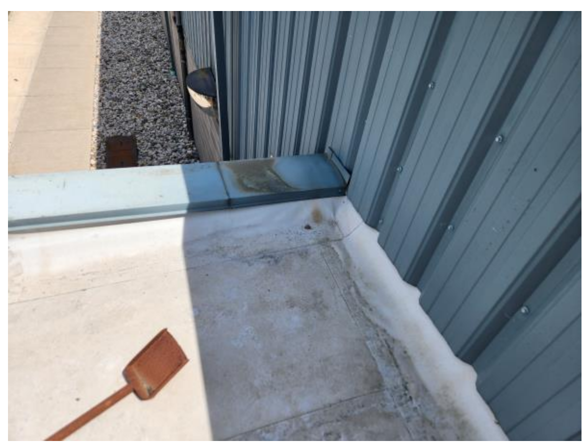
Recommendations | Observations
- Flat roof had some leaf and debris, should be cleaned
- Roof scuppers clear of debris
- No visual sign of leaks in building.
- Skylights did not show evidence of leaking.
- Soffits, down spouts and eave troughs in Fair condition

Opinion of Probable Cost
No comments.

Images

Sample Roof - Metal
Location: Main Office

Sample Roof - Metal
Location: Main Office



Sample: Single Ply Roofing Membrane
Location: Main Office

Images

Sample: Single Ply Roof Membrane roof.
Location: Main Office

Debris collecting by AHU.
Location: Main Office

Sample: Pitched metal Roofing
Location: Garage

Debris collecting by AHU.
Location: Main Office

2.3.1 Interior Finishes

Description
This section reviews the current state of interior finishes including ceilings, walls, flooring and interior doors.

Flooring	☑	Good	☐ fair	☐ Poor
Ceilings	☑	Good	☐ fair	☐ Poor
Doors	☑	Good	☐ fair	☐ Poor
Walls	☑	Good	☐ fair	☐ Poor

General Comments - Main Office

As an overview, the interior finishes of the main floor building are in good condition. The main office area is recently had renovations to a significant portion and is considered in good condition. The remaining flooring is a combination of carpet, vinyl tile, concrete and ceramic tile. The walls consist of gypsum board and painted finish. The floors are relatively level and the walls are relatively plumb. The ceilings are comprised of suspended acoustical ceiling systems and pre-fin linear metal ceiling in the garage. The doors are in fair condition. Washroom have are in good condition. The pre-engineered insulation lining in the garage is in fair condition with several rips and puncture holes.

The basement shows signs of water infiltration however this appears to have not occurred in a while and may be same "staining" as per previous report.

Recommendations | Observations
- Repair pre-engineered insulation liner in garage.
- Monitor basement storage room where floor is cracked and previous water infiltration occurred.
- IT room flooring cracked at control joint. Refer to structural.

Opinion of Probable Cost
Allow $4,500.00 for pre-engineered insulation liner repair.
Allow $7,500.00 for new flooring.
Allow $5,000.00 for misc paint touch ups

Images

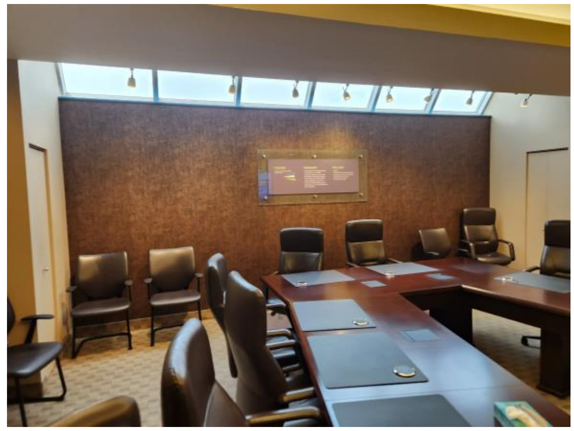
Crack in VCT flooring. Monitor
Location: IT room

Small water stain – to be monitored
Location: Main Office

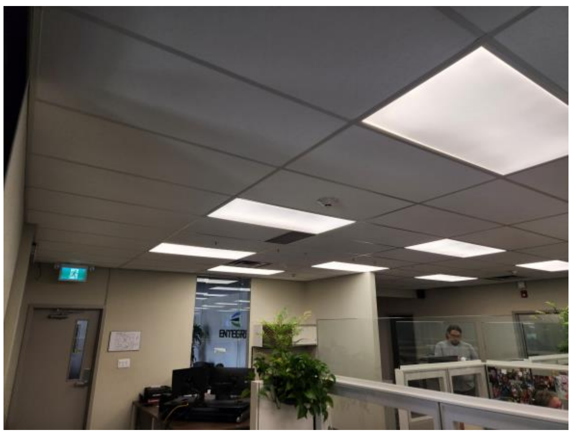
Sample Main office lobby – new renovations
Location: Front Entrance

Images

Sample Main office – new renovations
Location: Main Office



Sample: Board Room
Location: Mian Office



Sample Ceiling systems
Location: Main office

Sample of floor finishes
Location: Main Office

Sample of finishes
Location: Main Office

Sample of finishes
Location: Main Office

Images

Sample of washroom finishes
Location: Office Area

Sample of washroom finishes
Location: Office Area

Sample of finishes
Location: Main Office

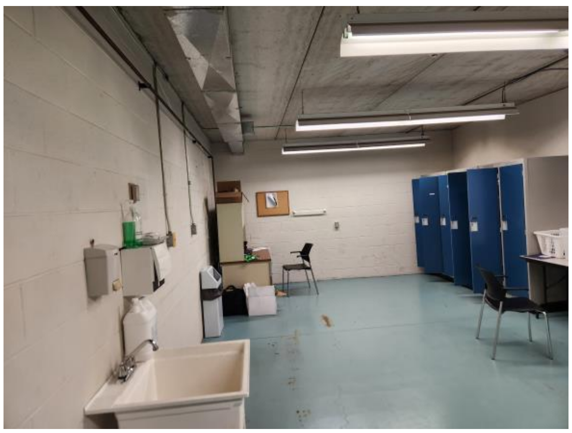
Water staining related to HVAC equipment
Location: Main Office

Sample of paint peeling – to be painted
Location: Main Office

Sample of door in fair condition
Location: Main office

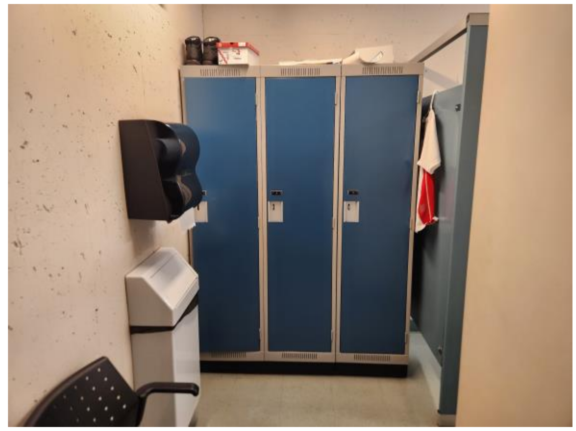
Images

Sample of finishes
Location: Staff Break Room



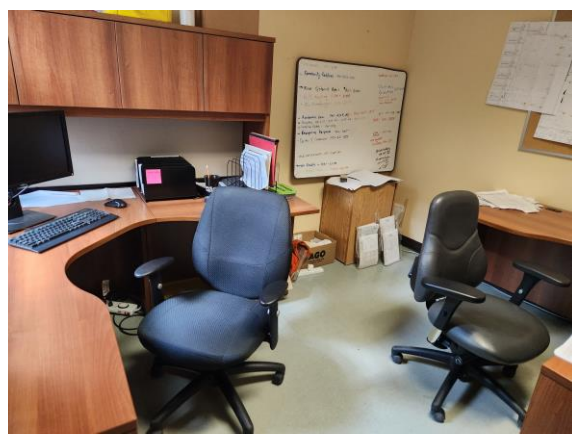
Signs of water infiltration (monitor)
Location: Basement electrical room

Signs of water infiltration (monitor)
Location: Basement electrical room



Basement locker room in fair condition
Location: Basement

Stairs showing wear but in fair condition



Sample office finishes
Location: Main Office

2.4.1 Structural Foundations

Description
This section covers the building foundations including the footing and foundation walls up to grade and slab on grade levels.

Foundations	☑ Good	☐ fair	☐ Poor
Slab On Grade	☐ Good	☑ fair	☐ Poor

General Comments - Main Office
The existing building drawings indicate a full basement with reinforced concrete basement and foundations walls on strip footings with interior reinforced concrete columns on spread footings. Foundation walls are concealed and could not be assessed. Basement walls and interior columns were generally found to be in good condition except as noted below.

There is a full-height vertical crack through the interior basement walls between the Men's Washroom and the Corridor and between the Men's Washroom and the Stores area. The cracks are approximately aligned with each other in the north-south direction. Other smaller cracks were also noted in the Stores basement wall. The cracks could be a result of concrete shrinkage.

The basement slab on grade was found to have narrow map cracking throughout the basement that propagates through the epoxy flooring in some locations. This appears likely due to control joints that are spaced too far apart to adequately address shrinkage cracking of the concrete. In the basement electrical room, staining around the cracks suggests there may have been water infiltrating up through the cracks at some point in the past.

General Comments - Works Garage
The existing building drawings indicate the Stores and Garage foundations consist of concrete foundation walls and footings. No cracks were observed in the masonry infill walls bearing on the foundations which could indicate potential foundation movement. Therefore, the foundations are presumed to be in good condition.

The slab on grade in the works garage has good slope towards the trench drains. The north and south trench drain appears to have been recently reconstructed. The slab on grade exhibited scaling and regular cracking throughout even with regular control joints in place. While these cracks do not present a structural concern, they do present a serviceability issue as the cracks can continue to widen and propagate over time and will further deteriorate the slab.

Recommendations | Observations
- Monitor the cracks in the basement walls.
- Routing and sealing the slab on grade cracks in the Garage only.

Opinion of Probable Cost
- Allow $7500 for routing and sealing the slab on grade cracks in the Garage only.

Images

Basement slab cracks and staining
Location: Electrical Room

Basement slab cracking through epoxy flooring.

Cracks in Basement Walls
Location: Corridor

Images

Cracks in Basement Walls
Location: Stores Area

Cracks in Basement Walls
Location : Stores Area

2.4.2 Structural Vertical Elements

Description
This section covers vertical elements such as building columns, walls and stairs.

Building Columns	☑	Good	☐	fair	☐	Poor
Masonry Walls	☑	Good	☐	fair	☐	Poor
Stairs	☑	Good	☐	fair	☐	Poor

General Comments - Main Office
The Main Office vertical construction is a combination of interior and exterior load-bearing masonry walls and some steel superstructure. Where exposed to view, vertical elements including steel columns, masonry walls, and stairs of concrete and steel construction were observed in generally good condition.

Isolated minor cracking in some of the infill masonry walls in the basement was observed which can indicate small settlements of the foundation; however no major deficiencies were observed.

General Comments – Garage / Stores
The Garage / Stores vertical construction is comprised of a pre-engineered rigid frame steel structure for the Garage with a pre-engineered lean-to structure for the Stores area. Vertical elements in the Garage / Stores area included pre-engineered steel building columns, infill masonry walls up to the first girt elevation and steel stairs in various locations. All construction was observed to be in generally good condition.

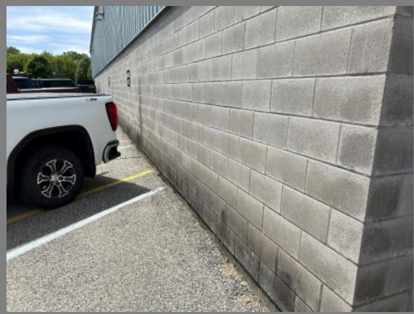
Recommendations | Observations
- No Comment

Opinion of Probable Cost
- No Comment

Images

Masonry stepped cracking in infill wall
Location : Basement

Masonry Stepped cracking
Location : Stairwell



Overview of exterior masonry wall.

Overview of Garage superstructure.

2.4.3 Structural Floor | Roof elements

Description
This section covers the suspended floor and roof construction.

Suspended Floor	☑ Good	☐ fair	☐ Poor
Roof Construction	☑ Good	☐ fair	☐ Poor

General Comments - Main Office
Based on existing drawings, the roof construction consists of standing seam roof deck on flat bottom timber trusses on structural steel framing and load bearing masonry walls. The roof structure was concealed by acoustical tile and drywall ceilings and could not be accessed for assessment.

The suspended ground floor construction consists of a concrete topping on hollow core precast planks varying from 8” to 14” thick. The precast planks bear on the concrete basement walls and columns. One crack was found in the IT room that had propagated through the vinyl floor tile. This crack is likely directly over a joint between precast planks and is the result of differential movement between the planks but is likely not a structural concern.

In the basement, two localized concrete spalls were noted on the precast concrete soffit; one in the Women’s washroom and one in the corridor in front of the freight elevator. One localized crack in the precast soffit was found in the storage room in the southeast corner of the basement. None of these defects present any structural concerns.

General Comments - Garage / Stores
The Garage / Stores superstructure is comprised of a pre-engineered rigid frame steel structure for the Garage with a pre-engineered lean-to structure for the Stores area. The existing roof construction for the stores area is a standing seam roof on cold formed steel purlins on pre-engineered lean-to steel frames. The garage roof consists of a standing seam metal roof on cold formed steel purlins on a pre-engineered rigid frame steel structure. The stores and garage roof structures were found to be generally in good condition.

Recommendations | Observations
- No Comment

Opinion of Probable Cost
- No Comment

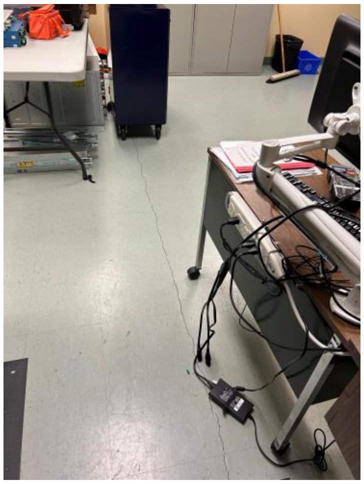
Images

Localized precast concrete soffit spalling
Location : Women’s Washroom

Localized Concrete precast soffit spalling.
Location: At freight elevator

Overview of Garage Slab on grade.
Location: Garage

Images



Precast floor crack.
Location : IT room

Reconstructed floor trench.
Location : Garage

Regular slab on grade cracking.
Location : Garage

SECTION 3 LIFE SAFETY

3.1 Life Safety

General Comments

Although the intent of this report was not to address Life Safety compliance to the Ontario Building Code. There were no observed items to note.

SECTION 4 Statement of Limitations

4.1 Statement of Limitations

The building condition assessment conducted was a visual assessment only. No physical, destructive testing or measurements of existing building structure were taken during the site visit. No assessment can be made where building structure and elements were either not exposed or easily accessible. Connections, fastenings and anchorage of building structure were not reviewed in detail. Existing structural and architectural drawings were provided for review but may not reflect the actual built construction. Comments and conclusions are therefore based on the visual and/or the apparent physical condition of the building elements. Any design and/or construction deficiencies that are not recorded in this report were not evident given the level of study undertaken.

The costing information presented here has been prepared from the engineers' experience and from past projects of a similar nature. The amount given are opinions only and must not be taken as a guarantee of price. If guaranteed pricing is required then the full scope of work needs to be detailed and appropriate contractor(s) approached for a quotation.

This study is intended for the client named and should not be distributed further without our consent.

Entegrus

Civil

Building Condition Survey

Project Location:
135 Edward Street St. Thomas, ON

Prepared for:
ROI Studios
67 King Street Chatham, ON
N7M 1C7

Prepared by:
MTE Consultants
123 St. George Street
London, ON N6A 3A1

July 19, 2024

MTE File No.: 47888-101

Engineers, Scientists, Surveyors.

CONTENTS

Appendices

1.0 INTRODUCTION

MTE Consultants were engaged by ROI Studios on behalf of the owner (Entegrus) to update the site condition survey of the existing Hydro Electric administration and operation property at 135 Edward Street in St. Thomas Ontario. The initial field review of the property and the site services was previously conducted July 10, 2020.

2.0 SCOPE OF REVIEW

The site service part of the review includes observations for storm sewers, sanitary sewers, grading and fire hydrants. The trench drain in the truck bay was also reviewed as part of this section. The site part of this review includes observations of exterior site work including concrete sidewalks, asphalt paving for driveways and parking areas and ground cover. It should be noted that physical testing, video inspections, or excavations of pipes was not included in the scope of work for this assignment.

The previous condition survey and report were completed on August 19, 2020. This review, completed on July 10, 2024, was conducted to build on the observations from that report and to advise on any recommended works completed and new problems or concerns that may have arisen since.

3.0 OBSERVATIONS

3.1 Garage Trench Drains

There are two trench drains in the garage area that run E-W the full length of the garage. Both trench drains are clean and appear to be in good condition. Entegrus employee mentioned concrete around drains had recently been reinstalled.

3.2 Watermains/ Fire Hydrants

The site is serviced with a system of watermains and fire hydrants. The hydrants were observed to be in good condition. No tests were conducted to confirm whether the valves operated correctly.

3.3 Edward Street Sewer Outlets

The building sanitary system outlets to the 200mm sanitary sewer on Edward Street along the east curb line of the visitor parking area. During MTE's site visit the sanitary outlet manhole was opened and no issues with the performance were observed.

The front visitor parking area and the employee parking areas outlet to an existing storm sewer on Edward Street. The catchbasin in the visitor parking lot and the CB's in the staff parking area was inspected during a rain event and appeared to be clean with water accumulating to the outlet level before draining. No issues were observed with this outlet.

3.4 SWM - Storm Sewer Outlets

The majority of the site (except the front and employee parking area) drains to a storm water retention area west of the site. A series of ditches along the south edge of the back parking lot conveys the storm flows to this facility. A ditch inlet catchbasin is located at the west end of the ditch area. All ditches and catch basins were checked to confirm proper operation. There was significant rainfall at the time of inspection but ditches were conveying rain water properly to outlets. Water was accumulating higher than the pipe invert at the ditch inlet catch basin but was flowing out.

The front and employee parking lot catchbasins were checked for condition and operation. All were draining and were in good condition.

3.5 Asphalt Driveways and Parking Areas

The asphalt driveways and parking areas are in varied condition. There are some significant cracking along the west side driveway (north of the gate) and in the drive aisle immediately south of the garage. Minor cracking was witnessed in both employee and visitor parking lots, especially near the curb in the visitor lot. There were no concerns observed with the sidewalks.

4.0 RECOMMENDATIONS

4.1 Garage Trench Drains

No changes required for these drains. They should be monitored and cleaned out as required.

4.2 Watermains/ Fire Hydrants

No concerns with the fire hydrants or water service that we could observe. Hydrants should be tested annually.

4.3 Edward Street Sewer Outlets

No concerns were noted for these services. The storm catchbasins should be cleaned every couple of months of debris and following the winter snow thaw.

4.4 SWM - Storm Sewer Outlets

No concerns were observed with the storm sewer system or catchbasins in the parking lot. No concerns were observed with the rear storm water management system and the outlet to the municipal SWM system. The catchbasins and open channel should be monitored for debris and plugging on a regular basis and cleaned out following the winter snow thaw.

4.5 Asphalt Driveways and Parking Areas

There is cracking of the asphalt in localized areas. These areas are identified in the photos attached to the report. These areas should be replaced and repaired or patched to make sure any cracking doesn't spread. The repairs generally will require pulverizing and replacing larger sections or filling of the cracks with asphalt emulsion in smaller sections. There were no concerns observed with the sidewalks or curb.

5.0 OPINION OF PROBABLE COSTS

1. n/a
2. allow $750/ yr for annual testing of fire hydrants
3. allow $750/ yr for annual cleaning and flushing and following heavy rainfall events (and snow melts)
4. allow $750/yr for regular cleaning and removal of debris
5. allow $2000 for repair and sealing of damages or cracked asphalt locations in the locations identified in the photos. Allow $25,000 for removal and replacement of asphalt in locations identified in the photos.

All of which is respectfully submitted,

MTE Consultants Inc.

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Director
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WHV:azp

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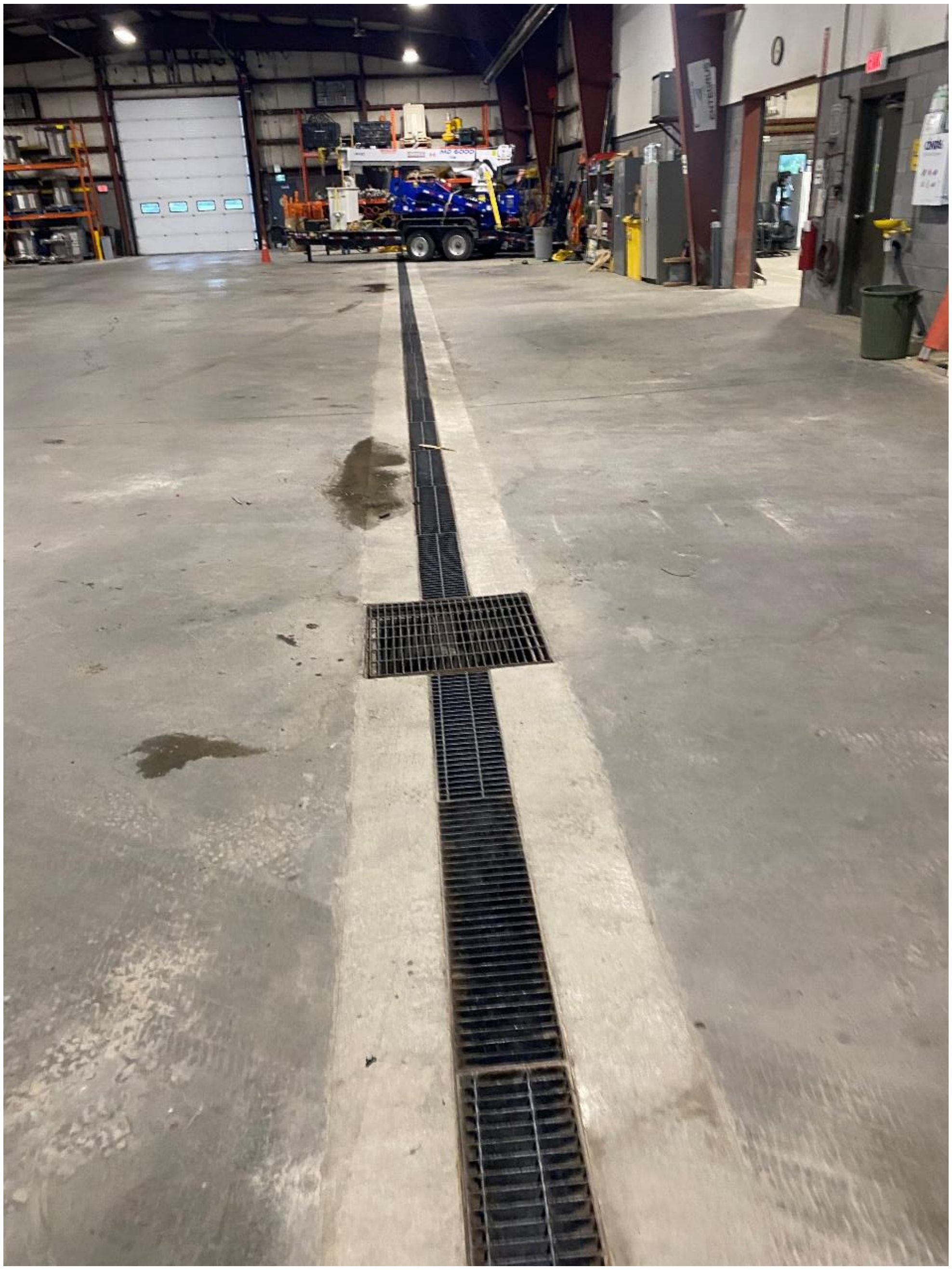
Appendix A

Photo Log



Trench Drain 1 – Located in garage – Clean and in good condition.

Trench Drain 2 – Located in garage – Clean and in good condition.

Driveway into garage is settling/cracking. Asphalt will need to be removed and replaced.

Back parking area, asphalt generally in good condition, some minor cracking. Minor repairs/ filling recommended. Monitor for further damage.

Employee parking area – asphalt generally in good condition, minor cracking should be monitored.

Back drive aisle, asphalt cracking. Asphalt will need to be removed and replaced.

Back storage area – drainage functioning properly. Minor repairs/ filling recommended. Monitor for further damage.

Back parking lot- minor cracking observed. Minor repairs/ filling recommended. Monitor for further damage.

Back swale – no issues

DICB – SWM outlet - rear of building – no issues

New driveway - rear of building – no issues

Front driveway – asphalt cracking and some separation along joint. Asphalt will need to be removed and replaced.

Front driveway – asphalt cracking and some separation along joint. Asphalt will need to be removed and replaced.

Driveway loading dock – some asphalt appears to have been repaired. Monitor to ensure cracking or further settlement does not occur.

Visitor parking CB – no issues

Employee parking lot CB – no issues

Sanitary MH – no issues

Visitor parking area – front entrance – some minor asphalt cracking. Minor repairs/ filling recommended. Monitor for further damage

Employee parking – asphalt cracking noted in a few locations. Generally, asphalt in good shape. Minor repairs/ filling recommended. Monitor for further damage

Appendix B

Asphalt Repair Mark-up

A - asphalt cracking in delivery driveway along east side, approximately 425m^2

B - asphalt cracking in drive aisle south of garage, approximately 340m^2

C - asphalt cracking in front of west entrance to garage, approximately 20m^2

VR
ENGINEERING FORWARD

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Mechanical & Electrical Engineers
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Entegrus Building Condition Report

Mechanical & Electrical Systems

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V&R Project No. 24-102
September 18, 2024

Table of Contents

1. Introduction

Vanderwesten & Rutherford has prepared the report to describe the current conditions and suggested improvements of the mechanical and electrical systems for Entegrus Power, at their St. Thomas office location on Edward Street.

A guided visual field review of the various existing building components was performed on Friday July 10, 2020, with the Architect, Consultants and Owner.

Original drawings and specifications for this building were made available prior to field review.

During our examination of the building, no physical or destructive testing was performed. Comments and conclusions are therefore based on the visual and/or the apparent physical condition of the building elements.

This study is intended for the client named and should not be distributed further without our consent.

2. Mechanical Systems

2.1. Fire Protection

Description

This section reviews Fire Protection related systems, including sprinkler, standpipe and fire extinguishers.

Sprinkler (N/A)

Stand Pipe (N/A)

Fire Extinguishers ☒ Good

General Comments – Main Building

Existing building does not have a sprinkler or standpipe system.

Fire extinguishers are present throughout the building and are readily accessible to public. Extinguishers observed were ABC dry chemical type and are appropriate for areas they are currently serving. Review of test certificate indicate testing is done and signed off accordingly.

Review of kitchenette/Lunch room found to have 5lb exposed ABC extinguishers.

Electrical/data rooms were found to be provided only with ABC and not with CO type extinguishers for electrical fires.

General Comments – Works Garage

Garage structure is not protected using sprinkler or standpipe system. Surface mount Fire Extinguishers are present throughout the Garage and Loading Bay and are readily accessible to public. Extinguishers observed were ABC dry chemical type and are appropriate for areas they are currently serving and new areas. Review of test certificate indicate testing is done and signed off accordingly.

Recommendations/Observations

- Found to be in good condition.
- Recommend that CO extinguishers be provided in all electrical and data rooms.

Figure 1: Fire Extinguishers within Garage

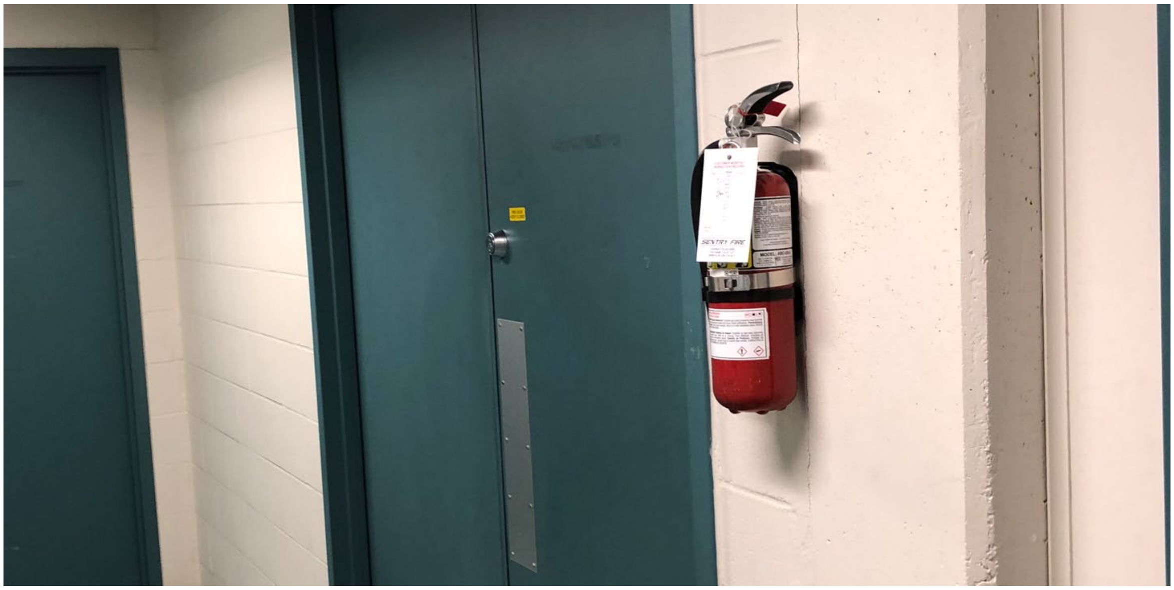


Figure 2: Fire Extinguisher located In Basement

Figure 3: Fire Extinguisher In Kitchenette / Lunch Room

Figure 4: Fire Extinguisher in Typical Office Area

2.2. Plumbing and Domestic Water

Description

This section reviews Domestic Water related systems, including Domestic Cold Water, Domestic Hot Water and Domestic Hot Water Re-Circulation systems.

Domestic Cold Water ☒ Good

Domestic Hot Water ☒ Good

Domestic HW Re-Circulation N/A

General Comments – Main Building

Water is supplied by the municipal water source. Based upon review of the building the water main supporting the facility is along Edward Street. The incoming six-inch (6") water supply was observed entering the basement in the north-east corner of the building (see Figure 5). This main splits and reduces down to a four inch (4") capped connection and a one and a half inch (1-½") domestic water pipe through a water meter before running along the basement ceiling and feeding domestic water heaters for the main building and garage. Backflow prevention was still not observed which is required as per current code and municipality (CSA B64.10).

Water piping throughout the building looks to be mainly original copper for small pipes and galvanized steel for larger piping. Small amounts of newer piping are present from renovations or repairs done in the past years. Exposed cooper did show signs of corrosion at joints but appear to be superficial.

- Expected service life for copper piping in this type of building is 35-40 years.
- Expected service life for Galvanized piping in this type of building is 40-50 years

Domestic hot water supply to front office kitchenette and washroom is provided by a single electric water heater which is located in ceiling area of the Water Meter Room (see Figure 6). Capacity of this unit is 6 Gallons. Unit appears to be original to area served.

Domestic hot water supply to main building is provided by a single electric water heater which is located in the laundry room (see Figure 8). Unit appears to have been replaced in Maay 2022. Capacity of this unit is 75 Gallons. No thermostatic mixing valve was present on hot water supply which could expose occupants to the danger of scalding water. No recirculation was present.

- Expected service life for water heater is 10-15 years.

Non-freeze wall hydrants and standard hose bibs located on exterior walls of the main building.

General Comments – Garage

Domestic hot water supply to garage is provided by a single conventional atmospheric gas water heater complete with power vent through roof. Unit is located on platform in garage (see Figure 9). Unit appears to be replaced at same time as laundry room 2022. No mixing valve was present, no recirculation was present.

- Accessibility to the water heater within the garage is difficult for maintenance.
- Expected service life for water heater is 10-15 years.

Observation/Recommendations

- Galvanized piping did appear to be in acceptable condition but with age can result in discolored water and pressure loss from corrosion if not change. Would recommend replacing as areas become renovated.

- Recommend that all water, sanitary and storm piping insulation be repaired and or new insulation be installed where piping is replaced or missing to reduce amount of condensation build up on piping and heat lose in domestic hot water system. Example of exposed copper and cast piping shown in Figure 6 & 7
- All water heaters do not have drainage present. Should be properly piped to the nearest drain. The water heater suspended within the water meter room 011 (see Figure 6) should be properly drained from the drain pan.
- Water Heater in Meter room 011 appears to be original and may require servicing as it is past the expected service life.
- Installation of Doublecheck backflow preventer required on existing building water service.

Opinion of Probably Cost

- Allow $40,000 to $60,000 for replacement of all or some items as noted above

Figure 5: Existing Water Service entering building located in basement Room 011

Figure 6: Electric Hot Water Heater hanging within Water Meter Room 011.

Figure 7: Example of exposed sanitary piping in storage room.

Figure 8: Electric Hot Water Heater located within Laundry Room

Figure 9: Gas Hot Water Heater located within Garage

2.3. Plumping/Sanitary and Storm

Description

This section reviews Sanitary, Storm and Sump Pits systems related to the building.

Sanitary System ☒ Good

Storm System ☒ Good

Sump Pits / Pumps ☒ Good

General Comments – Main Building

Sanitary system

Multiple connections to site services are provided for sanitary systems serving this building.

One eight inch (8") sanitary building connection exits the main building at the North end and connects with combined sewer running along Edward Street.

Underground sanitary piping condition is hard to evaluate. Typically, an estimate on 35-40 year replacement life is found to be acceptable with buildings of this type. It's suggested that the owner shall camera and cleanout the lines within the next couple of years to review condition of the piping, at minimum recommendation to scope and clean line at laundry and kitchenette area to prevent back ups due to lint and debris build up.

Cast iron, copper and ABS was found in in main building. ABS is not an acceptable material in this type of facility. Copper and cast iron were mainly insulated but portions were found to be exposed as seen in figure 7.

- Expected service life for cast iron sewer piping in this type of building is 50-65 years.
- Expected service life for copper dwv piping in this type of building is 40-50 years

Storm system

The main building is primarily drained with the use of an exterior gutter and downspout system and discharged onto property. There is a scupper drain utilized on the portion of flat roof where the roof top units are located which drains through an exterior downspout. There is minor pooling of water located at the scupper drain. Systems and piping appear to be original to building. Refer to figure 12.

Weeping tile drains are collected in weeper sump pit located in north-west corner of building. Storm sump pump then discharges to a four inch (4”) storm connection which exits north to the exterior where it connects to storm piping on exterior of building. Systems appear to be original

General Comments – Garage

Sanitary System:

Garage structure sanitary system consists of trench drain with oil interceptor. Oil interceptor complete with vents are located on exterior of the north face of garage as seen in figure 15 & 16.

Storm System:

Storm water is collected using exterior gutter and downspout system and discharged into underground storm sewer piping.

Observation/Recommendations

- Copper and cast did appear to be in decent condition, no typical signs of deterioration were visible on exposed area.
- Recommend Sump pit pump be investigated further to determine if existing pump and controls currently installed are operational or require servicing.
- Replace all exposed ABS piping with proper copper or cast iron, or code compliant PVC plastics throughout the building.
- Oil interceptor lid appears to show signs of wear and corrosion. Would recommend that it be reviewed internally to ensure no structural concerns are present. If not recommend at minimum to have the lid and frame be treated and repainted.
- Trench drains on interior to be cleaned and flushed out.

Opinion of Probably Cost

- Allow $10,000 to $15,000 for replacement of all or some items as noted above

Figure 10: Weeping Tile Sump Pump located in Basement Room 002

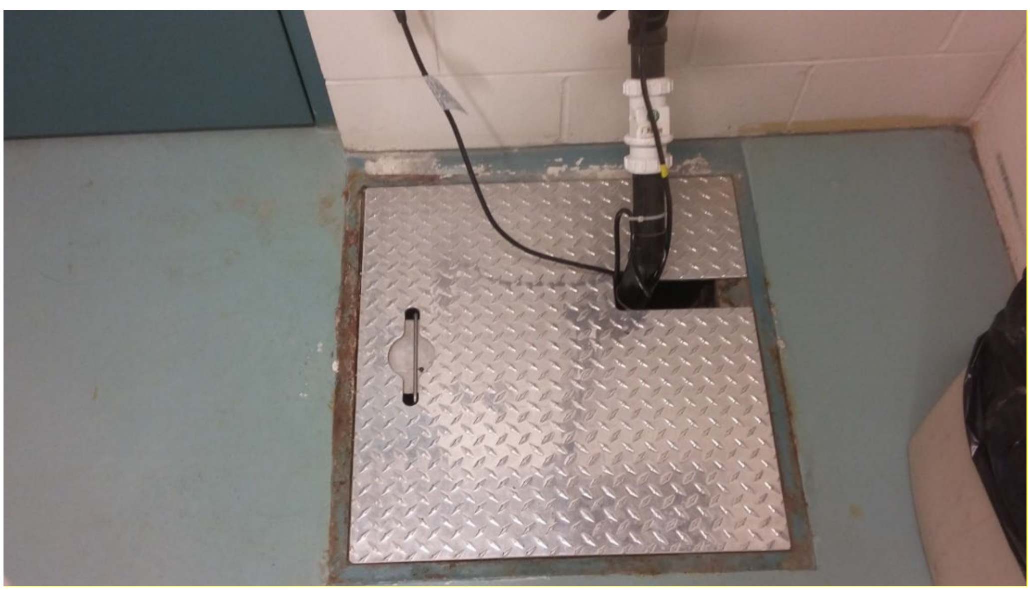


Figure 11: Sump Pit located in Drying Room

Figure 12: Exterior Storm water downspouts.

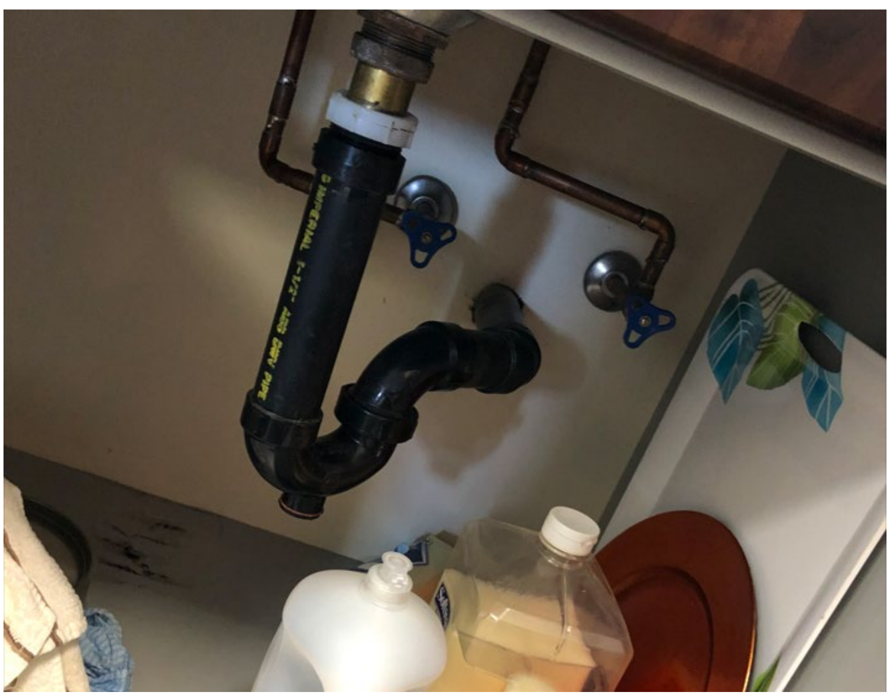


Figure 13: Typical ABS under counter.

Figure 14: Typical ABS in ceiling spaces.

Figure 15: Oil Interceptor on exterior.

Figure 16: Oil Interceptor Vents

2.4. Plumbing - Fixtures

Description

This section reviews the plumbing fixtures.

Plumbing Fixtures Ground ☒ Good

Plumbing Fixtures Basement ☒ fair

General Comments – Main Building

Plumbing fixtures appear to be newer in most washrooms on ground floor. Some original fixtures were found in basement level but were functional. Barrier free fixtures were found in main washroom but lavatory drains did not have offset grid strainers or insulation as per OBC Barrier free compliance.

Electronic faucets were used throughout the main building and boardroom washroom. Water closets and urinals were mainly electronic flush valve with a few locations having flush tank water closets. Did discover that the sensor on water closet with seat covers did not have extension so sensor obstruction could prevent automatic flush when left up.

Fixtures appear to be in working order with no immediate operational problems observed. Fixtures and service sinks in basement and laundry did appear to be mainly original from 1994 but in operational condition.

Showers for the most part were original but in fair condition.

Drinking fountain and bottle fill stations were found in corridors and appear to be new and in good condition.

General Comments – Garage

Garage has a few plumbing fixtures that appeared to be original with heavy use visible. Only one Safety Fixture, eyewash, is installed and was located next to mop sink but terminated on to floor as see in Figure 24. Eyewash did not have mixing valve station to temper water which can result in non compliance with Health and Safety temperature requirements for flushing.

Observations/Recommendations

- Plumbing fixtures on ground floor are in newer condition and found to be acceptable. Fixture in basement have reached their suggested replacement life and should be replaced or serviced to extend life.
- Drain piping and water piping used for barrier free lavatories to be insulated. Offset grid strainers should be provided on drains as needed.
- Recommend to revise water supply to eyewash station to include an emergency thermostatic mixing valve to temper water to health and safety temperature standards.
- If sensor obstruction at barrier free fixtures becomes an issue recommend replacing seats with backrest. Revisions to flush valves may be required to compensate for backrest.

Opinion of Probably Cost

- Allow $15,000 to $20,000 for replacement of all or some items as noted above

Figure 17: Kitchenette sink.

Figure 18: Lavatory in single washroom.

Figure 19: Barrier free flush valve in Main washrooms

Figure 20:Newer sinks in Main washrooms.

Figure 21: Wash basin located within Basement mens washroom

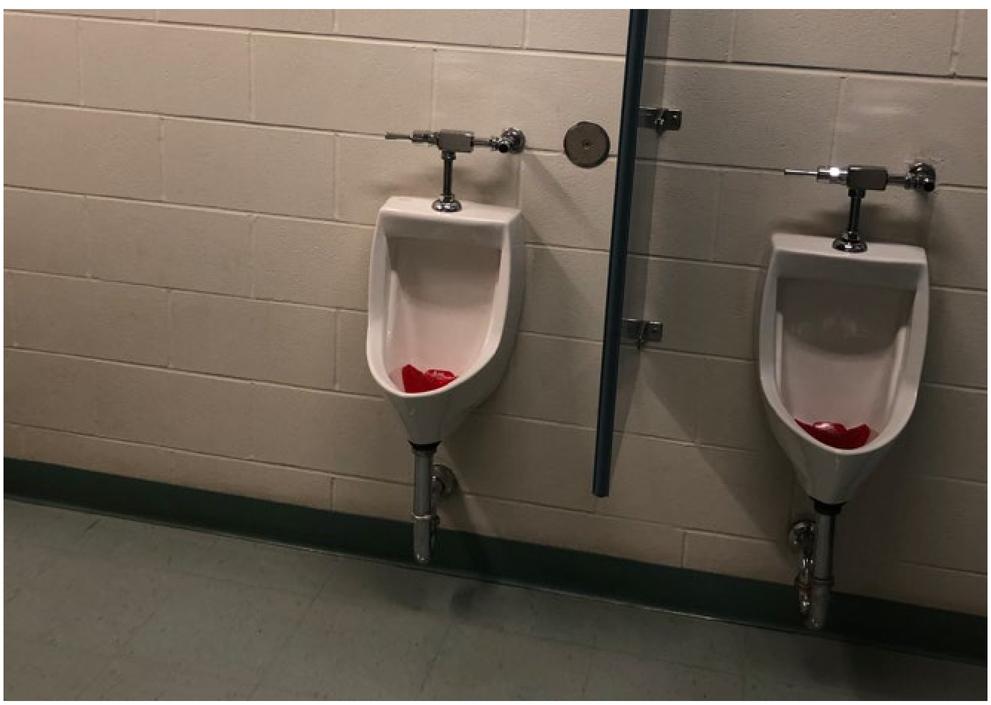


Figure 22: Urinals in Basement men's washroom.

Figure 23: Newer Fixture in Basement women's washroom.

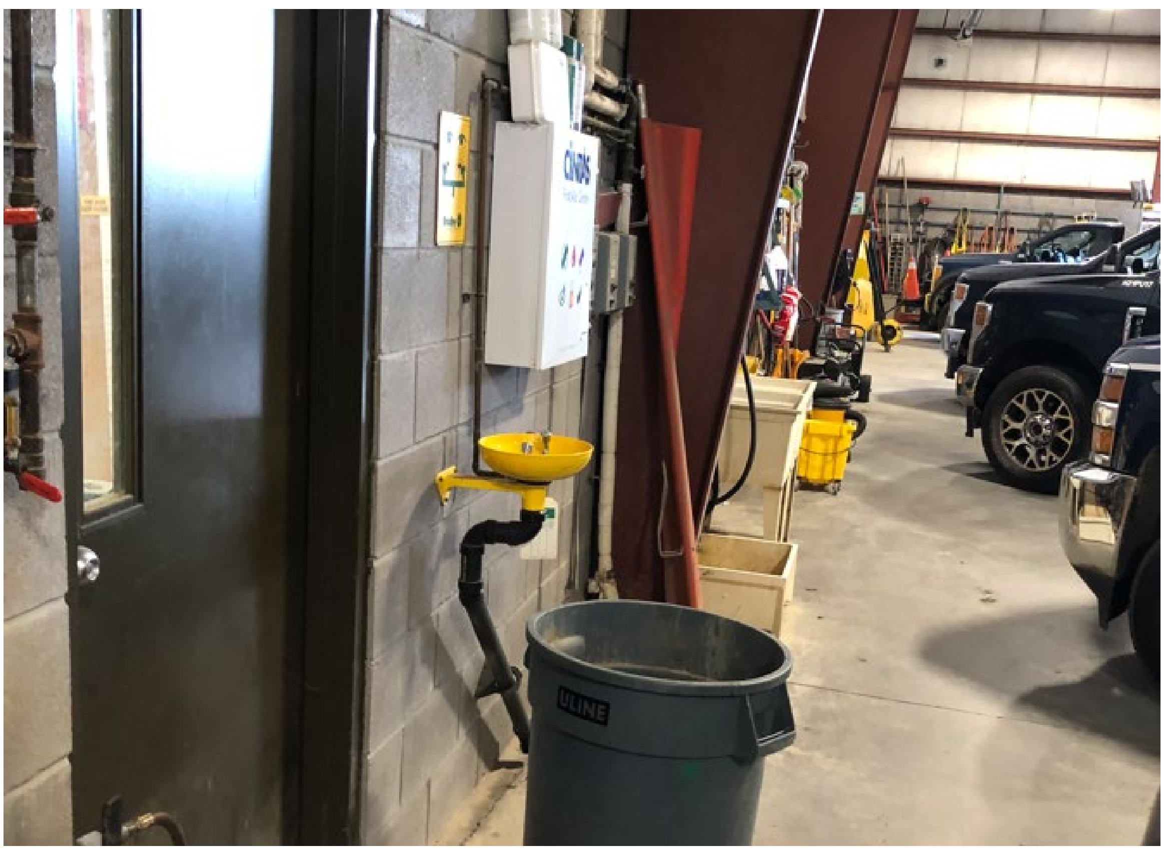


Figure 24: Eye wash station located in Garage with service sinks in background.

2.5. Natural Gas

Description

This section reviews the natural gas service.

Natural Gas ☒ Good

General Comments – Main Building

Natural gas meter is located outside along South side of the main building next to the loading bay. Gas piping runs up the exterior wall and onto the roof where it splits in order to supply the gas fired HVAC units located on the roof and the Garage. Minor rusting was observed on exterior gas piping.

A single three-quarter inch (3/4”) gas line enters the main building down into the laundry room. The connection is currently supported on an electrical disconnect box capped and no longer serving gas fired water heater.

General Comments – Garage

Natural gas supplies ceiling mounted heaters within this structure. As well as new domestic hot water heater.

Interior gas piping appears to be in good condition.

Observations/Recommendations

- Recommend that the current pipe supports on the roof be revised with approved supports sized accordingly to installation.
- A portion of the gas piping within the laundry room should be removed and properly capped in order to not interfere with other services.
- Existing natural gas system functions properly, no revisions are required.

Opinion of Probably Cost

- Allow $2,500 to $4,000 for replacement of all or some items as noted above

Figure 25: Gas meter header on exterior of building.

Figure 26: Gas fired heater located in Garage as well as water heater

2.6. Compressed Air

Description

This section reviews the compressed air service.

Compressed Air ☒ Fair

General Comments – Main Building

Air compressor is located in the Loading Bay area. Air lines are run to several locations within the basement area. Most connections are complete with isolation valve, separator and regulator.

General Comments – Garage

Air compressor is located in the Loading Bay area. Air compressor appeared to be original.

Observations/Recommendations

Piping and equipment found to be in fair condition.

Figure 27: Compressed air located within basement

2.7. Heating, Ventilation and Air Conditioning

Description

This section reviews the building's HVAC system and accessories.

General Comments – Main Office Building

There have been renovations to some of the main office area and front entrance (est. 2003), in which some interior HVAC finishes (GRD's) have been updated, otherwise the majority of HVAC systems remain as indicated on original construction drawings (1994).

The Gas-fired roof top units providing both heating and cooling to the office area/facility are located in a central location on the roof to the south end of the main building. Units Roof area is accessed by ladder only. Two (2) of the rooftop units (RTU's) have been recently replaced utilizing existing curb and ducting connections and are in good condition. The new units are Daiken in type (manufacturer). Four (4) of the RTU's are in fair to poor condition exceeding the expected lifecycle of such unit. It would be expected that continued replacement of the existing Carrier units is eminent, either by failure or need to improve efficiency operations and lifecycle costs. Condensate drains on all units appear to be in fair condition. Gas lines to units could be better supported with spread out supports, both fastened to pipe and spaced accordingly. It would be recommended to replace and remove all wood sleeper/supports from the roof.

The main building and its office areas are split into zones served by the roof top units (AC-1-AC-6). Controls appear to be done through existing VVT system controls as interconnected with the Carrier RTU's. It is noted that the controls systems and temperature control could be improved upon. It is possible VVT systems need replacement and new VAV's that could be integrated with the new RTU's when replaced. Some remnants of unused Carrier controls systems observed.

Figure 28: Existing RTU's on Office Roof

Figure 29: Controls/T-stat within interior Spaces

Existing ducting on roof from RTU's appear to be in poor condition were connected to the old/existing RTU's. This insulation is recommended for replacement and repair to improve both efficiency and ensure the life of ducting is maintained and everything is maintained as watertight.

Figure 30: Existing exterior ducting insulation

Figure 31: Existing torn ducting insulation

Air is distributed throughout these areas by ceiling mounted diffusers. Minimal additional supplemental/electric heating was observed in the office spaces, where the basement storage areas were found with supplemental unit heaters.

Figure 32: Renovated Office space – GRD's

Figure 33: Basement Unit heaters

There are two exhaust fans (EF-1 and Ef-2) located on the flat roof south of the rooftop units location EF-1 serves the large washrooms on each level. EF-2 serves the Drying area in the basement. These fans appear to be the original fans installed in 1994, motor condition unknown, fans are in poor condition.

The washroom next to the boardroom is served by EF-3 located within the ceiling space above the washroom and vented out through the soffit to the east.

Two general ceiling mounted exhaust fans (EF-4 and EF-5) were not observed above the ceiling tiles. Grilles for these fans are located within the meeting room and operations respectively)

Additionally, there are two exhaust fans located in the basement. EF-6 within room 006 and EF-7 within electrical room 009 as tagged on the original construction drawings. EF-6 is vented up through the south wall of the building. EF-7 is vented up to the same roof area through a louvre. These fans appear to be the original fans installed in 1994.

Figure 34: Exhaust Fans on Flat roof

There are two existing Humidifiers located in the laundry room the one to the left is dated 1994 while the second one to the right is dated 2019. Controls and operation of systems are unclear at the time of review.

Figure 35: Humidifiers

There are 2 split A/C units serving the IT/Main Server room with wall mounted distribution heads on adjacent walls within the space, and associated condensers mounted on roof above. Both indoor units are complete with condensate pumps (mounted on wall) not integral to unit. Controllers are mounted on the wall of the server room. Exterior units are mounted on pavers on roof, it would be recommended to raise condensers 24” above roof on support stand for winter operation. Existing units both use R410A refrigerant. Existing units are a 3 Ton Daiken unit (est. 1-3 years old), and a Mitsibushi unit (est. 15-20 years old). Older AC unit had reached expected lifecycle replacement.

Figure 36: Existing Exterior Condensers

Figure 37: Existing Interior A/C Split Unit Heads and Cond. Pumps

General Comments – Garage

The garage is heating only utilizing existing ceiling mounted gas-fired infrared tube heaters. Controls for the heaters are local to the area served. There are wall mounted exhaust fans located within the garage and loading dock areas with interlocked intake louvres. It is unclear if the louvres and fans run on temperature controls for the summer conditions, or off a gas detection system. Gas detection systems were not observed.

Figure 38: Infrared Tube heater (typ)

Existing flammable storage cabinets are noted within the garage floor area. Flammable storage cabinets should be vented too exterior directly.

Figure 39: Flammable Storage Cabinets

Generator room was observed, but reviewed in terms of building loading, gen size, operation of systems. There was an Elec. space heater within the dedicated room. Containment of systems was observed for tank, not for room, and generator vents out the exterior and to 36” above roof level. It is recommended that nothing remains in the room but that of the generator and related systems.

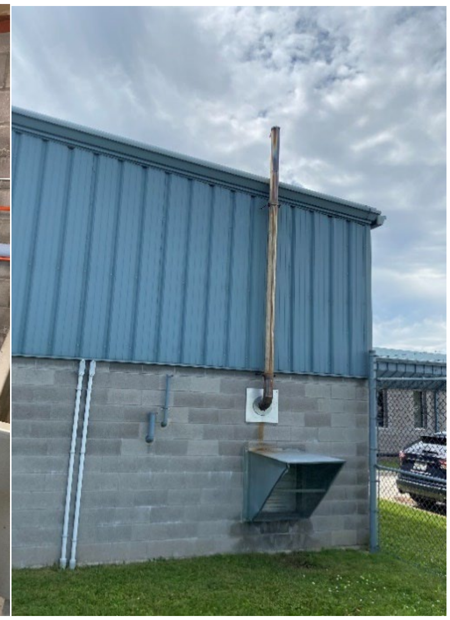



Figure 40: Generator Room and Venting

Observations/Recommendations

In general HVAC systems are operational and in working order, but some of the systems are in poor condition and/or need expected replacement.

- It is recommended that those rooftop HVAC units be replaced as listed below
  - Roof top unit AC-2 (Sep 2010)
  - Roof top unit AC-3 (Sep 2010)
  - Roof top unit AC-5 (Jan 2011)
  - Roof top unit AC-6 (Dec 2008)
- Exterior insulation on all exposed ducting has deteriorated and should be removed and replaced.
- Gas vent flue on AC-3 to be repaired
- Gas line supports to be all new and fastened to pipe (remove existing wood supports)
- Gas line to be painted
- Flammable Storage Cabinets to be vented
- Replace Mitsibushi AC unit serving Server Room
- Ensure gas detection system is in place within Bay/Garage area, serviced and or install new
- Replace aged exhaust fans as noted

Opinion of Probably Cost

- Allow $100,000 to $200,000 for replacement of all or some items as noted above

3. Electrical Systems

3.1. Electrical Service and Distribution

Description

This section reviews the electrical service and distribution equipment condition.

Service & Distribution ☒ Fair

Dry Transformers ☒ Good

General Comments

The electrical service supplying power to the building is from a utility owned pad mounted transformer located outside at the building's north end. The power is supplied from Edward Street at 27.6 kV, 3ø and transformed to 600V, 3ø. The 600V, 3ø electrical service comes underground into the building's electrical room from the utility owned pad mounted transformer. The electrical service is rated at 400 Amp, 347/600 Volt, 3ø.

Observation/Recommendations

The building's service equipment is made by Commander and is the original equipment installation of 1994. The Distribution equipment is made by Commander, Square D, Siemens and Culter-Hammer. The Distribution equipment consists of distribution boards – type S8004T, panel boards type NBL and QL, hand-off-auto starters and disconnect switches. The building does not contain any motor control centres.

The electrical equipment was found generally to be in good condition with no obvious signs of problems such as heating of terminations or excessive corrosion. Surface rust was found on five of the rooftop unit's disconnect switches. Building maintenance personnel reported no overloading or unusual tripping of breakers. Interior and exterior cable raceways appeared to be in good condition from visual inspection.

Square D is part of Schneider Electric's product line with spare parts and field service for the hand-off-auto starters being readily available. New spare circuit breakers can no longer be purchased for the Commander panel boards but spare fuses can still be purchased for the Commander disconnects. Field service can still be provided for the Commander panel boards and disconnects by Eaton Corporation. Culter-Hammer equipment is under the product line of Eaton Corporation with spare circuit breakers, fuses and field service support being readily available. Siemens provides spare fuses and field service support for their product line with both being readily available.

The electrical distribution system will need to be replaced within 5-10 years with regular maintenance and servicing of equipment. It's recommended for all the original equipment to undergo a thermal imaging scan by a qualified contractor to look for hot spots and thermal signature. The distribution should also be closely monitored for flaking of paint, sticky circuit breakers or black spots on connections.

The dry type transformers in the building are made by Rex Manufacturing and Bemag. Field service support is readily available from both companies. All dry type transformers were found to be in good condition but will need to the monitored with the same procedures as the distribution equipment.

Figure 41: Rusty Rooftop Disconnect Switch

Figure 42: Electrical Service Switchboard

Figure 43: Rooftop Disconnect

3.2. Emergency Power

Description

This section reviews the emergency power equipment condition.

Emergency Power ☒ good

General Comments

The electrical emergency power system in the building consists of a 100 kW (125 kVA), Stamford, 600V,3ø diesel engine driven standby generator and Cutler-Hammer Automatic Transfer switch rated for 400A.

Observation/Recommendations

The generator and automatic transfer switch both appeared to be in good condition. The generator can provide emergency power support for approximately 25% of the electrical service size. If a larger capacity of emergency power support is required from the emergency power system, it’s recommended to investigate a load shedding scheme. A visual inspection of the batteries showed no corrosion or rust on the terminals or wire leads.

It was observed that the generator area was being used to store Gatorade crates, etc. It is recommended that the area around the generator be cleared of any unessential items in the event urgent access is required.

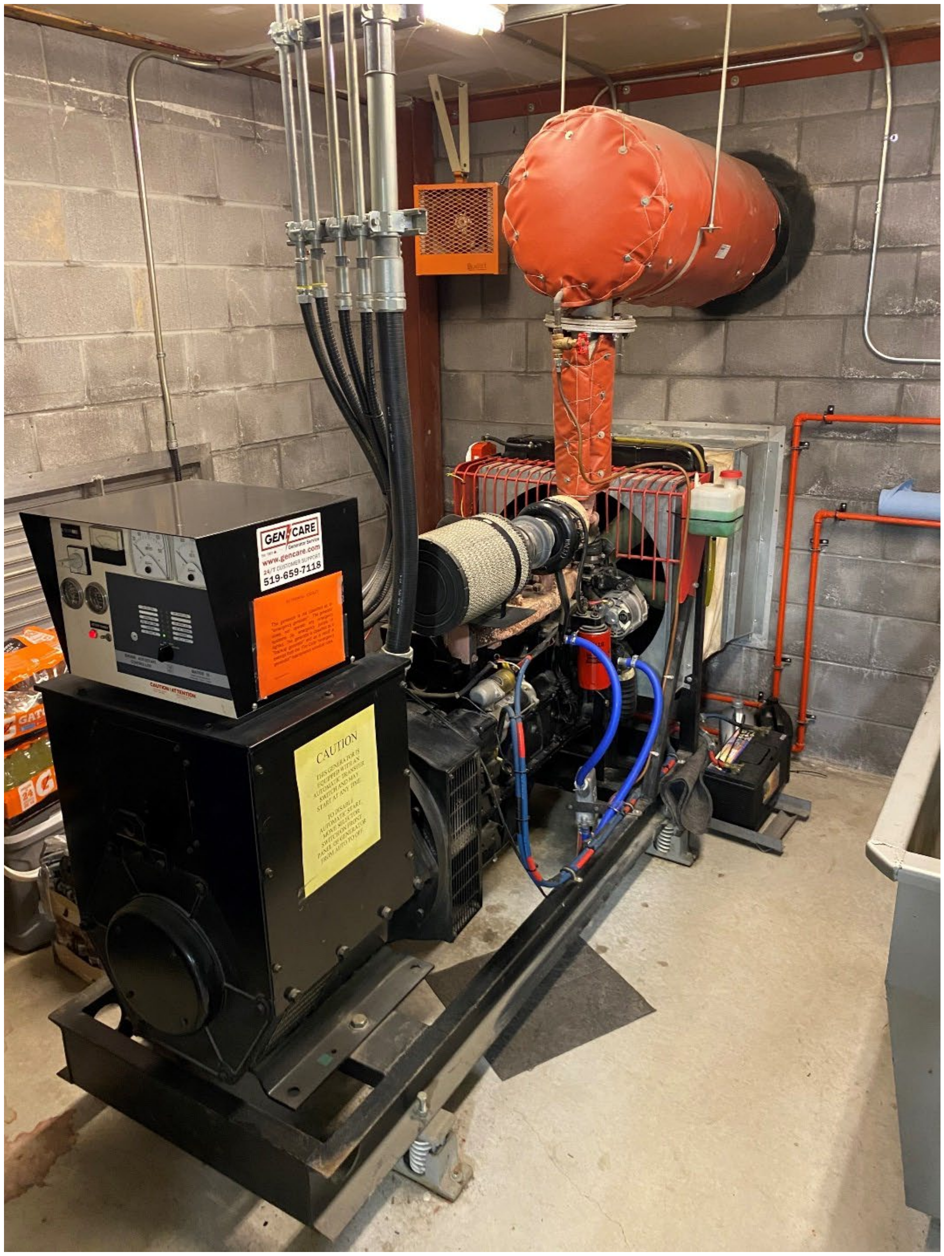


Figure 44: 100 kW Generator

Figure 45: 400A Automatic Transfer Switch

3.3. Lighting and Lighting Controls

Description

This section reviews the buildings lighting and associated lighting control systems.

Lighting ☒ Good

General Comments

The interior lighting appears to be T8 lamp light fixtures in some areas and newer LED light fixtures in other areas, controlled by ceiling-mounted occupancy sensors, sensor-switches and toggle switches. The exterior lighting is LED light fixtures controlled by a time clock/photocell.

Observation/Recommendations

It's recommended to upgrade the interior lighting from T8 lamp fixtures to LED light fixtures. Upgrading the interior light fixtures to LED light fixtures will give the option to upgrade the lighting controls to low voltage lighting control technology at the same time. The upgraded lighting control and LED light fixtures will increase the energy efficiency of the building provide better performance.

The exterior lighting is in good condition as it has been recently upgraded to LED lighting. The timeclock controlling the exterior lighting is original to the building and appeared to be in good condition.

Figure 46: Light Fixture & Ceiling Mounted Occupancy Sensor

Figure 47: Exterior LED Light Fixture

3.4. Emergency Lighting

Description

This section reviews the building's emergency lighting system.

Emergency Lighting ☒ Good

General Comments

The emergency lighting is supplied by remote light heads powered from battery packs spread throughout the building. The exit signage is LED illuminated.

Observations/Recommendations

The battery units, remote light heads and exit signage is in good condition with many of the units being recently updated. Red exit signs will need to be replaced with green (running-man) pictogram exit signs upon failure.

Figure 48: Remote Light Head/Battery Pack

Figure 49: Red Exit Sign

Figure 50: Green Exit Sign

3.5. Fire Alarm System

Description

This section reviews the building's fire alarm system.

Fire Alarm ☒ Good

General Comments

The fire alarm system serving the building is a single stage system with a Mircom Flexnet series panel located in the electrical room and a remote annunciator in the vestibule area.

Observations/Recommendations

The fire alarm system was completely replaced in 2018 and is in good condition. The fire alarm verification/testing certificate from February 25/2020 shows the fire alarm system is actively being monitored by the owner's security company for any trouble signals. The fire alarm panel has extra capacity remaining.

Figure 51: Fire Alarm Control Panel

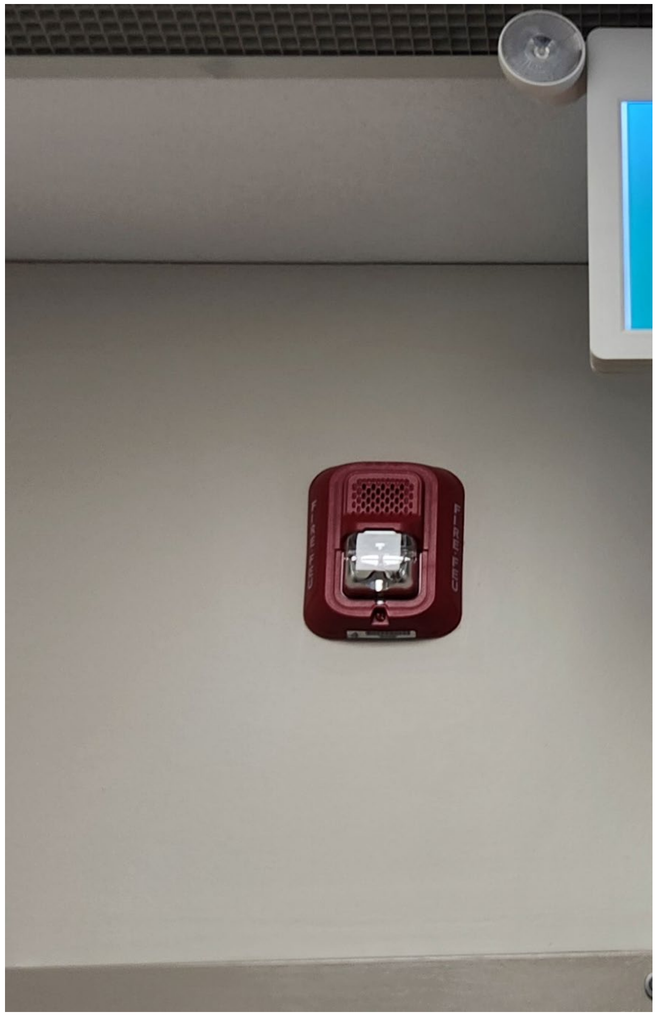


Figure 52: Speaker/Strobe Fire Alarm

3.6. Controls

Description

This section reviews the building's data & communication systems.

Data & Communication ☒ Good

General Comments

The communication system in the building is housed in multiple IT rooms and the electrical room. The electrical room contains various patch panels and switches within the IT rack. The communication and data system is based on a CAT6 structured cabling system. All IT racks and networking equipment belong to the owner. The shop has a PA system with speakers spread throughout the shop area and a microphone in the store's office.

Observations/Recommendations

The communication and data system appears to be in good working condition from visual inspection.

Figure 53: Data Outlet

3.7. Door Access and Security Systems

Description

This section reviews the building's door access & security systems.

Door access & Security ☒ Good

General Comments

The door access control and security system are made up of: card readers, door strikes, door contacts, keypads, motion detectors and automatic door operators. The CCTV monitoring system has various cameras located around the exterior and interior of the building.

Observations/Recommendations

The door access control system is in good working condition except for the access door between the shop and administration building. The door strike is currently not locking correctly and building maintenance was already aware of the issue. All automatic door operators tested were operational. Building staff indicated the CCTV camera is operating correctly, and all CCTV cameras appeared to be in good condition. The security system is in good condition and is remotely monitored by the owner's security contractor.

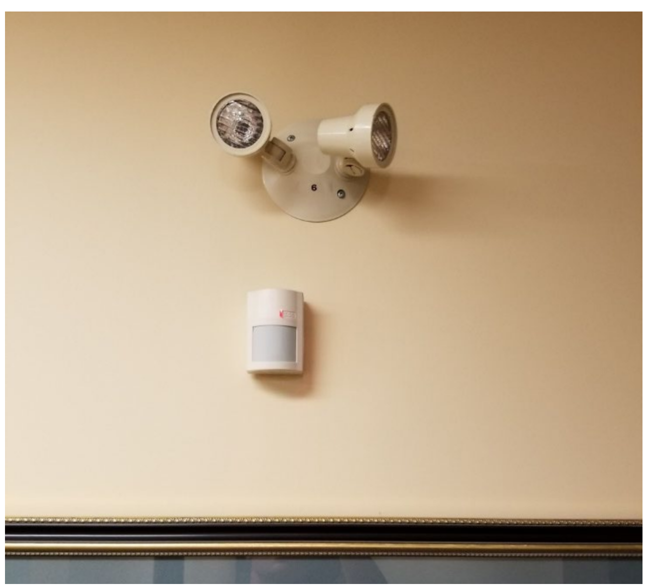


Figure 54: Motion Detector

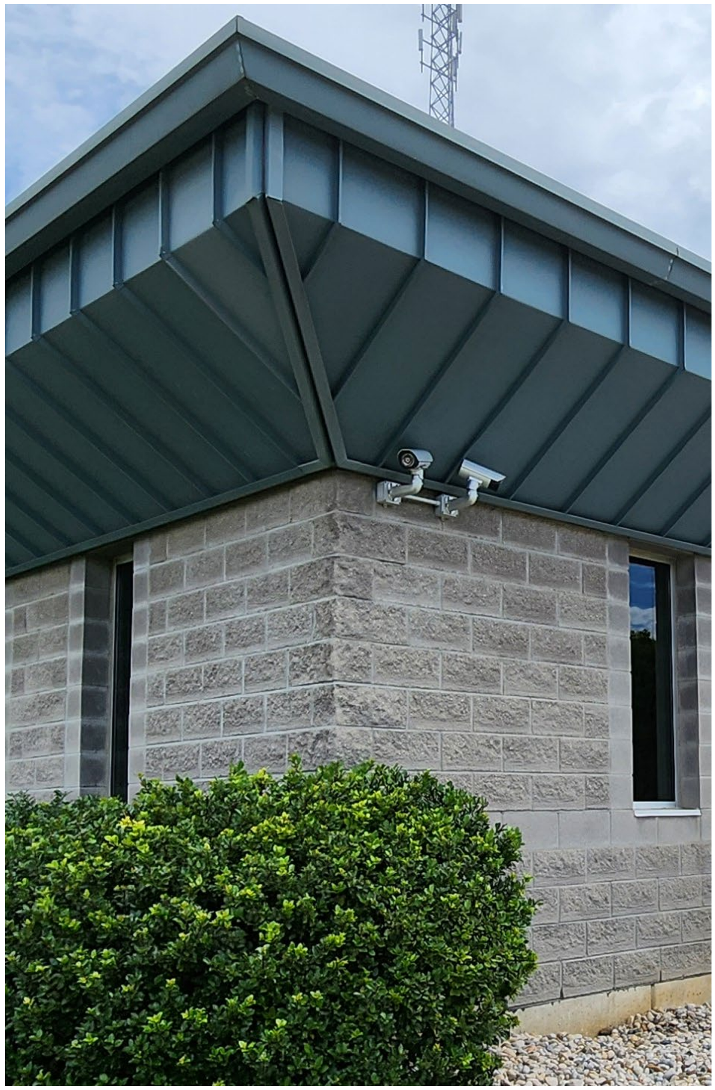


Figure 55: Exterior CCTV Camera

3.8. Receptacles

Description

This section reviews the receptacles and switches.

Interior Receptacles ☒ Good

Exterior Receptacles ☒ Fair

General Comments

The interior of the building has grounded receptacles spread throughout. The exterior of the building has weatherproofed receptacles on the wall spread around the building and one on the roof. The shop is equipped with cord reel receptacles to allow vehicles to be plugged in.

Observations/Recommendations

The interior and exterior receptacles on the walls of the building are in good condition. The equipment service receptacle on the roof needs to be replaced as the cover has broken off and water may leak in the receptacle causing a short circuit. There were very minimal power bars and extensions cords present in the building, indicating an adequate number of receptacles are spread out within the building. Cord reels in the shop area are in good condition.

There is one junction box in the office area which does not have a cover plate and potentially live wires with exposed ends are hanging out. There is another junction box in the office area without a cover plate with wires coming out of it.

Figure 56: Junction box cover plate missing

Figure 57: Cover plate missing

Figure 58: Broken Receptacle Cover on Roof

Figure 59: Cord Reel

3.9. Energy Consumption

The energy efficiency of the building could be improved by converting the T-8 lamps to LED lights. Building maintenance staff confirmed the electricity bills are constant with no abnormal usage of electricity.

4. Costs

4.1. Electrical Cost Summary

The Budgeted amount for that listed above within the electrical portion of the report is in the range of $50,000 - $70,000.

4.2. Methodology

In preparation of this report, we gathered information of the existing electrical systems through the site visit and visual observations on July 10, 2020, reviewed the original drawings (1994), and interviewed the operating personnel.

Note: Our review consisted only of visual inspection and no destructive testing was undertaken.

ATTACHMENT J

Material Investment Narratives

ENTEGRUS POWERLINES INC.

Attachment J:

Material Investment Narratives

ENTEGRUS POWERLINES INC.

CONTENTS

MATERIAL INVESTMENT NARRATIVE

PROJECT / PROGRAM:

01. Contributed Capital

INVESTMENT CATEGORY:

SYSTEM ACCESS

B. GENERAL INFORMATION ON THE PROJECT/PROGRAM

B.2. Overview

EPI receives capital contributions from its customers for specific capital work performed in order to provide the customers access to the distribution system. This program is comprised of customer driven work for additions or changes to EPI's distribution system. This includes new residential subdivisions, C&I customer expansions, customer requests for relocation of services and make-ready work for third party attachers.

In the early portion of the Historical Period, significant make-ready work for multiple Internet Service Providers (ISPs) occurred. During this period, the ISPs rapidly expanded their number of attachments to the EPI distribution system. When EPI receives such an attachment request, it reviews the request and determines if existing infrastructure can support the new/revised attachment. If changes to EPI's infrastructure are required to support this change, the make-ready work is performed. This may include installation or replacement of poles and anchors, and related infrastructure as required to meet both current standards and accommodate the revised attachment. The majority of the ISP growth projects were completed by 2023, which resulted in a reduction of capital contributions in the latter part of the Historical Period. However, ISPs continue to periodically apply for additions (or revisions) to their attachments to align with their business objectives and their customers' demands.

Capital contributions are also received for system access work related to new residential subdivisions, commercial developments, and other customer-driven expansion projects. When developers or commercial customers request a connection, EPI conducts an economic evaluation to determine the capital contribution required in accordance with the Distribution System Code (DSC). These contributions help offset the costs of expanding the distribution system to accommodate new loads while ensuring that existing customers are not subsidizing growth-related infrastructure investments. Typical system access work includes installing new feeders, transformers, and service connections to integrate new developments efficiently into EPI's network. EPI customer growth spiked between 2019 and 2022 before stabilizing near historical levels in 2023 and 2024. This tapering has continued into 2024 and 2025 and has reduced capital contributions received from customers.

Capital contributions are collected in accordance with the DSC and the provisions of its COS. In December 2024, Amendments to the DSC to Facilitate the Connection of Housing Developments and Residential Customers (EB-2024-0092) were enacted. The amendments included the extension of the revenue horizon for residential housing developments from 25 to 40 years. This extension results in 15 more years being included in the economic evaluation process, which in turn, also reduces the amount of capital contributions that EPI will collect from customers. This change has been incorporated into this DSP.

These capital contributions are received in compliance with the provisions in the OEB's Distribution System Code and EPI's Conditions of Service.

B.3. Timing

i. Start Date: January 2026
ii. In-Service Date: Through to December 2030

iii. Key factors that may affect timing: This program is scheduled and dictated by the requirements of third-party companies and is largely outside of EPI's control. Other key factors that may impact timing include legislation changes (e.g. the Building Broadband Faster Act) that further accelerate the response required by EPI.

B.4. Capital Expenditures

B.4.3 Historical and Future Capital Expenditures

Table 1. Historical and Future Capital ($, million)

Contributed Capital - Totals									
Historic Actual Expenditure				Bridge Year	Forecasted Budgeted Expenditure				
2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
$(2.84)	$(5.89)	$(3.07)	$(2.07)	$(1.54)	$(1.67)	$(1.70)	$(1.75)	$(1.78)	$(1.82)

The graph below illustrates the budget figures based on the anticipated customer activity for this investment category ($ in millions).

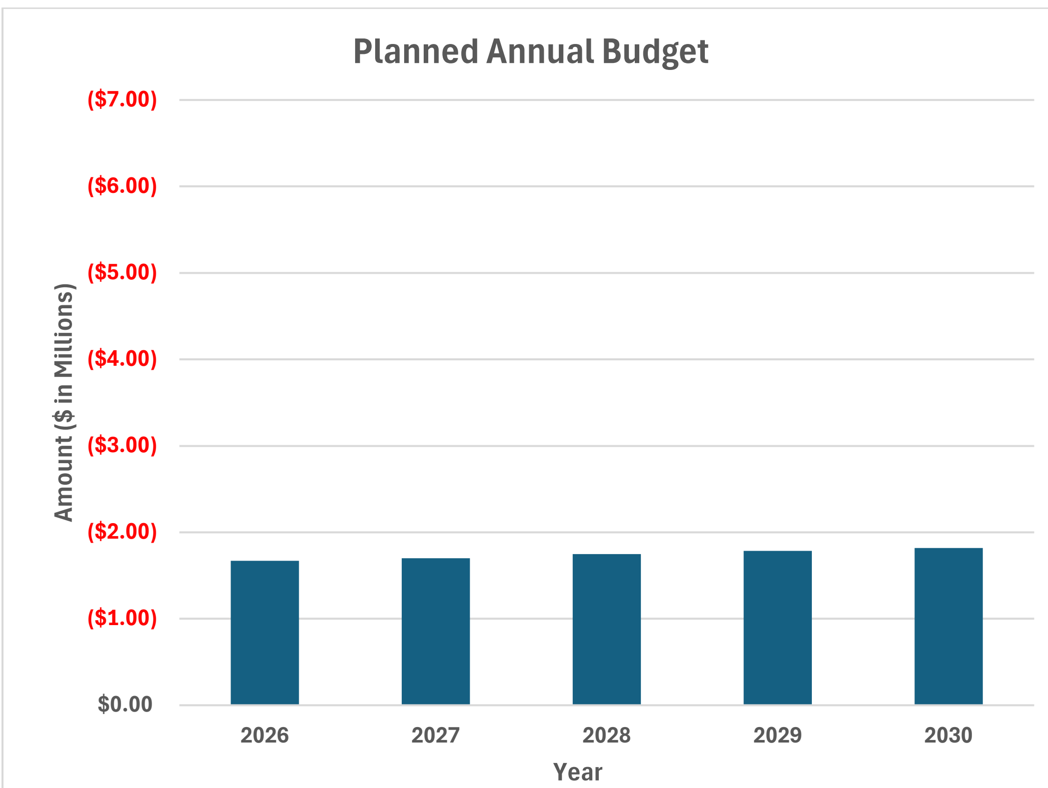


Fig 1: Anticipated Annual Capital Contributions

B.4.4 Economic Evaluation (Expansion projects)

Not Applicable

B.4.5 Comparative Historical Expenditure

The graph below shows that in 2022, EPI received a significant volume of contributed capital, which was primarily driven by the aforementioned spike in customer growth, which was accompanied by rapid ISP attachment levels in EPI's service territory. After the completion of ISP build out and a tapering of customer growth to near historical levels in 2023 and 2024, capital contribution levels also stabilized near historical levels. The recent extension of the DSC revenue horizon for residential housing developments from 25 to 40 years will also reduce the amount of capital contributions that EPI will collect for customers beginning in 2025.

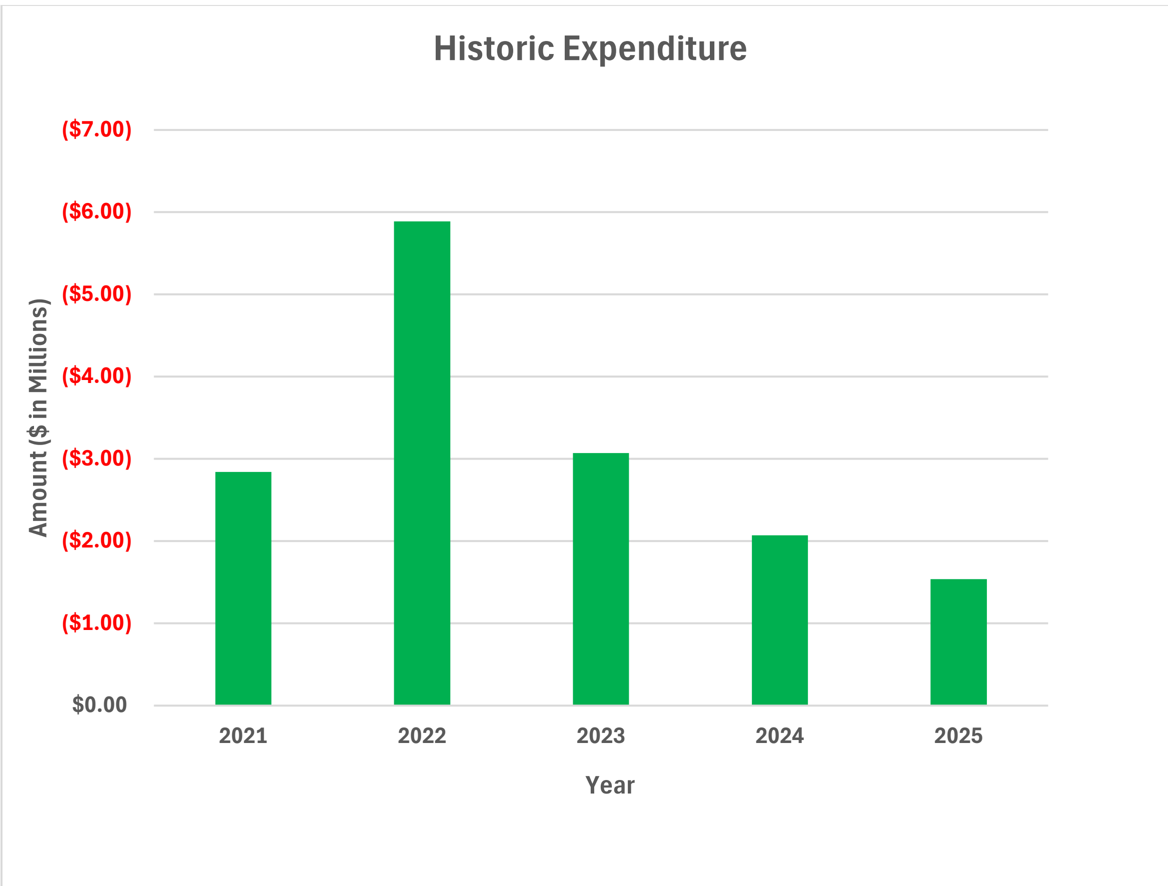


Fig 2: Annual Historic Contributed Capital ($ in Millions)

B.5. Investment Priority

There is no ranking associated with this program since it accounts for the contributions received for various capital jobs performed in response to customer requests associated with System Access work.

B.6. Alternative Analysis

There are no practical alternatives to this project. These capital contributions are necessary for EPI to execute capital jobs, and the contributions are received in compliance with the provisions in the OEB's Distribution System Code and EPI's Conditions of Service.

Collection of capital contributions are required to comply with the principle of beneficiary pays and to maintain equity across users of the distribution system. As such maintaining EPI's current program, which complies with all regulations and laws, is the most prudent course of action.

B.7. Innovative Nature of the Project

Not Applicable

B.8. Leave to Construct Approval

This project does not require leave to construct approval under Section 92 of the OEB Act.

C. EVALUATION CRITERIA AND INFORMATION REQUIREMENTS

C.2. Efficiency, Customer Value, Reliability & Safety

Table 1: Investment Evaluation - Efficiency, Customer Value, Reliability & Safety

Criteria	Description
Efficiency	Incremental capital contributions from new customer connections enable the utility to efficiently manage the rate base, aligning investments with customer growth and system needs. The program: 1. Helps manage the size of the connection queue and the workload of EPI engineering staff by ensuring that only serious applicants proceed to advanced stages of the connection process, reducing unnecessary administrative burden. 2. Reduces the financial burden on the utility by offsetting capital expenses with customer contributions, thereby helping to manage borrowing costs and contributing to short-term liquidity. 3. Promotes long-term system design efficiency, particularly for larger customers, by incentivizing them to seek interconnection points where costs are minimized, such as locations near existing facilities with sufficient capacity.
Customer Value	By collecting capital contributions in compliance with OEB provisions, the program ensures fairness and equity, aligning with the Beneficiary Pays Principle that underpins utility cost allocation. Through the connection process, customers providing deposits have input on the location, sizing, and other options for their facilities (where feasible), ensuring their connection experience aligns with their expectations. Customers have the option to procure contestable portions of the work independently, where applicable, allowing them to manage costs more effectively and maintain greater control over their projects (subject to approval). By allocating costs equitably, the program ensures that existing customers are not unduly impacted by the expenses of new connections or upgrades, developing customer fairness and trust.

Reliability	This project does not provide direct reliability enhancements. Instead, it reflects the scope and objectives of other projects to which individual customer contributions pertain, supporting broader system reliability improvements indirectly.
Safety	This project does not provide direct safety enhancements. Instead, it reflects the scope and objectives of other projects to which individual customer contributions pertain, supporting broader system safety improvements indirectly.

C.3. Investment Need

C.3.3 Primary Driver:

The primary driver for this project is customer-driven capital work performed in order to provide access to the distribution system. These capital contributions are received in compliance with the provisions in the OEB's Distribution System Code and EPI's Conditions of Service.

C.3.4 Secondary Drivers:

Not Applicable

C.3.5 Information Used to Justify the Investment:

As this project captures the contributed capital for each project, the exact number of assets associated with this project is inherited from the other projects in this document.

C.4. Investment Justification

C.4.3 Demonstrating Accepted Utility Practice:

The received contributed capital follows the provisions in the OEB's Distribution System Code and EPI's Conditions of Service

C.4.4 Cost-Benefit Analysis:

Not Applicable

C.4.5 Historical Investments & Outcomes Observed:

The magnitude of income associated with this project tracks other system access projects. Please see Section 5.1.1 for additional information.

C.5. Non-Wires Solution

Not Applicable

C.6. Innovation

Not Applicable

MATERIAL INVESTMENT NARRATIVE

PROJECT / PROGRAM:

02. Customer Connections: Commercial & Industrial

INVESTMENT CATEGORY:

SYSTEM ACCESS

A. GENERAL INFORMATION ON THE PROJECT/PROGRAM

A.1. Overview

EPI currently has approximately 6,400 Commercial & Industrial ("C&I") customers. The purpose of this project is to provide System Access (for new customer connections) and upgrades to EPI's distribution system (Service Upgrades) when necessary to continue to supply existing C&I customers.

Program volume may vary from year-to-year depending on the number of new C&I connection requests received and the overall plans of existing C&I customers and the nature of EPI's infrastructure in the area being addressed. EPI actively collaborates with customers and municipalities to anticipate growth, see Exhibit 2, DSP Section 4.2 for additional details on coordinated planning.

A.2. Timing

i. Start Date: January 2026

ii. In-Service Date: Through to December 2030

iii. Key factors that may affect timing: The timing of these expenditures is dictated by the requirements of the requesting party or applicable legislation and is deemed mandatory in accordance with the OEB's Distribution System Code. The following factors can impact the project schedule:

- Work associated with this project is customer-driven, which can vary and be subject to change based on a variety of factors, including economic conditions
- Timing and volumes are estimates based on customer collaboration and historical levels.
- Actual spend and timing will depend on customer requests.

A.3. Capital Expenditures

A.3.3 Historical and Future Capital Expenditures

Table 1. Historical and Future Capital ($, million)

Customer Conns: Commercial & Industrial - Totals									
Historic Actual Expenditure				Bridge Year	Forecasted Budgeted Expenditure				
2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
$1.62	$2.03	$1.84	$1.76	$1.40	$1.44	$1.48	$1.52	$1.56	$1.59

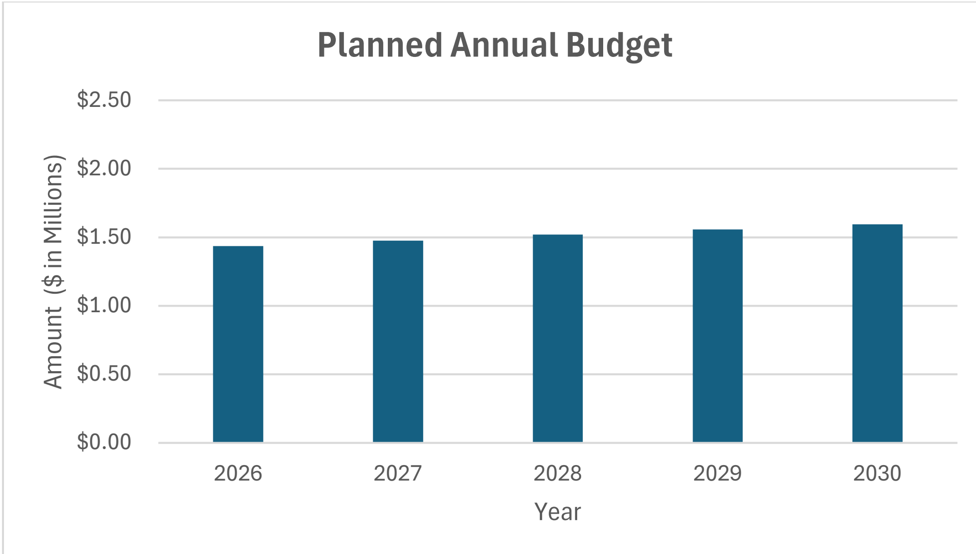


Fig 1: Planned Budget for Commercial & Industrial Customer Connections

The numbers above represent a cumulative budget for new C&I customers as well as rebuild costs. Several factors have been considered in budgeting, including ongoing projects and collaboration with economic planners and the municipalities to identify areas of growth. Additionally, considerations include any large projects that may seek connection in the near future (Section 4.4.3).

Figure 2 below further breaks down the planned budget between New C&I customers vs rebuild costs.

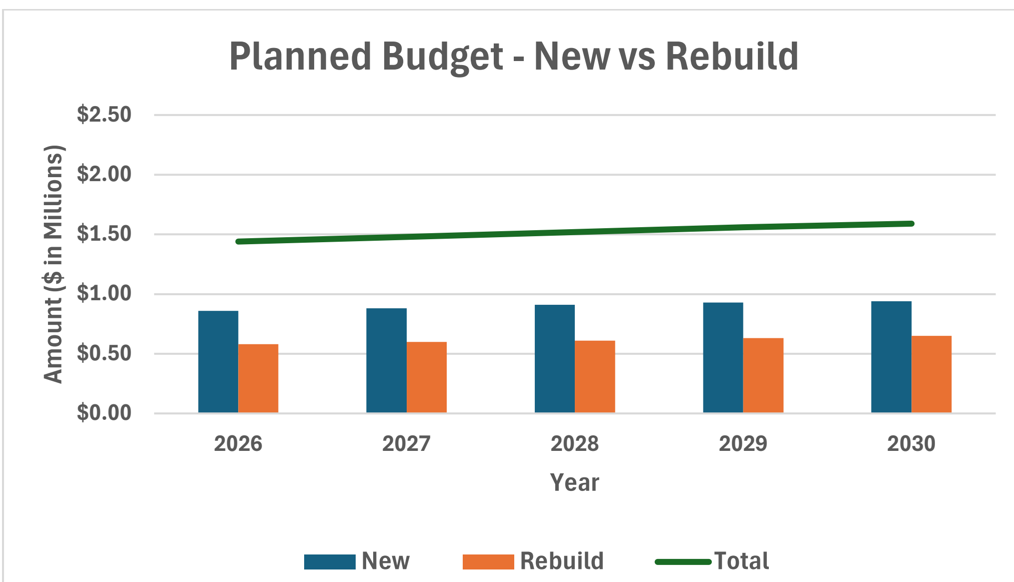


Fig 2: Planned Budget for New Customer Connections vs Rebuild Costs

A.3.4 Economic Evaluation (Expansion projects)

Capital contribution in this sector is calculated based on economic evaluation model (EEM) defined in the Distribution System Code and regulated by the OEB.

A.3.5 Comparative Historical Expenditure

Investments in this category are driven primarily by customer demand, which can fluctuate and make forecasting challenging. Through the pandemic period, EPI experienced a period of growth in customer connections leading to higher actual expenditures than originally forecasted.

However, as shown in Figure 3, this growth began to taper in 2023, with a continued decline into 2024 and 2025. This trend signals a return to more stable and predictable levels of activity. EPI's expenditure forecasts for the 2026 test year and beyond reflect this shift, incorporating recent trends and the constraints posed by limited development land within the service territory. The current plan is based on updated demand patterns and reflects a prudent, data-informed outlook. EPI anticipates a steady, linear increase in expenditures moving forward, guided by the more recent experience. EPI will continue to monitor for growth activity in St. Thomas associated with the battery plant, but no customers have approached at this time.

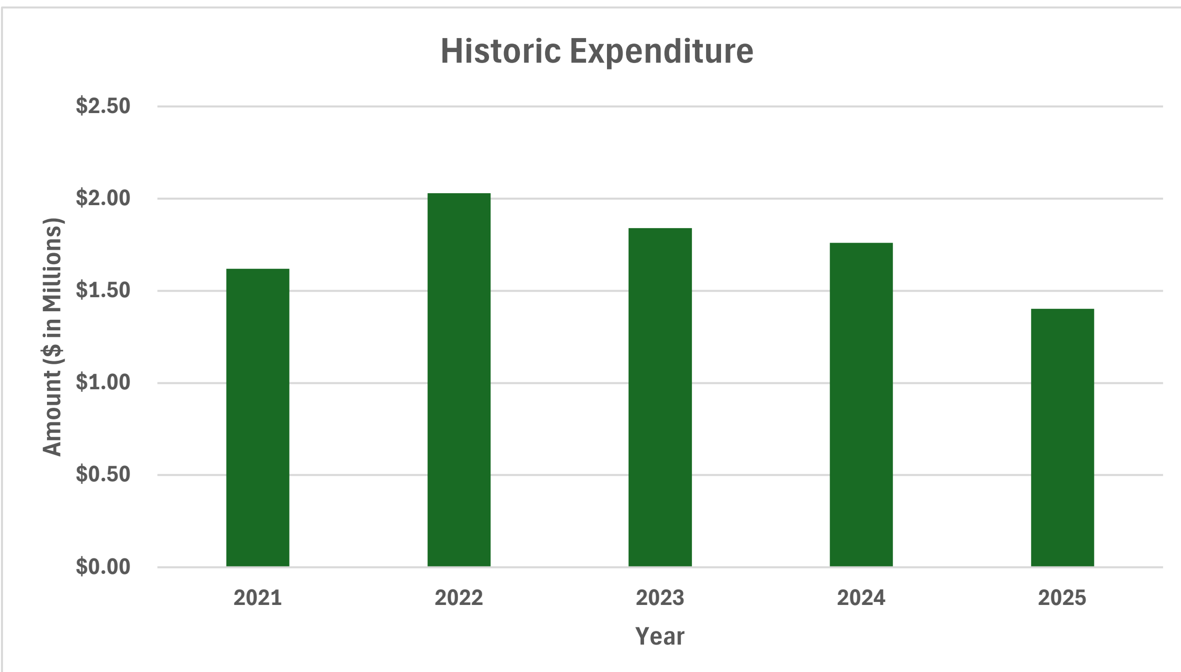


Fig 3: Historic Expenditure – Commercial & Industrial Connections

A.4. Investment Priority

This program consists of DSC mandated activities and timelines. As per EPI's capital project scoring, this sector ranks 8th out of 22 which indicates a higher priority in general function, ensuring system access to new C&I customers. However, this section ranks behind emergencies and other critical sections that ensure public safety and system functionality for existing customer base (Section 5.3).

A.5. Alternative Analysis

Alternatives are considered on individual basis for each connection request considering safety, economics, regulatory compliance, system reliability and customer relations to develop the most effective solution. In general, the lowest cost solution which meets EPI's technical requirements is selected unless customer preference drives a more costly solution (i.e. overhead vs. underground service). Where possible, costs are minimized through standard design, materials and EPI work practices.

A.6. Innovative Nature of the Project

Not Applicable

A.7. Leave to Construct Approval

Not Applicable

B. EVALUATION CRITERIA AND INFORMATION REQUIREMENTS

B.2. Efficiency, Customer Value, Reliability & Safety

Table 2: Investment Evaluation - Efficiency, Customer Value, Reliability & Safety

Criteria	Description
Efficiency	- This program supports the utility in maintaining financial health by aligning investments with system needs and customer growth. The standardized and streamlined connection processes significantly reduce costs for installing electrical services, ensuring efficient resource use. - The program helps maintain stable and predictable grid performance for current and future customers by adhering to utility standards for connections, ensuring long-term reliability and efficiency. - By enabling new customer connections and the associated energy and demand throughput, the utility optimizes the utilization rate and load factor of its assets, particularly in areas where incremental capacity additions are not required. This approach maximizes the lifecycle value of infrastructure, reduces underutilized capacity, and benefits all consumers through more efficient system operations. - The program strategically incorporates incremental capacity upgrades beyond immediate customer needs when it is cost-efficient to do so. By performing additional upgrades during the initial connection process, the utility minimizes future system upgrade costs, leveraging the same crew and resources to achieve cost efficiencies.
Customer Value	- This program provides essential access to the grid for C&I customers, enabling them to operate their facilities effectively and support local economic growth. - By meeting regulated timelines for new connections and service upgrades, the program ensures timely access to reliable electricity and meeting energy needs. - The program simplifies and streamlines the connection and service upgrade processes, providing transparent, accurate, and timely cost

	estimates for customers, meeting their expectations, and improving satisfaction. - By promoting equitable and consistent access to secure electricity, the program contributes to the community's economic wellbeing, enabling businesses to grow and thrive. - The program ensures fair cost allocation for new connections and upgrades, aligning customer contributions with system benefits, thereby promoting fairness and transparency. - By optimizing asset utilization, the program maximizes their value for a broader customer base, ensuring long-term value.
Reliability	- This program strengthens system reliability by enabling customer-driven investments in protection schemes, equipment upgrades, and asset renewals required for connecting the customers, thereby reducing the risk of unexpected service interruptions. - By conducting load flow studies and system modeling when and if needed, the program ensures that new connections do not compromise the stability or reliability of the grid. These proactive measures help identify and address potential system constraints or risks before they escalate. - The program supports the health and functionality of the distribution network by integrating spot-checks and condition assessments of upstream assets in areas where new connections are made. This ensures that the grid's capacity and performance remain robust while accommodating growth. -Incremental upgrades performed during the connection process enhance the utility's ability to manage operational demands effectively, ensuring a resilient network that adapts to future needs. -By aligning with broader system planning and operational objectives, the program contributes to long-term system reliability, safeguarding the delivery of electricity to all customers.
Safety	Maintaining CSA compliance ensures safety and reliability, making the process straightforward for customers helps prevent them from attempting unsafe practices, and bringing in capital allows us to improve and enhance our system.

	Ensures compliance: - By adherence to legislative requirements, safety standards and regulations such as Electrical Distribution Safety O.Reg. 22/04, ESA, CSA, Building codes, Fire codes, OHSA, etc. - By adherence to generally accepted and jointly used safety-by-design standards.

B.3. Investment Need

B.3.3 Primary Driver:

The sole driver of this project is customer-driven service upgrades and service requests. This is a mandated service obligation defined in the DSC and other regulations for a utility in order to accommodate the connection requests. EPI ensures that received connection requests are processed and allowed to connect to the grid as per DSC guidelines in an efficient manner through optimal designs.

B.3.4 Secondary Drivers:

Not Applicable

B.3.5 Information Used to Justify the Investment:

The number of commercial service connections needed depends on economic growth within the communities served, which can vary significantly between different communities and from year to year. EPI collaborates with economic development and municipal planners to identify potential growth areas and expected large projects in the pipeline.

B.4. Investment Justification

B.4.3 Demonstrating Accepted Utility Practice:

EPI plans and executes its new connections to accommodate customers and comply with regulations. All new connections installed comply with the latest standards and regulations, and all metering services will be carried out in accordance with EPI's standards and practices.

B.4.4 Cost-Benefit Analysis:

Before any work is conducted, an Offer to Connect agreement, detailing all associated costs for labor and equipment, is provided to the customer. The exact scope of work will vary based on specific customer requests, i.e., the factors affecting the final cost also depend on the customer's requirements. For example, customer preferences, such as choosing overhead versus underground service, can influence the final project cost. Generally, the lowest-cost solution that meets EPI's technical requirements is selected, unless the customer's preference leads to a more expensive option.

For connections requiring substantial infrastructure upgrades or system expansion, the additional costs are determined using the Economic Evaluation Model, as provided and regulated by the Ontario Energy Board (OEB).

B.4.5 Historical Investments & Outcomes Observed:

Please see Section A.3.3 for a discussion on historical investment levels for this program.

B.5. Non-Wires Solution

Non-wires solutions are not applicable to serve the purposes of this investment.

B.6. Innovation

Not Applicable

MATERIAL INVESTMENT NARRATIVE

PROJECT / PROGRAM:

03. Customer Connections: Residential & Subdivision

INVESTMENT CATEGORY:

SYSTEM ACCESS

A. GENERAL INFORMATION ON THE PROJECT/PROGRAM

A.1. Overview

The purpose of this project is to connect new residential customers to EPI's distribution system. Most of these new residential connections are in new subdivisions constructed by third-party developers. Typical System Access work by EPI in this regard includes installing new feeders, transformers, and service connections to integrate new developments efficiently into EPI's network.

New connections and service upgrades are developed using standardized designs that meet the requirements of O. Reg. 22/04.

Customer requests in this category are often emergent and not known at the time of budgeting. Forecast costs are driven by historical trends and impacted by inflation. After a significant, unprecedented residential growth starting in 2021 and particularly 2022, driven by new housing in the Northeast (St. Thomas, Strathroy, Mt. Brydges) and Southwest (particularly Chatham), growth tapered in 2023 and is forecast to remain at consistent levels over the 2026-2030 Forecast Period (Section 3.2.2 and 3.2.3).

A.2. Timing

i. Start Date: January 2026
ii. In-Service Date: Through to December 2030
iii. Key factors that may affect timing: The following factors can impact the project schedule:
- Work associated with this project is customer-driven, which can vary and be subject to change based on a variety of factors, including economic conditions.
- Timing and volumes are estimates based on historical levels.
- Actual spend and timing will depend on customer requests.

A.3. Capital Expenditures

A.3.3 Historical and Future Capital Expenditures

Table 1. Historical and Future Capital ($, million)

Customer Conns: Residential & Subdivision - Totals									
Historic Actual Expenditure				Bridge Year	Forecasted Budgeted Expenditure				
2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
$2.89	$5.92	$2.74	$1.55	$1.80	$1.90	$1.95	$2.01	$2.04	$2.07

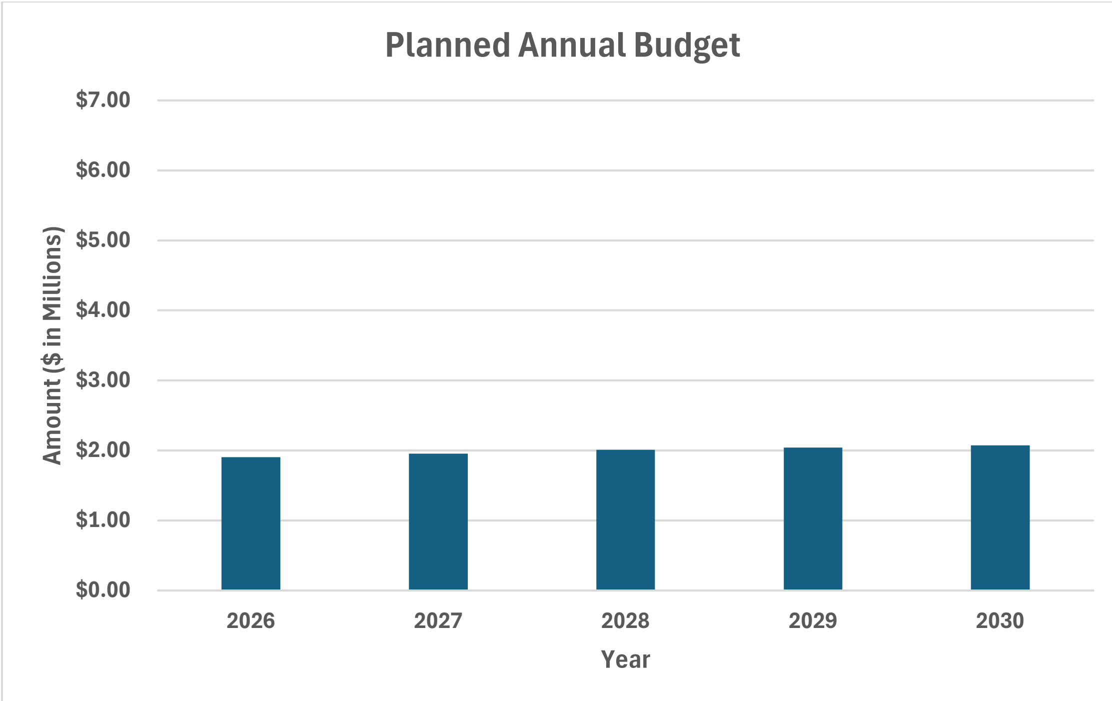


Fig 1: Planned Budget for Residential & Subdivision Connections

The graph above illustrates the annual planned budgets, which closely correlate with the volume of active customer applications and the costs associated in enabling access to customers in the residential sector and developing new subdivisions. The costs vary depending on the design complexity and the scale of investments required to prepare the distribution system for new connections.

A.3.4 Economic Evaluation (Expansion projects)

This is a mandated, customer-driven work. Capital contribution in this sector is calculated based on the economic evaluation model (EEM) defined in the Distribution System Code and regulated by the OEB.

A.3.5 Comparative Historical Expenditure

Investments in this category are driven by customer demand – customers approaching EPI for service connections, as well as housing development activities within the territory – which can fluctuate and make forecasting challenging. This can be seen during the pandemic period, where EPI experienced unusually high growth in customer connections leading to higher actual expenditures than originally forecasted.

However, this period of accelerated growth began to level off in 2023, with a continued to decline in 2024 and 2025. These developments suggest a transition toward lower and more stable connection volumes incorporating recent economic trends and the constraints posed by limited development land within the service territory. EPI anticipates steady expenditures moving forward, consistent with recent experience.

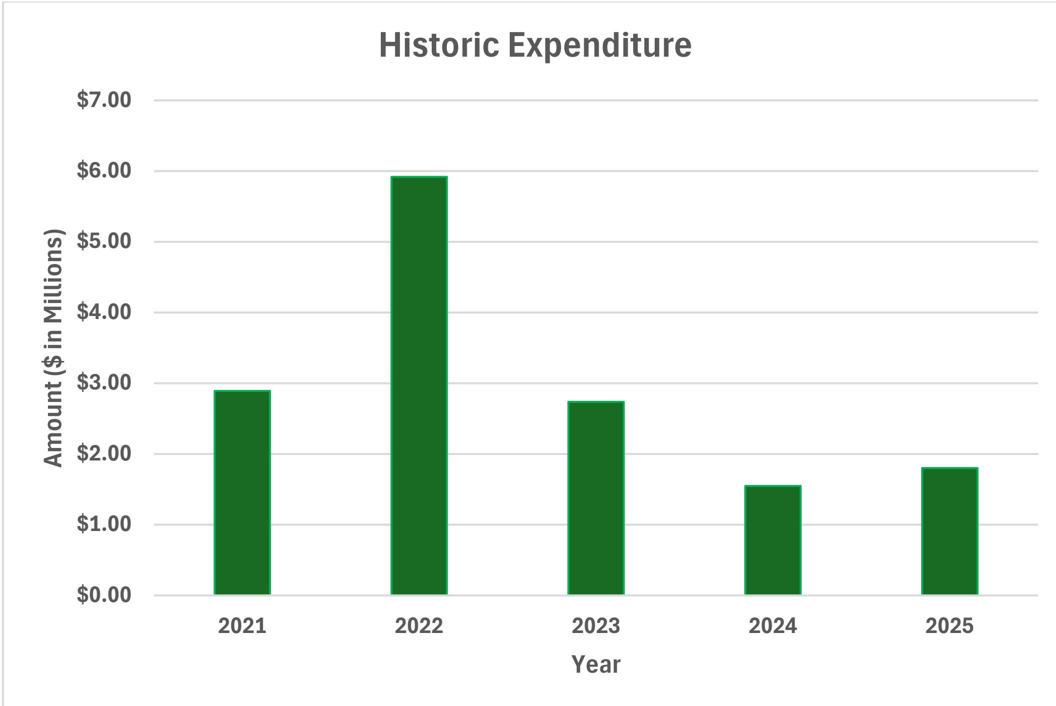


Fig 2: Historical Expenditure - Residential & Subdivision

A.4. Investment Priority

This program consists of DSC mandated activities and timelines. As per EPI's capital project scoring, this sector ranks 9th out of 22 which indicates a moderately high priority in general function, ensuring system access to new residential customers and development of new subdivisions in our service territories. However, this section ranks behind emergencies and other critical sections that ensure public safety and system functionality for the existing customer base (Section 5.3).

A.5. Alternative Analysis

Alternatives are considered on individual basis for each connection request considering safety, economics, regulatory compliance, system reliability and customer relations to develop the most effective solution. In general, the lowest cost solution which meets EPI's technical requirements is selected unless customer preference drives a more costly solution (i.e. overhead vs. underground service). Where possible, costs are minimized through standard design, materials and EPI work practices.

A.6. Innovative Nature of the Project

Not Applicable

A.7. Leave to Construct Approval

This project does not require leave to construct approval under Section 92 of the OEB Act.

B. EVALUATION CRITERIA AND INFORMATION REQUIREMENTS

B.2. Efficiency, Customer Value, Reliability & Safety

Table 3: Investment Evaluation - Efficiency, Customer Value, Reliability & Safety

Criteria	Description
Efficiency	- This program supports the utility in maintaining financial health by aligning investments with system needs and customer growth. The standardized and streamlined connection processes significantly reduce costs for installing electrical services, ensuring efficient resource use. - The program helps maintain stable and predictable grid performance for current and future customers by adhering to utility standards for connections, ensuring long-term reliability and efficiency. - By enabling new customer connections and the associated energy and demand throughput, the utility optimizes the utilization rate and load factor of its assets, particularly in areas where incremental capacity additions are not required. This approach maximizes the lifecycle value of infrastructure, reduces underutilized capacity, and benefits all consumers through more efficient system operations. - The program strategically incorporates incremental capacity upgrades beyond immediate customer needs when it is cost-efficient to do so. By performing additional upgrades during the initial connection process, the utility minimizes future system upgrade costs, leveraging the same crew and resources to achieve cost efficiencies.
Customer Value	- This program provides essential access to the grid for subdivision developers and individual residential customers, enabling them access capacity (new connections and service upgrades) effectively and supporting local economic growth. - By meeting regulated timelines for new connections and service upgrades, the program ensures timely access to reliable electricity and meeting energy needs. - The program simplifies and streamlines the connection and service upgrade processes,

	providing transparent, accurate, and timely cost estimates for customers, meeting their expectations, and improving satisfaction. - By promoting equitable and consistent access to secure electricity, the program contributes to the community's economic wellbeing, enabling businesses to grow and thrive. - The program ensures fair cost allocation for new connections and upgrades, aligning customer contributions with system benefits, thereby promoting fairness and transparency. - By optimizing asset utilization, the program maximizes their value for a broader customer base, ensuring long-term value.
Reliability	- This program strengthens system reliability by enabling customer-driven investments in protection schemes, equipment upgrades, and asset renewals required for connecting the customers, thereby reducing the risk of unexpected service interruptions. - By conducting load flow studies and system modeling when and if needed, the program ensures that new connections do not compromise the stability or reliability of the grid. These proactive measures help identify and address potential system constraints or risks before they escalate. - The program supports the health and functionality of the distribution network by integrating spot-checks and condition assessments of upstream assets in areas where new connections are made. This ensures that the grid's capacity and performance remain robust while accommodating growth. -Incremental upgrades performed during the connection process enhance the utility's ability to manage operational demands effectively, ensuring a resilient network that adapts to future needs. -By aligning with broader system planning and operational objectives, the program contributes to long-term system reliability, safeguarding the delivery of electricity to all customers.
Safety	Maintaining CSA compliance ensures safety and reliability, making the process straightforward for customers helps prevent them from attempting unsafe practices, and bringing in capital allows us to improve and enhance our system.

	Ensures compliance: - By adherence to legislative requirements, safety standards and regulations such as Electrical Distribution Safety O.Reg. 22/04, ESA, CSA, Building codes, Fire codes, OHSA, etc. - By adherence to generally accepted and jointly used safety-by-design standards.

B.3. Investment Need

B.3.3 Primary Driver:

The sole driver of this project is customer demand, including service upgrades and specific service requests. This is a mandated service obligation defined in the DSC and other regulations for a utility in order to accommodate the connection requests. EPI ensures that received connection requests are processed and enabled to connect to the grid as per DSC guidelines in an efficient manner through optimal designs.

B.3.4 Secondary Drivers:

There are no secondary drivers for investments in this project.

B.3.5 Information Used to Justify the Investment:

This is a mandated service obligation defined in the DSC and other regulations. The justification for the investment is mandated customer-driven work and the requirement to meet all OEB mandated requirements regarding the timing of customer connections. The number of residential service connections required is a function of economic growth in the communities served and can vary dramatically between communities and between years. EPI confers with economic development and municipal planners to try and ascertain areas of growth. Historical pacing is a valuable part of this evaluation and forecasted investment amount.

B.4. Investment Justification

B.4.3 Demonstrating Accepted Utility Practice:

EPI plans and executes its new connections to accommodate customers and comply with regulations. All new connections installed comply with the latest standards and regulations, and all metering services will be carried out in accordance with EPI's standards and practices.

B.4.4 Cost-Benefit Analysis:

This is a mandated service obligation defined in the Distribution System Code (DSC) and other regulations. According to the DSC, distributors are required to provide a basic connection allowance to new residential customers, which covers the financial credit for the necessary transformer capacity and thirty (30) meters of overhead conductor. Additional costs incurred for labor, materials, and equipment (such as meters) are covered by the customer.

B.4.5 Historical Investments & Outcomes Observed:

Section A.3.3 highlights the historic expenses and the variance in budgeting vs actual spending in this investment program. The main outcome of this program is the successful connection of residential customers to the electrical grid through collaborations with the customers, municipalities, builders and housing developers to develop plans, designs and execute constructions as needed.

B.5. Non-Wires Solution

Not Applicable

B.6. Innovation

Not Applicable

MATERIAL INVESTMENT NARRATIVE

PROJECT / PROGRAM:

04. Engineering Support Capital

INVESTMENT CATEGORY:

SYSTEM ACCESS

A. GENERAL INFORMATION ON THE PROJECT/PROGRAM

A.1. Overview

This program captures the cost of capitalized overhead (such as engineering supervision) as well as the engineering effort early in the project life cycle where specific project level tracking is not yet available. It also captures the costs of fielding customer inquiries such as connection requests which do not proceed to connection (Section 5.1.2.1.3).

The primary objectives of this initiative are to uphold public safety by ensuring strict compliance with construction and safety standards, and to promote cost control through rigorous, consistent, and accurate job estimation practices. These outcomes are supported by a structured application of engineering standards, enabling efficient resource allocation, supporting proactive asset management, and fostering customer confidence through transparent, predictable service delivery.

A.2. Timing

i. Start Date: January 2026
ii. In-Service Date: Through to December 2030
iii. Key factors that may affect timing: The following factors can impact the project schedule:
   - This is an ongoing project.
   - Pacing of expenditures may vary depending on the volume of projects under consideration, and if early engagement by consultants is required.

A.3. Capital Expenditures

A.3.3 Historical and Future Capital Expenditures

Table 1. Historical and Future Capital ($, million)

Engineering Support Capital - Totals									
Historic Actual Expenditure				Bridge Year	Forecasted Budgeted Expenditure				
2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
$0.92	$0.96	$0.97	$0.98	$0.84	$0.70	$0.72	$0.74	$0.76	$0.79

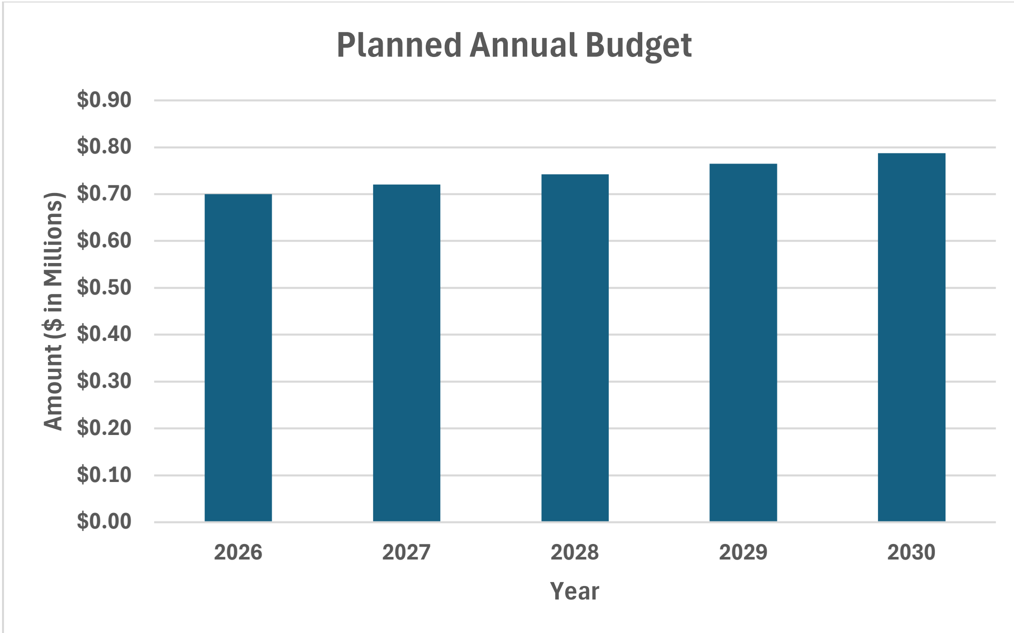


Fig 1: Planned Budget for Engineering Support Capital

A.3.4 Economic Evaluation (Expansion projects)

Not Applicable

A.3.5 Comparative Historical Expenditure

The graph below shows the actual spending for years 2021-2024 and the planned spending for 2025. The level of historical spend is primarily driven by pacing and volume of projects. For example, an influx in capital construction jobs (customer or internally driven) may require additional engineering support resources to ensure public safety with construction standards and cost control through accurate job estimation.

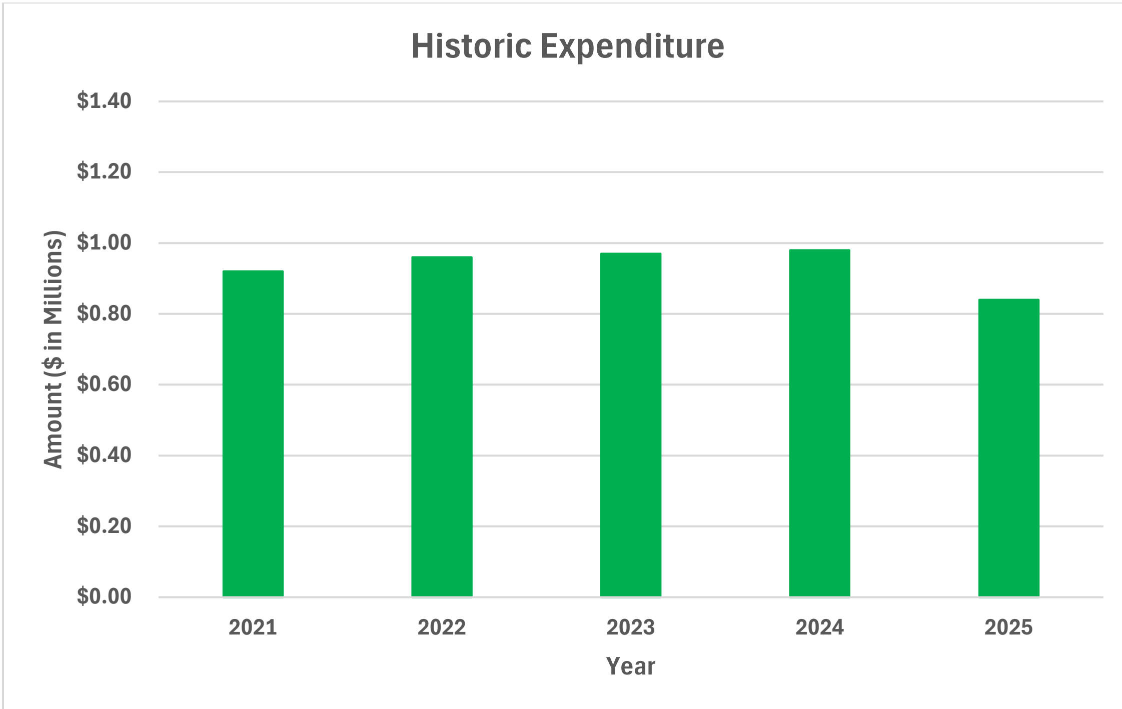


Fig 2: Historic Expenditure – Engineering Support Capital

Given the relationship between this program and the volume of customer connection requests, EPI forecasts a decrease in investment in this category, consistent with the rationale outlined in Material Investment Narratives 2 and 3.

A.4. Investment Priority

As per EPI's capital project scoring, this segment ranks 4th out of 22, reflecting its high priority. The primary driver for this project is to ensure public safety through compliance with construction standards and cost control through accurate job estimation (Section 5.3).

A.5. Alternative Analysis

The projects included in this category support the core engineering and analytical functions required for the safe, efficient, and compliant operation of EPI's distribution system. These activities are essential for system planning, capital project design, and operational coordination. They are aligned with EPI's long-term strategy to develop strong internal capabilities while ensuring cost-effectiveness and organizational resilience.

The following alternatives were considered:

a. **Do Nothing / Eliminate Engineering and Program Support Activities**
   This alternative would involve significantly reducing or eliminating engineering and planning functions. However, these functions are essential to ensuring the safe and reliable development and execution of capital and operational work. Without adequate engineering and program support, EPI would risk non-compliance with regulatory standards, degradation of system performance, and delays or failures in project execution.

Conclusion: *Not viable. Eliminating core planning and design functions would compromise system integrity and regulatory compliance.*

b. Expand Outsourcing of Engineering and Analytical Work

EPI currently outsources specific engineering tasks where appropriate. While it is technically feasible to expand this outsourcing, doing so presents challenges. Greater reliance on external consultants increases oversight requirements, creates inefficiencies, and may result in higher overall costs. It is also inconsistent with EPI's strategic objective to maintain a strong internal knowledge base, especially given the importance of localized system expertise.

Conclusion: *Not preferred. Reduces internal capacity, increases costs, and weakens long-term organizational effectiveness.*

c. Maintain Internal Capabilities with Standardized Tools and Practices (Preferred Option)

EPI's preferred strategy is to maintain a dedicated internal team for engineering and program support functions. This approach ensures continuity, operational flexibility, and local system expertise. It also enables the use of standardized tools, designs, and work practices to improve project delivery efficiency and control system operation costs. Maintaining these internal capabilities supports long-term strategic goals and enhances the utility's ability to adapt to emerging challenges.

Conclusion: *Best alternative. Supports reliability, cost-effectiveness, and internal capacity building.*

A.6. Innovative Nature of the Project

Not Applicable

A.7. Leave to Construct Approval

This project does not require leave to construct approval under Section 92 of the OEB Act.

B. EVALUATION CRITERIA AND INFORMATION REQUIREMENTS

B.2. Efficiency, Customer Value, Reliability & Safety

Table 4: Investment Evaluation - Efficiency, Customer Value, Reliability & Safety

Criteria	Description
Efficiency	This project supports utility efficiency by providing engineering expertise to develop and apply standards and oversee construction activities. It supports overall utility efficiency by: - By optimizing use of resources, including labor, materials, and equipment through planning and leveraging shared services. - By optimizing procurement and supply chain management through standardizing equipment and reducing the variety of asset types in the system. - By supporting asset management practices to meet the needs of customers and stakeholders, balancing safety, reliability, and cost-effectiveness - By minimizing costs for installing electrical services through streamlined processes and standards.
Customer Value	Having adequate engineering supervision ensures customers can move forward with a level of economic assurance though a rigorous and accurate job estimation process. These job estimates are streamlined by the application of regularly updated engineering standards, which improves consistency and controls costs to generate the estimate. This work ensures construction is built to the appropriate standard to minimize risk, including public safety, equipment failure, economic risk This work includes supporting customer choice: - By enabling customers to connect clean technologies and renewable energy sources efficiently. Improves customer value: - By providing access to energy needs for new connections and service upgrades, meeting regulated timelines. - By ensuring a safer, more reliable, and cost-effective distribution system to meet customer needs and maintain customer trust.

	- By promoting economic wellbeing in the community through providing consistent access to secure and reliable electricity. - By ensuring fair and equitable cost allocation for new connections and connection upgrades.
Reliability	This project provides indirect support to system reliability: - By reducing the number of outages by proactively replacing assets that are at or beyond their useful life or show signs of significant material degradation to prevent failures. - By developing plans to replace aging equipment with modern, properly sized assets designed to handle variable loads and bi-directional power flows to support the adoption of EVs and DERs. - By developing plans to stage construction work in a way that minimizes customer disruptions and asset unavailability. - By reviewing, updating and creating construction standards to ensure that the distribution system is well prepared to address both current and anticipated future demands. - By making recommendations to: - replace equipment in strategic locations to better withstand weather-related disruptions. - replace critical overhead assets with underground infrastructure in key areas. - By simplifying replacement efforts during major grid restoration by standardizing installed equipment. - Enable safe and reliable customer and DER connections:
Safety	Ensures public safety: - By reducing safety risks and hazards to the public associated with managing and operating grid infrastructure. - By reducing public exposure to significant risks posed by aged and deteriorated equipment, including electrical faults, fires, or hazardous conditions. - By supporting the immediate replacement of equipment damaged by weather-related events, motor vehicle accidents or dig-ins. Improves worker and public safety: - By relocating equipment to improve accessibility.

	- By reducing the time of worker exposure to higher risk environments (e.g. confined space, switching). Ensures compliance: - By adherence to legislative requirements, safety standards and regulations such as Electrical Distribution Safety O.Reg. 22/04, ESA, CSA, Building codes, Fire codes, OHSA, etc. - By adherence to generally accepted and jointly used safety-by-design standards.

B.3. Investment Need

B.3.3 Primary Driver:

The main driver for this project is Mandated Service Obligations. This project is to ensure public safety through compliance with construction standards and cost control through accurate job estimation.

B.3.4 Secondary Drivers:

There are no secondary drivers for investments in this project.

B.3.5 Information Used to Justify the Investment:

This project captures the engineering effort for each capital project, such as project designs, technical reviews, standards compliance, and cost-effective execution. The exact number of assets associated with this project is directly inherited from the scope of other projects outlined in this document.

B.4. Investment Justification

B.4.3 Demonstrating Accepted Utility Practice:

EPI maintains a team of experienced engineers and engineering technologists to support System Access investments, including third-party attachment requests and new customer connections. These roles also play a critical part in ensuring compliance with USF design standards and O.Reg. 22/04 during construction.

B.4.4 Cost-Benefit Analysis:

There are no practical alternatives to the activities captured in the cost of this program. While outsourcing to third-party contractors is a potential alternative of accomplishing the requisite activities, it conflicts with EPI's vision of developing a strong core of internal specialists intimately familiar with the local system characteristics and capable of performing a wide range of analytical tasks. Additionally, outsourcing is generally considered more costly than performing the work in-house. Through standardized designs, work practices and equipment EPI ensures cost-effective system operation and maximizes the value of this investment.

B.4.5 Historical Investments & Outcomes Observed:

The level of historical spend is primarily driven by pacing and volume of projects. For example, an influx in capital construction jobs (customer or internally driven) may require additional engineering support resources to ensure public safety with construction standards and cost control through accurate job estimation.

B.5. Non-Wires Solution

Not Applicable

B.6. Innovation

Not Applicable

MATERIAL INVESTMENT NARRATIVE

PROJECT / PROGRAM:

05. Miscellaneous System Access

INVESTMENT CATEGORY:

SYSTEM ACCESS

A. GENERAL INFORMATION ON THE PROJECT/PROGRAM

A.1. Overview

Miscellaneous System Access addresses additional customer and third-party driven requests not covered in other System Access programs. Specifically, program expenditure primarily supports customer DER as well as municipal request for asset relocations.

This investment category allows EPI to have a flexible response to diverse customer needs and community-based infrastructure improvements, ensuring that such ad hoc customer requests are efficiently supported, and the overall customer satisfaction is maintained.

A.2. Timing

i. Start Date: January 2026
ii. In-Service Date: Through to December 2030
iii. Key factors that may affect timing: The following factors can impact the project schedule:
   - Variability in work volume
   - Unpredictability of project complexity
   - Ad hoc requests can have unpredictable timing impacting the project schedule

A.3. Capital Expenditures

A.3.3 Historical and Future Capital Expenditures

Table 1. Historical and Future Capital ($, million)

Miscellaneous System Access - Totals									
Historic Actual Expenditure				Bridge Year	Forecasted Budgeted Expenditure				
2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
$0.36	$0.33	$0.07	$0.84	$0.40	$0.72	$0.15	$0.16	$0.16	$0.17

The graph below illustrates the planned budget figures for this investment category ($ in millions).

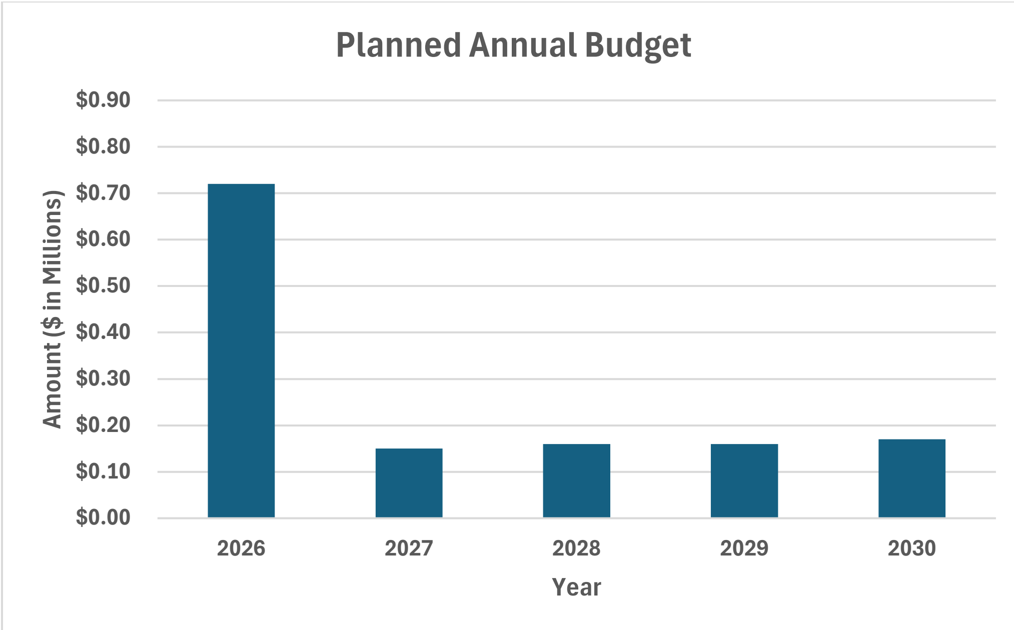


Fig 1: Planned Budget for Miscellaneous System Access

Since the nature of these miscellaneous requests are customer-driven, and vary largely in scope, geography, complexity and timing, the budget planning is done considering historic spending and known/confirmed projects. The planned budget for the immediate future years includes provisions for certain miscellaneous work requests that are either known or highly expected, and it has been adjusted accordingly to accommodate these needs.

The 2026 capital budget includes a significant utility work related to the Highway 401 and Bloomfield Road Interchange Improvement Project at Chatham, driven by the Ontario Ministry of Transportation (MTO). As part of the project, EPI will be required to relocate an existing overhead pole line and convert an existing overhead road crossing to an underground crossing. This allocation reflects the confirmed scope and anticipated cost impact to EPI, ensuring appropriate funding is available to support this work within the project's construction timeline.

A.3.4 Economic Evaluation (Expansion projects)

When requested to relocate distribution plants by civic authorities, EPI shall comply with regulated requirements for timelines and cost recovery. In the event a relocation would not be covered by these regulations, EPI shall resolve the issue in a fair and reasonable manner.

For net-metered generation requests, EPI acts in accordance with the DER Connection Procedure (DERCP) to prepare cost estimates for our customers. Responsibility of said costs are dictated by Chapter 3 of the Distribution System Code, and connections completed within the allowed timelines.

A.3.5 Comparative Historical Expenditure

Historically, the spending in this category has been allocated to support miscellaneous expenses associated with DER interconnection requests and municipal requests for asset relocation for civil expansion.

The historic spending (2021-2024) and planned spending (2025) has been shown in the figure below:

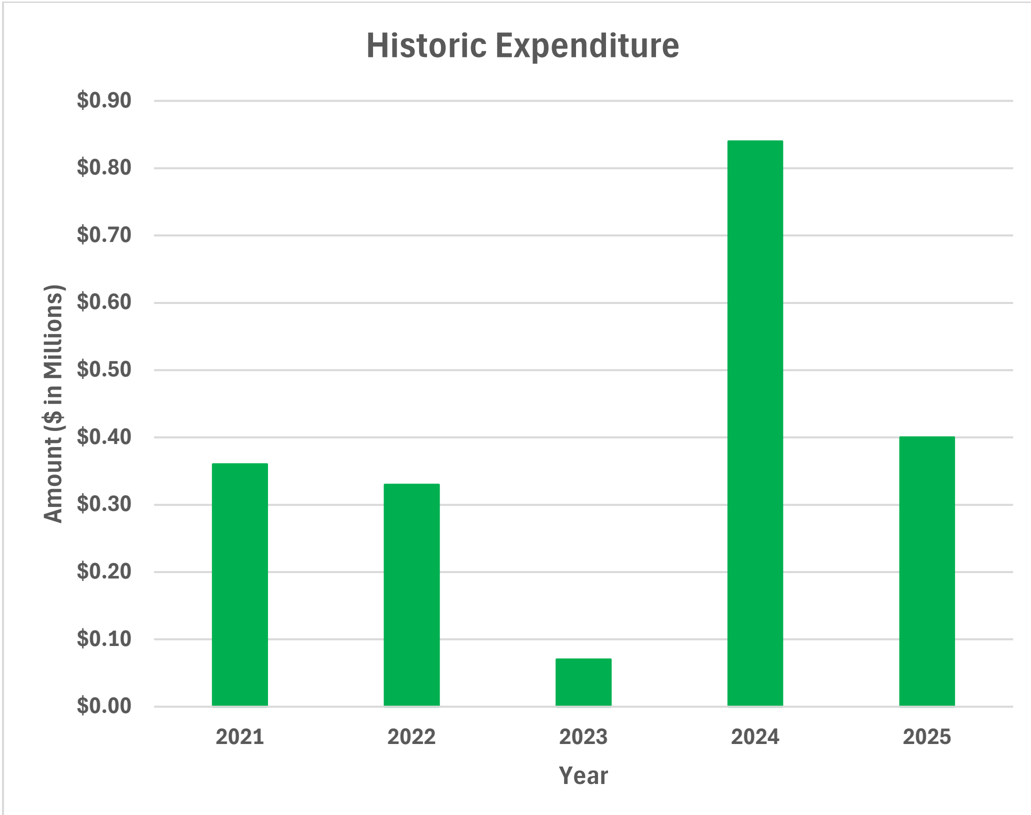


Fig 2: Historic Expenditure – Miscellaneous System Access

Investment levels rose towards the end of the historical period due to numerous requests for asset relocation in St Thomas primarily driven by road widening project.

A.4. Investment Priority

Investments in Miscellaneous System Access rank 19th out of the 22 investment categories as per EPI's latest capital project scoring. Since this segment is designed to address requests and projects that are miscellaneous and ad hoc in nature, serving as a supplementary resource to support the main System Access budget, its priority has been assessed as relatively low (section 5.3).

A.5. Alternative Analysis

Alternatives are considered on individual basis for each customer request considering safety, economics, regulatory compliance, system reliability and customer relations to develop the most effective solution. In general, the lowest cost solution which meets EPI's technical requirements is selected unless customer preference drives a more costly solution. Where possible, costs are minimized through standard design, materials and EPI work practices.

A.6. Innovative Nature of the Project

Not Applicable

A.7. Leave to Construct Approval

This category does not require leave to construct approval under Section 92 of the OEB Act.

B. EVALUATION CRITERIA AND INFORMATION REQUIREMENTS

B.2. Efficiency, Customer Value, Reliability & Safety

Table 5: Investment Evaluation - Efficiency, Customer Value, Reliability & Safety

Criteria	Description
Efficiency	This program supports efficient operation of the utility by: - This program supports the utility in maintaining financial health by aligning investments with system needs and to diverse customer needs and community-based infrastructure improvements not covered by other programs. The standardized and streamlined processes significantly reduce costs for accessing, updating, installing or relocating equipment. - By optimizing use of resources, including labor, materials, and equipment through planning and leveraging shared services. - The program helps maintain stable and predictable grid performance for current and future customers by adhering to utility standards for connections, ensuring long-term reliability and efficiency. - The program strategically incorporates incremental capacity upgrades beyond immediate customer needs when it is cost-efficient to do so. By performing additional upgrades during the initial connection process, the utility minimizes future system upgrade costs, leveraging the same crew and resources to achieve cost efficiencies.
Customer Value	This program provides customer value by: - Supporting the utility in maintaining financial health by aligning investments with system needs and the needs of our joint use partners, municipalities and other agencies. The standardized and streamlined processes significantly reduce costs for accessing, updating, installing or relocating equipment. - By optimizing use of resources, including labor, materials, and equipment through planning and leveraging shared services. - The program helps maintain stable and predictable grid performance for current and future customers by adhering to utility standards for improvements, upgrades and relocations, ensuring long-term reliability and efficiency.

	- The program strategically incorporates incremental capacity upgrades beyond immediate customer needs when it is cost-efficient to do so. By performing additional upgrades during joint use or relocation activities, the utility minimizes future system upgrade costs, leveraging the same crew and resources to achieve cost efficiencies. - By promoting economic wellbeing in the community through providing consistent access to secure and reliable electricity.
Reliability	- This program strengthens system reliability by enabling third party driven investments in shared assets thereby reducing the risk of unexpected service interruptions. - By conducting load flow studies and system modeling when and if needed, the program ensures that new connections do not compromise the stability or reliability of the grid. These proactive measures help identify and address potential system constraints or risks before they escalate. - The program supports the health and functionality of the distribution network by integrating spot-checks and condition assessments of upstream assets in areas where new connections are made. This ensures that the grid's capacity and performance remain robust while accommodating growth. Incremental upgrades performed during the connection process enhance the utility's ability to manage operational demands effectively, ensuring a resilient network that adapts to future needs. By aligning with broader system planning and operational objectives, the program contributes to long-term system reliability, safeguarding the delivery of electricity to all customers.
Safety	Maintaining CSA compliance ensures safety and reliability, making the process straightforward for third parties and municipalities. This helps avoid potential unsafe practices, and bringing in capital allows us to improve and enhance our system. Ensures compliance: - By adherence to legislative requirements, safety standards and regulations such as Electrical Distribution Safety O.Reg. 22/04, ESA, CSA, Building codes, Fire codes, OHSA, etc.

	- By adherence to generally accepted and jointly used safety-by-design standards.

B.3. Investment Need

B.3.3 Primary Driver:

The primary driver of this project is mandated service obligation.

B.3.4 Secondary Drivers:

There are no secondary drivers for investments in this project.

B.3.5 Information Used to Justify the Investment:

This project addresses customer-driven regulated activities and is non-discretionary. Budgeted amounts are based on historical trends and specific known projects.

B.4. Investment Justification

B.4.3 Demonstrating Accepted Utility Practice:

Every task under this program is executed in full compliance with required regulations, standards and policies.

All necessary design and construction are completed in compliance with applicable USF standards supplemented by standards developed internally. The use of USF standards ensures that the design and construction of this project will be done according to a set of standards utilized by many other utilities in Ontario. EPI is O.Reg. 22/04 compliant to ensure employee and public safety.

B.4.4 Cost-Benefit Analysis:

This program focuses on customer-driven projects that focuses on facilitating connection of customers to the distribution grid and municipally driven asset relocations.

B.4.5 Historical Investments & Outcomes Observed:

Section A.3.3 highlights the historic expenses and the variance in budgeting vs actual spending in this investment program. The main outcome of this program is to address unanticipated requests from customers and third parties and facilitate access to the grid.

B.5. Non-Wires Solution

Not Applicable

B.6. Innovation

Not Applicable

MATERIAL INVESTMENT NARRATIVE

PROJECT / PROGRAM:

06. Third-Party Attachments

INVESTMENT CATEGORY:

SYSTEM ACCESS

A. GENERAL INFORMATION ON THE PROJECT/PROGRAM

A.1. Overview

EPI is required to accommodate third-party attachment requests on its distribution poles in accordance with OEB regulations. As part of this process, EPI conducts detailed inspections of its assets to assess the need for any upgrades necessary to facilitate safe and compliant third-party attachments. The primary objectives of this initiative are to ensure regulatory compliance, support safe infrastructure sharing, and maintain high customer satisfaction.

In the early portion of the Historical Period, significant make-ready work for multiple Internet Service Providers (ISPs) occurred. During this period, the ISPs rapidly expanded their number of attachments to the EPI distribution system. When EPI receives such an attachment request, it reviews the request and determines if existing infrastructure can support the new/revised attachment. If changes to EPI's infrastructure are required to support this change, the make-ready work is performed. This may include installation or replacement of poles and anchors, and related infrastructure as required to meet both current standards and accommodate the revised attachment.

The majority of the ISP growth projects were completed by 2023, which resulted in a reduction of capital contributions in the latter part of the Historical Period. However, ISPs continue to periodically apply for additions (or revisions) to their attachments to align with their business objectives and their customers' demands.

A.2. Timing

a. Start Date: January 2026
b. In-Service Date: Through to December 2030
c. Key factors that may affect timing: The following factors can impact the project schedule:

- Unpredictability of work volume
- Potential for resource constraints
- Supply chain disruptions

The primary risk associated with third-party attachment work is the unpredictable nature of these requests, which can vary significantly between communities and years. In the early portion of the Historical Period, Fiber-to-the-home projects were significant. To minimize the risk of unforeseen, emergent requests, EPI works with third-party companies, economic development offices and municipal planners to forecast their project plans and future demand. Additionally, historical data and effective inventory management are crucial to ensure the availability of materials and resources to execute these attachments. Outsourcing work, when appropriate can further alleviate the fluctuating demand at times when there are resource constraints.

A.3. Capital Expenditures

A.3.3 Historical and Future Capital Expenditures

Table 1. Historical and Future Capital ($, million)

Third Party Attachments - Totals									
Historic Actual Expenditure				Bridge Year	Forecasted Budgeted Expenditure				
2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
$1.08	$0.68	$0.33	$0.02	$0.11	$0.13	$0.12	$0.12	$0.13	$0.13

The graph below illustrates the planned budget figures for this investment category ($ in millions).

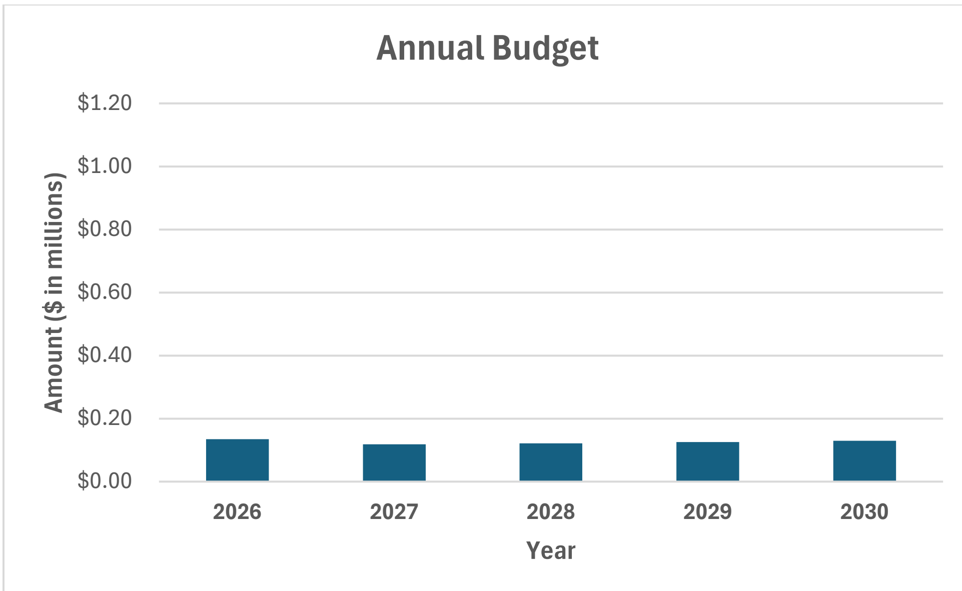


Fig 1: Planned Budget for third-party attachments

The graph above illustrates the annual budget planned for third-party attachments for the period of this DSP. The budget is based on estimating the number of asset attachment request from third parties each year. EPI collaborates with economic development agencies across its communities, municipal planners, and third parties to identify potential growth areas and forecast demand (Section 5.2.2.1). In the early part of the Historical Period, EPI has received a significant number of requests from ISPs. The majority of the ISP growth projects were completed by 2023, such that near-term projections for such requests are more moderate, as reflected in the budget shown above.

A.3.4 Economic Evaluation (Expansion projects)

Economic Evaluation model is not applicable to third-party attachment requests.

A.3.5 Comparative Historical Expenditure

The graph below shows the actual spending for years 2021-2024 and the planned spending for 2025. The variance in finance comes from the unpredictable nature of this segment as it is completely driven by third-party request. The volume of these requests can vary significantly between communities and between years (Section 3.1.2.1). Even with ongoing consultations, plans can change between budget time and project execution.

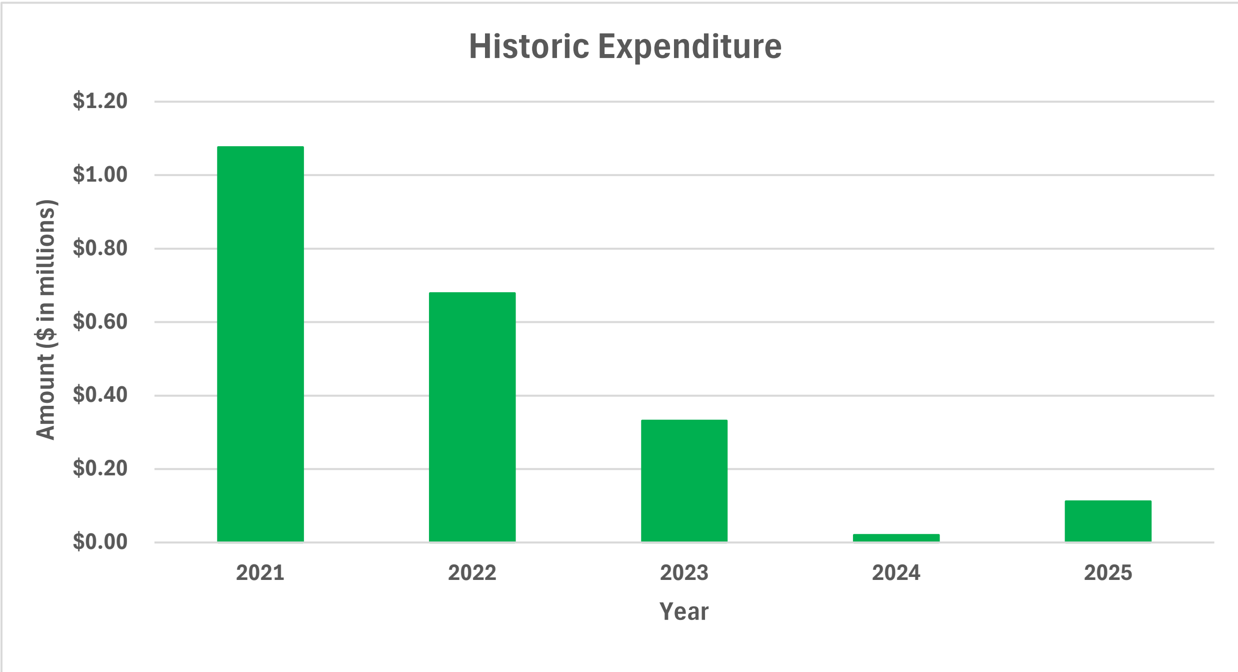


Fig 2: Historic Expenditure -Third-Party Attachments

A.4. Investment Priority

Investments in third-party attachment segment are prioritized, ranking 10th out of the 22 investment categories as per EPI's latest capital project scoring. This balanced approach supports third-party companies to expand their business and operations, while ensuring that EPI's infrastructure is able to accommodate such requests.

A.5. Alternative Analysis

Alternatives are considered on individual basis for each attachment request considering safety, economics, regulatory compliance, system reliability and customer relations to develop the most effective solution. In general, the lowest cost solution which meets EPI's technical requirements is selected unless ISP preference drives a more costly solution. Where possible, costs are minimized through standard design, materials and EPI work practices.

A.6. Innovative Nature of the Project

Not Applicable

A.7. Leave to Construct Approval

This category does not require leave to construct approval under Section 92 of the OEB Act.

B. EVALUATION CRITERIA AND INFORMATION REQUIREMENTS

B.2. Efficiency, Customer Value, Reliability & Safety

Table 6: Investment Evaluation - Efficiency, Customer Value, Reliability & Safety

Criteria	Description
Efficiency	This program supports efficient operation of the utility by: - This program supports the utility in maintaining financial health by aligning investments with system needs and the needs of our joint use partners, municipalities and other agencies. The standardized and streamlined processes significantly reduce costs for accessing, updating, installing or relocating equipment. - By optimizing use of resources, including labor, materials, and equipment through planning and leveraging shared services. - The program helps maintain stable and predictable grid performance for current and future customers by adhering to utility standards for connections, ensuring long-term reliability and efficiency. - The program strategically incorporates incremental capacity upgrades beyond immediate customer needs when it is cost-efficient to do so. By performing additional upgrades during the initial connection process, the utility minimizes future system upgrade costs, leveraging the same crew and resources to achieve cost efficiencies.
Customer Value	This program provides customer value by: - Supporting the utility in maintaining financial health by aligning investments with system needs and the needs of our joint use partners, municipalities and other agencies. The standardized and streamlined processes significantly reduce costs for accessing, updating, installing or relocating equipment. - By optimizing use of resources, including labor, materials, and equipment through planning and leveraging shared services. - The program helps maintain stable and predictable grid performance for current and future customers by adhering to utility standards for improvements, upgrades and relocations, ensuring long-term reliability and efficiency.

	- The program strategically incorporates incremental capacity upgrades beyond immediate customer needs when it is cost-efficient to do so. By performing additional upgrades during joint use or relocation activities, the utility minimizes future system upgrade costs, leveraging the same crew and resources to achieve cost efficiencies. - By promoting economic wellbeing in the community through providing consistent access to secure and reliable electricity.
Reliability	- This program strengthens system reliability by enabling third-party driven investments in shared assets thereby reducing the risk of unexpected service interruptions. - By conducting load flow studies and system modeling when and if needed, the program ensures that new connections do not compromise the stability or reliability of the grid. These proactive measures help identify and address potential system constraints or risks before they escalate. - The program supports the health and functionality of the distribution network by integrating spot-checks and condition assessments of upstream assets in areas where new connections are made. This ensures that the grid's capacity and performance remain robust while accommodating growth. Incremental upgrades performed during the connection process enhance the utility's ability to manage operational demands effectively, ensuring a resilient network that adapts to future needs. By aligning with broader system planning and operational objectives, the program contributes to long-term system reliability, safeguarding the delivery of electricity to all customers.
Safety	Maintaining CSA compliance ensures safety and reliability, making the process straightforward for third parties and municipalities. This helps avoid potential unsafe practices, and bringing in capital allows us to improve and enhance our system. Ensures compliance:

	- By adherence to legislative requirements, safety standards and regulations such as Electrical Distribution Safety O.Reg. 22/04, ESA, CSA, Building codes, Fire codes, OHSA, etc. - By adherence to generally accepted and jointly used safety-by-design standards.

B.3. Investment Need

B.3.3 Primary Driver:

The sole driver of this project is third-party infrastructure demands. This is a mandated service obligation defined in the DSC and other regulations.

B.3.4 Secondary Drivers:

There are no secondary drivers for investments in this project.

B.3.5 Information Used to Justify the Investment:

This is a mandated service obligation defined in the DSC and other regulations. The justification for the investment is driven by customer needs and the requirement to comply with all Ontario Energy Board (OEB) mandated timelines for customer connections. The source of this investment is consultation with common third-party requestors, and municipal planners as well as historical trends to forecast future investments.

B.4. Investment Justification

B.4.3 Demonstrating Accepted Utility Practice:

To ensure that all upgrades and repairs necessary for safe third-party attachments are identified, EPI conducts detailed asset inspections in accordance with Appendix C of the DSC supplemented by additional processes developed internally. Such inspections include in-field visual inspections as well as engineering standards and load/stress analysis.

All necessary design and construction are completed in compliance with applicable USF standards supplemented by standards developed internally. The use of USF standards ensures that the design and construction of this project will be done according to a set of standards utilized by many other utilities in Ontario. EPI is O.Reg. 22/04 compliant to ensure employee and public safety.

B.4.4 Cost-Benefit Analysis:

This is a mandated service obligation outlined in the Distribution System Code (DSC) and other regulations. By investing in infrastructure upgrades to accommodate third-party assets both EPI and the third-party can realize significant benefits. EPI follows OEB rules and regulations around processing connection requests and cost recovery.

B.4.5 Historical Investments & Outcomes Observed:

Section A.3.3 highlights the historic expenses and the variance in budgeting vs actual spending for this segment.

B.5. Non-Wires Solution

Non-wires solutions are not applicable to serve the purposes of this investment.

B.6. Innovation

Not Applicable

MATERIAL INVESTMENT NARRATIVE

PROJECT / PROGRAM:

07. Critical Defect Replacements

INVESTMENT CATEGORY:

SYSTEM RENEWAL

A. GENERAL INFORMATION ON THE PROJECT/PROGRAM

A.1. Overview

The DSC provides requirements for inspecting distribution systems. Specifically, section 4.4.2 of the DSC mandates that distributors perform inspection activities in accordance with the requirements set out in Appendix C of the Code. These inspection requirements, which include guidelines for the frequency and scope of inspections. Based on these requirements, the entire EPI distribution system is inspected every three years, which results in inspection of approximately one-third of the system each year (Section 4.3.2).

This project is to replace critical defective assets identified through the inspection program which may pose an immediate danger to the public. This project covers all range of assets repairs to the electrical system that must be addressed immediately.

The target outcome of this project is to maintain system safety to the public, as well as reliability. The routine inspection program ensures critically defective assets are captured and resolved.

A.2. Timing

a. Start Date: January 2026
b. In-Service Date: Through to December 2030
c. Key factors that may affect timing: The following factors can impact the project schedule:
    - Unpredictability of work volume
    - Supply chain disruptions

A.3. Capital Expenditures

A.3.3 Historical and Future Capital Expenditures

Table 1. Historical and Future Capital ($, million)

Critical Defect Replacements - Totals									
Historic Actual Expenditure				Bridge Year	Forecasted Budgeted Expenditure				
2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
$0.21	$0.39	$0.28	$0.50	$0.12	$0.31	$0.32	$0.33	$0.34	$0.35

The graph below illustrates the planned budget figures for this investment category ($ in millions).

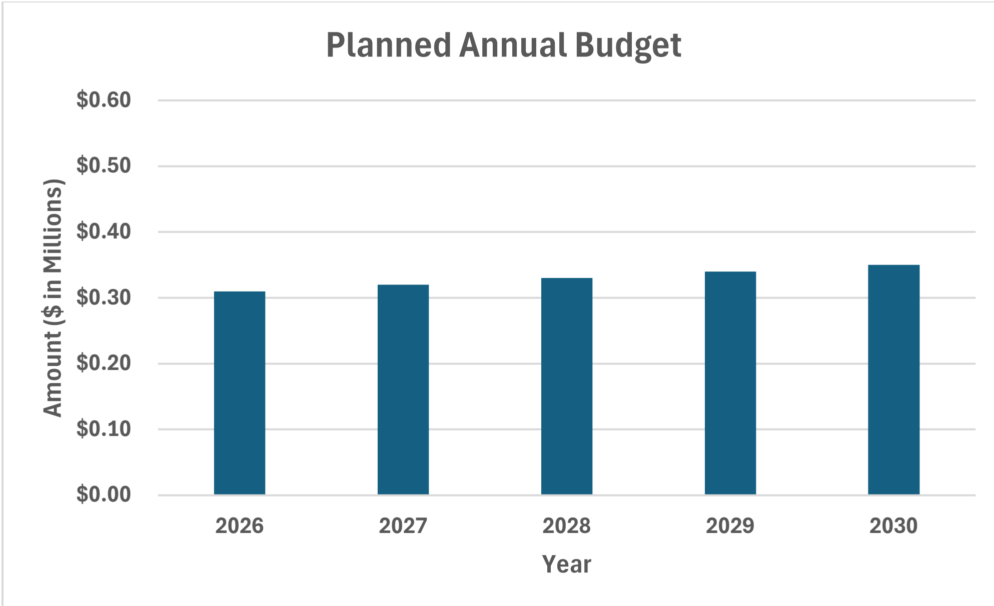


Fig 1: Planned Annual Budget for Critical Defect Replacements

A.3.4 Economic Evaluation (Expansion projects)

Not Applicable

A.3.5 Comparative Historical Expenditure

Although the volume of assets inspected is held consistent year-to-year, the specifics of those assets change year to year (average age, voltage level, construction style).

Spending is expected to be maintained within inflation for the forecast period. Below is a graph that illustrates the historical data of actual expenditure on critical defect replacements for years 2021-2024 and the planned expenditure for 2025:

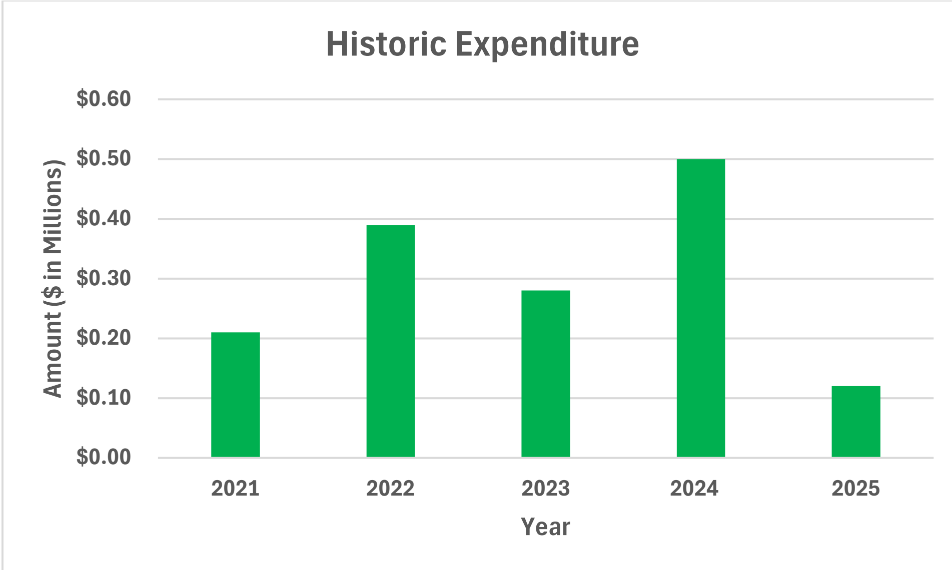


Fig 2: Historical Expenditure – Critical Defect Replacements

A.4. Investment Priority

As per EPI's capital project scoring, this segment ranks 2nd out of 22, reflecting its high priority. The primary driver for this project is to ensure public safety through repairs of assets that pose as a potential danger to the public (Section 5.3).

A.5. Alternative Analysis

The projects included in this category have been identified through cyclical asset inspections and condition assessments. Line staff or other qualified individuals have reviewed these assets and flagged them for action due to their deteriorating condition, potential public safety risks, and the threat they pose to customer reliability.

For this program, the following alternatives were considered:

a. <u>**Do Nothing / Reactive Replacement**</u>
This approach involves deferring action until equipment fails, triggering emergency replacements. This would likely result in unplanned outages often occurring outside of business hours and require more expensive reactive work. Additionally, operating assets in poor condition increases the risk of safety incidents and reduced service reliability. The assets identified in this program have a limited remaining service life and cannot be deferred beyond a year without elevated risk.
Conclusion: *Not considered a viable alternative.*

b. <u>**Selective Hardening or Partial Replacement**</u>
This strategy involves reinforcing existing structures (e.g., pole stubbing, bracing, or guying) or replacing only critical components (such as crossarms or conductors) rather than the entire structure. It can extend asset life in specific cases where the pole is degraded but not fully compromised.
Conclusion: *A viable alternative for select cases, but not broadly applicable due to the advanced deterioration of many assets in this program as evident in Section 4.2.2. of the DSP.*

c. <u>**Targeted Deferral with Enhanced Monitoring**</u>

In low-risk areas, deferral may be considered alongside increased inspection frequency to track deterioration. This strategy allows EPI to reallocate capital in the short term while monitoring asset health more closely.
Conclusion: *May be suitable in limited, low-risk situations but not appropriate for the majority of assets in this program.*

d. **Bundled Renewal with Other Programs**
Where possible, pole and line renewals can be coordinated with other planned work (such as system automation, or capital rebuilds) to reduce mobilization costs and service interruptions.
Conclusion: *A preferred strategy when logistically feasible, but not an alternative to the work itself.*

e. **Like-for-Like Replacement**
This is the preferred and most broadly applicable approach. Replacing deteriorated assets with modern equivalents minimizes disruption to customers and the environment, preserves standardization, and ensures safe and reliable service delivery. It is also the most cost-effective and efficient option across most cases identified in this program.
Conclusion: *Best alternative. Cost-effective, operationally efficient, and aligned with utility standards.*

A.6. Innovative Nature of the Project

Not Applicable

A.7. Leave to Construct Approval

This project does not require leave to construct approval under Section 92 of the OEB Act.

B. EVALUATION CRITERIA AND INFORMATION REQUIREMENTS

B.2. Efficiency, Customer Value, Reliability & Safety

Table 7: Investment Evaluation - Efficiency, Customer Value, Reliability & Safety

Criteria	Description
Efficiency	Proactive replacement of critical defective assets identified through routine inspections helps maintain system reliability and minimizes costs by enabling orderly replacements during working hours, avoiding costly emergency repairs. The program: 1. Helps drive operational efficiency: - By ensuring operability of assets and grid flexibility to restore or isolate sections of the distribution system in an efficient and effective manner. - By ensuring implementation of asset management practices to meet the needs of customers and stakeholders, balancing safety, reliability, and cost-effectiveness. 2. Promotes cost-effectiveness: - By proactively replacing deteriorated assets to avoid higher costs, degraded service levels and safety hazards associated with equipment malfunction, unplanned failures, and emergency repairs and replacements. - By minimizing the likelihood of catastrophic asset failures and subsequent associated costs through early risk identification and mitigation. 3. Maintains Financial Health: - By maximizing ratepayer value through proactive maintenance and replacements in a financially prudent manner. - By maintaining system health metrics to sustain grid performance and prevent increases in emergency repairs and defective equipment replacements due to an increasing number of failing assets. - By ensuring stable and predictable grid performance for current and future customers by managing assets responsibly.
Customer Value	The primary value of this program lies in safeguarding public safety and supporting system availability by addressing defective or deteriorated equipment, reducing risks to

	customers and reinforcing trust in the utility's commitment to reliability. The program: 1. Enhances customer experience: - By notifying customers in advance of any planned work or unplanned outages and restoration time and efforts, enabling them to plan their day-to-day activities around repair or maintenance projects. 2. Helps to improves Customer Value: - By optimizing overall system lifecycle management by targeting for replacement only the assets identified as most critical through inspections and prioritization, ensuring efficient allocation of resources and preventing premature retirement of surrounding assets. - By ensuring a safer, more reliable, and cost-effective distribution system to meet customer needs and maintain customer trust. - By promoting economic wellbeing in the community through providing consistent access to secure and reliable electricity. - By minimizing costs for infrastructure upgrades while maximizing ratepayer value through proactive maintenance and asset replacement. - By reducing system downtime and mitigating risks of lengthy outages, especially on feeders serving critical loads.
Reliability	This project targets the proactive replacement of failed or deteriorated equipment prior to it causing an outage. While the main focus is on ensuring public safety, these proactive replacements also help maintain overall system reliability. The project improves system reliability by reducing the number of outages by proactively replacing assets that are at or beyond their useful life or show signs of significant material degradation to prevent failures.
Safety	The program helps to: 1. Ensure public safety: - By reducing public exposure to significant risks posed by aged and deteriorated equipment, including electrical faults, fires, or hazardous conditions.

	- By reducing the likelihood of dangerous equipment failures through preventing equipment overloading and addressing potential issues proactively. - By supporting system availability though proactive over reactive replacement 2. Ensure compliance: - By adherence to legislative requirements, safety standards and regulations such as Electrical Distribution Safety O.Reg. 22/04, ESA, CSA, OHSA, etc. - By adherence to generally accepted and jointly used safety-by-design standards. 3. Mitigate hazards: - By eliminating equipment-related safety hazards. 4. Mitigate environmental impact: - By removing assets that contain environmentally hazardous material with a high exposure risk.

B.3. Investment Need

B.3.3 Primary Driver:

The main driver for investment for this project is Failure & Failure Risk. Repairing critically defective assets immediately are needed to safeguard the public.

B.3.4 Secondary Drivers:

System Reliability – This project supports maintenance of reliability by proactive addressing assets which may fail.

B.3.5 Information Used to Justify the Investment:

Both the assurance of public safety and System inspection are a mandated activity. Expenditures under this project are made after inspection by trained professionals identify assets in need of immediate remediation.

B.4. Investment Justification

B.4.3 Demonstrating Accepted Utility Practice:

To ensure that all upgrades and repairs necessary are identified, EPI conducts detailed asset inspections in accordance with Appendix C of the DSC supplemented by additional processes developed internally. The frequency of inspections is compliant with Appendix C of the DSC with any EPI-specific schedules detailed in Section 4.3.2. of the DSP. Such inspections include in-field visual inspections as well as engineering standards and load/stress analysis.

All necessary design and construction are completed in compliance with applicable USF standards supplemented by standards developed internally. The use of USF standards ensures that the design and construction of this project will be done according to a set of standards utilized by many other utilities in Ontario. EPI is O.Reg. 22/04 compliant to ensure employee and public safety.

B.4.4 Cost-Benefit Analysis:

Remediation is required to maintain public safety. Work cannot be deferred. Projects are evaluated on an individual basis to determine if repair, like-for-like replacement or referral for an engineered solution is the most appropriate for the given deficiency.

B.4.5 Historical Investments & Outcomes Observed:

The historical inspection and repairs associated with this project have been well aligned with the budget, seeing only modest variances in the historical period. These projects have contributed to EPI's safety record and helped maintain system reliability.

B.5. Non-Wires Solution

Not Applicable

B.6. Innovation

Not applicable

MATERIAL INVESTMENT NARRATIVE

PROJECT / PROGRAM:

08. Emergency Response

INVESTMENT CATEGORY:

SYSTEM RENEWAL

A. GENERAL INFORMATION ON THE PROJECT/PROGRAM

A.1. Overview

This project includes urgent, reactive repairs to the electrical system that are necessary to restore service to customer following unforeseen failures or external impacts. These repairs must be completed immediately to mitigate customer service disruptions and ensure the reliability of the distribution system.

The program encompasses costs associated with storm-related damage, emergency tree trimming, defective equipment and on-call premiums. The objective is to balance emergency reactive repairs and proactive asset replacement.

A key focus of this program is maintaining a consistent investment level while ensuring the ongoing provision of safe and reliable electricity to EPI customers. By strategically managing emergency repair activities, the program aims to minimize unplanned expenditures over time and enhance overall system resilience. The primary outcome is the immediate restoration of service while working to reduce the frequency and severity of emergency repairs through ongoing infrastructure renewal and preventive measures.

A.2. Timing

i. Start Date: January 2025
ii. In-Service Date: Through to December 2030
iii. Key factors that may affect timing:
   a. This project is reactionary, addressing emergency repairs to the distribution system.
   b. Expenditure pacing is uneven and challenging to predict.
   c. Primary causes include:
      i. Storm Response (e.g., weather-related damage).
      ii. Third-Party Interference (e.g., motor vehicle accidents, dig-ins).
      iii. Defective Equipment.

A.3. Capital Expenditures

A.3.3 Historical and Future Capital Expenditures

Table 1. Historical and Future Capital ($, million)

Emergency Response - Totals									
Historic				Bridge Year	Estimated				
2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
$0.85	$0.77	$1.31	$1.06	$0.81	$0.86	$0.88	$0.90	$0.92	$0.94

The graph below illustrates the planned budget figures for this investment category ($ in millions).

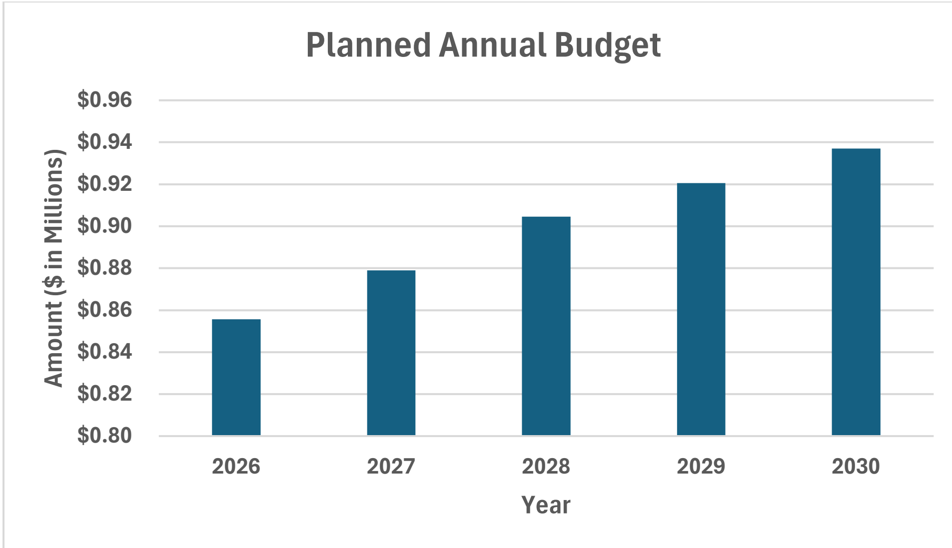


Fig 1: Planned Budget for Emergency Response

A.3.4 Economic Evaluation (Expansion projects)

Not Applicable

A.3.5 Comparative Historical Expenditure

Increases in spending in this category are primarily driven by adverse weather events and defective equipment. As detailed in Section 2.3.2.3, in 2023, there was a sharp rise in weather-related outages and a steady increase in outages caused by defective equipment (including 4 Major Event Days in 2023). Combined with rising material costs discussed throughout this DSP, these factors have contributed to increased historical expenditures. These considerations were incorporated into the Forecasted Budget, with historical averages serving as the basis for projections.

Below is a graph that illustrates the historical data of actual expenditure on Emergency Response:

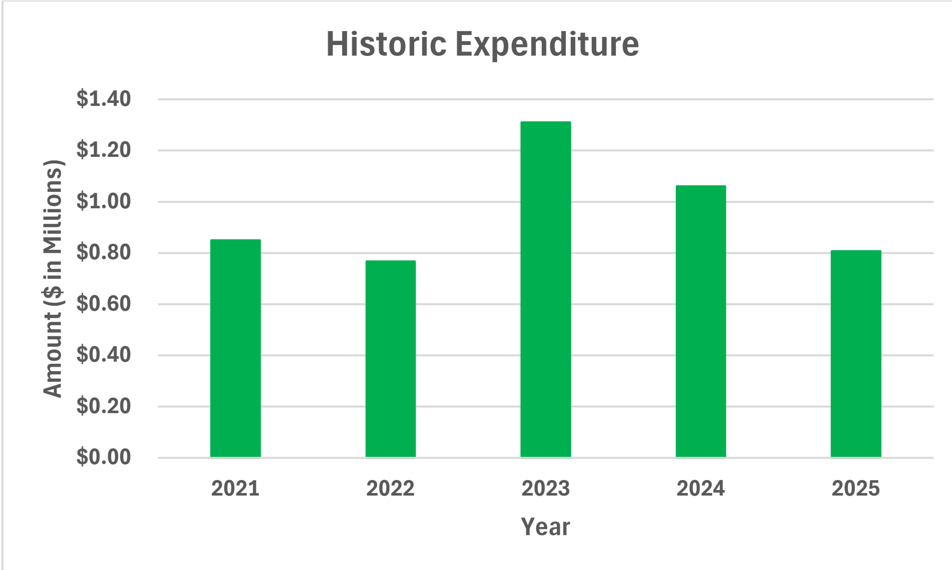


Fig 2: Historical Expenditure – Emergency Response

A.4. Investment Priority

Emergency Response is the highest-priority program among the 22 evaluated. Proper investment in this program is essential to ensuring employee and public safety while maintaining system reliability. Due to its critical nature, this work cannot be deferred (Section 5.3).

A.5. Alternative Analysis

Given the urgency of emergency conditions, most asset replacements are conducted on a like-for-like basis to expedite restoration. However, in select cases, EPI evaluates opportunities to optimize outcomes through engineering referrals and longer-term remediation strategies.

For this program, the following alternatives were considered:

a. <u>Do Nothing / Reactive Replacement</u>
This option involves delaying the repair or replacement of failed assets. However, such deferral is not acceptable under the DSC, which requires immediate restoration of service to impacted customers. Failure to respond promptly would increase customer outage durations, pose safety risks, and potentially breach regulatory obligations.
Conclusion: *Not a viable alternative. Emergency repairs must proceed without delay.*

b. <u>Temporary Reconfiguration or Bypass to Defer Final Repair</u>
In some cases, temporary switching or alternate system configurations may be used to safely restore power to customers without completing full repairs immediately. This allows EPI to defer the final work to regular hours, reducing overtime and contractor costs. It also creates an opportunity for engineering to assess the failed asset and determine whether a different configuration, route, or asset type may be more appropriate.
Conclusion: Viable where technically feasible. Provides flexibility and cost control while enabling engineering optimization.

c. <u>Engineering Referral for Redesigned Permanent Fix</u>
Where circumstances permit, EPI may refer emergency repairs to engineering for follow-up remediation. This allows the utility to re-evaluate the failed asset's function, location, and configuration. In some cases, a redesigned solution may better meet modern safety standards, enhance system resilience, or accommodate upcoming planned work—thereby reducing the likelihood of early replacement or redundant work.
Conclusion: *Preferred when practical. Enables alignment with long-term system planning.*

d. **<u>Like-for-Like Replacement (Immediate Restoration)</u>**
This is the most common and operationally necessary response to asset failure. Replacing damaged or failed components with identical or equivalent assets ensures rapid restoration of service, minimizes disruption to customers, and complies with regulatory requirements. Like-for-like repairs are typically executed on-site with available materials and crews, often during adverse conditions or off-hours.
Conclusion: *Essential for the majority of emergency events. Most effective method for meeting regulatory and customer service objectives.*

A.6. Innovative Nature of the Project

Not Applicable

A.7. Leave to Construct Approval

This project does not require leave to construct approval under Section 92 of the OEB Act.

B. EVALUATION CRITERIA AND INFORMATION REQUIREMENTS

B.2. Efficiency, Customer Value, Reliability & Safety

Table 8: Investment Evaluation - Efficiency, Customer Value, Reliability & Safety

Criteria	Description
Efficiency	This program covers the reactive replacement of failed assets, either due to foreign interference, weather events, defective equipment or other causes. It is also used to address assets which are showing signs of imminent failure. Accepting a level of reactive asset replacement helps improve the overall cost efficiency of the distribution system by ensuring that the full value of an asset has been realized. This program facilitates a well-coordinated, efficient restoration effort.
Customer Value	Improve customer value: - By ensuring a safer, more reliable, and cost-effective distribution system to meet customer needs and maintain customer trust. - By promoting economic wellbeing in the community through providing consistent access to secure and reliable electricity. - By reducing system downtime and mitigating risks of lengthy outages. - Controlling asset renewal costs by ensuring the full value of these assets is realized
Reliability	This program directly supports reliability by addressing assets which have failed in service. The effective and efficient response controls duration of outages and supports like-for-like replacement of the failed assets. This program may also be used to address assets which show signs of imminent failure.
Safety	Ensures public safety: - By reducing public exposure to significant risks posed by aged and deteriorated equipment, including electrical faults, fires, or hazardous conditions. - By immediately replacing equipment damaged by weather-related events, motor vehicle accidents or dig-in. Ensures compliance:

	- By adherence to legislative requirements, safety standards and regulations such as Electrical Distribution Safety O.Reg. 22/04, ESA, CSA, Building codes, Fire codes, OHSA, etc. - By adherence to generally accepted and jointly used safety-by-design standards. Mitigates hazards: - By eliminating equipment-related safety hazards. Mitigates environmental impact: - By removing assets that contain environmentally hazardous material with a high exposure risk.

B.3. Investment Need

B.3.3 Primary Driver:

The primary driver for this investment is asset failure caused by deteriorated equipment, weather-related damage, or third-party incidents such as motor vehicle accidents or dig-ins. Restoration of customer service is a mandated activity and cannot be deferred.

B.3.4 Secondary Drivers:

Not Applicable

B.3.5 Information Used to Justify the Investment:

Restoration of customer supply is a utility obligation and cannot be deferred. Uncontrollable external disturbances such as motor vehicle accidents and severe weather may damage assets in the distribution grid. The number of these emergency response repairs required is unknown and can vary dramatically between communities and between years. Historical data is a valuable part of this evaluation and forecasted investment amount. The increase in budget amounts in the forecast period is to better align with historical actuals.

B.4. Investment Justification

B.4.3 Demonstrating Accepted Utility Practice:

Every task under this program is executed in full compliance with all applicable regulations, standards, and internal policies. EPI consistently applies Utilities Standards Forum (USF) standards to ensure proper and standardized construction practices. In emergency situations, including after-hour repairs, O.Reg. 22/04 is referenced to guide safe and compliant response procedures.

B.4.4 Cost-Benefit Analysis:

The alternative to spending on reactive system repairs is additional spending on proactive replacement and system hardening. EPI believes that avoiding all outages would require an unreasonable level of investment in the distribution system to achieve. Instead, it believes that this represents a balance between proactive investment and reactive replacement which yields a sustainable distribution system and is supported by our customers (Section 4.3.1.1.2).

B.4.5 Historical Investments & Outcomes Observed:

Spending over the historical period has been reasonably stable for a reactive work program but has been poorly aligned with the budgetary amount. EPI has re-aligned the forecasted budgetary amount to reduce this variance.

B.5. Non-Wires Solution

Not Applicable

B.6. Innovation

Not Applicable

MATERIAL INVESTMENT NARRATIVE

PROJECT / PROGRAM:

09. Metering Renewal

INVESTMENT CATEGORY:

SYSTEM RENEWAL

A. GENERAL INFORMATION ON THE PROJECT/PROGRAM

A.1. Overview

EPI owns and operates approximately 64,000 revenue meters installed at customer premises which measure power consumption and demand and enable EPI to provide accurate bills to customers.

As an approved early adopter of smart meters, EPI originally installed most of its smart meter fleet starting in 2006-2007. Accordingly, many of these meters are past their typical lifespan and sustainment investments are required over the 2026-2030 Forecast Period.

Where possible, EPI utilizes the Measurement Canada Sampling based re-sealing program to ensure measurement accuracy and minimize replacement cost. Approximately 5,000 meters tested poorly during the 2nd seal period sampling in 2024. As per Measurement Canada's sampling regulation, the lots were granted the maximum two-year extension without the ability to be sampled again. EPI had applied for a 6-year extension. Now these meters must be replaced no later than 2026, which has led to advancing some smart meter replacement in this 2026 DSP. In order to support the efficient operation of the current generation of AMI meters, along with the large-scale replacement of the individual metering units, upgrades to the AMI communication infrastructure (Network Servers, Signal Amplifiers, Network Controllers) and the Head-End System will be undertaken. These investments support meter reading reliability and resiliency, while enabling more meters to operate with fewer collection assets as compared to EPI's original generation of equipment.

The outcome of this project is to replace meters and AMI communication infrastructure that are at end-of-life. This replacement project is considered non-discretionary spending and is necessary to maintain a supply of electric metering infrastructure to measure consumption as required for new and existing electric services and meter failures. Simultaneously, EPI will renew/re-seal other smart meters to extend their lifecycle as technical and economic feasibility permit.

A.2. Timing

i. Start Date: January 2026
ii. In-Service Date: Through to December 2030
iii. Key factors that may affect timing: The following factors can impact the project schedule:
   - The timing and priority of the project is based on meters reaching their re-seal period as specified by Measurement Canada. During the 2026 – 2030 period, approximately 39,700 meters seal will expire. Where possible, EPI utilizes Measurement Canada Sampling program to ensure measurement accuracy and minimize replacement cost. Approximately 5,000 meters tested poorly during their 2024, 2nd seal period sampling. As per Measurement Canada sampling regulation, the lots were granted the maximum 2 Year extension without the ability to be sampled again. During the 2025-2026 period, these will be required to be replaced (section 5.1.1.5).
   - During the 2026 – 2030 period, a subgroup of approximately 450 polyphase meters will reach the end of their sampling program for which they can no longer be sampled. These require replacement.

- Approximately an additional 65% of EPI meters will need to be resealed during the forecast window. Unanticipated group failures have the potential to drive additional costs.
- Damaged meters are replaced as needed.

A.3. Capital Expenditures

A.3.3 Historical and Future Capital Expenditures

Table 1. Historical and Future Capital ($, million)

Metering Renewal - Totals									
Historic Actual Expenditure				Bridge Year	Forecasted Budgeted Expenditure				
2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
$1.36	$1.45	$1.53	$2.49	$2.66	$2.93	$3.01	$2.58	$2.48	$2.55

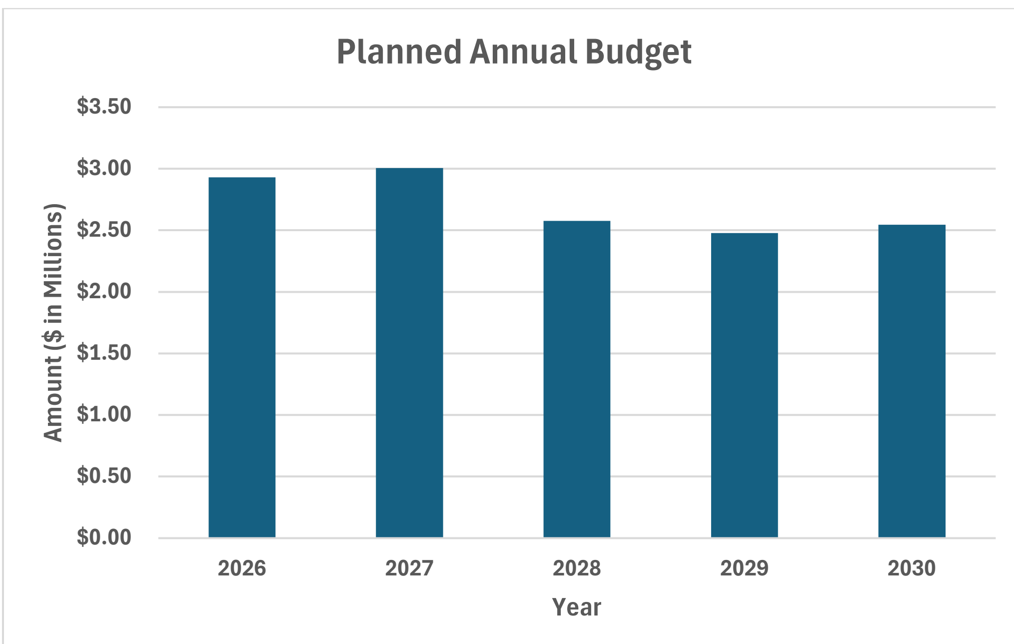


Fig 1: Planned Budget for Metering Renewals

The graph above illustrates the annual budget planned for this investment program.

A.3.4 Economic Evaluation (Expansion projects)

Not Applicable

A.3.5 Comparative Historical Expenditure

The graph below shows the actual spending for years 2021-2024 and the planned expenditure for 2025. The timing and drivers of historical spending is based on meters reaching their re-seal period as specified by Measurement Canada. Damaged meters are replaced as needed.

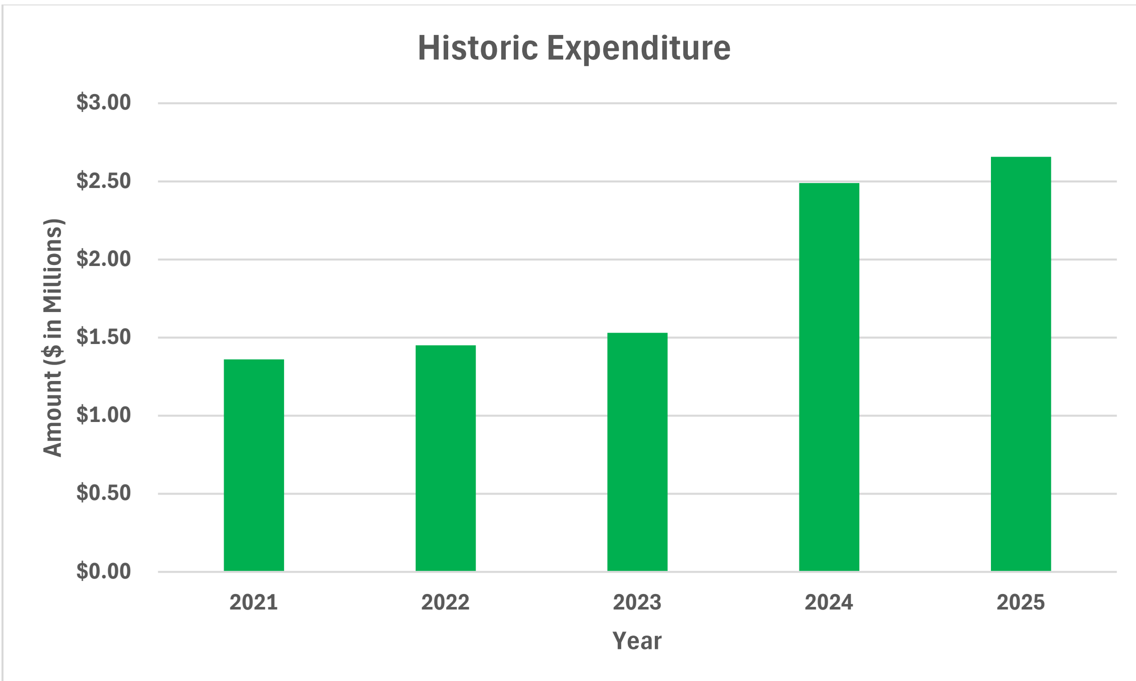


Fig 2: Actual Expenditure – Metering Renewal

A.4. Investment Priority

As per EPI's capital project scoring, this segment ranks 14th out of 22. Meter replacements are a necessary asset for accurate billing of EPI customers and compliance with OEB and Measurement Canada requirements (Section 5.3).

A.5. Alternative Analysis

The projects included in this investment category have been identified based on condition-based assessments, Measurement Canada compliance requirements, and operational inefficiencies resulting from the operation of multiple legacy metering systems. These projects also support EPI's long-term strategy to consolidate metering infrastructure following utility amalgamations and prepare the system for advanced metering infrastructure (AMI 2.0).

For this program, the following alternatives were considered:

a. <u>Do-Nothing / Defer Meter Maintenance or Replacement</u>

This alternative would involve allowing meters to remain in service without performing the resealing, repair, or replacement activities required by Measurement Canada. Such inaction would place EPI in violation of the Distribution System Code (DSC) and federal metering accuracy regulations. It would also jeopardize the accuracy of billing and settlement data and could lead to customer disputes or regulatory penalties.
Conclusion: *Not a viable option. Regulatory non-compliance and data integrity risks make this approach unacceptable.*

b. <u>Full Meter Replacement and Immediate Network Consolidation</u>
Under this approach, all existing meters would be proactively replaced and immediately migrated to a single smart metering platform. While this would simplify system operations and eliminate legacy infrastructure, the approach would require substantial capital investment and offer minimal incremental benefit. Current meters have low failure rates, and technological improvements in residential metering do not justify mass replacement.
Conclusion: *Not cost-effective at this time. Rejected due to high cost and limited additional value.*

c. <u>Maintain Separate Legacy Metering Networks</u>
Where EPI currently operates two smart metering systems inherited through amalgamation. Continuing to maintain these systems is technically feasible but operationally inefficient. It results in duplicative licensing fees, maintenance contracts, and communication infrastructure costs. Furthermore, it hinders EPI's ability to modernize the network, deploy AMI 2.0 features, and support future customer growth.
Conclusion: *Not sustainable. Operational inefficiencies and modernization barriers make this approach unsuitable.*

***d.* <u>Targeted Like-for-Like Meter Replacement with Phased Network Consolidation</u>**
This is the preferred approach. It involves the condition-based replacement of meters that have failed, become obsolete, or reached reseal expiration. At the same time, EPI will gradually consolidate its metering infrastructure onto a single network. This minimizes disruption to customers, optimizes capital investment, and allows strategic upgrades to supporting infrastructure such as signal amplifiers, network servers, and head-end systems. This staged approach also enhances disaster resilience and supports the planned transition to AMI 2.0.
Conclusion: *Most cost-effective and operationally efficient alternative. Fully compliant with regulatory obligations and aligned with long-term strategic goals.*

A.6. Innovative Nature of the Project

Not Applicable

A.7. Leave to Construct Approval

This project does not require leave to construct approval under Section 92 of the OEB Act.

B. EVALUATION CRITERIA AND INFORMATION REQUIREMENTS

B.2. Efficiency, Customer Value, Reliability & Safety

Table 9: Investment Evaluation - Efficiency, Customer Value, Reliability & Safety

Criteria	Description
Efficiency	Improves operational efficiency: - By optimizing procurement and supply chain management through standardizing equipment and reducing the variety of asset types in the system. - By ensuring implementation of asset management practices to meet the needs of customers and stakeholders, balancing safety, reliability, and cost-effectiveness. Ensures cost-effectiveness: - By metering assets and equipment to achieve the lowest overall lifecycle costs. - By supporting revenue collection and accuracy, controlling costs and reducing the need for unplanned crew access to customer properties through implementing reliable metering solutions. - By maximizing ratepayer value through proactive maintenance and replacements in a financially prudent manner. - By preventing a significant accumulation of the renewal investment backlogs and ensuring long-term rate stability for customers. - By maintaining system health metrics to prevent increases in emergency repairs and defective equipment replacements due to an increasing number of failing assets
Customer Value	Investments in this program drive customer benefits through: - Improved leverage of AMI assets to provide outage information to customers through the company website (outage map). - By ensuring timely and accurate billing information to utility customers based on actual usage in compliance with regulations. - By metering assets and equipment to achieve the lowest overall lifecycle costs. - By supporting revenue collection and accuracy, controlling costs and reducing the need for unplanned crew access to customer properties

	through implementing reliable metering solutions. - By maximizing ratepayer value through proactive maintenance and replacements in a financially prudent manner. - By preventing a significant accumulation of the renewal investment backlogs and ensuring long-term rate stability for customers.
Reliability	This project indirectly supports system reliability. By driving real time outage data into EPI outage tracking and visualization tools it supports the coordination of restoration efforts, analysis of grid state, and enables efficient resource dispatch.
Safety	Ensures compliance: - By adherence to legislative requirements, safety standards and regulations such as Electrical Distribution Safety O.Reg. 22/04, ESA, CSA, Building codes, Fire codes, OHSA, etc.

B.3. Investment Need

B.3.3 Primary Driver:

The drivers for this investment are regulatory compliance and functional obsolescence. Over the 2026-2030 Forecast Period approximately 35% of EPI's fleet of smart meters will have reached the end of their first re-seal period as specified by Measurement Canada and 30% will have entered their second re-seal period.

B.3.4 Secondary Drivers:

There are no secondary drivers for investments in this project.

B.3.5 Information Used to Justify the Investment:

The justification of this investment is non-discretionary work required to meet Measurement Canada rules. This project is necessary to maintain a supply of electric metering infrastructure to measure consumption as required for new and existing electric services and meter failures. This project ensures compliance with requirements for smart meters in 2026 – 2030.

B.4. Investment Justification

B.4.3 Demonstrating Accepted Utility Practice:

EPI plans and executes its metering program to accommodate failed meters and comply with regulations. All new meters installed are Measurement Canada ("MC") approved and comply with internally developed standards. Resealing processes are completed on a schedule according to MC mandate and are completed by an MC-accredited reverification laboratory.

All necessary design and construction are completed in compliance with applicable USF standards supplemented by standards developed internally. The use of USF standards ensures that the design and construction of this project will be done according to a set of standards utilized by many other utilities in Ontario. EPI is O.Reg. 22/04 compliant to ensure employee and public safety.

B.4.4 Cost-Benefit Analysis:

The 2026-2030 Forecast Period expenditures are predicated on a paced smart meter replacement and re-sealing strategy, which will require close monitoring against the risk of technological obsolescence and in-service failures due to the age of the EPI smart meter fleet. Over the 2026-2030 Forecast Period approximately 35% of EPI's fleet of smart meters will have reached the end of their first re-seal period as specified by Measurement Canada and 30% entered their second re-seal period. A primary risk with this project execution is timing to meet re-seal period and a secondary risk is the potential necessity to do a second re-sealing period for certain batches of meters. Further, long equipment lead-times and available resources to facilitate the meter change-outs may require EPI to outsource replacement work, increasing costs to maintain meter compliance. These risks are mitigated through diligent planning and inventory management practices for long-lead materials.

B.4.5 Historical Investments & Outcomes Observed:

Section A.3.3 highlights the historic expenses and the variance in budgeting vs actual spending.

B.5. Non-Wires Solution

Not Applicable

B.6. Innovation

Not Applicable

MATERIAL INVESTMENT NARRATIVE

PROJECT / PROGRAM:

10. Miscellaneous System Renewal

INVESTMENT CATEGORY:

SYSTEM RENEWAL

A. GENERAL INFORMATION ON THE PROJECT/PROGRAM

A.1. Overview

In addition to the programs outlined in the other seven System Renewal projects, EPI recognizes and budgets for remaining asset lifecycle practices under this Miscellaneous System Renewal project. Specifically, this program focuses on assets with higher failure impact and those that are challenging to repair reactively.

Planned projects for the Forecast Period include asset life extension of EPI-owned substation facilities (including monitoring of station transformers) and the replacement of aged critical cables, including replacement of egress cables from Edgeware TS and underground river crossing cables in Wallaceburg. This proactive approach mitigates reactive replacement, which would have significant operational, reliability or economic impact.

A.2. Timing

i. Start Date: January 2025
ii. In-Service Date: Through to December 2030
iii. Key factors that may affect timing: The following factors can impact the project schedule:
    - Asset Condition – Replacements are prioritized based on observed condition and failure impact.
    - Coordination with Upstream Transmitters – Specifically for egress cable replacement, EPI may require coordination to isolate and safely work on equipment.
    - Lead Time on Equipment.

A.3. Capital Expenditures

A.3.3 Historical and Future Capital Expenditures

Table 1. Historical and Future Capital ($, million)

Miscellaneous System Renewal - Totals									
Historic Actual Expenditure				Bridge Year	Forecasted Budgeted Expenditure				
2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
$0.00	$0.15	$0.21	$0.10	$0.18	$0.18	$0.18	$0.19	$0.19	$0.20

The graph below illustrates the planned budget figures for this investment category ($ in millions).

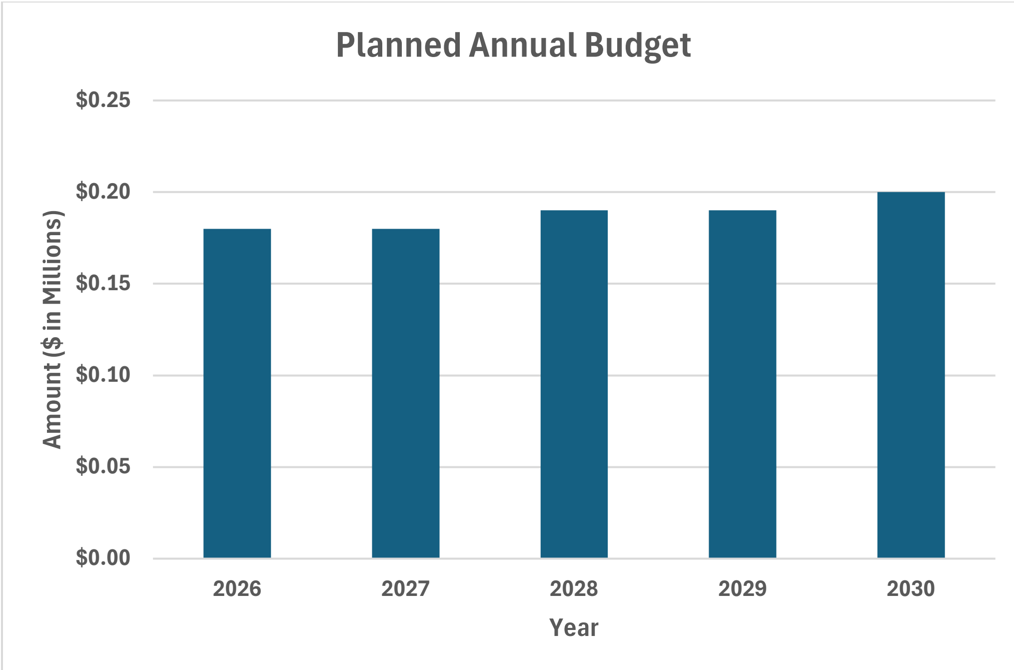


Fig 1: Planned Budget for Miscellaneous System Renewal

A.3.4 Economic Evaluation (Expansion projects)

Not Applicable

A.3.5 Comparative Historical Expenditure

Historically, the spending in this category is primarily driven by replenishment and maintenance of various legacy assets at 4kV substations to extend their lifespan and the replacement of critically aged cables (such as the egress cables from Edgeware TS, see Section 4.3.1.1.2). Depending on possible changes in conversion schedule and the asset conditions or associated risks of asset failure, the amount and timing of these investments have varied.

The historic spending from 2021-2024 and the planned spending for 2025 has been shown in the figure below:

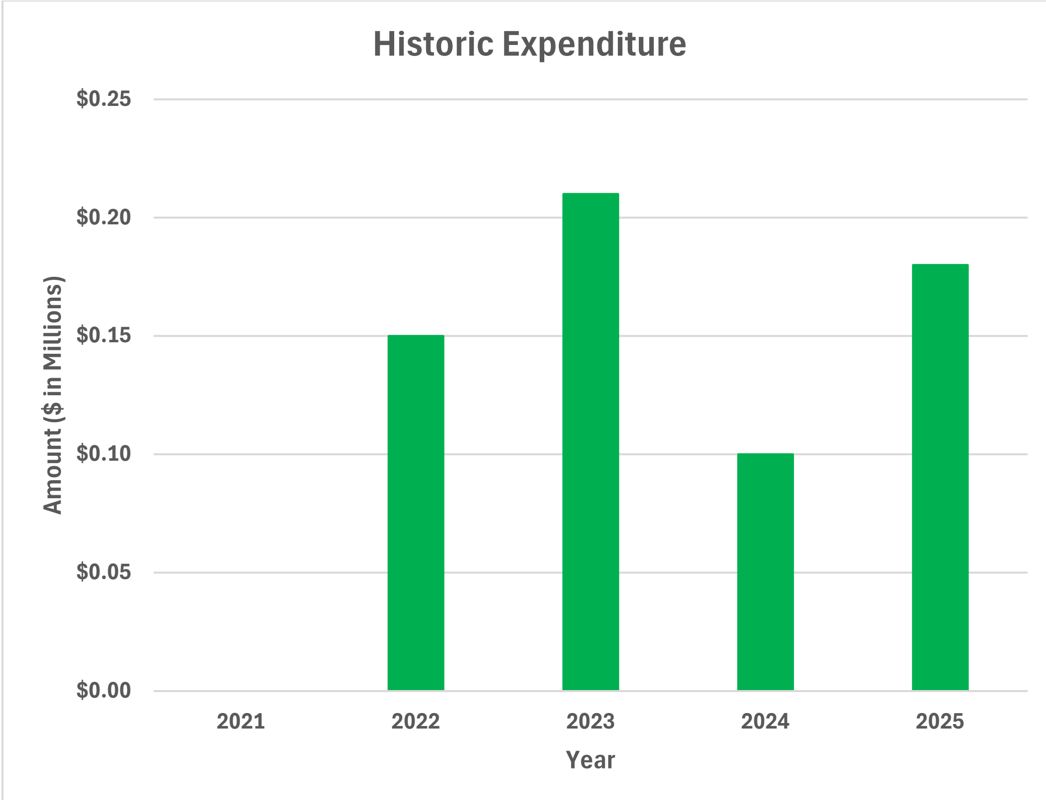


Fig 2: Historic Expenditure – Miscellaneous System Renewal

As stated throughout this document, in 2021 System Access related customer requests grew significantly in magnitude compared to previous years. EPI's obligation to connect customers was prioritized over planned miscellaneous system renewal jobs. Later in the Historical Period, expenditures rose over planned as EPI caught up on lifecycle practices.

A.4. Investment Priority

The potential candidates in this program are prioritized by evaluating the asset conditions (health indices and inspection records), the number of customers served by the asset, and any alternative grid configurations which may mitigate the impact of a failure. If applicable, the timing planned conversion is also considered to see if it is reasonable to avoid a renewal. As per EPI's capital project scoring, this investment segment ranks 20th out of 22 (Section 5.3).

A.5. Alternative Analysis

The largest portion of this program is invested in critical asset replacement which includes targeted replacement of deteriorating distribution assets such as egress feeders, major underground cables, and river crossings, identified through condition assessments and prioritized based on risk to reliability and safety.

These assets are essential to the safe and reliable operation of the distribution network and are prioritized based on condition and criticality.

a. <u>Do Nothing / Defer Replacement</u>

This alternative involves postponing replacement of known deteriorated assets. While potentially justifiable in rare, low-risk cases, general deferral exposes the system to increased failure probability, unplanned outages, higher emergency repair costs, and diminished reliability.
Conclusion: *Not appropriate for most cases. Considered only where risk is demonstrably low and temporary mitigation is in place.*

b. Replace Underground Assets with Overhead Construction

Overhead construction was reviewed as a lower-cost alternative to underground replacements. However, most of the affected assets are located in residential or urban environments where overhead lines conflict with land use planning, aesthetics, and design standards.
Conclusion: *Not feasible in most contexts. Often rejected due to incompatibility with site conditions.*

c. Like-for-Like Replacement (Underground Cable or River Crossing)

This is the preferred approach for critical asset renewals. Although some locations pose construction challenges—requiring more costly techniques such as directional drilling—like-for-like replacement ensures system continuity, minimizes community disruption, and preserves existing infrastructure layout.
Conclusion: *Best overall solution. Supports reliability, operational continuity, and long-term efficiency.*

A.6. Innovative Nature of the Project

Not Applicable

A.7. Leave to Construct Approval

This project does not require leave to construct approval under Section 92 of the OEB Act.

B. EVALUATION CRITERIA AND INFORMATION REQUIREMENTS

B.2. Efficiency, Customer Value, Reliability & Safety

Table 10: Investment Evaluation - Efficiency, Customer Value, Reliability & Safety

Criteria	Description
Efficiency	Investments in life extension and enhancements of key assets such as protection and coordination equipment, station egress cables and river crossings are required for the long-term integrity of the distribution system. Proactively replacing these assets as inspection and performance data shows they are reaching end-of-life helps control cost, maintain system reliability and operation flexibility. Improves operational efficiency: - By ensuring implementation of asset management practices to meet the needs of customers and stakeholders, balancing safety, reliability, and cost-effectiveness. Ensures cost-effectiveness: - By proactively replacing deteriorated assets to avoid higher costs, degraded service levels and safety hazards associated with equipment malfunction, unplanned failures, and emergency repairs and replacements. - By minimizing the likelihood of catastrophic asset failures and subsequent associated costs through early risk identification and mitigation. - By maximizing ratepayer value through proactive maintenance and replacements in a financially prudent manner. - By ensuring stable and predictable grid performance for current and future customers by managing assets responsibly.
Customer Value	Improve customer value: - By ensuring a safer, more reliable, and cost-effective distribution system to meet customer needs and maintain customer trust. - By promoting economic wellbeing in the community through providing consistent access to secure and reliable electricity.
Reliability	Improve power quality: - By deploying grid sensors, monitoring equipment, and analytics tools to provide real-

	time insights into voltage fluctuations and power quality disturbances. - By optimizing voltage levels and reactive power flows throughout the distribution system. - By replacing aging equipment with modern, higher-rated assets designed to handle variable loads and bi-directional power flows to support the adoption of EVs and DERs. - By converting overhead distribution lines in critical areas to underground systems to mitigate voltage flickers and sags caused by environmental factors. - By implementing efficient outage management systems to coordinate restoration efforts, analyze grid state, and dispatch resources effectively. - By supporting faster outage responses through improved communication systems.
Safety	Ensures public safety: - By reducing public exposure to significant risks posed by aged and deteriorated equipment, including electrical faults, fires, or hazardous conditions. - By reducing safety risks and hazards to the public associated with managing and operating grid infrastructure. - By installing remote switching, thereby reducing crew exposure to safety risks associated with manual switching. - By adherence to legislative requirements, safety standards and regulations such as Electrical Distribution Safety O.Reg. 22/04, ESA, CSA, Building codes, Fire codes, OHSA, etc.

B.3. Investment Need

B.3.3 Primary Driver:

The primary driver for this is system capital investment support. By renewing key assets or performing life-extension work, EPI mitigates the higher costs and reliability impacts associated with reactive like-for-like asset replacements.

B.3.4 Secondary Drivers:

There are no secondary drivers for this program.

B.3.5 Information Used to Justify the Investment:

The spending in this project is essential to ensuring continued operations and undisrupted service for EPI customers. The focus is on maximizing the life of existing equipment and optimizing the use of funds to maintain and upgrade critical assets such as station egress cables, river crossings, legacy stations and associated equipment.

B.4. Investment Justification

B.4.3 Demonstrating Accepted Utility Practice:

This program includes assets requiring upgrades or repairs that are not captured under other capital programs. To ensure that all upgrades and repairs necessary are identified, EPI conducts detailed asset inspections in accordance with Appendix C of the DSC supplemented by additional processes developed internally. The frequency of inspections is compliant with Appendix C of the DSC with any EPI-specific schedules detailed in Section 4.3.2. of the DSP.

In addition to repair needs identified through inspections, the program also includes a targeted list of assets selected for proactive replacement. These are typically high-impact, critical components that are difficult to replace quickly and whose failure would significantly impact system reliability and operational flexibility due to the extended time required for restoration.

Where applicable, EPI applies Utilities Standards Forum (USF) standards for these projects to ensure consistency in design and construction. For work outside the scope of USF standards, contracted professional engineers are engaged to design and approve the necessary plans.

B.4.4 Cost-Benefit Analysis:

The cost-benefit analysis for this investment category highlights avoiding large capital expenditures for substation replacement and accelerated conversion projects through limited, targeted investments in life extension measures of existing station asset, and the proactive life-cycling of other critical non-station assets. This approach ensures a reliable service, aligns with planned investment schedules, and minimizes costs for customers, making it a well-balanced strategy for asset management as well modernization of the distribution system.

B.4.5 Historical Investments & Outcomes Observed:

Section A.3.3 highlights the historic expenses in this segment. Investments in this category are aimed to yield a key outcome: the reliable function of key assets such as station egress cables, river crossings and legacy voltage station ensuring undisrupted operations and service to customers.

B.5. Non-Wires Solution

Non-wires solutions are not applicable to serve the purposes of this investment.

B.6. Innovation

Not Applicable

MATERIAL INVESTMENT NARRATIVE

PROJECT / PROGRAM:

11. Operations Support Capital

INVESTMENT CATEGORY:

SYSTEM RENEWAL

A. GENERAL INFORMATION ON THE PROJECT/PROGRAM

A.1. Overview

This program encompasses investment associated with overseeing the construction work of capital projects, ensuring that construction activities are completed safely, efficiently and in alignment with EPI's operational standards, EDA regulations and O. Reg 22/04. This includes non-engineering salaries, project management costs and other resources necessary to support the coordination and execution of capital work.

This program includes the allocation of resources, specialized personnel, and infrastructure necessary to manage large-scale investments in the distribution system. Budget forecasts are determined based on historical spending and projected capital project needs, reflecting the embedded costs required to support major system investments. The scope and associated costs of this initiative may fluctuate annually due to project-specific requirements and unforeseen circumstances. However, the overarching goal remains the same—to sustain a consistent investment in project oversight, enabling the successful delivery of capital projects while upholding EPI's commitment to safety, reliability, and regulatory compliance.

A.2. Timing

i. Start Date: January 2026
ii. In-Service Date: Through to December 2030
iii. Key factors that may affect timing: The following factors can impact the project schedule:
   - Variable Costs – since annual spending can fluctuate based on the scope of work and unforeseen events
   - This project is considered a high priority since proper supervision is key to supporting safe work practices

As a regulated utility, EPI is obliged to adhere to strict safety standards and operational policies. To mitigate these risks, it is crucial to employ experts and well-trained management leaders who can oversee and guide the crews and ensure compliance with industry procedures and policies in place. Failure to do so can lead to serious safety incidents, regulatory fines due to incompliance and damage to property.

A.3. Capital Expenditures

A.3.3 Historical and Future Capital Expenditures

Table 1. Historical and Future Capital ($, million)

Operations Support Capital									
Historic Actual Expenditure				Bridge Year	Forecasted Budgeted Expenditure				
2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
$1.06	$0.92	$1.07	$0.91	$0.97	$1.04	$1.07	$1.10	$1.14	$1.17

The graph below illustrates the planned budget figures for this investment category ($ in millions).

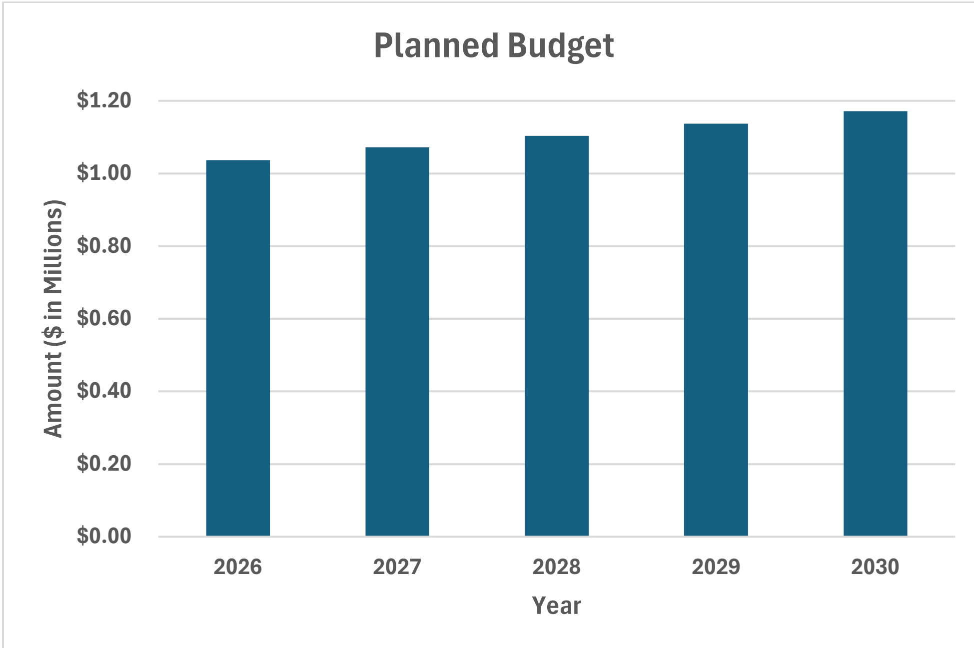


Fig 1: Planned Budget for Operations Support

A.3.4 Economic Evaluation (Expansion projects)

Not Applicable

A.3.5 Comparative Historical Expenditure

The historic spending from 2021-2024 and planned spending in 2025 has been shown in the figure below. Capital projects executed by a utility distributor vary widely in work scope, budgets, associated safety risks, and labor requirements. As a result of this diversity, the annual spending can fluctuate significantly depending on work volume, nature and the split between contracted and internal work.

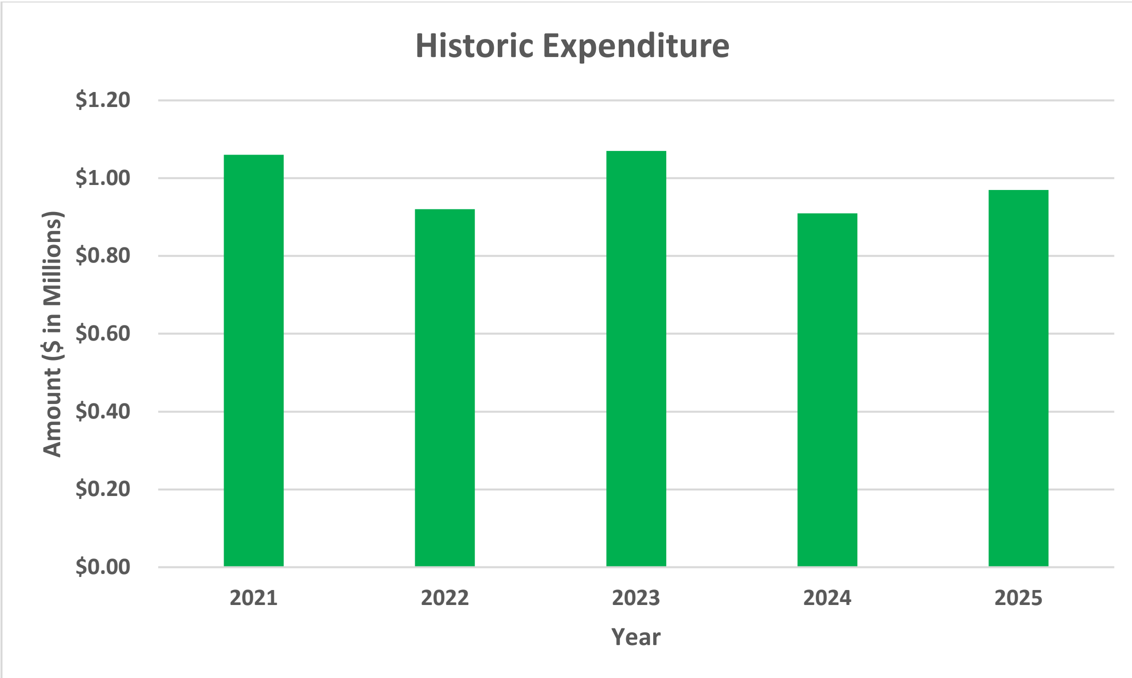


Fig 2: Annual Historic Budgets vs Actual Expenditure

A.4. Investment Priority

As per EPI's capital project scoring, this sector ranks 3rd out of 22 as adequate supervision is required to ensure compliance with regulations and cost control (Section 5.3).

A.5. Alternative Analysis

This investment category supports the oversight, coordination, and quality assurance functions necessary for the safe, compliant, and efficient execution of EPI's capital plan. These functions ensure that construction projects meet regulatory requirements, follow standardized practices, and are delivered in a cost-effective and timely manner. Oversight also mitigates risks such as property damage, safety incidents, and project delays.

For this program, the following alternatives were considered:

a. Do Nothing / Eliminate Oversight Activities
This alternative would involve discontinuing or significantly reducing oversight and coordination activities associated with capital project execution. Without these functions, EPI would be unable to ensure compliance with industry regulations, internal design standards, or safety protocols. It would also increase the likelihood of construction errors, cost overruns, and damage to third-party property or utility assets.
Conclusion: *Not viable. Eliminating oversight would pose unacceptable operational, financial, and regulatory risks.*

b. Outsource Oversight Functions to External Consultants
This approach would shift oversight and coordination responsibilities to third-party service providers. While technically feasible, outsourcing introduces challenges such as reduced familiarity with local infrastructure, diminished accountability, and the need for increased internal oversight of

the external contractors themselves. It is also typically more costly over time than maintaining internal capacity.
Conclusion: *Not cost-effective or operationally efficient. Misaligned with EPI's objective to maintain internal expertise and system familiarity.*

c. **Maintain Current Internal Oversight and Coordination Capabilities**
This is the preferred approach. Maintaining the current level of investment ensures that capital projects are planned, executed, and reviewed in a safe, compliant, and cost-efficient manner. It supports EPI's commitment to optimizing workflows, improving design standards, and managing material and labour resources effectively.
Conclusion: *Best alternative. Ensures continued oversight, regulatory compliance, and project delivery efficiency.*

A.6. Innovative Nature of the Project

Not Applicable

A.7. Leave to Construct Approval

This project does not require leave to construct approval under Section 92 of the OEB Act.

B. EVALUATION CRITERIA AND INFORMATION REQUIREMENTS

B.2. Efficiency, Customer Value, Reliability & Safety

Table 11: Investment Evaluation - Efficiency, Customer Value, Reliability & Safety

Criteria	Description
Efficiency	This project supports utility efficiency by providing operations supervision to oversee construction activities. It supports overall utility efficiency by: - By continuously monitoring and assessing the progress of capital projects to ensure alignment with system priorities and objectives and the most efficient use of resources. - By supporting asset management practices to meet the needs of customers and stakeholders, balancing safety, reliability, and cost-effectiveness. - By minimizing costs for installing electrical services through streamlined processes and standards. - By reducing Workplace Safety Insurance Board premiums as a result of maintaining a strong safety record. - By managing fleet and equipment assets to achieve the lowest overall lifecycle costs.
Customer Value	Having adequate operations supervision ensures customers' interests are served by the effective, efficient completion of maintenance and construction activities. This work ensures construction is built to the appropriate standard to minimize risk, including public safety, equipment failure, and economic risk. This work includes supporting customer choice: - By enabling customers to connect clean technologies and renewable energy sources efficiently. Improve customer value: - By providing access to energy needs for new connections and service upgrades, meeting regulated timelines. - By ensuring a safer, more reliable, and cost-effective distribution system to meet customer needs and maintain customer trust. - By promoting economic wellbeing in the community through providing consistent access to secure and reliable electricity.

Reliability	This project provides support to system reliability: - by coordinating both emergency repair activities and planned work for cost efficient, timely completion. - By assisting in the development of plans to stage construction work in a way that minimizes customer disruptions and asset unavailability. - By ensuring correct application of construction standards to ensure that the distribution system is well prepared to address both current and anticipated future demands. By making recommendations to: - replace equipment in strategic locations to better withstand weather-related disruptions. - replace critical overhead assets with underground infrastructure in key areas. - Enable safe and reliable customer and DER connections
Safety	Ensures public safety: - By reducing safety risks and hazards to the public associated with managing and operating grid infrastructure. - By reducing public exposure to significant risks posed by aged and deteriorated equipment, including electrical faults, fires, or hazardous conditions. - By supporting the immediate replacement of equipment damaged by weather-related events, motor vehicle accidents or dig-ins. Improves worker and public safety: - By relocating equipment to improve accessibility. - By maintaining safe conditions at the workplace for utility workers. - By ensuring safe work practices for utility workers. - By adherence to legislative requirements, safety standards and regulations such as Electrical Distribution Safety O.Reg. 22/04, ESA, CSA, Building codes, Fire codes, OHSA, etc. - By adherence to generally accepted and jointly used safety-by-design standards.

B.3. Investment Need

B.3.3 Primary Driver:

The main driver for this investment is system capital investment support to ensure adequate non-engineering supervision for the remaining capital programs. This ensures that capital construction jobs are executed in the safest manner possible while following the most efficient techniques and standardized processes. These measures help mitigate risks of accidents, injuries and property damage and ensure compliance to all relevant safety regulations.

B.3.4 Secondary Drivers:

There are no secondary drivers for investments in this project.

B.3.5 Information Used to Justify the Investment:

Given the laws and regulations regulatory requirements governing utilities, there are no alternatives to investing in operational support. Aligned with EPI goals of ensuring a strong core team, the majority of this effort is in house staff, with contractors addressing the balance, and any additional surge needs. The budget for this project is forecasted based on current head count, historical spending and an assessment of planned capital projects.

B.4. Investment Justification

B.4.3 Demonstrating Accepted Utility Practice:

EPI maintains a team of experienced operations support staff to support System Access and System Renewal investments. These roles also play a critical part in ensuring compliance with USF design standards, OEC, ESA and O.Reg. 22/04 during construction.

B.4.4 Cost-Benefit Analysis:

Investments in this project are crucial as the risk of not providing sufficient capital to support the operations team can significantly hamper EPI's ability to efficiently conduct the field operations to support the existing and new customer base while also ensuring adherence to various industry regulations as well as safety standards. Failure to maintain compliance could result in Health & Safety incidents, Ministry of Labour citations and damage to property. By investing in skilled personnel and implementing standard operating procedures utilities can minimize costs, operate at higher efficiency and enhance customer satisfaction. This is a proactive approach that ensures a high-quality service, safe project executions as well as a robust infrastructure development that benefits both EPI and its customers.

B.4.5 Historical Investments & Outcomes Observed:

Section A.3.3 highlights the historic expenditures in this segment. The main outcomes of this project are safe execution of capital constructions and a well-trained workforce. Historically, EPI has demonstrated its commitment to safety by proving its compliance to the industry regulations and has managed to execute numerous capital jobs with minuscule safety concerns or incidents.

B.5. Non-Wires Solution

Not Applicable

B.6. Innovation

Not Applicable

MATERIAL INVESTMENT NARRATIVE

PROJECT / PROGRAM:

12. Pole Replacements

INVESTMENT CATEGORY:

SYSTEM RENEWAL

A. GENERAL INFORMATION ON THE PROJECT/PROGRAM

A.1. Overview

This program specifically addresses the aging poles within our service territory, focusing on replacing those that have been identified reaching their end-of life or their condition is most at-risk.

The objective is to remediate potential risks associated with pole failures, which can lead to power outages, safety hazards and increased maintenance costs. These poles are not associated with any broader, specific project (i.e. Voltage Conversion); instead, at-risk poles are identified and prioritized typically based on field inspections (including pole testing). The selected poles are either at the end of their useful life or have prematurely degraded.

As detailed in Section 3.1.3, pole testing helps EPI obtain a more precise evaluation of the condition of its poles. Each pole replaced under this program is referred to Engineering for evaluation to determine if like-for-like is the most appropriate option, or if planned or anticipated work in the area would merit a change in pole height, class or framing style, to ensure that when the future work is completed, the pole will still be suitable for use.

Proactive and planned replacements of deteriorating poles is a strategic investment approach that prioritizes reliability, operational efficiency and minimizes costly emergency repairs.

A.2. Timing

i. Start Date: January 2026
ii. In-Service Date: Through to December 2030
iii. Key factors that may affect timing: The following factors can impact the project schedule:
   - Resource Constraints – Project execution can be constrained by unplanned and/or higher priority work arising.
   - Availability of Contracted Services – The project schedule is contingent upon the timely completion of asset condition analysis achieved through in-field pole testing.

A.3. Capital Expenditures

A.3.3 Historical and Future Capital Expenditures and Comparative Analysis

Table 1. Historical and Future Capital ($, million)

Pole Replacements - Totals									
Historic Actual Expenditure				Bridge Year	Forecasted Budgeted Expenditure				
2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
$0.77	$0.68	$0.44	$0.85	$0.56	$0.59	$0.60	$0.62	$0.63	$0.64

While EPI's pole testing and pole replacement targets remained consistent year-over-year, actual expenditures varied annually for several reasons. As noted earlier, this project's priority is occasionally deferred due to labour and material constraints, particularly when System Access work, driven by customer requests, takes precedence. Moreover, since this project involves individual pole replacements (primarily like-for-like), unit costs vary more than in conversion projects, and urgent repairs or replacements identified during pole testing may necessitate additional investment to ensure system reliability and public safety.

The graph below illustrates the planned budget figures for this investment category ($ in millions).

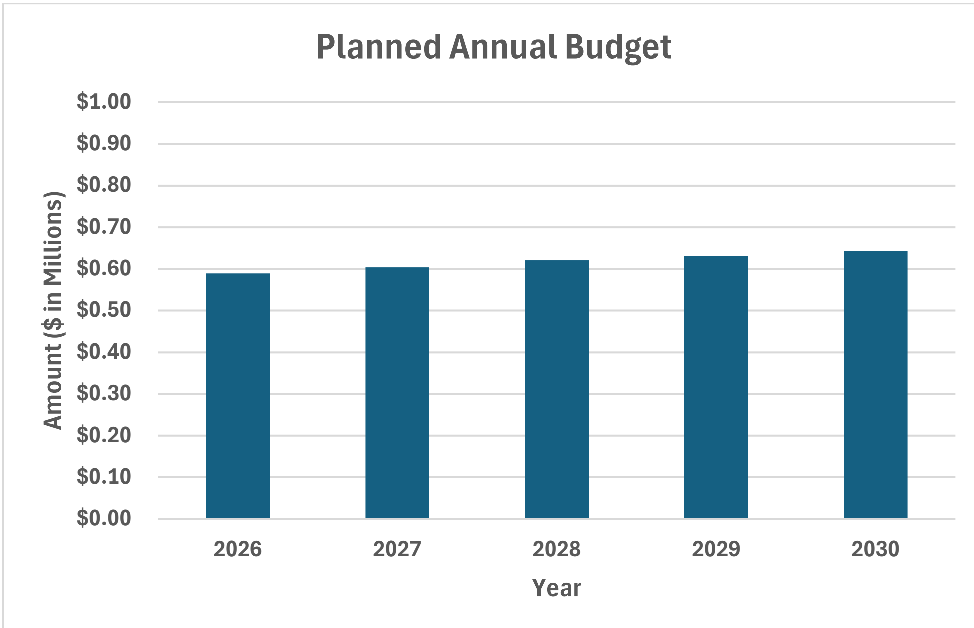


Fig 1: Planned Budget for Pole Replacements

A.3.4 Economic Evaluation (Expansion projects)

Not Applicable

A.3.5 Comparative Historical Expenditure

The spending in this category is primarily driven by replacements of identified poles that are at the end of their useful life which have undergone multiple in-field testing procedures and have been deemed unfit for service due to deterioration. EPI tries to be proactive, and plans pole replacements to minimize any service disruptions or public safety concerns. Replenishing near end-of-life poles are needed to maintain the integrity of the distribution grid and provide reliable power to EPI customers.

The historic spending from 2021-2024 and planned spending in 2025 has been shown in the figure below:

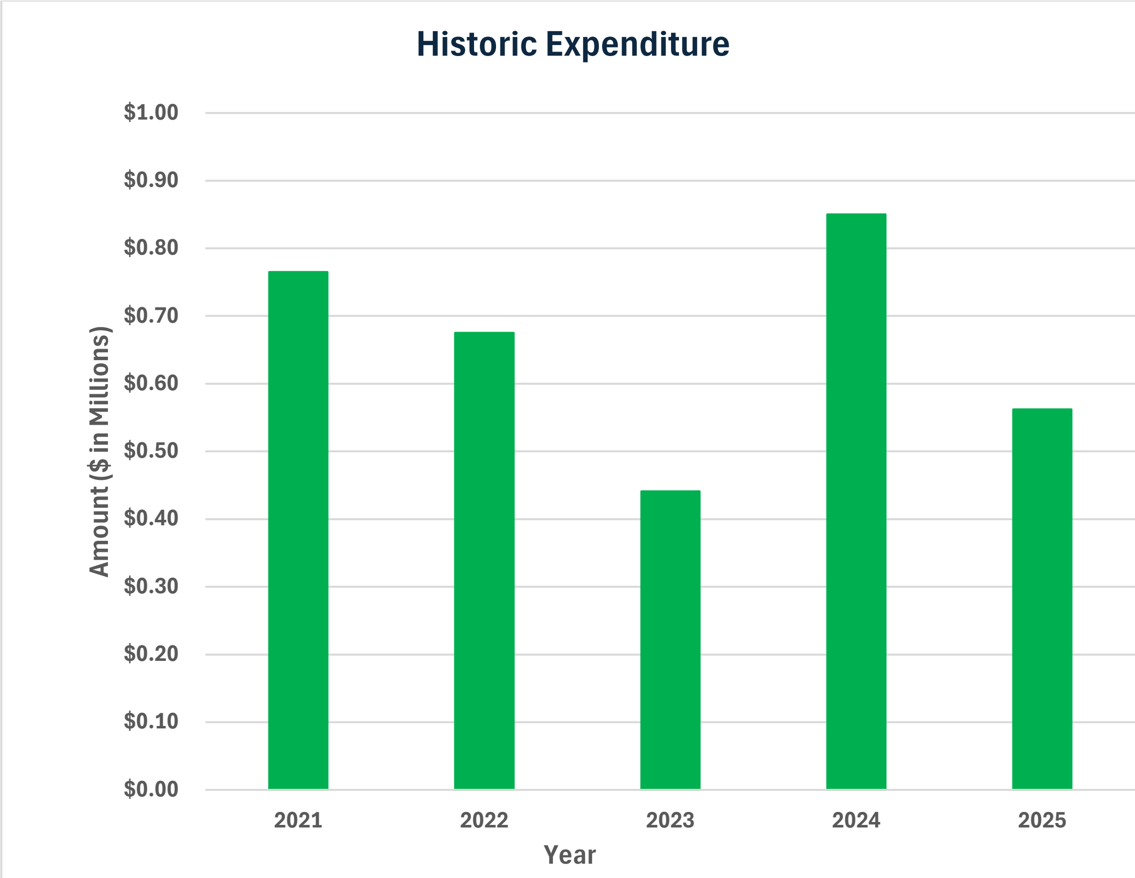


Fig 2: Historic Expenditure - Pole Replacements

In most years, spending in this segment exceeds the budget, primarily due to an expanded pole count and case-by-case decisions to alter the size of class of the pole being replaced to account for planned or anticipated future work such as expansions, potential future customers, and updated engineering standards. Identified poles often necessitate the replacement of adjacent poles due to being the same vintage and construction style.

A.4. Investment Priority

As per EPI's capital project scoring, this segment ranks 13th out of 22 (Section 5.3).

A.5. Alternative Analysis

The projects in this investment category involve the proactive replacement of deteriorated poles and related infrastructure, identified through annual pole testing programs and condition-based assessments. These poles are prioritized based on health indicators, location on key feeder routes, and their impact on public safety and system reliability. Each replacement is reviewed by subject matter experts and undergoes engineering analysis to determine the most effective configuration, including potential upsizing to meet future capacity needs.

For this program, the following alternatives were considered:

a. **Do Nothing / Reactive-Only Replacement Approach**
This approach would rely solely on run-to-failure methodology, with poles replaced only after failure occurs. While this would reduce short-term capital expenditures, it would significantly degrade system reliability, increase the frequency and duration of customer outages, and raise long-term costs due to unplanned emergency repairs. This option is especially detrimental for poles on main feeder lines, where failures result in widespread outages and longer restoration times.
Conclusion: *Not viable. Inconsistent with EPI's corporate goals for reliability, safety, and electrification readiness.*

b. **Like-for-Like Replacement Without Engineering Input**
This alternative would involve replacing deteriorated poles in-kind without involving engineering review. While it may reduce design costs, it prevents consideration of updated standards, future load growth, and upcoming capital projects. This could lead to missed opportunities for network optimization and may result in redundant future work if infrastructure must later be rebuilt to support system upgrades.
Conclusion: *Not recommended. Eliminates key benefits of proactive asset planning and modernization.*

c. **Replace Overhead Infrastructure with Underground Systems**
Converting overhead lines to underground infrastructure was evaluated for its potential reliability benefits. However, underground construction involves significantly higher installation and restoration costs, particularly in built-up or residential areas. According to EPI benchmarks, these costs far exceed the value gained in the context of this program.
Conclusion: *Not feasible for broad application. Cost-prohibitive except in rare, context-specific scenarios.*

d. **Expanded Proactive Replacement Program**
EPI considered increasing the scale of its proactive pole replacement efforts to further improve long-term system reliability. However, this was rejected in favour of allocating resources toward system conversion initiatives (e.g., voltage upgrades), which deliver broader modernization benefits. A larger proactive program would reduce failures, but diverting capital from station renewal could increase risk exposure to substation-level outages.
Conclusion: *Strategically deferred. Resources prioritized toward system conversion with higher risk mitigation impact.*

e. **Targeted, Engineered Like-for-Like Replacement (Preferred Approach)**
This is the preferred approach. EPI replaces deteriorated poles based on condition and strategic priority, incorporating engineering input to assess whether upsizing or reconfiguration would better support long-term system performance, future demand, or nearby planned work. While refurbishment is considered in isolated cases, it is generally not pursued due to limited cost-effectiveness and the condition of aging infrastructure.
Conclusion: *Best overall option. Balances cost control, reliability, safety, and future system readiness.*

A.6. Innovative Nature of the Project

Not Applicable

A.7. Leave to Construct Approval

This project does not require leave to construct approval under Section 92 of the OEB Act.

B. EVALUATION CRITERIA AND INFORMATION REQUIREMENTS

B.2. Efficiency, Customer Value, Reliability & Safety

Table 12: Investment Evaluation - Efficiency, Customer Value, Reliability & Safety

Criteria	Description
Efficiency	Replacing critical poles proactively is a cost-effective method of maintaining system reliability, while providing predictable workloads for operations. Proactive replacements are well planned, budgeted and executed in the field, allowing future work to be contemplated in the replacement process, ensuring that recently replaced poles do not have to be replaced in the future due to unsuitability. Improves operational efficiency by ensuring implementation of asset management practices to meet the needs of customers and stakeholders, balancing safety, reliability, and cost-effectiveness. Ensures cost-effectiveness by minimizing the likelihood of catastrophic asset failures and subsequent associated costs through early risk identification and mitigation. Maintain financial health: - By maximizing ratepayer value through proactive replacements in a financially prudent manner. - By preventing a significant accumulation of the renewal investment backlogs and ensuring long-term rate stability for customers. - By maintaining system health metrics to sustain grid performance and prevent increases in emergency repairs and defective equipment replacements due to an increasing number of failing assets. - By ensuring stable and predictable grid performance for current and future customers by managing assets responsibly.
Customer Value	Well maintained and monitored poles help maintain system reliability, minimizes safety risks and leads to a high level of customer satisfaction. Improve customer value:

	- By ensuring a safer, more reliable, and cost-effective distribution system to meet customer needs and maintain customer trust. - By promoting economic wellbeing in the community through providing consistent access to secure and reliable electricity. - By minimizing costs for infrastructure upgrades while maximizing ratepayer value through proactive maintenance and asset replacement. - By supporting system reliability by replacing critical infrastructure with a high risk of failure in the short or medium term.
Reliability	Deteriorating poles which pose a significant risk of failure which can lead to power outages and potential safety concerns. Timely replacements of these poles maintain reliability though avoidance of outages incurred though reactive replacement. Improve system reliability by proactively replacing key assets that are at or beyond their useful life or show signs of significant material degradation to avoid a reactive replacement and the significant outage incurred. Increase system resiliency by replacing equipment in strategic locations to provide better access or to better withstand weather-related loading.
Safety	This investment will help maintain a safe distribution grid for the public, EPI's staff and its joint use partners by replacing existing poles and their associated framing with newer standards of framing to allow for improved safe work practices. This program supports public safety: - By reducing public exposure to significant risks posed by aged and deteriorated equipment, including electrical faults, fires, or hazardous conditions. - By immediately replacing equipment damaged by weather-related events, motor vehicle accidents or dig-ins. Improves worker safety: - By reducing the likelihood of dangerous equipment failures by addressing potential issues proactively.

	- Mitigates the need for special work procedures associated with obsolete or degraded equipment. Ensures compliance: - By adherence to legislative requirements, safety standards and regulations such as Electrical Distribution Safety O.Reg. 22/04, ESA, CSA, Building codes, Fire codes, OHSA, etc. - By adherence to generally accepted and jointly used safety-by-design standards.

B.3. Investment Need

B.3.3 Primary Driver:

The primary driver for this is Failure Risk of deteriorating poles. Proactive and planned replacements of deteriorating poles is a strategic investment approach that prioritizes reliability, operational efficiency and minimizes costly emergency repairs.

B.3.4 Secondary Drivers:

There are no secondary drivers for investments in this project.

B.3.5 Information Used to Justify the Investment:

To ensure service reliability of the distribution grid and deliver consistent power to EPI customers, it is crucial to make timely replacements of failed or aging poles that are nearing the end of their service life. Section 4.2.2.3 provides a comprehensive assessment of poles that might require replacement due to their deteriorating conditions.

B.4. Investment Justification

B.4.3 Demonstrating Accepted Utility Practice:

This program is for pole replacements required as identified through appropriate visual inspections in accordance with Appendix C of the DSC supplemented by additional processes developed internally and a cyclical pole drilling program as described in Section 4.3.2.3 of the DSP.

All necessary design and construction are completed in compliance with applicable USF standards supplemented by standards developed internally. The use of USF standards ensures that the design and construction of this project will be done according to a set of standards utilized by many other utilities in Ontario. EPI is O.Reg. 22/04 compliant to ensure employee and public safety.

B.4.4 Cost-Benefit Analysis:

Investing in pole line maintenance is crucial for ensuring reliable power delivery through overhead infrastructure. Pole failures can lead to widespread outages and safety risks for the public and EPI crew.

Timely replacements of deteriorating poles with targeted scheduling and selection through asset management techniques helps ensure a robust overhead distribution system with high service reliability and minimizes outage times. As mentioned above the allocated budget is used to replace poles shortlisted through annual testing, reliability impact and safety concerns. Factoring in multiple criteria for choosing poles for replacement EPI takes a comprehensive approach that maximizes the value of investments.

B.4.5 Historical Investments & Outcomes Observed:

Section A.3.3 highlights the historic spending in this segment. The general outcome of investments in this category is a robust overhead distribution line with healthy poles capable of safely and reliably supplying power to the communities. This project prioritizes proactive investments over reactive measures to maximize value for money.

B.5. Non-Wires Solution

Not Applicable

B.6. Innovation

Not Applicable

MATERIAL INVESTMENT NARRATIVE

PROJECT / PROGRAM:

13. Transformer Replacement

INVESTMENT CATEGORY:

SYSTEM RENEWAL

A. GENERAL INFORMATION ON THE PROJECT/PROGRAM

A.1. Overview

Transformers are critical assets in the distribution system used to step down distribution voltage to serve the secondary distribution systems. While EPI typically runs transformers to failure and then performs reactive replacements, in cases where transformers exhibit a higher risk and impact of failure, EPI accelerates the replacements and conducts them proactively. This project targets all overhead and underground transformers, including both 3-phase and single phase, that are nearing end-of-life for replacement (Section 4.2.2.1).

The main outcome of this project is to renew defective or failing transformers that have been identified by visual or infrared inspection. Additionally, this program includes the targeted replacement of obsolete equipment, including the phase-out of submersible transformers (and, historically, the removal of the obsolete "Pole-Tran" style transformers). EPI strives for pro-active replacements by conducting inspections for potential hazards wherever possible to ensure equipment is right-sized, to minimize outages and address safety concerns.

A.2. Timing

i. Start Date: January 2026
ii. In-Service Date: Through to December 2030
iii. Key factors that may affect timing:
   - Resource Constraints – Project execution can be constrained by unplanned and/or higher priority work arising.
   - Equipment Lead Time

A.3. Capital Expenditures

A.3.3 Historical and Future Capital Expenditures

Table 1. Historical and Future Capital ($, million)

Transformer Replacements - Totals									
Historic Actual Expenditure				Bridge Year	Forecasted Budgeted Expenditure				
2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
$0.70	$0.34	$0.67	$0.89	$0.18	$0.20	$0.20	$0.21	$0.22	$0.22

The graph below illustrates the planned budget figures for this investment category ($ in millions). Since spending in this category primarily supports the replacement of failing transformers that pose a safety or operational risk, budgeting is largely informed by historical expenses and past asset failure rates which tend to be inconsistent given varied lifecycles of transformer assets.

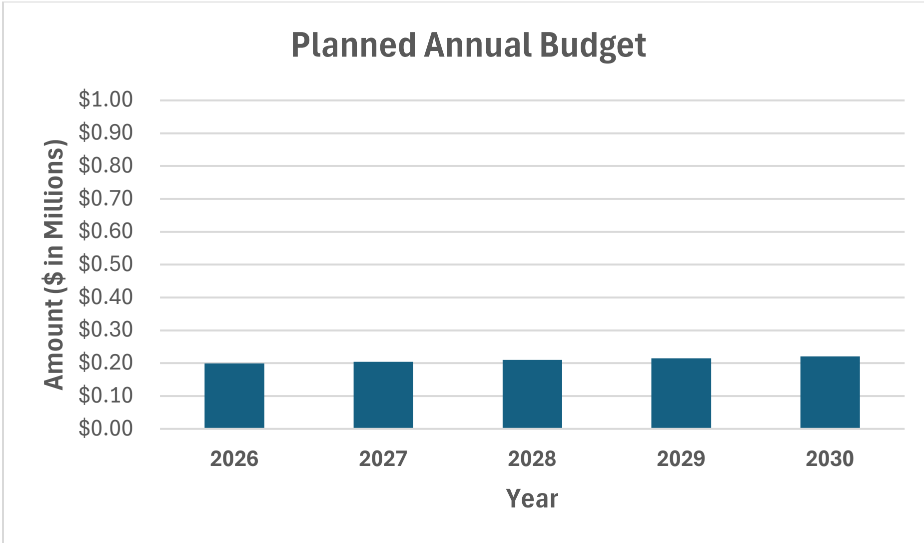


Fig 1: Planned Budget for Transformer Replacements

The difference between historical and future budgets can be explained by the completion of a specific pole-transformer modernization program. The main objective of this program during this window is the ongoing accelerated conversion of submersible transformers. The remaining funding has been reallocated to accelerate other asset renewal programs.

A.3.4 Economic Evaluation (Expansion projects)

Not Applicable

A.3.5 Comparative Historical Expenditure

The historic spending from 2021-2024 and planned spending in 2025 has been shown in the graph below:

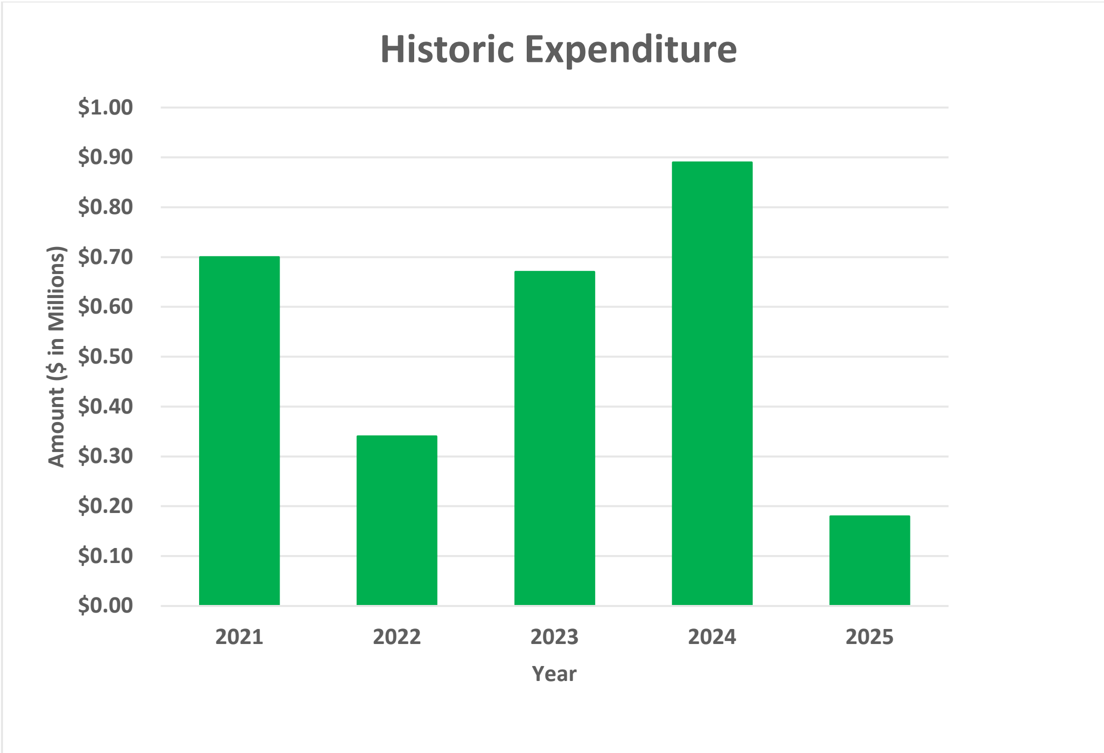


Fig 2: Annual Historic Budgets vs Actual Expenditure

The decrease in expenditure in 2025, within the Historical Period, can be attributed to the completion of the pole-transformer replacement program, through which all remaining pole-mounted transformers were replaced with pad-mounted units by the end of 2024.

Ongoing spending in this category is primarily driven by the need to replace defective assets. This demand can vary significantly from year to year, as it depends heavily on the frequency, quantity, and geographic distribution of asset failures. Historically, EPI has operated transformers until failure, or until replaced as part of a voltage conversion project. However, when inspections identify assets at risk of imminent failure, this program also contains funds for their proactive replacement.

As a result, the spending in this category is based on need and may fluctuate unpredictably from the planned budget.

A.4. Investment Priority

The priority of this investment category ranks 12th out of 22 as per our recent project rankings. It is prioritized higher than several others due to the recognized importance of replacing obsolete equipment and the broader benefits of proactive replacement. These include ensuring assets are appropriately sized, enhancing safety, and realizing cost-efficiencies through planned rather than reactive replacements (Section 5.3).

A.5. Alternative Analysis

This investment category addresses the proactive replacement of aging and obsolete transformers, switches, and switchgear assets particularly submersible transformers that are no longer aligned with modern safety, operational, or load management standards. Assets included in this program have been identified through condition assessments and engineering review and are prioritized based on reliability risk, access constraints, and alignment with long-term capital planning objectives.

For this program, the following alternatives were considered:

a. <u>Do Nothing / Run-to-Failure Replacement Approach</u>
This approach would rely solely on reactive replacement after asset failure. While this may reduce near-term capital expenditure, it increases customer outage duration, particularly when failures occur outside of business hours—leading to premium replacement costs. It also limits the opportunity to right-size equipment for forecasted loads or replace obsolete configurations (e.g., submersible units) with modern, accessible solutions like pad-mounted transformers.
Conclusion: *Not viable. Inconsistent with EPI's reliability goals, safety standards, and electrification readiness objectives.*

b. <u>Like-for-Like Replacement Without Engineering Review</u>
Eliminating engineering input would reduce design costs, but it would significantly reduce the benefits of proactive planning. This approach would miss opportunities to update equipment to meet current safety standards, accommodate expected load growth, or align with future capital plans in the area.
Conclusion: *Not recommended. Fails to support modern system requirements or long-term efficiency.*

c. <u>Adjusted Sizing Based on Load Analysis</u>
Transformer replacements are evaluated for proper sizing based on updated load analysis and expected growth. Undersized units are upsized to prevent premature overloading, while oversized units may be downsized to reduce losses and improve cost-efficiency. This ensures that new assets are appropriately matched to both current and forecasted demand, supporting EPI's electrification objectives.
Conclusion: *Preferred engineering practice. Ensures long-term system optimization.*

d. <u>Like-for-Like Replacement with Modernized Standards</u>
This is the typical and preferred replacement strategy. It involves replacing transformers and switchgear with units of similar capacity and footprint, but with updated features such as current-limiting fuses, improved safety ratings, and standardized designs. This approach minimizes disruption to customers and adjacent properties while supporting compliance, safety, and modernization.
Conclusion: *Most cost-effective and operationally efficient solution. Aligns with utility standards and long-term goals.*

A.6. Innovative Nature of the Project

Not Applicable

A.7. Leave to Construct Approval

This project does not require leave to construct approval under Section 92 of the OEB Act.

B. EVALUATION CRITERIA AND INFORMATION REQUIREMENTS

B.2. Efficiency, Customer Value, Reliability & Safety

Table 13: Investment Evaluation - Efficiency, Customer Value, Reliability & Safety

Criteria	Description
Efficiency	Newer transformers incorporate updated specifications that reduce losses compared to legacy models. Proactive replacements are more cost-efficient than reactive replacements, as emergency replacements often incur higher costs due to overtime labor and urgent material procurement. Additionally, proactive replacement allows for system redesign opportunities, rather than being limited to a like-for-like replacement approach allowing equipment relocation or rightsizing to occur. Improves operational efficiency: - By ensuring implementation of asset management practices to meet the needs of customers and stakeholders, balancing safety, reliability, and cost-effectiveness. - By upgrading the system to ensure sufficient capacity available to meet customer needs and avoid costly emergency measures. Ensures cost-effectiveness: - By proactively replacing deteriorated assets to avoid higher costs, degraded service levels and safety hazards associated with equipment malfunction, unplanned failures, and emergency repairs and replacements. - By minimizing the likelihood of catastrophic asset failures and subsequent associated costs through early risk identification and mitigation. Maintain financial health: - By maximizing ratepayer value through proactive maintenance and replacements in a financially prudent manner. - By preventing a significant accumulation of the renewal investment backlogs and ensuring long-term rate stability for customers. - By ensuring stable and predictable grid performance for current and future customers by managing assets responsibly.
Customer Value	Well maintained and monitored transformers help maintain system reliability, minimizes safety

	risks and leads to a high level of customer satisfaction. Anticipated electrical growth from Electrification over the medium and long term is expected to drive increased need for proactive transformer replacements to address asset right-sizing. Improve customer value: - By ensuring a safer, more reliable, and cost-effective distribution system to meet customers current and anticipated needs and maintain customer trust. - By promoting economic wellbeing in the community through providing consistent access to secure and reliable electricity. - By minimizing costs for infrastructure upgrades while maximizing ratepayer value through proactive maintenance and asset replacement and right-sizing. - By supporting system reliability by replacing critical infrastructure with a high risk of failure in the short or medium term. Improve customer choice by facilitating new or modified loads such as EV's as well as DER connections by reducing delays and technical constraints. Improve customer value: - By ensuring a safer, more reliable, and cost-effective distribution system to meet customer needs and maintain customer trust. - By promoting economic wellbeing in the community through providing consistent access to secure and reliable electricity. - By reducing system downtime and mitigating risks of lengthy outages, especially on assets serving critical loads. - By minimizing costs for infrastructure upgrades while maximizing ratepayer value through proactive maintenance and asset replacement. - By enabling revenue opportunities for DR/DERs/BESS technologies, encouraging their adoption and integration into the grid. - By proactively alleviating technical barriers for renewable energy sources support customer-driven clean energy initiatives.

Reliability	Deteriorating transformers can pose a significant risk of failure which will lead to power outages and potential safety concerns. Timely replacements of these assets maintain reliability though avoidance of outages incurred though reactive replacement. Increase system resiliency by replacing equipment in strategic locations to provide better access or to better withstand weather-related loading. Improve system reliability: - By reducing the number of outages by proactively replacing assets that are at or beyond their useful life or show signs of significant material degradation to prevent failures. - By right sizing equipment to ensure adequate capacity for current and anticipated customer needs. - By reducing risks of failure due to equipment operating beyond capacity. Improve power quality: - By replacing aging equipment with modern, higher-rated assets designed to handle variable loads and bi-directional power flows to support the adoption of EVs and DERs. Enable safe and reliable customer and DER connections: - By proactively upgrading infrastructure capacity to accommodate evolving customer needs and capacity constraints.
Safety	This investment will help maintain a safe distribution grid for the public and EPI's staff by replacing existing transformers and their associated equipment with right sized, modern equipment which supports current safe work practices. This approach also allows maintenance crews to work in controlled environments rather than responding to emergency situations, further minimizing safety risks and ensuring a secure and reliable power supply for customers. This program supports public safety: - By reducing public exposure to significant risks posed by aged and deteriorated equipment,

	including electrical faults, fires, or hazardous conditions. - By immediately replacing equipment damaged by weather-related events, motor vehicle accidents or dig-in. Improves worker safety: - By reducing the likelihood of dangerous equipment failures by addressing potential issues proactively. - Mitigates the need for special work procedures associated with obsolete or degraded equipment. -By relocating equipment to improve accessibility. - By reducing the time of worker exposure to higher risk environments (e.g. confined space, switching). - By reducing the likelihood of dangerous equipment failures due to equipment overloading. Ensures compliance: - By adherence to legislative requirements, safety standards and regulations such as Electrical Distribution Safety O.Reg. 22/04, ESA, CSA, Building codes, Fire codes, OHSA, etc. - By adherence to generally accepted and jointly used safety-by-design standards.

B.3. Investment Need

B.3.3 Primary Driver:

The primary driver for this investment is to address asset failure and mitigate the anticipated risk of failure. EPI typically operates its distribution transformers until failure. However, in cases where transformers exhibit an unusual risk profile such as body damage or insulation failure, proactive replacements are prioritized and schedule with costs allocated under this program.

B.3.4 Secondary Drivers:

There are no secondary drivers for investments in this project.

B.3.5 Information Used to Justify the Investment:

To ensure service reliability of the distribution grid and deliver consistent power to EPI customers, it is crucial to make timely replacements of failed or aging transformers that are nearing the end of their service life. Section 4.2.2.3 provides a comprehensive assessment of transformers that might require replacement due to their deteriorating conditions.

B.4. Investment Justification

B.4.3 Demonstrating Accepted Utility Practice:

In alignment with its internal asset management policy, EPI has implemented a targeted program to proactively replace submersible transformers, enhancing employee safety by reducing the risks associated with reactive replacements.

Additional investments in the category are replacements of transformers as identified through appropriate visual inspections in accordance with Appendix C of the DSC supplemented by additional processes developed internally and a cyclical infrared inspection as described in Section 4.3.2.3 of the DSP.

All necessary design and construction are completed in compliance with applicable USF standards supplemented by standards developed internally. The use of USF standards ensures that the design and construction of this project will be done according to a set of standards utilized by many other utilities in Ontario. EPI is O.Reg. 22/04 compliant to ensure employee and public safety.

B.4.4 Cost-Benefit Analysis:

Investments in this category are crucial for maintaining continuous power supply to customers as failure of transformers cause outages involving multiple homes and businesses. Proactive replacements of end-of-life transformers enables engineering review of the equipment to ensure right-sizing of the newly installed equipment, minimizes outage periods, and ensures a smoother in-field operation for the crews resulting in better quality work at reduced costs (Section 4.3.1.1.2).

B.4.5 Historical Investments & Outcomes Observed:

Section A.3.3 highlights the historic spending in this segment. The general outcome of this program is a safe and robust distribution system with reliable, well-functioning transformers.

B.5. Non-Wires Solution

Non-wires solutions are not applicable to serve the purposes of this investment category as transformers are necessary equipment to step down voltage levels and distribute power safely to the public.

B.6. Innovation

Not Applicable

MATERIAL INVESTMENT NARRATIVE

PROJECT / PROGRAM:

14. Voltage Conversion

INVESTMENT CATEGORY:

SYSTEM RENEWAL

A. GENERAL INFORMATION ON THE PROJECT/PROGRAM

A.1. Overview

EPI serves 17 communities across Southwestern Ontario, operating overhead and underground line assets supported by 16 transformer substations that stepdown power from 27.6 kV to 8.32 kV, 4.16 kV or 2.4 kV delta. Voltage Conversion is a longstanding program of EPI and its legacy utilities to upgrade the distribution system from these legacy voltages to a common 27.6 kV standard.

EPI's fleet of distribution stations are nearing end-of-life, and the availability of parts for repair is dwindling. The 2026-2030 Forecast Period voltage conversion costs are driven by a combination of inflationary pressures on major materials related to the planned offloading of 5 legacy voltage substations, as well the higher number of customers requiring conversion in comparison to previous decommissionings.

Voltage Conversion not only enhances system reliability and capacity but also directly addresses challenges related to outdated and inefficient infrastructure. The benefits of Voltage Conversion include avoided substantial capital station costs by decommissioning distribution stations, reduced line losses, enhanced weather resilience, and greater capacity to accommodate emerging grid uses such as distributed generation and electric vehicle charging. Successful conversion allows the decommissioning of EPI's substations rather than their refurbishment or rebuild, avoiding significant costs (Section 5.1.2.2.1).

A.2. Timing

i. Start Date: January 2026
ii. In-Service Date: Through to December 2030
iii. Key factors that may affect timing:
   - Identified safety hazards
   - Supply chain disruptions

During the 2026-2030 Forecast Period, EPI plans to offload 5 substations with concentrated efforts in Strathroy, Blenheim and Wheatley. The timing and priority of the project is based on the age and condition of the assets and stations.

A.3. Capital Expenditures

A.3.3 Historical and Future Capital Expenditures

Table 1. Historical and Future Capital ($, million)

Voltage Conversion - Totals									
Historic Actual Expenditure				Bridge Year	Forecasted Budgeted Expenditure				
2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
$2.14	$2.39	$2.83	$3.58	$4.39	$3.55	$4.40	$4.30	$4.93	$5.26

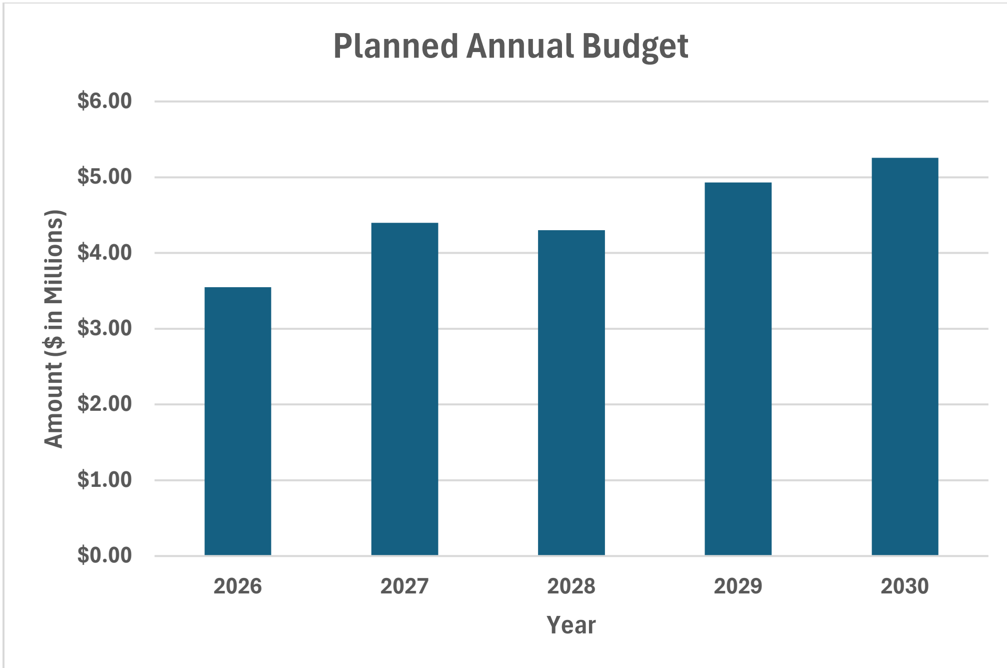


Fig 1: Planned Budget for Pole Replacements

A.3.4 Economic Evaluation (Expansion projects)

Not Applicable

A.3.5 Comparative Historical Expenditure

The timing and drivers of historical expenditure are based on aging station assets and the preference to offload stations prior to equipment failure and the subsequent need for it to be replaced. The 2026-2030 Forecast Period voltage conversion costs are driven by a combination of inflationary pressures on major materials related to the planned offloading of 5 legacy voltage substations, as well the higher number of customers requiring conversion in comparison to previous decommissionings.

The historic spending from 2021-2024 and planned spending for 2025 has been shown in the figure below:

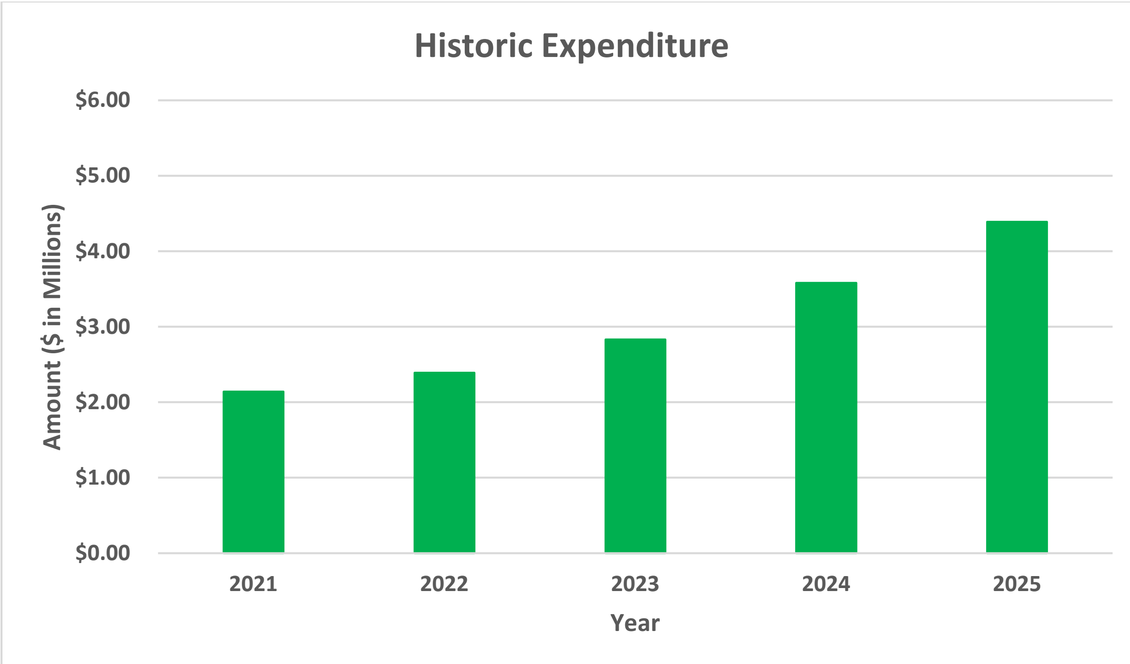


Fig 2: Historic Expenditure – Voltage Conversion

A.4. Investment Priority

The priority of this investment category ranks 15th out of 22 as per our recent project rankings. This project is one of the highest ranked programs that is considered discretionary and not mandated for legislative or safety reasons. EPI recognizes the benefits of proactive voltage conversion to mitigate the risk of aging substation failure by offloading and decommissioning said substations. It is routine work in the utility industry and targets the replacement of assets nearing end of life (Section 5.3).

A.5. Alternative Analysis

This investment category involves the planned conversion of legacy 4kV and 2.4kV distribution systems to 27.6kV. These conversions are essential to support system reliability, modernize aging infrastructure, accommodate electrification-driven load growth, and improve overall network efficiency. Projects are prioritized based on the condition of substation transformers, the geographic distribution of the load, and the age and risk level of associated feeders.

The following alternatives were considered for this program:

a. **Do Nothing / Run-to-Failure Approach**
Under this alternative, EPI would defer voltage conversion activities and allow legacy assets to operate until failure. Reactive replacement would be triggered during unplanned outages, requiring emergency response. This results in elevated customer outage durations, higher costs due to overtime premiums, and re-investment in obsolete infrastructure. Critically, this approach also removes the opportunity to upgrade the system to meet growing capacity needs and electrification targets.

Conclusion: *Not viable. Results in long-term cost inefficiency, reliability degradation, and missed modernization opportunities.*

b. Like-for-Like Replacement of Legacy Voltage Equipment

This option would involve replacing failing 4kV or 2.4kV assets with equipment of similar specifications. While this may provide short-term relief, it is misaligned with EPI's strategic objective to retire legacy voltage systems. It also fails to accommodate anticipated growth in distributed energy resources (DER), electric vehicles (EV), and automation capability. Rebuilding at outdated voltage levels risks future redundancy of new assets and continued system fragmentation.
Conclusion: *Not aligned with long-term planning. Results in sunk costs in obsolete infrastructure.*

c. Reduced Investment Pace

EPI considered slowing the pace of voltage conversion by reducing annual investment. While this would yield marginal short-term customer savings, it would extend the useful life of at-risk substations, increasing the likelihood of costly failures. This approach reduces the ability to decommission aging substations on schedule and may require unplanned capital for emergency rebuilds. It also limits system readiness for electrification-driven load growth.
Conclusion: *Not preferred. Increased reliability risk and potential for unplanned capital exposure.*

d. Accelerated Investment Pace

An accelerated investment scenario was evaluated, which would expedite voltage conversions and complete them earlier in the planning period. While this approach would enhance reliability and avoid near-term emergency rebuilds, it also increases immediate capital requirements. Given current funding constraints and competing priorities (e.g., substation renewal), EPI determined that the current pace strikes a reasonable balance between risk mitigation, modernization, and affordability.
Conclusion: *Strategically beneficial, but currently limited by capital availability and resource capacity.*

e. Planned Conversion at Current Pace (Preferred Option)

EPI's preferred strategy is to continue with a managed pace of voltage conversion, prioritizing areas based on asset condition, risk, and community growth. This approach aligns with EPI's long-term objective of retiring legacy systems, reduces maintenance and inventory complexity, and enables modernized system performance, including automation and DER integration. Engineering reviews are conducted to determine appropriate upgrades to capacity and configuration on a case-by-case basis.
Conclusion: *Most effective balance of cost, reliability, modernization, and customer value. Supports system-wide standardization and future growth.*

A.6. Innovative Nature of the Project

Not Applicable

A.7. Leave to Construct Approval

This project does not require leave to construct approval under Section 92 of the OEB Act.

B. EVALUATION CRITERIA AND INFORMATION REQUIREMENTS

B.2. Efficiency, Customer Value, Reliability & Safety

Table 14: Investment Evaluation - Efficiency, Customer Value, Reliability & Safety

Criteria	Description
Efficiency	EPI's conversion program addresses several key aspects of improving the utilities efficiency. The 27.6kV distribution voltage offers advantages for the cost-effective integration of DER's, anticipated electrification loads and distribution automation equipment. It also reduces line losses compared to legacy voltages. Successful conversion allows the decommissioning of EPI's substations rather than their refurbishment or rebuild, avoiding significant costs. Improves operational efficiency: - By reducing line losses through system upgrades of 4kV feeders and targeted investments. - By ensuring operability of assets and grid flexibility to restore or isolate sections of the distribution system in an efficient and effective manner. - By ensuring implementation of asset management practices to meet the needs of customers and stakeholders, balancing safety, reliability, and cost-effectiveness. - By reducing waste, conserving energy, adopting environmentally friendly practices, and lowering long-term operational costs. - By optimizing procurement and supply chain management through standardizing equipment and reducing the variety of asset types in the system. - By proactively replacing deteriorated assets to avoid higher costs, degraded service levels and safety hazards associated with equipment malfunction, unplanned failures, and emergency repairs and replacements. - By mitigating costs associated with refurbishing and supporting non-standard assets. - By upgrading the system to ensure sufficient capacity available to meet customer needs and avoid costly emergency measures.

	- By maximizing ratepayer value through proactive maintenance and replacements in a financially prudent manner. - By preventing a significant accumulation of the renewal investment backlogs and ensuring long-term rate stability for customers. - By ensuring stable and predictable grid performance for current and future customers by managing assets responsibly.
Customer Value	Improve customer choice: - By empowering customers to actively participate in the grid by choosing how they use and generate electricity. - By facilitating new or modified load and DER connections by reducing delays and technical constraints. - By enhancing grid flexibility to support diverse customer preferences and needs. Improve customer value: - By ensuring a safer, more reliable, and cost-effective distribution system to meet customer needs and maintain customer trust. - By promoting economic wellbeing in the community through providing consistent access to secure and reliable electricity. - By reducing system downtime and mitigating risks of lengthy outages, especially on feeders serving critical loads. - By enabling revenue opportunities for DR/DERs/BESS technologies, encouraging their adoption and integration into the grid. - By proactively alleviating technical barriers for renewable energy sources, supporting customer-driven clean energy initiatives. - By investing in additional capacity and grid flexibility to enable customers to adopt electric vehicles and space heating.
Reliability	Improve system reliability: - By reducing the number of outages by proactively replacing assets that are at or beyond their useful life or show signs of significant material degradation to prevent failures. - By reducing risks of failure due to equipment operating beyond capacity. - By replacing aging equipment with modern, higher-rated assets designed to handle variable

	loads and bi-directional power flows to support the adoption of EVs and DERs. - Allows for the cost-effective implementation of Smart Grid equipment (see section 4.3.1.16 B.1). - By implementing advanced tools to improve fault detection, isolation, and restoration times. - By reducing outages caused by lack of contingency in the system due to undersized or derated equipment. Increase system resiliency: - By simplifying replacement efforts during major grid restoration by standardizing installed equipment. - By replacing equipment in strategic locations to better withstand weather-related disruptions. Enable safe and reliable customer and DER connections: - By proactively upgrading infrastructure capacity to accommodate evolving customer needs and capacity constraints.
Safety	Legacy voltage systems (2.4kV and 4kV) systems were constructed to standards long deemed obsolete. These construction techniques, combined with the advanced age of the equipment can pose increased risk when working on these lines. EPI has policies to identify these assets and special procedures to address them. Updating these to modern construction standards and equipment will improve the safety stance of the company. Improves worker safety: - By improving safety conditions at the workplace for utility workers. - By improving safe work practices for utility workers. - By relocating equipment to improve accessibility. Ensures public safety: - By reducing safety risks and hazards to the public associated with managing and operating grid infrastructure. - By reducing public exposure to significant risks posed by aged and deteriorated equipment,

	including electrical faults, fires, or hazardous conditions. - By eliminating unauthorized access by the public to high-risk grid infrastructure. - By adherence to legislative requirements, safety standards and regulations such as Electrical Distribution Safety O.Reg. 22/04, ESA, CSA, Building codes, Fire codes, OHSA, etc. - By adherence to generally accepted and jointly used safety-by-design standards. Mitigates environmental impact: - By reducing GHG emissions. - By removing assets that contain environmentally hazardous material with a high exposure risk.

B.3. Investment Need

B.3.3 Primary Driver:

The primary drivers for this investment are Functional Obsolescence, Substandard Performance & Failure Risk. Replacing aged legacy assets is needed to bring the system up to modern construction standards and avoids the need to stock the same inventory for multiple voltage levels.

B.3.4 Secondary Drivers:

Not Applicable

B.3.5 Information Used to Justify the Investment:

Conversion is routine work in the utility industry. Equipment deemed for conversion is approaching or has passed its useful life and is subject to replacement according to EPI asset replacement policies. Forecasted expenditures are driven from EPI asset life cycle policies and procedures as described in Section 4.3.2 and Section 4.3.3 of the DSP. Converting aged assets to 27.6kV allows for line loss reductions, modern automation installations, and reduces required inventory, and enables EPI to avoid spending on substation renewal.

B.4. Investment Justification

B.4.3 Demonstrating Accepted Utility Practice:

Voltage conversion has been a widely adopted strategy across many Ontario utilities for many years. EPI's voltage conversion program is an integral part of its system renewal process and the plan, as presented, represents this dedicated effort (See 4.3.3.2 for more discussion).

All necessary design and construction are completed in compliance with applicable USF standards supplemented by standards developed internally. The use of USF standards ensures that the design and construction of this project will be done according to a set of standards utilized by many other utilities in Ontario. EPI is O.Reg. 22/04 compliant to ensure employee and public safety.

B.4.4 Cost-Benefit Analysis:

The avoided cost of decommissioning vs. rebuilding EPI's legacy voltage network makes timely conversion a cost-effective asset sustainment strategy. Asset renewal at the existing voltages would hinder many of EPI's goals, such as reducing system losses, being able to accommodate DER's, and incremental loads, as well as the implementation of distribution automation equipment.

The do-nothing option is untenable, as rebuilding distribution stations is very expensive and both the station equipment and its transformer are high-cost, long-lead items, which would leave the EPI distribution network compromised for extended periods of time in a reactive replacement regime.

B.4.5 Historical Investments & Outcomes Observed:

The historical expenses and conversion associated with this project have been slightly below what was expected in the budget. This is a result of higher-than-expected activity in the System Access portfolio of projects. The conversion plan was successful in decommissioning 5 substations over the historical period, eliminating the need for their reconstruction, and bringing benefits to the customers the stations previously served.

B.5. Non-Wires Solution

Not Applicable

B.6. Innovation

Not Applicable

MATERIAL INVESTMENT NARRATIVE

PROJECT / PROGRAM:

15. Miscellaneous System Service

INVESTMENT CATEGORY:

SYSTEM SERVICE

A. GENERAL INFORMATION ON THE PROJECT/PROGRAM

A.1. Overview

The Miscellaneous System Service segment addresses additional investments required to enhance system reliability, increase system capacity, safety and power quality though the development of feeder ties. This program also covers upgrades to substation and automated switch protection equipment.

At this time, EPI does not plan to introduce additional ties in the 2026-2030 timeframe.

New for this DSP period, is the introduction of a satellite imagery program to guide vegetation management activities. Using a combination of GIS data and satellite imagery, a 3D model of each tree in proximity to our overhead lines can be generated. This will enable EPI to provide much more accurate information when seeking tenders for vegetation management, as well as enabling optimization of the existing rotation based trimming program. This program was supported by customer consultation (Section 3.2.1.2.1 and 3.2.1.2.2).

A.2. Timing

i. Start Date: January 2026
ii. In-Service Date: Through to December 2026
iii. Key factors that may affect timing:
- Variability in work volume
- Varying project complexity
- Unpredictability of project timeline changes

A.3. Capital Expenditures

A.3.3 Historical and Future Capital Expenditures

Table 1. Historical and Future Capital ($, million)

Miscellaneous System Service – Totals									
Historic Annual Expenditure				Bridge Year	Forecasted Budgeted Expenditure				
2021	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
$0.61	$0.21	$0.12	$0.19	$0.08	$0.17	$0.11	$0.11	$0.11	$0.11

The graph below illustrates the planned budget figures for this investment category ($ in millions).

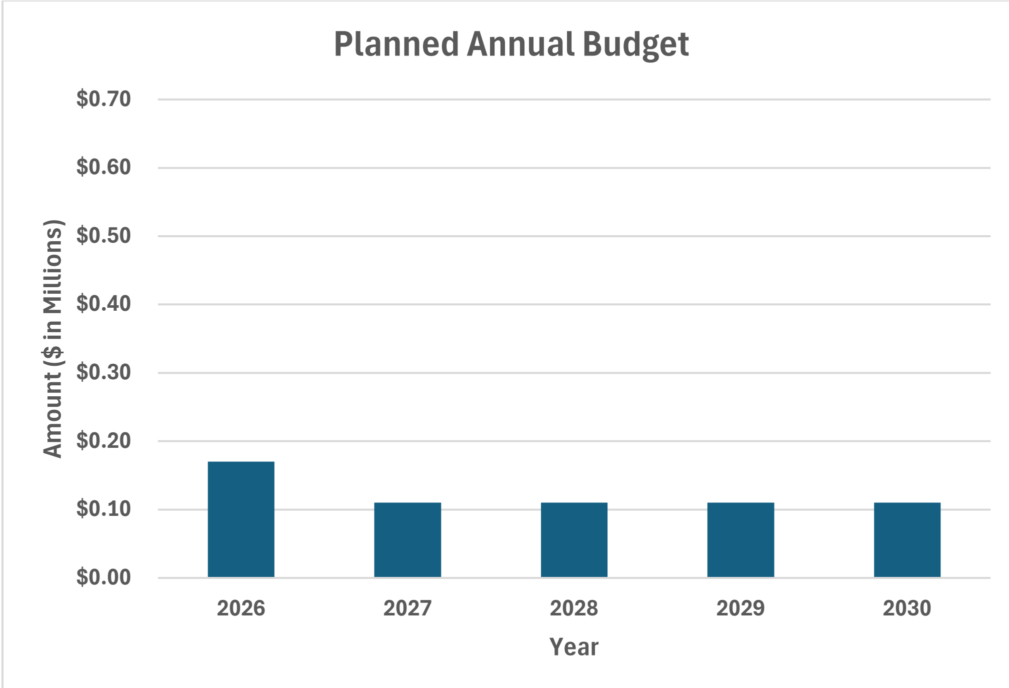


Fig 1: Planned Budget for Miscellaneous System Service

The nature of the projects executed through this investment program can vary largely in scope, geography, complexity and timing. Based on current load forecasts, no projects are forecasted in the out years of the forecast window. If a higher growth scenario materializes as the actual growth rate, EPI may have to perform additional work in this category to maintain operational flexibility and grid integrity.

A.3.4 Economic Evaluation (Expansion projects)

Not applicable

A.3.5 Comparative Historical Expenditure

Historically, the spending in this category has been allocated to support miscellaneous expenses for addressing system reliability and capacity issues, including projects like adding or repairing protection equipment, performing minor upgrades at stations, and refurbishment of distribution automation equipment.

The historic spending from 2021-2024 and planned spending in 2025 has been shown in the figure below:

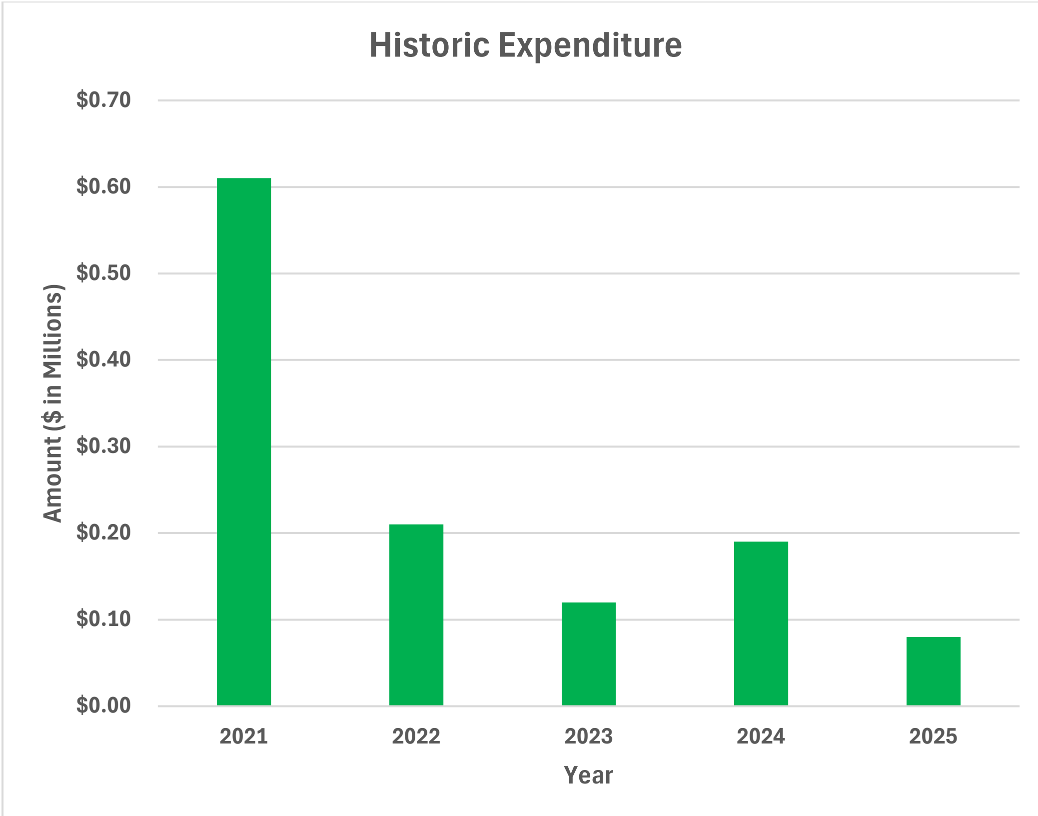


Fig 2: Historic Expenditure – Miscellaneous System Service

A.4. Investment Priority

Investments in miscellaneous system access rank 22nd out of the 22 investment categories as per EPI's latest capital project scoring. The spending in this segment is focused on solving small-scale system capacity, reliability and safety issues that need to be addressed to ensure service quality efficiency.

A.5. Alternative Analysis

Fault indicators are essential tools that enhance situational awareness across the distribution system. By providing operators with real-time or near-real-time fault location information, they reduce outage response times and support more efficient system operation.

a. <u>Do Nothing / No Fault Indicator Deployment</u>
Choosing not to install fault indicators would require continued reliance on manual fault location techniques, which are more time-consuming and less precise. This results in longer outage durations for customers and increased restoration costs—especially in rural or complex network configurations.
Conclusion: *Not viable. Leads to slower outage response, reduced operational efficiency, and higher restoration costs.*

***b.* <u>Install Line Sensing / Fault Indication Devices Only (Without Automation)</u>**
This option involves installing standalone fault indicators without integrating them into a broader automation strategy. While this provides valuable insight for operations teams and improves outage

response time, it does not enable automated fault isolation or load transfer.
Conclusion: *A partially effective solution. Improves response time but does not offer the full benefits of automation.*

c. **Install Fault Indicators as Part of a Coordinated Automation Plan (Preferred Option)**
EPI's preferred approach is to install fault indicators as part of a broader distribution system modernization strategy. Fault indicators are deployed strategically to enhance outage detection and isolation while complementing existing or future automation assets. This integrated method improves system performance, shortens outage duration, and reduces long-term operating costs.
Conclusion: *Most effective option. Provides immediate reliability benefits and supports long-term automation goals.*

A.6. Innovative Nature of the Project

Not Applicable

A.7. Leave to Construct Approval

This category does not require leave to construct approval under Section 92 of the OEB Act.

B. EVALUATION CRITERIA AND INFORMATION REQUIREMENTS

B.2. Efficiency, Customer Value, Reliability & Safety

Table 15: Investment Evaluation - Efficiency, Customer Value, Reliability & Safety

Criteria	Description
Efficiency	Improves operational efficiency: - By ensuring operability of assets and grid flexibility to restore or isolate sections of the distribution system in an efficient and effective manner. - By ensuring implementation of asset management practices to meet the needs of customers and stakeholders, balancing safety, reliability, and cost-effectiveness. - By upgrading the system to ensure sufficient capacity available to meet customer needs and avoid costly emergency measures. Ensures cost-effectiveness: - By proactively replacing deteriorated assets to avoid higher costs, degraded service levels and safety hazards associated with equipment malfunction, unplanned failures, and emergency repairs and replacements. - By minimizing the likelihood of catastrophic asset failures and subsequent associated costs through early risk identification and mitigation. Maintain financial health: - By maximizing ratepayer value through proactive maintenance and replacements in a financially prudent manner. - By maintaining system health metrics to sustain grid performance and prevent increases in emergency repairs and defective equipment replacements due to an increasing number of failing assets. - By ensuring stable and predictable grid performance for current and future customers by managing assets responsibly.
Customer Value	Improve customer value: - By ensuring a safer, more reliable, and cost-effective distribution system to meet customer needs and maintain customer trust.

	- By promoting economic wellbeing in the community through providing consistent access to secure and reliable electricity. - By reducing system downtime and mitigating risks of lengthy outages, especially on feeders serving critical loads. - By minimizing costs for infrastructure upgrades while maximizing ratepayer value through proactive maintenance and asset replacement. - By facilitating new or modified load and DER connections by reducing delays and technical constraints. - By enhancing grid flexibility to support diverse customer preferences and needs. - By reducing system downtime and mitigating risks of lengthy outages, especially on feeders serving critical loads. - By enabling revenue opportunities for DR/DERs/BESS technologies, encouraging their adoption and integration into the grid. - By proactively alleviating technical barriers for renewable energy sources, supporting customer-driven clean energy initiatives. - By investing in additional capacity and grid flexibility to enable the customers to adopt electric vehicles and space heating.
Reliability	Improve system reliability: - By reducing the number of outages by proactively replacing assets that are at or beyond their useful life or show signs of significant material degradation to prevent failures. - By implementing advanced tools to improve fault detection, isolation, and restoration times. - By minimizing the impact of planned outages by adding sectionalizing switches for planned or unplanned work. - By reducing the average duration of outages caused by supply interruptions. - By replacing hardware and software to maintain access to timely vendor support and updates. - By deploying grid sensors, monitoring equipment, and analytics tools to provide real-time insights into voltage fluctuations and power quality disturbances. - By supporting faster outage responses through improved communication systems. Improve power quality:

	- By deploying grid sensors, monitoring equipment, and analytics tools to provide real-time insights into voltage fluctuations and power quality disturbances. - By optimizing voltage levels and reactive power flows throughout the distribution system. Increase system resiliency: - By reducing the average duration of outages caused by supply interruptions. - By simplifying replacement efforts during major grid restoration by standardizing installed equipment. - By ensuring the utility is equipped to handle operational demands effectively. - By providing back-up supply for low-probability, high-impact, long-duration station loss-of-supply incidents.
Safety	This program bolsters safety by addressing potential risks associated with aging and underperforming infrastructure. It ensures maintenance of crucial station assets to proactively safeguard the public and personnel from hazards such as equipment failures and fire risks. Improves worker safety: - By improving safety conditions at the workplace for utility workers. - By improving safe work practices for utility workers. - By installing remote switching, thereby reducing crew exposure to safety risks associated with manual switching. - By installing switching equipment to de-energize feeders and enable planned work in safe conditions. Ensures compliance: - By adherence to legislative requirements, safety standards and regulations such as Electrical Distribution Safety O.Reg. 22/04, ESA, CSA, Building codes, Fire codes, OHSA, etc. - By adherence to generally accepted and jointly used safety-by-design standards. Mitigates hazards:

	- By enabling continuous monitoring of equipment to prevent its failure when workers are in close proximity to the equipment.

B.3. Investment Need

B.3.3 Primary Driver:

The primary drivers for this program are system reliability, functional obsolescence and efficiency.

B.3.4 Secondary Driver:

There are no secondary drivers for investments in this project.

B.3.5 Information Used to Justify the Investment:

This program ensures that the protective and system segmentation equipment in EPI's distribution system remains in good repair, and suitable for use. This program ensures such maintenance activities and other unanticipated events such as equipment failure or power quality issues (Section 3.3.1.1.3) are addressed to minimize the impact of outages and address possible safety concerns.

B.4. Investment Justification

B.4.3 Demonstrating Accepted Utility Practice:

In alignment with established reliability metrics, operator feedback and system planning principles, EPI prioritizes addition system service investments in areas when they will have the greatest impact on reducing outage duration and improving system resilience.

B.4.4 Cost-Benefit Analysis:

Investments in this program help maintain system reliability by keeping the protective and segmentation elements of EPI's distribution system in service. Where it is cost effective to do so, and the risk profile merits it, protective elements may be upgrades due to technical obsolescence or to address emerging needs on the distribution system. While the upfront spending is modest, this program ensures high returns by minimizing equipment downtime, enhancing system protection and maintaining reliability of the distribution system.

B.4.5 Historical Investments & Outcomes Observed:

Section A.3.3 highlights the historic expenditure in this investment program. Maintenance of station assets and equipment has historically helped EPI defer high long-term costs, enhance system safety and reliability, and reduce the impact of supply disruptions.

B.5. Non-Wires Solution

Not Applicable

B.6. Innovation

Not Applicable

MATERIAL INVESTMENT NARRATIVE

PROJECT / PROGRAM:

16. System Modernization and Planning

INVESTMENT CATEGORY:

SYSTEM SERVICE

A. GENERAL INFORMATION ON THE PROJECT/PROGRAM

A.1. Overview

This program captures the Engineering effort associated with EPI's asset management activities, as well as the cost of EPI's investments in distribution automation and other types of smart equipment.

System Service investments include installation of automated and/or remotely operated SCADA switches, GIS data analytics and software, Control Room upgrades, SCADA system implementation, etc. The primary objectives of these capital investments are to reduce the duration of outages experienced by EPI's customers and manage system loading. Sectionalization and automation are used as a high impact investments to directly influence the reliability of a circuit, including mitigation of outage duration.

EPI historically has targeted automation and system modernization projects in areas with poor reliability and implements systems that provide maximum value within available budget. Historically these have been remote communities with poor reliability due to loss of supply. In addition to This ensures as EPI continues to decommission 4.16kV substations and customers aggregate on the 27.6 kV circuits, that the impact of a single failure is not amplified. This increasing penetration of distribution automation and smart grid devices reduces outage time for customers within larger towns such as Chatham, St. Thomas, and Strathroy. Chatham received a set of three switches in 2024 and will be receiving an additional set in 2025. Accordingly, modernizing St. Thomas feeders will then be a significant focus during the Forecast Period.

These projects are developed in conjunction with asset renewal plans to ensure maximum impact of each project.

A.2. Timing

i. Start Date: January 2026
ii. In-Service Date: Through to December 2030
iii. Key factors that may affect timing: The following factors can impact the project schedule:
   - Technological interruptions
   - Health of pre-existing field assets
   - Protection settings coordination with the transmitter

As with all technology projects involving multiple parties, there are material risks of project delay, either due to technical or coordination issues. EPI manages these by engaging its host utility early in the project lifecycle, and selecting well established, well supported technologies for deployment in its distribution system.

A financial risk associated with these projects is poor condition of assets in proximity to a given project. While EPI maintains a database of equipment health indexes which are referenced during project planning, early consultation with Engineering and early site visits provide insight into the full scope of construction required to complete a given project.

A final risk associated with this project is measuring project performance. Reliability on the distribution system is a statistical measure. Over any given period, a specific set of assets (feeder or circuit segment) may perform better or worse than the forecast. For distribution automation equipment, measurement of avoided outage hours over longer windows of time helps ensure short term statistical deviations in performance are adequately smoothed.

A.3. Capital Expenditures

A.3.3 Historical and Future Capital Expenditures

Table 1. Historical and Future Capital ($, million)

System Modernization and Planning - Totals									
Historic				Bridge Year	Forecasted Budgeted Expenditure				
2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
$0.63	$0.69	$0.98	$0.91	$1.24	$1.37	$1.41	$1.45	$1.50	$1.38

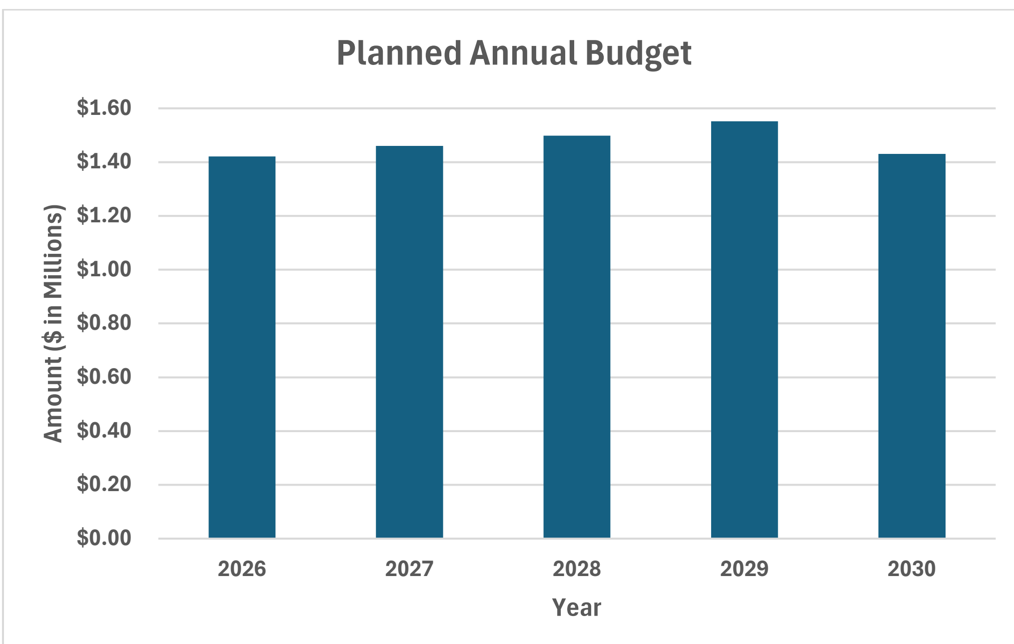


Fig 1: Planned Budget for System Modernization & Planning

A.3.4 Economic Evaluation (Expansion projects)

Not Applicable

A.3.5 Comparative Historical Expenditure

Previous smart grid projects were driven by improving reliability for EPI customers experiencing the worst number of outage hours, including from Loss of Supply. EPI and the upstream supplier have collaborated over the Historical Period to mitigate the effects of Loss of Supply via the installation of reclosing switches in several communities such as Tilbury, Ridgetown, Blenheim and Wallaceburg. EPI has completed installation of reclosers in communities served by multiple feeders which are distant from the transmission station serving them (Section 3.3.2.5, Table 3-27)

In the latter part of the Historical Period, EPI has focused on improving segmentation on its feeders with the largest customer counts in Chatham. These projects utilize automated smart switches to isolate damaged sections of a power line to prevent upstream breaker lockouts and to restore power from another available supply. Certain expenses are also driven by software assets and licensing, control room and GIS support, and SCADA materials required for communications and data collection.

To support continued System Service deployment investments in the larger communities of Chatham and St. Thomas during the Forecast Period, EPI made an investment into a centralized FLISR system, which enables better utilization of legacy equipment in Chatham, while being more suited to the complexity of Chatham's distribution network. This investment occurred in 2024, along with a small increase in the pace of deployed assets where two feeders in Chatham were modernized with smart switches .

The graph below shows the historical spending for years 2021-2024 and the planned spending for 2025.

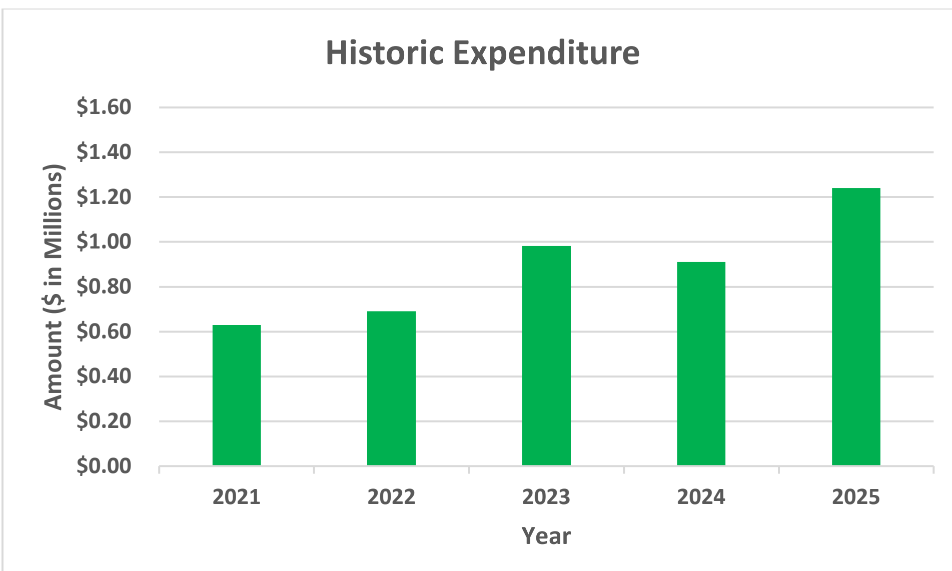


Fig 2: Historic Expenditure – System Modernization & Planning

A.4. Investment Priority

As per EPI's capital project scoring, this program sector ranks 7th out of 22 as it's a high priority project. This program contains a significant engineering component, which is required to maintain system sustainability and reliability across EPI's wide service territory. Aside from limiting the direct impact of outages on customer operations, deploying additional smart grid equipment, and implementing feeder automation enables operational savings as outage response costs can be minimized to reduce truck rolls and other cost drivers such as staff overtime. Please see section 4.5 for further discussion.

A.5. Alternative Analysis

This capital program is designed to reduce outage duration and frequency while enhancing overall service reliability for EPI customers. It addresses small-scale but critical system capacity, safety, and reliability concerns that are essential to maintaining the integrity of the distribution network. In parallel, the program enables strategic deployment of distribution automation equipment, directly supporting EPI's broader goals of grid modernization and aligning with customer expectations for a more responsive, future-ready electrical system.

Maintaining this program at a minimum of its current investment level is essential to sustaining a safe, flexible, and resilient distribution system.

a. <u>Contracting External Resources for Automation Design</u>
EPI could outsource elements of automation design and planning to external consultants. While technically feasible, this approach is inconsistent with EPI's long-term strategy. Critical automation-related engineering work is better managed internally to ensure the development of core expertise, retention of system-specific knowledge, and consistency in planning and implementation practices.
Conclusion: *Not preferred.* Reduces internal capability, increases dependency on external resources, and weakens institutional knowledge.

b. <u>Slow or Suspend the Program</u>
Scaling back investment in distribution automation would postpone reliability enhancements, reduce operational flexibility, and impede progress toward a modernized grid. This would contradict EPI's corporate objectives and customer priorities. With accelerating electrification—driven by electric vehicles, heating electrification, and distributed energy resource (DER) integration—automation becomes increasingly vital for managing dynamic system conditions, avoiding costly infrastructure expansion, and maintaining service quality.
Conclusion: *Not viable.* Undermines customer trust, weakens system preparedness, and delays grid modernization objectives.

c. <u>Maintain Program at Current Pace (Preferred Option)</u>
EPI's preferred approach is to maintain current investment levels in distribution automation. This strategy ensures continued enhancement of system reliability, resilience, and operational efficiency. Automation deployments are prioritized based on network topology, load growth forecasts, asset condition, and opportunities for integration with other system upgrades (e.g., voltage conversion, feeder improvements).
Benefits include:

- Faster fault isolation and reduced outage duration
- Greater operational flexibility and remote switching capability
- Enhanced system performance during peak loading, storms, or planned maintenance
- Cost savings through fewer truck rolls and more efficient restoration
- Improved preparedness for electrification-driven load growth

Conclusion: *Preferred option.* Strategically aligned with long-term system needs, customer expectations, and EPI's modernization objectives.

A.6. Innovative Nature of the Project

EPI specifies the use of modern, industry standard equipment and communications protocols. EPI monitors vendor end-of-production and end-of-support dates when specifying technology equipment for its projects to ensure support can be expected for the life of the equipment. This maximizes flexibility to address future needs, cyber security vulnerabilities or changes in best practice. To the maximum extent practicable, telemetry data from all devices capable of providing it is gathered into SCADA. This provides immediate operational benefits. The data is also archived in a Historian to assist the planning department with a rich historical data set when performing analysis.

A.7. Leave to Construct Approval

This project does not require leave to construct approval under Section 92 of the OEB Act.

B. EVALUATION CRITERIA AND INFORMATION REQUIREMENTS

B.2. Efficiency, Customer Value, Reliability & Safety

Table 16: Investment Evaluation - Efficiency, Customer Value, Reliability & Safety

Criteria	Description
Efficiency	By having adequate planning resources and supporting modernization efforts, EPI is able to ensure that the capital programs it develops are efficient and effective at meeting its corporate goals. Improves operational efficiency: - By ensuring operability of assets and grid flexibility to restore or isolate sections of the distribution system in an efficient and effective manner. - By ensuring implementation of asset management practices to meet the needs of customers and stakeholders, balancing safety, reliability, and cost-effectiveness. - By reducing waste, conserving energy, adopting environmentally friendly practices, and lowering long-term operational costs. - By optimizing use of resources, including labor, materials, and equipment through planning and leveraging shared services. - By optimizing procurement and supply chain management through standardizing equipment and reducing the variety of asset types in the system. - By reducing expenses associated with vegetation management and equipment restoration through proactive practices. - By continuously monitoring and assessing the progress of capital projects to ensure alignment with system priorities and objectives and the most efficient use of resources. - By improving asset management practices to meet the needs of customers and stakeholders, balancing safety, reliability, and cost-effectiveness - By upgrading the system to ensure sufficient capacity available to meet customer needs and avoid costly emergency measures.

	- By increasing asset utilization while maintaining adequate grid flexibility, thus extracting greater value out of the equipment's lifecycle. Ensures cost-effectiveness: - By proactively replacing deteriorated assets to avoid higher costs, degraded service levels and safety hazards associated with equipment malfunction, unplanned failures, and emergency repairs and replacements. - By minimizing the likelihood of catastrophic asset failures and subsequent associated costs through early risk identification and mitigation. - By adopting innovative technologies to lower costs, improve system resilience against adverse weather conditions, and streamline operations. - By mitigating costs associated with refurbishing and supporting non-standard assets.
Customer Value	Improve customer choice: - By empowering customers to actively participate in the grid by choosing how they use and generate electricity. - By facilitating new or modified load and DER connections by reducing delays and technical constraints. - By enhancing grid flexibility to support diverse customer preferences and needs. - By offering tools and resources to guide customers and investors to identify optimal locations for DER installation. - By enabling customers to connect clean technologies and renewable energy sources efficiently. Improve customer value: - By providing access to energy needs to residential, commercial and industrial customers for new connections and service upgrades, meeting regulated timelines. - By ensuring a safer, more reliable, and cost-effective distribution system to meet customer needs and maintain customer trust. - By promoting economic wellbeing in the community through providing consistent access to secure and reliable electricity. - By reducing system downtime and mitigating risks of lengthy outages, especially on feeders serving critical loads.

	- By minimizing costs for infrastructure upgrades while maximizing ratepayer value through proactive maintenance and asset replacement. - By ensuring fair and equitable cost allocation for new connections and connection upgrades. - By encouraging energy conservation and cost savings for customers through enabling flexible demand technologies and connecting distributed energy resources behind the meter. - By enabling revenue opportunities for DR/DERs/BESS technologies, encouraging their adoption and integration into the grid. - By proactively alleviating technical barriers for renewable energy sources, supporting customer-driven clean energy initiatives. - By investing in additional capacity and grid flexibility to enable customers to adopt electric vehicles and space heating.
Reliability	The outcome of this project creates a modernized distribution grid to better serve EPI customers. Automation improves resilience and reliability by avoiding or reducing the scope of unplanned outages. Advanced operational software assists in directing line crews to accelerate repairs and determining points of failure to improve future reliability. Improve system reliability: - By reducing the number of outages by proactively replacing assets that are at or beyond their useful life or show signs of significant material degradation to prevent failures. - By implementing advanced tools to improve fault detection, isolation, and restoration times. - By minimizing the impact of planned outages by adding sectionalizing switches for planned or unplanned work. - By reducing outages caused by lack of contingency in the system due to undersized or derated equipment. - By reducing outage duration by installing SCADA-enabled sectionalizing points, ADMS, FLISR to enhance remote control and grid automated restoration capabilities. - By reducing risks of failure due to equipment operating beyond capacity.

	- By enabling quicker outage response through efficient, scalable, and reliable communication infrastructure. - By utilizing AMI infrastructure, grid sensors, and near-real-time status reporting to improve grid situational awareness. - By implementing analytical tools to proactively monitor asset health, schedule maintenance, and prevent unexpected failures. - By replacing hardware and software to maintain access to timely vendor support and updates. - By ensuring the utility is equipped to handle operational demands effectively. - By providing modern, reliable, and secure enterprise-wide critical systems that enhance efficient distribution system management. Improve power quality: - By deploying grid sensors, monitoring equipment, and analytics tools to provide real-time insights into voltage fluctuations and power quality disturbances. - By optimizing voltage levels and reactive power flows throughout the distribution system.
Safety	Ensures public safety: - By reducing public exposure to significant risks posed by aged and deteriorated equipment, including electrical faults, fires, or hazardous conditions. Improves worker safety: - By installing remote switching, thereby reducing crew exposure to safety risks associated with manual switching. - By installing switching equipment to de-energize feeders and enable planned work in safe conditions. - By reducing the likelihood of dangerous equipment failures through preventing equipment overloading and addressing potential issues proactively. Ensures compliance: - By adherence to legislative requirements, safety standards and regulations such as Electrical Distribution Safety O.Reg. 22/04, ESA, CSA, Building codes, Fire codes, OHSA, etc.

	- By adherence to generally accepted and jointly used safety-by-design standards. Mitigates hazards: - By eliminating equipment-related safety hazards. - By enabling continuous monitoring of equipment to prevent its failure when workers are in close proximity to the equipment. Mitigates environmental impact: - By removing assets that contain environmentally hazardous material with a high exposure risk.

B.3. Investment Need

B.3.3 Primary Driver:

The main investment driver of this program is System Reliability & Efficiency. Optimal system planning and modernization gives EPI the opportunity to improve system reliability and efficiency with goals of minimizing the number and duration of sustained outages. This also allows for an increase in customer restoration efficiency during an outage.

B.3.4 Secondary Drivers:

There are no secondary drivers for investments in this project.

B.3.5 Information Used to Justify the Investment:

Asset Management and System planning exercises heavily leverage the ACA and the GIS system, while pulling in historical loading information from SCADA and the billing system. Forecast data is developed from historical trends, as well as local economic forecasts, industry trends, customer inquiries and high-resolution demographic data. Residential customer growth in St. Thomas, as well as high growth in other communities in the EPI northeast region are a driving force for reinforcement. These customer-driven requests are a top priority and the primary justification for investment.

B.4. Investment Justification

B.4.3 Demonstrating Accepted Utility Practice:

In alignment with established reliability metrics and system planning principles, EPI prioritizes the installation of smart grid switches in areas where segmentation will have the greatest impact on reducing outage duration and improving system resilience. This strategy reflects a transition from previously targeted investments in remote communities to urban centers with high customer density, such as Chatham, St. Thomas, and Strathroy.

Smart switch installations are planned and phased based on reliability performance data and capital availability. For example, Chatham received three switches in 2024, with additional installations scheduled for 2025 due to identified reliability needs. As a result of this prioritization, switch installations in St. Thomas were deferred to the 2026–2030 Forecast Period, following an updated evaluation of system requirements and resource constraints, as outlined in Section 4.1.3.2 of the DSP.

All necessary design and construction are completed in compliance with applicable USF standards supplemented by standards developed internally. The use of USF standards ensures that the design and construction of this project will be done according to a set of standards utilized by many other utilities in Ontario. EPI is O.Reg. 22/04 compliant to ensure employee and public safety.

B.4.4 Cost-Benefit Analysis:

Costs associated with the implementation of system modernization are mainly derived from upfront equipment cost. EPI customers agree that the benefits of these investments outweigh the associated costs (see Section 3.2.1). Restoration automation, increased data collection and monitoring, remote operation, and greater overall system flexibility result in more reliable power delivery for EPI's customers.

B.4.5 Historical Investments & Outcomes Observed:

Section A.3.3 highlights the historic expenditure in this investment segment. EPI has several historical investments in system modernization and automation that have increased reliability and reduced outages in several towns. Reliability impact summary of historical smart grid investments can be seen in Section 3.3.2.5 Table 3-27. Wallaceburg received four SCADA operated switches communicating in a local automation team which reduced the number of customer outage hours by 27% since installation. Blenheim received two reclosers and one SCADA operated switch in a local automation team which reduced the number of customer outage hours by 31% since installation. Ridgetown received a three-recloser locally automated switching team which has reduced the number of customer outage hours by 51% since installation.

B.5. Non-Wires Solution

Non-wires solutions are not applicable to serve the purposes of this investment.

B.6. Innovation

Not Applicable

MATERIAL INVESTMENT NARRATIVE

PROJECT / PROGRAM:

17. Capacity Enhancements

INVESTMENT CATEGORY:

SYSTEM SERVICE

A. GENERAL INFORMATION ON THE PROJECT/PROGRAM

A.1. Overview

Capacity Enhancements is a newly established investment program designed to address specific system capacity constraints and ensure the EPI system can support ongoing community growth. This program focuses on strategic upgrades to address a broader range of system-wide capacity constraints.

Key investments in this program include the 2025 construction of a new breaker at Edgeware TS in St. Thomas, along with construction of associated new feeders, which will address current loading and improve operational flexibility.

A capacity-related project to enable phasing out the existing low voltage system in Mount Brydges is planned for the 2026-2030 Forecast Period. This new embedded supply point and capacity related voltage conversion project will allow the system to handle higher loads as demand grows.

A third element of this program which is being introduced with the support of our customers (see Section 3.2.1.2.2 of the DSP) is to proactively begin upgrading distribution transformer assets where overloading and accelerated aging is being experienced or is forecast to become an issue in the short term.

This program is driven by the need to provide sufficient capacity for expanding residential, commercial, and industrial developments while maintaining system performance and reliability. Annual spending levels may vary depending on project scope and system requirements, but the program remains focused on ensuring that capacity evolves in step with local growth.

A.2. Timing

i. Start Date: January 2026
ii. In-Service Date: Through to December 2030
iii. Key factors that may affect timing: The following factors can impact the project schedule:
   - Unexpected & rapid load growth due to electrification
   - Delays in acquiring more capacity from the transmitter
   - Modifications to the planned conversion project schedule

A.3. Capital Expenditures

A.3.3 Historical and Future Capital Expenditures

Table 1. Historical and Future Capital ($, million)

Capacity Enhancements - Totals									
Historic				Bridge Year	Forecasted Budgeted Expenditure				
2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
$0.00	$0.00	$0.00	$0.11	$3.90	$0.71	$0.67	$0.92	$0.91	$0.92

The graph below illustrates the planned budget figures for this investment category ($ in millions).

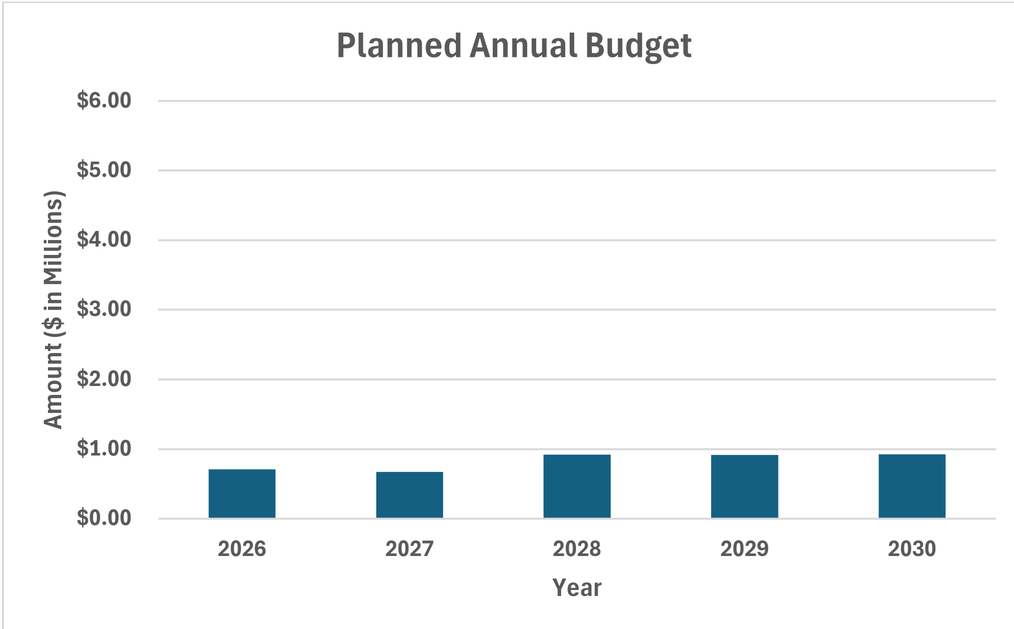


Fig 1: Planned Budget for Capacity Enhancements

A.3.4 Economic Evaluation (Expansion projects)

As this program is designed to address capacity needs originating from organic growth rather than new connections, the Economic Evaluation does not apply.

A.3.5 Comparative Historical Expenditure

There was no spending in this investment program for years 2021-2023, as there were no planned projects or budget allocations for capacity enhancements prior to 2023. The variance in 2023 was due to delays in receiving approval from the energy supplier which resulted in the deferral of planned investments to subsequent years.

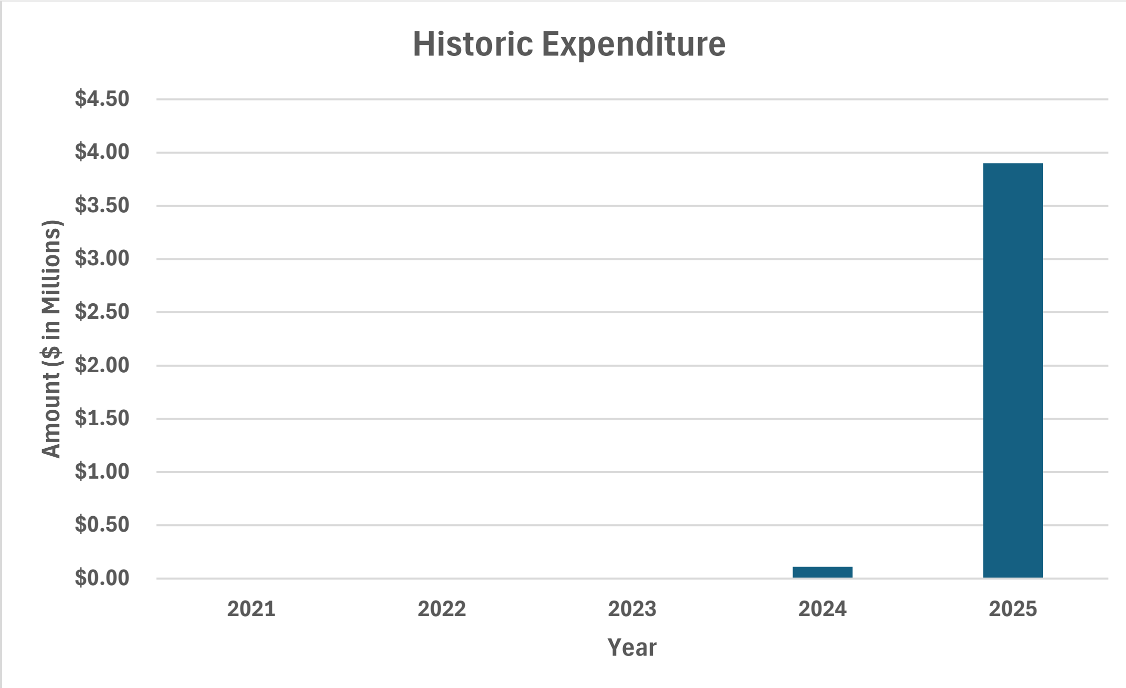


Fig 2: Annual Historic Capacity Enhancements ($ in Millions)

A.4. Investment Priority

As per EPI's capital project scoring, this investment segment ranks 11th out of 22 investment categories (Section 5.3).

A.5. Alternative Analysis

This capital program is focused on addressing emerging capacity constraints across EPI's distribution system. It supports the safe and timely expansion of system capacity to accommodate increasing electricity demand from residential development, commercial operations, and industrial growth within EPI's service territory. These investments are aligned with the Distribution System Code (DSC), which requires distributors to maintain adequate capacity for all customers in a safe, reliable, and cost-effective manner.

The following alternatives were considered:

a. **Implement Non-Wire Alternatives (NWAs)**
EPI evaluates all capital projects for NWA suitability in accordance with the OEB's Benefit-Cost Analysis (BCA) framework. However, the projects forecasted in this program involve introducing new voltage levels or large-scale infrastructure upgrades, which are not compatible with typical NWA solutions. Each project has been screened individually, and none met the technical or economic criteria for NWA implementation under current guidelines.
Conclusion: *Technically unsuitable. No forecasted projects meet NWA applicability requirements.*

b. **Redistribute Load Across Existing Infrastructure**
Where feasible, EPI redistributes load across existing feeders or substations to optimize the use of available capacity. This is a standard planning practice and is applied before pursuing capital

expansion. However, in many areas identified in the forecast period, existing infrastructure is already operating near its maximum capacity. Load redistribution alone cannot accommodate the magnitude of forecasted growth.

Conclusion: *Used as a first step, but insufficient to meet projected demand in high-growth areas.*

c. **Defer Investment**

EPI has historically managed capacity constraints through incremental upgrades and system optimization. However, due to the significant forecasted growth outlined in Section 3.2.6—including new subdivisions, commercial builds, and industrial expansions—continued deferral is not a viable option. These projects require long lead times for design, procurement, and construction, making timely investment essential.

Conclusion: *Not viable. Deferral would risk service limitations, potential customer connection delays, and non-compliance with regulatory requirements.*

d. **Proceed with Planned Capacity Enhancements (Preferred Option)**

EPI's preferred approach is to proceed with planned capacity upgrades, including transformer replacements, feeder extensions, and substation expansions as required. These projects are based on localized demand forecasts and system studies. They ensure that EPI can meet customer connection needs, support electrification-driven demand increases, and maintain compliance with the DSC.

This approach provides:

- Adequate capacity for new customer connections
- Improved system loading and reduced risk of overloads
- Support for economic development within EPI's communities
- Long-term cost effectiveness by avoiding emergency reinforcements

Conclusion: *Best alternative. Timely and targeted investments ensure compliance, reliability, and customer readiness in growing communities.*

A.6. Innovative Nature of the Project

Not Applicable

A.7. Leave to Construct Approval

This project does not require leave to construct approval under Section 92 of the OEB Act.

B. EVALUATION CRITERIA AND INFORMATION REQUIREMENTS

B.2. Efficiency, Customer Value, Reliability & Safety

Table 17: Investment Evaluation - Efficiency, Customer Value, Reliability & Safety

Criteria	Description
Efficiency	Investments in capacity enhancements optimize asset utilization, reduce system overloading and support operational flexibility as well as service reliability. Timely upgrades ensure there is sufficient capacity to meet customer needs, reducing the need for costly emergency measures. Improves operational efficiency: - By upgrading the system to ensure sufficient capacity is available to meet customer needs and avoid costly emergency measures. - By increasing asset utilization while maintaining adequate grid flexibility, thus extracting greater value out of the equipment's lifecycle. - By upgrading the system to ensure sufficient capacity available to meet customer needs and avoid costly emergency measures. Maintain financial health: - By ensuring stable and predictable grid performance for current and future customers by managing assets responsibly.
Customer Value	Improve customer choice: - By empowering customers to actively participate in the grid by choosing how they use and generate electricity. - By facilitating new or modified load and DER connections by reducing delays and technical constraints. - By enhancing grid flexibility to support diverse customer preferences and needs. Improve customer value: - By promoting economic wellbeing in the community through providing consistent access to secure and reliable electricity. - By proactively alleviating technical barriers for renewable energy sources, supporting customer-driven clean energy initiatives.

	- By investing in additional capacity and grid flexibility to enable customers to adopt electric vehicles and space heating.
Reliability	Improve system reliability: - By reducing outages caused by lack of contingency in the system due to undersized or derated equipment. - By reducing risks of failure due to equipment operating beyond capacity. - By ensuring the utility is equipped to handle operational demands effectively. Increase system resiliency: - By increasing the number and geographic spread of supply points to our service territory. - By simplifying replacement efforts during major grid restoration by standardizing installed equipment. - increasing the density of interconnections between circuits in the distribution system, enabling additional options to restore power during contingency. Enable safe and reliable customer and DER connections: - By proactively upgrading infrastructure capacity to accommodate evolving customer needs and capacity constraints. - By ensuring that the operation of the distribution system remains within safe and allowable short-circuit current limits. - By ensuring that bi-directional power flows remain within the system's design parameters.
Safety	Ensures public safety: - By eliminating unauthorized access by the public to high-risk grid infrastructure. - By reducing public exposure to significant risks posed by aged and deteriorated equipment, including electrical faults, fires, or hazardous conditions. Ensures compliance: - By adherence to legislative requirements, safety standards and regulations such as Electrical Distribution Safety O.Reg. 22/04, ESA, CSA, Building codes, Fire codes, OHSA, etc. - By adherence to generally accepted and jointly used safety-by-design standards.

B.3. Investment Need

B.3.3 Primary Driver:

The primary driver for this investment is system reliability and efficiency and the need to address current and anticipated capacity constraints, ensure reliable service, and support load growth across the service territory.

B.3.4 Secondary Drivers:

There are no secondary drivers for this program.

B.3.5 Information Used to Justify the Investment:

This is a mandated service obligation defined in the DSC and other regulations.

B.4. Investment Justification

B.4.3 Demonstrating Accepted Utility Practice:

Key investments in this program include a capacity-driven project to phase out the existing low-voltage system in Mount Brydges, along with a proactive initiative to upgrade distribution transformers that are currently overloaded or projected to experience overloading and accelerated aging in the near term.

Voltage conversion has long been a standard strategy adopted by many Ontario utilities including EPI. While the Mount Brydges project is being executed under this program specifically to enhance system capacity, all other engineering principles and implementation practices remain consistent with established utility norms.

All necessary design and construction are completed in compliance with applicable USF standards supplemented by standards developed internally. The use of USF standards ensures that the design and construction of this project will be done according to a set of standards utilized by many other utilities in Ontario. EPI is O.Reg. 22/04 compliant to ensure employee and public safety.

To proactively identify transformers at greatest risk, EPI's Data Scientist conducted a comprehensive review of academic literature and industry research to select multiple suitable artificial intelligence (AI) models. These models were trained using EPI's smart meter data to determine the most accurate and effective predictive approach. The AI-generated recommendations are then reviewed and validated by engineering staff to confirm consistency with real-world system conditions and operational priorities.

B.4.4 Cost-Benefit Analysis:

This is a mandated service obligation outlined in the Distribution System Code (DSC) and other regulations. Utilities are required to upgrade infrastructure and acquire additional capacity in response to observed and forecasted load growth ensuring adequacy and reliability of service to address customer needs. EPI follows OEB rules and regulations in planning and executing such investments to support load demands as needed. Refer to Section 4.6 of the DSP for an overview of EPI's methodology for evaluating cost-effective options in its planning process to address capacity constraints.

B.4.5 Historical Investments & Outcomes Observed:

As mentioned in Section A.3.3 there are no historical expenditures in this investment program from 2021-2023. The key outcomes of this investment program are securing additional capacity through new embedded supply points, procuring and installing breakers, and supporting the execution of conversion projects to address capacity needs.

B.5. Non-Wires Solution

In compliance with OEB's NWA BCA Framework, EPI evaluates the eligibility and necessity of NWA through a structured screening process. This includes conducting a cost-benefit analysis to defer or avoid traditional wired infrastructure investments, where applicable. Pertaining to this, eligible capacity enhancement projects will undergo screening and may be implemented with customer agreement. Section 5.1.3.3.2 of the DSP provides further insight into EPI's NWS considerations within its system planning process, specifically addressing capacity enhancement strategies in accordance with regulatory requirements.

B.6. Innovation

Not Applicable

MATERIAL INVESTMENT NARRATIVE

PROJECT / PROGRAM:

18. Building

INVESTMENT CATEGORY:

GENERAL PLANT

A. GENERAL INFORMATION ON THE PROJECT/PROGRAM

A.1. Overview

This program captures the costs of upkeep and enhancements to EPI's two Operation Centres.

Key activities planned for the 2026-2030 timeframe include a renewed roof for the Chatham office and the replacement of some HVAC units in the St. Thomas building as recommended in the third-party Facilities Assessments included as Attachment J and Attachment K. Other investments include upgrading of the Chatham Control Room hardware and software due to end-of-support from the vendor, the replacement of VCT tile and ceramic flooring, ongoing building maintenance expenses and minor upgrades and refurbishment to support health and safety of EPI's staff and visitors (Section 5.1.2.4.2).

The Chatham roof replacement has been paced over two years starting in 2025 to lessen the impact of the substantial investment on any one year's budget. Its replacement has been recommended previously and again in 2024 by the third-party facilities assessors and will include the complete replacement of the roof and skylights. The audit found that the 1986 edition is original EPDM and was in poor condition. A 50 square foot section was soft and likely meant the insulation was saturated or deteriorated and will need replacement. The poor roof condition has begun negatively affecting the building interior, determined by evidence of leaks in multiple locations which will require ceiling and flooring replacement.

The St. Thomas HVAC system is generally in good shape aside from a few aged units. Four rooftop units specifically have been identified as being recommended to be replaced along with the exterior insulation on all exposed ducting. The aged units and insulation have led to water staining related to the equipment within the office on ceiling tiles. It was also recommended that certain gas lines and vents be repaired along with aged exhaust fans.

A.2. Timing

e. Start Date: January 2026
f. In-Service Date: Through to December 2030
g. Key factors that may affect timing: The following factors can impact the project schedule:

- Unplanned / reactive building investments
- Newly identified safety hazards

The timing and priority of this project is based on third-party inspections and their findings. EPI is obligated to provide a safe work environment for its employees and maintains their operating facilities and mitigate risks in the workplace.

A.3. Capital Expenditures

A.3.3 Historical and Future Capital Expenditures

Table 1. Historical and Future Capital ($, million)

Building - Totals

Historic Actual Expenditure				Bridge Year	Forecasted Budgeted Expenditure				
2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
$0.23	$0.25	$0.23	$0.53	$1.45	$0.90	$0.79	$0.60	$0.56	$0.85

The graph below illustrates the planned budget figures for this investment category ($ in millions).

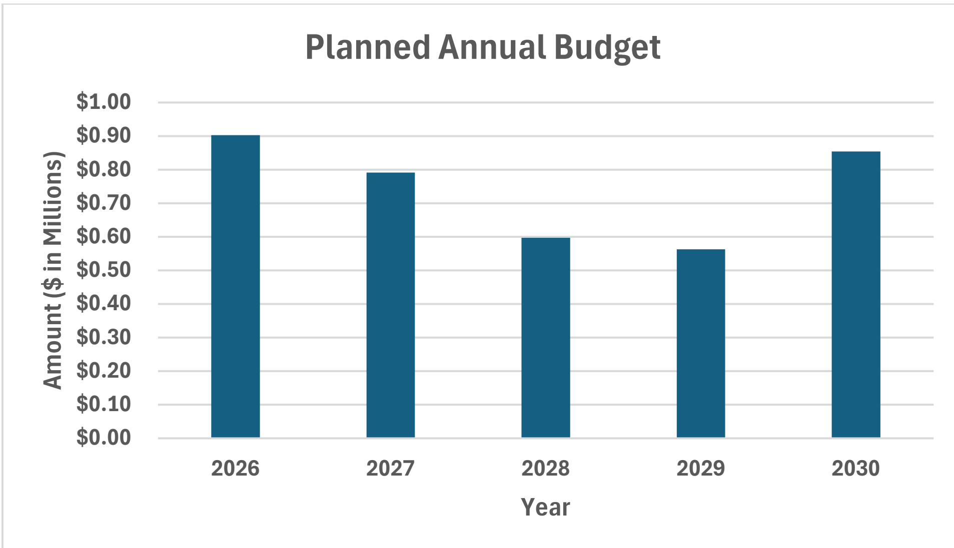


Fig 1: Planned Budget for Building costs

A.3.4 Economic Evaluation (Expansion projects)

Not Applicable

A.3.5 Comparative Historical Expenditure

Historical investments in this program were primarily driven by major building improvements at the St. Thomas office to properly consolidate with the former Strathroy operating centre (Section 3.3.1.5). Other drivers of historical spend included utilizing third-party contractors to complete general maintenance and repairs.

The Historic Period spending has been shown in the figure below:

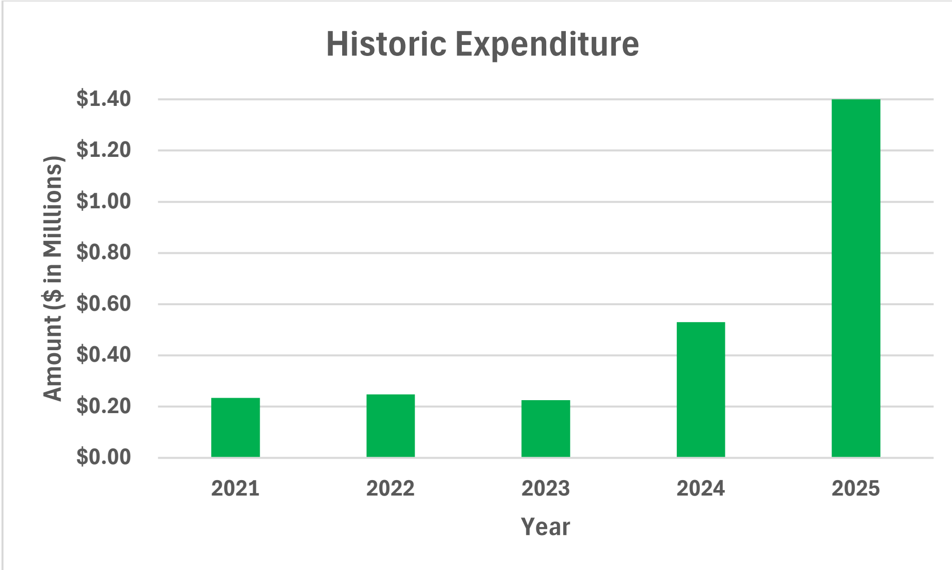


Fig 2: Historic Expenditure – Building Costs

A.4. Investment Priority

As per EPI's capital project scoring, this program ranks 16th out of 22. This project's ranking is based on its long-term focus (Section 5.3).

A.5. Alternative Analysis

This capital program captures necessary facility improvements and maintenance work at EPI's Operating Centres, with a focus on ensuring continued usability, safety, and efficiency of the buildings that support utility operations. Key investments in this DSP period include roof replacement at the Chatham Operating Centre and HVAC system renewal at the St. Thomas facility. These investments have been deferred in previous planning cycles but can no longer be postponed without risking costly failure and disruption to critical operations.

The following alternatives were considered:

a. **Defer Investment**
These building investments—specifically the Chatham roof replacement and HVAC upgrades in St. Thomas—have already been deferred in previous DSPs. Further deferral increases the likelihood of failure, rising repair costs, and risk of facility disruption. The rooftop HVAC units in St. Thomas are past their service life and require replacement, along with the associated exterior insulation, to maintain safe and habitable working conditions. In Chatham, roof leaks are now affecting interior spaces and must be addressed to prevent further degradation of the building structure.
Conclusion: *No longer viable. Further deferral exposes EPI to higher costs, facility downtime, and potential safety or operational concerns.*

b. **Relocate to or Construct a New Facility**
EPI considered the alternative of relocating operations or constructing a new facility as an alternative to ongoing building upkeep. However, both relocation and new construction carry significantly higher capital costs compared to maintaining the existing buildings, which continue to

meet EPI’s operational needs.
Conclusion: *Not cost-effective. Existing buildings remain functionally adequate and support current operational requirements.*

c. **Accelerate Investment (Single-Year Completion)**
The Chatham roof replacement was evaluated for completion in a single year. While this would address the issue more quickly, it would significantly impact the capital budget in that year. EPI and the roofing contractor have agreed that phasing the work over two years presents a manageable risk and allows for better financial planning and resource coordination.
Conclusion: *Not preferred. Phased approach balances risk, cost, and operational continuity.*

d. **Proceed with Planned Two-Year Phased Investment (Preferred Option)**
EPI’s preferred approach is to proceed with building improvements as planned over a two-year period. This includes $500k per year for roof replacement in Chatham and $250k per year for HVAC unit replacement and other building upgrades in St. Thomas and Chatham. This approach addresses deteriorating infrastructure before failure, minimizes disruption to operations, maintains safe and habitable work environments, and spreads capital impacts across multiple years.
Conclusion: *Best alternative. Cost-effective, low-risk, and operationally sound approach to maintaining essential facilities.*

A.6. Innovative Nature of the Project

Not Applicable

A.7. Leave to Construct Approval

This project does not require leave to construct approval under Section 92 of the OEB Act.

B. EVALUATION CRITERIA AND INFORMATION REQUIREMENTS

B.2. Efficiency, Customer Value, Reliability & Safety

Table 18: Investment Evaluation - Efficiency, Customer Value, Reliability & Safety

Criteria	Description
Efficiency	Maintaining the integrity of our buildings and their systems is key to maintaining a safe, efficient working environment. These investments ensure employees will continue to have access to their workspaces. Replacement of aged HVAC units and insulation improves the operational efficiency of the system by reducing energy bills. Repairing the roofs to ensure their proper function will avoid significant extra future cost. These proactive replacements allow modernization and can help avoid costly repairs or emergency replacement that would result from equipment failure. Improves operational efficiency: - By conserving energy and lowering long-term operational costs. - By optimizing facility space to accommodate flexible work environments, operational demands, and shifting work patterns. - By maintaining integrity of facilities to ensure safe and efficient work environments. Ensures cost-effectiveness: - By proactively replacing deteriorated assets to avoid higher costs, degraded service levels and safety hazards associated with equipment malfunction, unplanned failures, and emergency repairs and replacements. Maintain financial health: - By maximizing ratepayer value through proactive maintenance and replacements in a financially prudent manner.
Customer Value	An important value of this project is maintaining safe working conditions for employees which allows EPI staff to complete their work effectively and to focus on providing optimal service to customers. Improve customer value:

	- By minimizing costs for infrastructure upgrades while maximizing ratepayer value through proactive maintenance and asset replacement.
Reliability	Having access to suitable buildings, equipment and systems to support EPI's operations allow staff to efficiently respond to outages. Improve system reliability: - By ensuring the utility is equipped to handle operational demands effectively.
Safety	The goal of this project is to maintain EPI's structures in a safe and serviceable condition, compliant with applicable codes and regulations, providing staff a safe place to carry on EPI's business activities. Improves worker safety: - By improving safety conditions at the workplace for utility workers. - By eliminating unauthorized access to utility grounds. Ensures compliance: - By adherence to legislative requirements, safety standards and regulations such as Electrical Distribution Safety O.Reg. 22/04, ESA, CSA, Building codes, Fire codes, OHSA, etc. Mitigates environmental impact: - By reducing GHG emissions.

B.3. Investment Need

B.3.3 Primary Driver:

The main investment driver is Non-System Physical Plant. Repairing failing or soon to be failing parts of the facilities is needed to safeguard employees and ensure EPI can continue to operate efficiently (Section 5.3).

B.3.4 Secondary Drivers:

Not Applicable

B.3.5 Information Used to Justify the Investment:

The need to provide a safe work environment for employees is required of all businesses in Ontario and Canada. Significant investments under this project are made after qualified third-party auditors identify the condition of each property and highlight major repairs that must be done to maintain a safe facility for employees as well as avoiding even higher long-term project costs. These investments were identified in previous building assessments and can no longer be deferred.

B.4. Investment Justification

B.4.3 Demonstrating Accepted Utility Practice:

Asset renewal decisions follow the lifecycle management methodology as discussed in Section 4.8 of the DSP. Asset replacement criteria within the purchasing policy are aligned with Ontario LDC norms.

B.4.4 Cost-Benefit Analysis:

Regular facility maintenance and upkeep is required to maintain employee safety. Chatham roofing work has previously been deferred and can no longer wait before serious internal workplace safety hazards may arise. Other upkeep is determined on an individual basis to determine if repair is immediately necessary for employee safety or the overall long-term integrity of the facility. As such, the HVAC work required in St. Thomas is needed to prevent water leakage and subsequently an even higher repair cost in the future if the work is delayed.

B.4.5 Historical Investments & Outcomes Observed:

A significant historical investment in this project was the migration of the Strathroy Operation Centre to the St. Thomas Operations Centre. Strategic planning and investments in the St. Thomas office minimized challenges with the migration to allow a smooth closure of the Strathroy office. The migration to one office reduced EPI's overall facilities footprint per employee and reduced the total cost incurrent by EPI to support its staff.

B.5. Non-Wires Solution

Not Applicable

B.6. Innovation

Not Applicable

MATERIAL INVESTMENT NARRATIVE

PROJECT / PROGRAM:

19. IT Hardware

INVESTMENT CATEGORY:

GENERAL PLANT

A. GENERAL INFORMATION ON THE PROJECT/PROGRAM

A.1. Overview

This investment program captures the expenses of all IT infrastructure and supporting equipment that are necessary to conduct and maintain day to day utility operations by EPI employees, including the major priority of cyber security, as well as ongoing improvement to EPI's information technology capabilities.

Budget for this project includes both the IT hardware equipment like personal computing and communication devices (laptops, tablets, cellphones, headsets, etc.) and back-office equipment like servers and networking infrastructure.

By investing in modern technologies and hardware EPI aims to enhance corporate efficiency and accuracy across Engineering, Operations and all other EPI departments. This program will minimize system downtime and ensure seamless departmental functionality.

A.2. Timing

i. Start Date: January 2026
ii. In-Service Date: Through to December 2030
iii. Key factors that may affect timing:
   - Delays in supply chain and logistics to procure required IT equipment
   - Discontinuation of future offerings or IT support by vendors
   - Testing and validation could extend timelines, including cybersecurity threat mitigation

IT hardware carries several risks including vendor market changes (e.g. mergers & acquisitions affecting support or offerings), emerging cybersecurity threats, challenges in system interoperability, and evolving customer technology requirements. EPI has mitigated these risks by drawing insights from strategies of other utilities, through a three-pillar approach: preference of strengthening in-house expertise over outsourcing, focus on cybersecurity to ensure business continuity, and optimizing the value of core business applications over customization (Section 4.7.1).

A.3. Capital Expenditures

A.3.3 Historical and Future Capital Expenditures

Table 1. Historical and Future Capital ($, million)

IT Hardware - Totals									
Historic Actual Expenditure				Bridge Year	Forecasted Budgeted Expenditure				
2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
$0.22	$0.20	$0.21	$0.33	$0.26	$0.22	$0.21	$0.34	$0.28	$0.29

The graph below illustrates the planned budget figures for this investment category ($ in millions) for this DSP timeline:

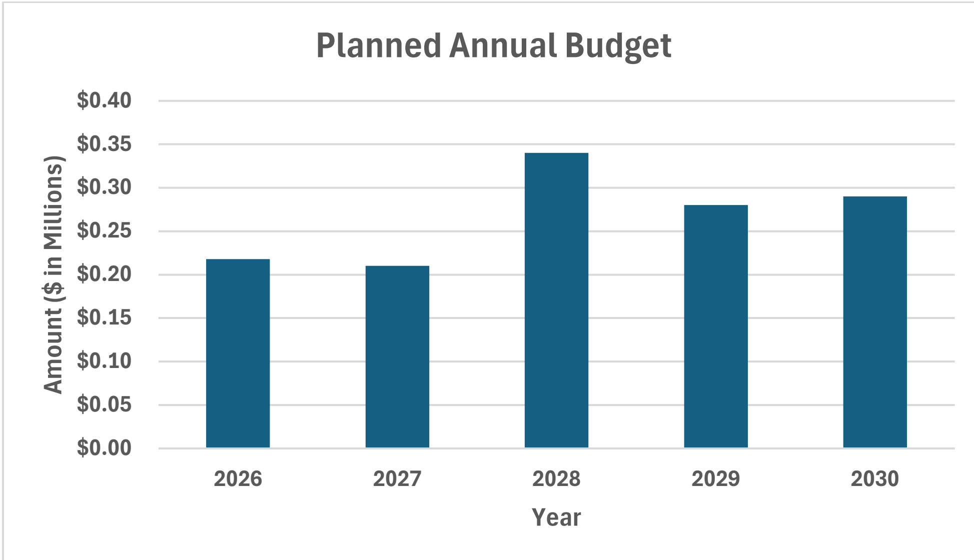


Fig 1: Planned Budget for IT Hardware

A.3.4 Economic Evaluation (Expansion projects)

Not Applicable

A.3.5 Comparative Historical Expenditure

The investments in this program are primarily driven in acquiring and maintaining IT hardware equipment for employees' daily work functions.

The historic spending in 2021-2024 and planned spending in 2025 has been shown in the figure below:

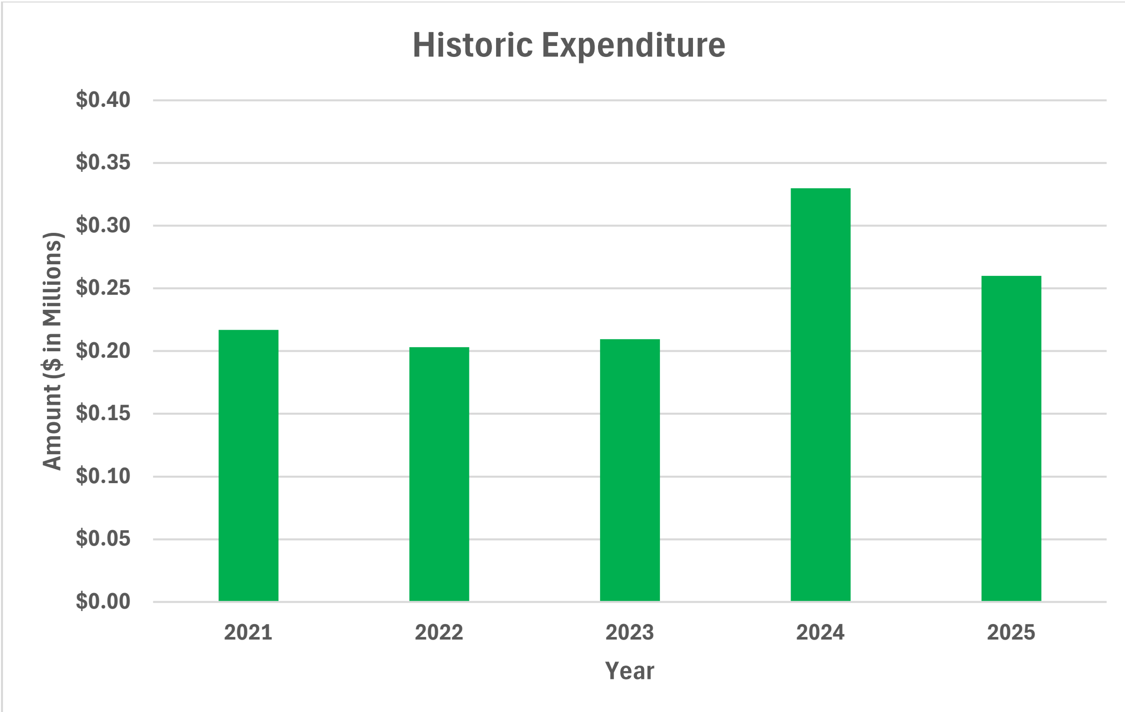


Fig 2: Historic Expenditure on IT Hardware

A.4. Investment Priority

As per EPI's latest project scoring, this program is ranked 6th out of 22 reflecting its high priority as this project directly impacts the performance and daily work of EPI employees. It also holds an impact on customer service and digital communication since it enables EPI to effectively relay outage maps through its website and other critical information directly to customers. Lack of proactive investments and annual planning to acquire essential equipment will lead to untimely hardware failures, loss of productivity and ultimately poor customer satisfaction.

A.5. Alternative Analysis

EPI has developed a strong and reliable IT foundation through prior investments in upgraded workstations, modern communication tools, and increased server storage. These investments have enabled secure data management and operational efficiency across the organization. In this DSP period, EPI will continue to invest in IT infrastructure with a renewed focus on lifecycle management and cybersecurity enhancement to protect against increasing threats and ensure uninterrupted service delivery.

The IT department actively manages asset lifecycles and adjusts replacement timelines in response to evolving technology, usage demands, and emerging security risks. Maintaining investment at the current level is essential to preserve system integrity, support internal operations, and safeguard sensitive customer data.

The following alternatives were considered:

a. Do Nothing / Continue to Use and Repair Existing Equipment

Under this approach, EPI would maintain aging IT hardware and perform ad hoc repairs as needed. However, as devices age, failure rates and maintenance needs increase—resulting in more frequent downtime, decreased employee productivity, and higher operational costs. Additionally, outdated systems are less secure, exposing the utility to greater cyber risk and potential data breaches.
Conclusion: *Not feasible. Increases operational risk, reduces productivity, and exposes EPI to unacceptable cybersecurity vulnerabilities.*

b. Replace Equipment with Reduced Specifications

This alternative would involve procuring lower-performance or lower-cost IT equipment to reduce upfront capital costs. However, this would limit functionality across the organization, constrain work activities, and result in greater pressure on shared or underpowered systems. The cumulative impact would be reduced efficiency, increased user frustration, and diminished service levels.
Conclusion: *Not viable. Compromises organizational effectiveness and does not support long-term value or reliability.*

c. Proceed with Lifecycle-Based Replacement and Security Investment (Preferred Option)

EPI's preferred approach is to follow a structured lifecycle replacement program for IT hardware while investing in modern tools and cybersecurity capabilities. This strategy ensures that employees have the necessary tools to operate efficiently and securely. It also enables proactive risk mitigation, reduces long-term maintenance costs, and ensures alignment with technology trends.
Conclusion: *Best alternative. Maintains productivity, security, and system reliability while aligning with customer service expectations and corporate resilience objectives.*

A.6. Innovative Nature of the Project

Not Applicable

A.7. Leave to Construct Approval

This project does not require leave to construct approval under Section 92 of the OEB Act.

B. EVALUATION CRITERIA AND INFORMATION REQUIREMENTS

B.2. Efficiency, Customer Value, Reliability & Safety

Table 19: Investment Evaluation - Efficiency, Customer Value, Reliability & Safety

Criteria	Description
Efficiency	By investing in IT equipment and infrastructure, EPI aims to improve operational efficiency and enhance the quality of customer experience. Upgraded systems can minimize downtime and deter potential cybersecurity threats. Improves operational efficiency: - By ensuring implementation of asset management practices to meet the needs of customers and stakeholders, balancing safety, reliability, and cost-effectiveness. - By optimizing procurement and supply chain management through standardizing equipment and reducing the variety of asset types in the system. - By ensuring IT systems are reliable, available, and secure to support corporate and operational functions, reducing risks and costs associated with unsupported and outdated hardware/software, and cybersecurity threats. Ensures cost-effectiveness: - By minimizing the likelihood of catastrophic asset failures and subsequent associated costs through early risk identification and mitigation. - By mitigating costs associated with supporting non-standard assets.
Customer Value	With robust and secure IT systems, reliable and uninterrupted service is ensured, maintaining both customer facing resources, the Customer Information System (CIS) and internal systems needed to complete EPI's business activities. IT infrastructure helps protect sensitive customer data and secure their financial transactions. It also allows EPI to avoid costs through automation, which may ultimately lower the service rates for customers. Enhance customer experience:

	- By leveraging technological tools to deliver seamless, timely, and effective customer service and manage service requests. Improve customer choice: - By providing consumption analytics to the customers to enable active management of energy consumption and energy bills.
Reliability	Maintaining EPI's IT infrastructure with current technology is vitally important to support EPI's systems including core systems they host such as SCADA, AMI, CIS, GIS and more. Expenditures in this category support system reliability: - By replacing hardware to maintain access to timely vendor support and updates. - By ensuring the utility is equipped to handle operational demands effectively. - By providing modern, reliable, and secure enterprise-wide critical systems that enhance efficient distribution system management. - By mitigating the risks of system-wide outage due to inadequate performance of IT systems or cybersecurity threats.
Safety	Strong infrastructure is essential in creating a safe digital workspace to protect data, enhance connectivity, and build a secure work network. By prioritizing in-house cybersecurity abilities, and optimization of business applications, EPI aims to strengthen decision making, increase operational efficiency, and operate in a secure digital space. Ensures public safety: - By reducing safety risks and hazards to the public associated with managing and operating grid infrastructure. - By eliminating unauthorized access by the public to high-risk grid infrastructure. Improves worker safety: - By improving safety conditions at the workplace for utility workers. Ensures compliance: - By adherence to legislative requirements, safety standards and regulations such as Electrical

	Distribution Safety O.Reg. 22/04, ESA, CSA, Building codes, Fire codes, OHSA, etc.

B.3. Investment Need

B.3.3 Primary Driver:

The primary driver for this investment is non-system physical plant and the need to create and maintain a reliable and secure IT infrastructure that provides an efficient digital platform for EPI employees to perform their daily work. EPI aims to continuously improve its operational efficiency, enhance customer experience, deter and mitigate potential cybersecurity threats and strategically adapt and evolve with the technological trends.

B.3.4 Secondary Drivers:

There are no secondary drivers for this investment.

B.3.5 Information Used to Justify the Investment:

EPI replaces its IT assets based on the lifecycle policies while considering associated software support and the fast-paced evolution of the industry. Manufacturers and supplier options are regularly evaluated at the beginning of each lifecycle. To stay aligned with technological advancements and industry trends, EPI regularly reviews its asset replacement timelines, adapting them as needed based on organizational goals and business requirements. This is a proactive approach that helps EPI maintain a modern, sophisticated and efficient IT infrastructure to deliver high quality service to its customers and employees.

B.4. Investment Justification

B.4.3 Demonstrating Accepted Utility Practice:

Asset renewal decisions follow the lifecycle management methodology for the appropriate asset class as discussed in Section 4.7.2 of the DSP. Asset replacement criteria within the purchasing policy are aligned with Ontario LDC norms.

B.4.4 Cost-Benefit Analysis:

Investments in this category have significant benefits on workforce productivity, data and system security, operational efficiency and overall customer satisfaction. Proactive upgrades prevent unexpected system failures, avoiding emergency repairs, minimizing service disruptions and preserving business continuity. Although initial costs could be significant, the long-term value, reactive cost avoidance, and risk mitigation heavily outweigh the investment capital making this a crucial step to maintain operational excellence.

B.4.5 Historical Investments & Outcomes Observed:

Section A.3.3 highlights the historic expenditure for this investment segment.

B.5. Non-Wires Solution

Non-wires solutions are not applicable to serve the purposes of this investment.

B.6. Innovation

Not Applicable

MATERIAL INVESTMENT NARRATIVE

PROJECT / PROGRAM:

20. IT Software

INVESTMENT CATEGORY:

GENERAL PLANT

A. GENERAL INFORMATION ON THE PROJECT/PROGRAM

A.1. Overview

The IT Software program includes the licensing costs of new and existing software solutions used by EPI as well as the labour costs associated with periodic system upgrades and support. EPI maintains several sophisticated utility-specific solutions like those supporting Metering, Customer Care and Billing, and Control Centre and Asset Management functions, among others.

Cybersecurity is a major priority for EPI, which actively monitors and manages any potential vulnerabilities within its network. The investments made through this project will allow EPI to efficiently meet required customer and regulatory requirements and satisfaction levels.

One key project over the forecast period is a transition in virtualization platforms. Virtualization technologies allow a far more efficient use of hardware assets than traditional deployments and have been standard at EPI for many years. Recent acquisitions in the market have caused a dramatic shift in ongoing licensing costs. EPI intends to review the marketplace's current pricing structures with the expectation that a new vendor will be selected, and a migration project will be undertaken.

In response to customer consultation (Section 3.2.1.2.1 and 3.2.1.2.2), new for this DSP period, is the introduction of a customer app. This application will enable consolidated, more mobile friendly access to information from EPI's "My Account" portal and EPI's outage map, starting in 2026. The mobile application will also add the ability to report outages.

A.2. Timing

i. Start Date: January 2026
ii. In-Service Date: Through to December 2030
iii. Key factors that may affect timing:
  - Ongoing critical projects
  - Changes in vendor marketplace and risk of discontinuation of future support
  - Interoperability and compatibility across major systems and versions might cause integration challenges
  - Testing and validation could extend timelines, including cybersecurity threat mitigation

Investment in the IT software segment is susceptible to various project delay risks including technical and security risks when integrating with existing systems, delays from the vendor in software delivery or customization, extensive testing and validation requirements, and project modifications to address any emergent cybersecurity threats identified during product development (Section 4.7.1).

A.3. Capital Expenditures

A.3.3 Historical and Future Capital Expenditures

Table 1. Historical and Future Capital ($, million)

IT Software - Totals		
Historic Actual Expenditure	Bridge Year	Forecasted Budgeted Expenditure

2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
$0.32	$0.54	$0.53	$0.49	$0.62	$1.07	$0.54	$0.50	$0.59	$0.61

The graph below illustrates the planned budget figures for this investment category ($ in millions) for this DSP timeline:

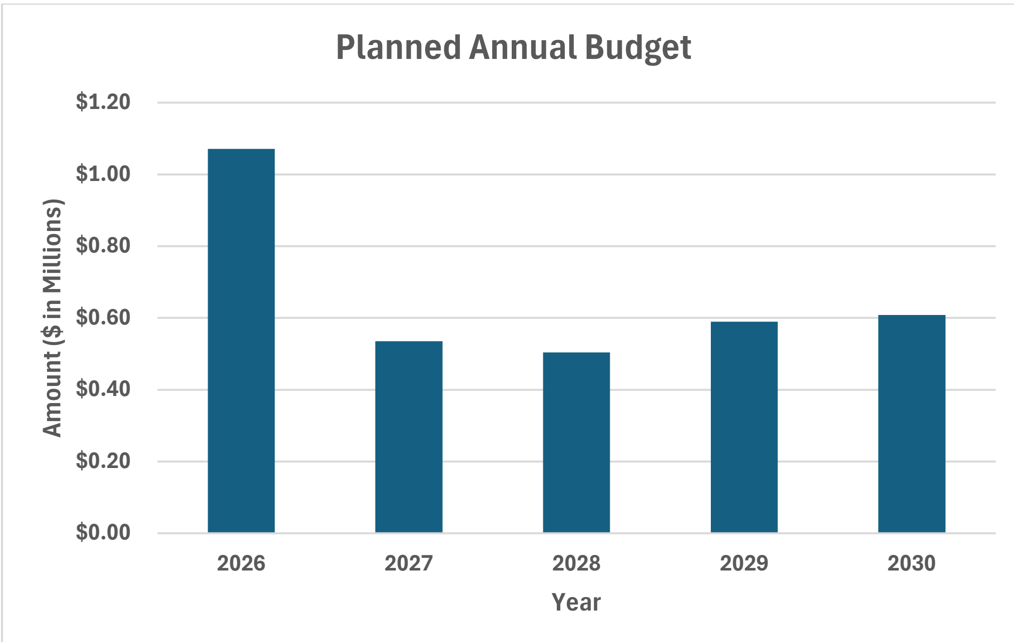


Fig 1: Planned Budget for IT Software

The IT Software capital budget peaks in 2026, primarily driven by two major initiatives: a full website redesign and a transition to a new virtualization platform. EPI is revamping its website to improve how customers access information related to outages, self-service tools, safety, and billing. Informed by annual customer satisfaction surveys (discussed in Exhibit 1, Section 1.6.2), the redesign will deliver a more intuitive and accessible platform using modern technologies to enhance communication and overall user experience.

In parallel, EPI will transition away from its current infrastructure virtualization solution, which has moved to a financially unsustainable licensing model, and the latest software version no longer supported on the company's existing server hardware. A sustainable virtualization platform is critical for EPI to ensure reliable and cost-effective delivery of IT services, enabling multiple applications to operate securely on shared infrastructure while supporting rapid recovery, scalability, and system security. This transition to a new virtualization platform, aligned with EPI's regular five-year refresh cycle, will enhance system security, reliability, and performance, while improving long-term maintainability and controlling operational costs.

Following the implementation of these two initiatives in 2026, software-related spending is expected to return to a steady level over the remainder of the planning period.

A.3.4 Economic Evaluation (Expansion projects)

Not applicable

A.3.5 Comparative Historical Expenditure

The graph below shows the historical spending for the Historical Period:

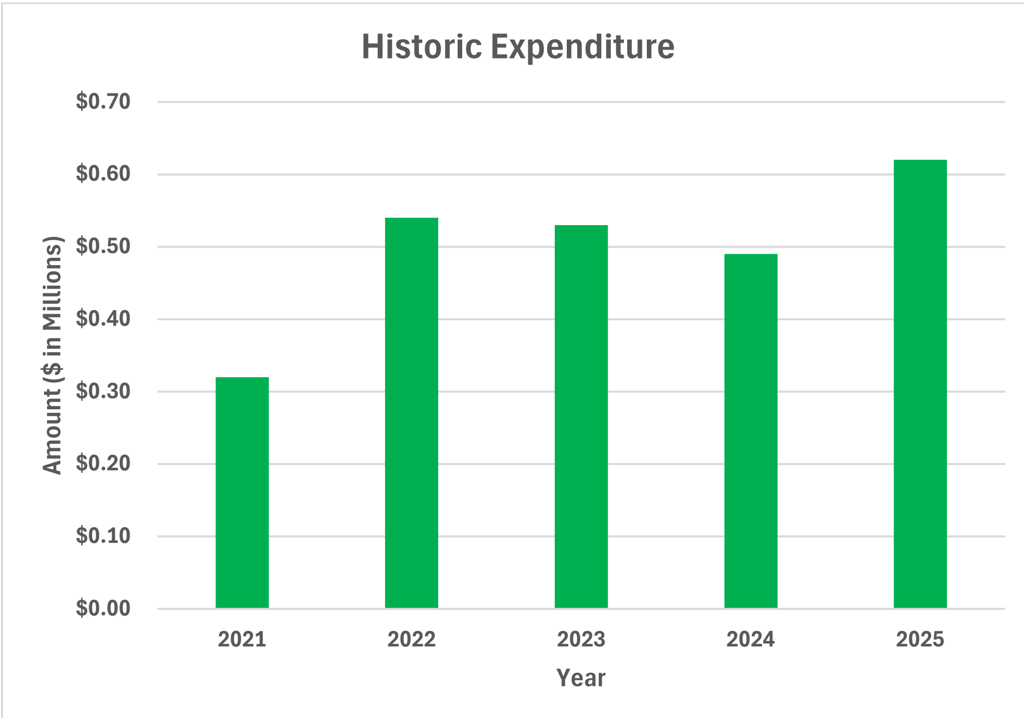


Fig 2: Historic Expenditure - IT Software

A.4. Investment Priority

As per EPI's capital project scoring, this sector ranks 5th out of 22, highlighting its importance as it directly impacts the performance and daily work of majority of EPI employees, as well as the protection of sensitive customer information. This includes operating software systems such as SCADA, Engineering Design, AMI, outage maps, billing and customer care systems.

A.5. Alternative Analysis

This capital program supports the ongoing evaluation, acquisition, and lifecycle management of software systems across all departments within EPI. These systems enable critical utility functions including Metering, Engineering, GIS, Customer Care and Billing, Control Centre operations, and Asset Management. EPI's IT team conducts a case-by-case analysis of all software packages annually to assess cost-effectiveness, operational efficiency, system integration, customer impact, and cybersecurity.

Given the rapid pace of change in technology and software offerings—driven by vendor updates, industry acquisitions, and evolving utility needs—EPI maintains active vendor support agreements and adapts replacement timelines accordingly. A lifecycle-based approach ensures that software systems remain secure, functional, and aligned with operational requirements.

The following alternatives were considered:

a. <u>Do Nothing / Continue to Use and Repair Existing Equipment</u>
Under this approach, EPI would continue to rely on aging software without renewing support agreements or performing updates. Over time, this would result in compatibility issues, loss of vendor support, increased maintenance complexity, and potential security vulnerabilities. It would also delay access to new features and integrations needed for efficient utility operations.
Conclusion: *Not feasible. Increases operational risk, reduces service quality, and exposes EPI to cybersecurity threats.*

b. <u>Replace with Lower-Cost or Reduced-Functionality Software</u>
This alternative would involve procuring software with reduced capabilities to limit capital expenditure. However, this may compromise key functionality, constrain operations across departments, and reduce integration with other enterprise systems. It would also increase user frustration and inefficiencies due to a lack of tailored features required in utility-specific workflows.
Conclusion: *Not viable. Results in productivity loss, system fragmentation, and diminished service value.*

c. <u>Defer Investment and Extend Software Lifespans</u>
Deferring software investments or license renewals has been rejected as a viable alternative. In addition to creating operational limitations, it risks violating regulatory or cybersecurity best practices. Maintaining current levels of investment is essential to ensure the continued security, support, and compliance of EPI's core systems—especially in light of changing vendor offerings and utility sector digitalization.
Conclusion: *Not acceptable. Deferral exposes EPI to system failure, vendor lockout, and security risks*

d. <u>Case-by-Case Evaluation with Lifecycle Replacement (Preferred Option)</u>
EPI's preferred strategy is to continue with its annual, department-specific review of software systems to determine optimal timing for renewal, upgrade, or replacement. This approach ensures that software tools deliver value, efficiency, and integration, while adhering to industry cybersecurity standards and vendor support requirements. It also allows for dynamic adaptation to changes in product offerings, licensing models, and enterprise needs.
Conclusion: *Best alternative. Balances cost control, performance, security, and alignment with corporate goals.*

A.6. Innovative Nature of the Project

Not Applicable

A.7. Leave to Construct Approval

This project does not require leave to construct approval under Section 92 of the OEB Act.

B. EVALUATION CRITERIA AND INFORMATION REQUIREMENTS

B.2. Efficiency, Customer Value, Reliability & Safety

Table 20: Investment Evaluation - Efficiency, Customer Value, Reliability & Safety

Criteria	Description
Efficiency	Keeping EPI IT software up to date keeps the utility connected, making operations increasingly efficient and reducing potential downtime caused by outdated software. Improves operational efficiency: - By ensuring implementation of asset management practices to meet the needs of customers and stakeholders, balancing safety, reliability, and cost-effectiveness. - By optimizing procurement and supply chain management through standardizing equipment and reducing the variety of asset types in the system. - By ensuring IT systems are reliable, available, and secure to support corporate and operational functions, reducing risks and costs associated with unsupported and outdated hardware/software, and cybersecurity threats. Ensures cost-effectiveness: - By minimizing the likelihood of catastrophic asset failures and subsequent associated costs through early risk identification and mitigation. - By mitigating costs associated with supporting non-standard assets.
Customer Value	This program helps maintain and improve the security and reliability of all internal and customer-facing services, such as outage maps, billing, information systems, and other communication channels. Up-to-date software also enables faster response times, increases corporate efficiency, and provides a user-friendly interface for customers, directly enhancing customer experience. Enhance customer experience: - By leveraging technological tools to deliver seamless, timely, and effective customer service and manage service requests.

	Improve customer choice: - By providing consumption analytics to the customers to enable active management of energy consumption and energy bills.
Reliability	Investments in load monitoring and management software help minimize downtimes, improve response times, and enhance the overall stability of services to provide a reliable service delivery to customers. Expenditures in this category support system reliability - By replacing hardware to maintain access to timely vendor support and updates. - By ensuring the utility is equipped to handle operational demands effectively. - By providing modern, reliable, and secure enterprise-wide critical systems that enhance efficient distribution system management. - By mitigating the risks of system-wide outage due to inadequate performance of IT systems or cybersecurity threats.
Safety	A robust IT infrastructure helps monitor and manage critical infrastructure, risk mitigation from cybersecurity threats and prevents system failures, protecting both public and EPI personnel from potential hazards related to system failures and security breaches. Ensures public safety: - By reducing safety risks and hazards to the public associated with managing and operating grid infrastructure. - By eliminating unauthorized access by the public to high-risk grid infrastructure. Improves worker safety: - By improving safety conditions at the workplace for utility workers. Ensures compliance: - By adherence to legislative requirements, safety standards and regulations such as Electrical Distribution Safety O.Reg. 22/04, ESA, CSA, Building codes, Fire codes, OHSA, etc.

B.3. Investment Need

B.3.3 Primary Driver:

The main investment driver for this segment is non-system physical plant and to enhance operational efficiency, maintain compliance, and ensure security from cyber threats through proactive software asset management. This includes supporting critical functions like GIS, Engineering Design, Customer Care and Billing, Metering, etc.

B.3.4 Secondary Drivers:

There are no secondary drivers for this investment.

B.3.5 Information Used to Justify the Investment:

These investments are made in response to a variety of regulated business requirements, as well as industry best practices. IT is aligned with EPI goals of building strong core teams, and is used to address EPI's operational needs, mitigate cybersecurity risk, and ensure regulatory compliance. Cost controls are managed through EPI's established asset lifecycle replacement plan as well as a cyber security working group comprised of senior management and IT leadership.

B.4. Investment Justification

B.4.3 Demonstrating Accepted Utility Practice:

Asset renewal decisions follow the lifecycle management methodology for the appropriate asset class as discussed in Section 4.7.3 of the DSP. Asset replacement criteria within the purchasing policy are aligned with Ontario LDC norms.

B.4.4 Cost-Benefit Analysis:

There are inherent risks associated with investments in IT software including changes in the vendor landscape, emerging cybersecurity threats, and challenges in system integration, interoperability, and employee adoption. EPI's IT strategy addresses these risks through three pragmatic pillars: prioritizing in-house skill development over outsourcing, investing in cybersecurity to preserve business continuity, and maximizing the value of core business applications over customized solutions.

B.4.5 Historical Investments & Outcomes Observed:

Section A.3.3 highlights the historic expenditure for this investment segment.

B.5. Non-Wires Solution

Non-wires solutions are not applicable to serve the purposes of this investment.

B.6. Innovation

Not Applicable

MATERIAL INVESTMENT NARRATIVE

PROJECT / PROGRAM:

21. Miscellaneous General Plant

INVESTMENT CATEGORY:

GENERAL PLANT

A. GENERAL INFORMATION ON THE PROJECT/PROGRAM

A.1. Overview

This project captures investments associated with the substation facilities. This encompasses costs associated with significant refurbishments, improvements, as well as decommissioning costs once the station has been retired from service.

Over the 2026-2030 Forecast Period, the primary cost driver is the costs are associated with betterments needed to former substation properties to make them suitable for disposal, such as with removing electrical equipment, environmental studies and minor facility repairs (see more in Section 5.1.2.2.1).

A.2. Timing

i. Start Date: January 2026
ii. In-Service Date: Though to December 2030
iii. Key factors that may affect timing: The following factors can impact the project schedule:
- Substation facility health
- Voltage conversion plans
- Damages due to vandalism

A.3. Capital Expenditures

A.3.3 Historical and Future Capital Expenditures

Table 1. Historical and Future Capital ($, million)

Miscellaneous General Plant - Totals									
Historic Actual Expenditure				Bridge Year	Forecasted Budgeted Expenditure				
2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
$0.13	$0.20	$0.00	$0.11	$0.17	$0.16	$0.10	$0.12	$0.09	$0.16

The graph below illustrates the annual budget planned for Miscellaneous General Plant program for the period of this DSP:

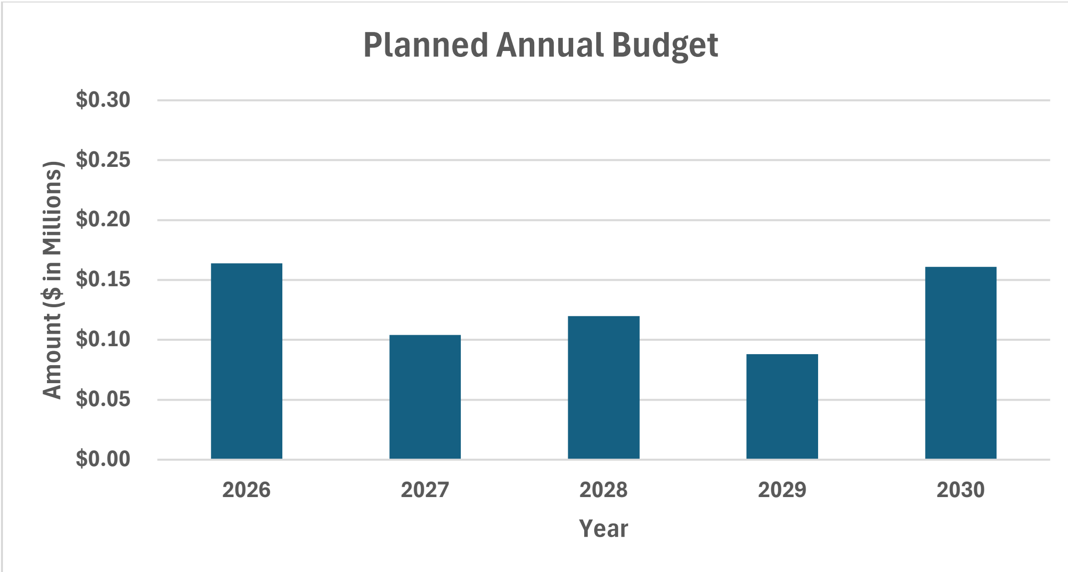


Fig 1: Planned Budget for Miscellaneous General Plant

A.3.4 Economic Evaluation (Expansion projects).

Not Applicable

A.3.5 Comparative Historical Expenditure

The graph below shows the actual spending for years 2021-2024 and the planned spending for 2025. The timing of historical spending primarily aligns with the utility's voltage conversion plans. For example, in 2024 the legacy 4.16 kV Chatham Substation 4 feeders were converted to 27.6kV. As a result, this job encompasses the cost to safely decommission the aged substation and to ensure compliance with environmental regulations. Third-party Interference, namely vandalism has driven costs in the historical period too. For example, the Chatham Sub 6 station neutral was stolen, resulting in a fire inside the station and significant damage to station assets. Additionally, periodic break-ins necessitate regular facility repairs, as well as drive modifications such as bricking up windows reachable from ground level.

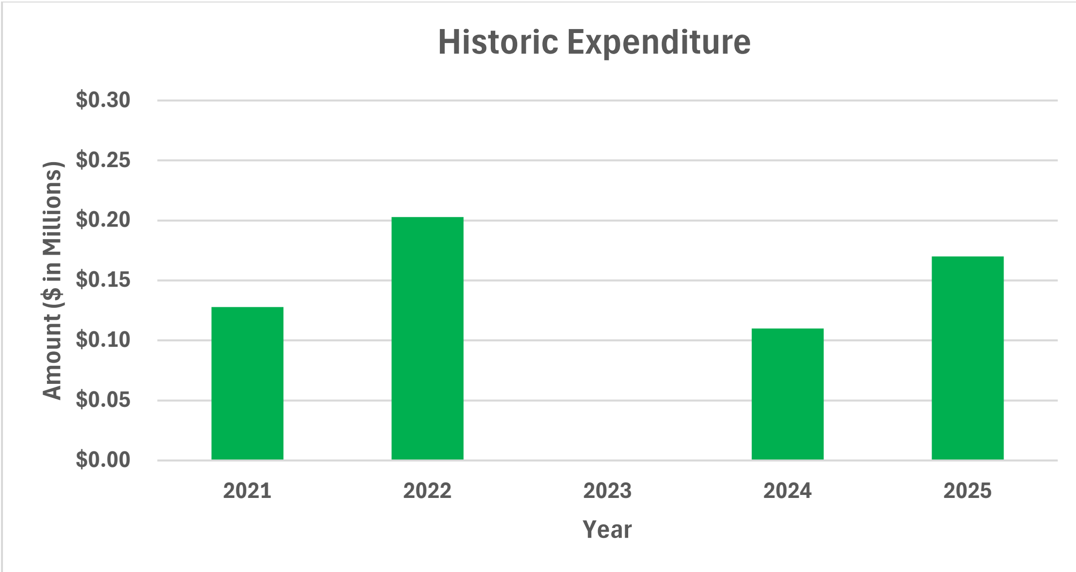


Fig 2: Historic Expenditure – Miscellaneous General Plant

A.4. Investment Priority

As per EPI's latest capital project scoring, this segment ranks 21 out of 22. Periodic substation maintenance is a required activity. Deferral of this work will interfere with our ability to meet EPI obligations (Section 5.3).

A.5. Alternative Analysis

This program supports the safe and cost-effective decommissioning of retired station assets following voltage conversion or functional replacement. These stations are no longer required for operational purposes but continue to impose financial and security burdens on the utility if left in place. Decommissioning eliminates risks associated with unused infrastructure while enabling potential land divestiture and reducing long-term maintenance obligations.

Maintaining the program at a minimum of its current investment level is essential to mitigate risks related to vandalism, reduce property upkeep costs (e.g., taxes, utilities, and grounds maintenance), and optimize system performance by addressing residual system losses associated with retired infrastructure.

a. <u>Defer Decommissioning (Do Nothing)</u>

EPI considered delaying the removal of decommissioned stations beyond the current DSP period. While this may defer capital costs in the short term, it introduces unnecessary risk and long-term operating expenses. Unused stations remain vulnerable to vandalism, unauthorized access, and environmental degradation—potentially leading to liability concerns. Furthermore, these sites continue to accrue costs such as property taxes, security, and upkeep, without providing any operational value.

Conclusion: *Not viable. Increases long-term cost exposure and safety/security risks with no corresponding benefit.*

b. <u>Maintain Program at Current Pace (Preferred Option)</u>

The preferred strategy is to continue decommissioning work at the current planned pace, ensuring that assets are safely removed in a staged, risk-informed manner. This approach enables EPI to align decommissioning timelines with broader system plans, such as phased voltage conversions, and allows for coordinated planning across capital programs. Removing retired assets reduces EPI's risk profile and enables property disposition or repurposing where applicable.

Conclusion: *Preferred option. Reduces long-term O&M costs, improves site safety, and supports efficient system planning.*

A.6. Innovative Nature of the Project

Not applicable

A.7. Leave to Construct Approval

This project does not require leave to construct approval under Section 92 of the OEB Act.

B. EVALUATION CRITERIA AND INFORMATION REQUIREMENTS

B.2. Efficiency, Customer Value, Reliability & Safety

Table 21: Investment Evaluation - Efficiency, Customer Value, Reliability & Safety

Criteria	Description
Efficiency	It improves system losses through elimination of the station transformers. It also frees up employee hours (previously associated with maintenance and repair activities) to be allocated against other work. Improves operational efficiency: - By lowering long-term operational costs. Improve system reliability: - By ensuring the utility is equipped to handle operational demands effectively.
Customer Value	Elimination of substations and their grounds reduces O&M associated with their periodic maintenance and repair. It improves system losses through elimination of the station transformers. It also frees up employee hours (previously associated with maintenance and repair activities) to be allocated against other work. Also, by mitigating the probability of break-in related incidents which necessitate repairs and could result in costly lawsuits, both of which deteriorate customer value.
Reliability	Ensuring substations are in sound condition is key to maintaining reliable service to the customers they support. Improve system reliability: - By ensuring the utility is equipped to handle operational demands effectively.
Safety	Vandalism poses serious safety threats to both EPI staff and the public. Copper ground theft at substations has been a common recurring problem despite EPI's efforts. Repairing vandalism caused damage is critical to ensure the safe operation of equipment and the safety of EPI personnel and the public. Ensures public safety:

	- By eliminating unauthorized access by the public to high-risk grid infrastructure. Improves worker safety: - By improving safety conditions at the workplace for utility workers. - By eliminating unauthorized access to utility work centers and site locations. Ensures compliance: - By adherence to legislative requirements, safety standards and regulations such as Electrical Distribution Safety O.Reg. 22/04, ESA, CSA, Building codes, Fire codes, OHSA, etc. Mitigates environmental impact: - By removing assets that contain environmentally hazardous material with a high exposure risk. - By reducing GHG emissions.

B.3. Investment Need

B.3.3 Primary Driver:

The main investment driver is Non-System Physical Plant.

B.3.4 Secondary Drivers:

There are no secondary drivers for investments in this project.

B.3.5 Information Used to Justify the Investment:

Decommissioning timing is determined in consultation with both planning and construction engineering groups and is generally pursued as quickly as is practicable once all supplied customers have been converted.

Repairs and remediation of vandalism is reactive and performed as required.

B.4. Investment Justification

B.4.3 Demonstrating Accepted Utility Practice:

EPI's capital investment plan prioritizes the structured approach to decommissioning legacy step-down substations as part of its broader voltage conversion to a 27.6 kV standard. This work is timed to occur before major component replacements are needed, avoiding unnecessary capital costs and aligning with prudent asset management principles.

Decommissioned equipment is disposed of in an environmentally and economically responsible manner, with efforts to recover residual value through scrap and, where feasible, real estate disposal. This approach also reduces ongoing O&M requirements and the need to stock obsolete parts, allowing resources to be redirected to other aging infrastructure. All project planning and execution are carried out in accordance with applicable standards and evaluated on a case-by-case basis to ensure efficiency and minimal disruption.

B.4.4 Cost-Benefit Analysis:

This project represents the final investment at the end of EPI's conversion program. This project yields benefits in terms of ongoing O&M costs for maintenance as well as improvements to system losses.

The alternative of do nothing would involve incurring ongoing expenses to maintain assets which are at end of life, obsolete and no-longer in service.

B.4.5 Historical Investments & Outcomes Observed:

Section A.3.3 highlights the historic expenditure in this investment segment. As mentioned in the above sections, the timing of historical spending primarily aligns with the utility's voltage conversion plans. Other unknown factors, such as vandalism, have resulted in unexpected spend.

B.5. Non-Wires Solution

Non-wires solutions are not applicable to serve the purposes of this investment category

B.6. Innovation

Not applicable

MATERIAL INVESTMENT NARRATIVE

PROJECT / PROGRAM:

22. Rolling Stock

INVESTMENT CATEGORY:

GENERAL PLANT

A. GENERAL INFORMATION ON THE PROJECT/PROGRAM

A.1. Overview

This program includes EPI's fleet investment requirements, including vehicles and other specialized mobile equipment.

Vehicles and associated equipment are an essential component of EPI operations, necessary for the timely restoration of power during planned and unplanned outages, and the efficient construction and maintenance of the distribution system.

Asset renewal decisions follow the lifecycle management methodology for the appropriate vehicle class discussed in Section 4.3. EPI's service territory spans 17 communities across 5,000 square km. Given the physical span of this service territory, it is imperative that the EPI fleet remains reliable to enable response to outages, completion of service requests and to facilitate capital construction and maintenance activities. The main driver to the project is the replacement of end-of-life vehicles and major repairs or life extension projects.

A major cost driver over the 2026-2030 Forecast Period is the replacement of six bucket trucks, one incremental single bucket truck and replacement of 13 small fleet vehicles. For the bucket trucks, three replacements each in Chatham and St. Thomas are planned. These vehicles have currently reached or will reach the end of their useful lives as per EPI's vehicle purchasing policy. The incremental bucket truck is required to support the newly hired field crews. The 13 light vehicles are replacements for existing vehicles which have reached the end of their useful life. Table 1 summarizes the number of replacement and incremental vehicles in the Forecast Period.

Table 1: Forecast Fleet Additions

Category	Forecast Period					Total
	2026	2027	2028	2029	2030	
Bucket Trucks	1	2	1	2	1	**7**
Dump Trucks	0	1	1	0	0	**2**
Light Duty Vehicles	4	3	4	2	0	**13**
Other	0	0	0	0	1	**1**
Total	**5**	**6**	**6**	**4**	**2**	

A.2. Timing

i. Start Date: January 2026
ii. In-Service Date: Through to December 2030
iii. Key factors that may affect timing: The following factors can impact the project schedule:
   - Supply chain distributions
   - Unpredictable vehicle failure

The timing and priority of rolling stock is based on reducing O&M costs by replacing vehicles that have reached the end of their useful life per EPI's vehicle purchasing policy.

A.3. Capital Expenditures

A.3.3 Historical and Future Capital Expenditures

Table 2: Historical and Future Capital ($, million)

Rolling Stock - Totals									
Historic Actual Expenditure				Bridge Year	Forecasted Budgeted Expenditure				
2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
$0.86	$0.86	$1.33	$1.09	$1.32	$0.96	$1.20	$0.89	$1.24	$0.97

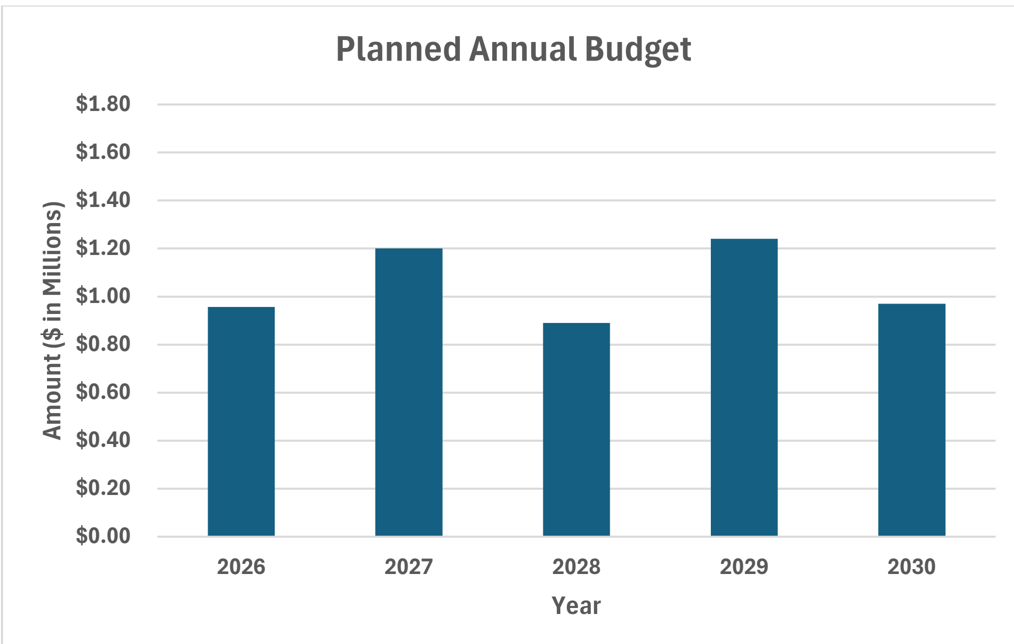


Fig 1: Planned Budget for Rolling Stock

A.3.4 Economic Evaluation (Expansion projects)

Economic Evaluation model is not applicable to third-party attachment requests.

A.3.5 Comparative Historical Expenditure

Historical Period investment has been shown in the figure below:

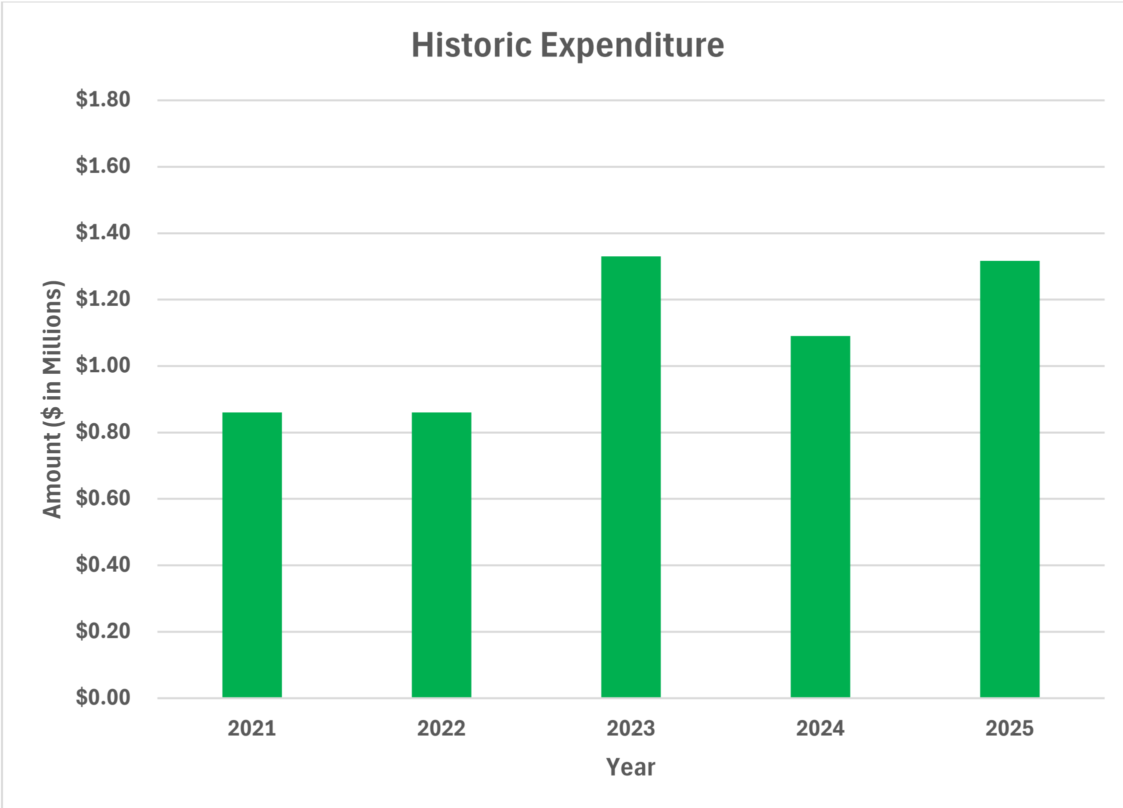


Fig 2: Historic Expenditure – Rolling Stock

The spending in this category is primarily driven by vehicles reaching the end of their useful lives. In 2023, EPI invested in equipment required for conversion work in confined areas allowing less space for typical equipment.

EPI has faced significant cost increases in the cost and lead time for bucket trucks, well beyond inflation, with lead times at the time of writing in the 24-month range. Given these increases, EPI has planned for a consistent pacing of investments over the Forecast Period.

A.4. Investment Priority

As per EPI's latest capital project rankings, investments in the rolling stock segment rank 17th out of the 22 investment categories. It is imperative that EPI's fleet remains in optimal operating condition to respond to outages, complete service requests and facilitate capital construction and maintenance activities.

A.5. Alternative Analysis

This capital program addresses the replacement of heavy and light-duty fleet vehicles that have reached or exceeded their expected service life. Vehicles are assessed under EPI's lifecycle management framework, as outlined in Sections 3.1 and 4.9.1. Where life extension strategies are technically and economically feasible, they are applied. However, when vehicles no longer meet safety, reliability, or operational thresholds, renewal becomes the only viable option.

Maintaining the program at a minimum of its current level is necessary to ensure safe and efficient field operations. Running vehicles beyond their useful life can lead to increased failure rates, downtime, rising maintenance costs, and safety concerns. For example, the planned purchase of a new bucket truck has been structured over two years—acquiring the chassis in one year and completing the vehicle build in the next—to manage capital impacts responsibly.

The following alternatives were considered:

a. Do Nothing / Continue to Use and Repair Vehicles
Continuing to use aging vehicles past their service life would increase the risk of mechanical failure and maintenance downtime. This leads to lost productivity for crews, higher operating costs, and greater disruption to scheduled work such as capital construction and maintenance.
Conclusion: *Not feasible. Increases safety risks, reduces reliability, and undermines cost control and customer service goals.*

b. Replace with Lower-Specified Vehicles
This alternative would involve purchasing vehicles with reduced functionality or capability (e.g., non-insulated or smaller lift capacity units). Such vehicles may not be suitable for critical tasks such as energized line work and would place greater strain on the remaining fleet. This could lead to scheduling conflicts, decreased service capacity, and inefficiencies in project delivery.
Conclusion: *Not viable. Impairs operational effectiveness and productivity across departments.*

c. Purchase Used Vehicles
While used vehicle purchases have been considered and utilized in the past, they were not pursued in this DSP period. Used vehicles carry reliability concerns, limited warranty availability, and reduced opportunity for competitive procurement. EPI's past experience has shown that any upfront savings from purchasing used vehicles are outweighed by increased long-term risk and operating costs.
Conclusion: *Not preferred. Higher lifecycle risk and cost exposure outweigh the short-term capital savings.*

d. Lifecycle-Based Replacement with Phased Procurement (Preferred Option)
EPI's preferred strategy is to replace vehicles based on a structured lifecycle approach, ensuring that operational safety, reliability, and efficiency are maintained. Where appropriate, large purchases are phased across years to reduce capital burden in any single year. This ensures continuity of operations, minimizes downtime, and supports safe and timely completion of field work.
Conclusion: *Best alternative. Ensures fleet readiness, cost-effectiveness, and alignment with capital planning*

A.6. Innovative Nature of the Project

Not Applicable

A.7. Leave to Construct Approval

This project does not require leave to construct approval under Section 92 of the OEB Act.

B. EVALUATION CRITERIA AND INFORMATION REQUIREMENTS

B.2. Efficiency, Customer Value, Reliability & Safety

Table 22: Investment Evaluation - Efficiency, Customer Value, Reliability & Safety

Criteria	Description
Efficiency	Proactively replacing aged vehicles reduces the risk of failures in the field, minimizing project delays and preventing wasted labor hours, thereby increasing operational efficiency. Improves operational efficiency: - By ensuring implementation of asset management practices to meet the needs of customers and stakeholders, balancing safety, reliability, and cost-effectiveness. Ensures cost-effectiveness: - By proactively replacing deteriorated assets to avoid higher costs, degraded service levels and safety hazards associated with equipment malfunction, unplanned failures, and emergency repairs and replacements. - By minimizing the likelihood of catastrophic asset failures and subsequent associated costs through early risk identification and mitigation. - By managing fleet and equipment assets to achieve the lowest overall lifecycle costs. Maintain financial health: - By maximizing ratepayer value through proactive maintenance and replacements in a financially prudent manner.
Customer Value	Access to safe and reliable vehicles allow EPI crews to promptly respond to outages and efficiently complete construction & maintenance activities, ensuring quality and uninterrupted service, directly benefiting customers. Improve customer value: - By minimizing costs for infrastructure upgrades while maximizing ratepayer value through proactive maintenance and asset replacement.
Reliability	Investment in this project ensures the safe and reliable operation of EPI's service vehicle fleet that enables the crew to promptly respond to

	outages and service calls, maintaining high service reliability for customers. Improve system reliability: - By ensuring the utility is equipped to handle operational demands effectively.
Safety	Reliable fleet provides a secure platform to employees for high-voltage work, minimizes breakdown risks, and reduces hazards for workers and the public. Ensures public safety: - By reducing safety risks and hazards to the public associated with managing and operating grid infrastructure. - By reducing public exposure to significant risks posed by aged and deteriorated equipment. Improves worker safety: - By improving safety conditions at the workplace for utility workers. - By reducing the likelihood of dangerous equipment failures by addressing potential issues proactively. Ensures compliance: - By adherence to legislative requirements, safety standards and regulations such as Electrical Distribution Safety O.Reg. 22/04, ESA, CSA, Building codes, Fire codes, OHSA, etc. Mitigates hazards: - By eliminating equipment-related safety hazards. Mitigates environmental impact: - By reducing GHG emissions.

B.3. Investment Need

B.3.3 Primary Driver:

The main investment driver for this project is System Capital Investment Support. Access to an adequate quantity of reliable vehicles is imperative for the crews to effectively perform their daily tasks (Section 5.3)

B.3.4 Secondary Drivers:

There are no secondary drivers for investments in this project.

B.3.5 Information Used to Justify the Investment:

Given the physical span of EPI's service territory, it is imperative that its fleet remains in optimal operating condition to respond to outages, complete service requests and facilitate capital construction and maintenance activities. Vehicle failures on the jobsite are very time-consuming to get alternative vehicles to the jobsite, driving cost and delay. The major expenditures this cycle is the replacement of six bucket trucks, the addition of one new single bucket truck, and the life cycling of 12 existing small vehicles.

Table 2 outlines the planned fleet replacements during the forecast period. For further details on EPI's fleet renewal practices, refer to Section 4.9.1. Please note that EPI operates single bucket trucks in various sizes, which are classified and managed as either heavy or light vehicles accordingly.

Table 2: Planned Fleet Replacement

2026							
Proposed			Existing Vehicle				Asset Replacement Criteria Met
Category	Vehicle	Department Assigned	Vehicle Number	Manufacturing Year	Projected Mileage (in 2026)	Age (in 2026)	
Heavy Vehicle	Single Bucket Truck	Operations	H11BK08	2011	339,606 km	15 yrs	✓
Light Vehicle	Pickup Truck	Locates	H16SUV32	2016	211,816 km	10 yrs	✓
	Pickup Truck	Operations	H16PU116	2016	303,493 km	10 yrs	✓
	Pickup Truck	Field Service	SV16VN12	2016	350,236 km	10 yrs	✓
	Pickup Truck	Metering	M16PU09	2016	199,799 km	10 yrs	✓
2027							
Proposed			Existing Vehicle				Asset Replacement Criteria Met
Category	Vehicle	Department Assigned	Vehicle Number	Year	Projected Mileage (in 2027)	Age (in 2027)	
Heavy Vehicle	Dump Truck	Operations	H13DP66	2013	91,792 km	14 yrs	✓
Light Vehicle	Single Bucket Truck	Operations	H17BK15	2017	242,317 km	10 yrs	✓
	Pickup Truck	Health & Safety	H17PU03	2017	224,053 km	10 yrs	✓
	Pickup Truck	Operations	H17PU150	2017	221,485 km	10 yrs	✓
	Pickup Truck	Field Service	SV17VN35	2017	263,873 km	10 yrs	✓
2028							
Proposed			Existing Vehicle				Asset Replacement Criteria Met
Category	Vehicle	Department Assigned	Vehicle Number	Year	Projected Mileage (in 2028)	Age (in 2028)	
Heavy Vehicle	Single Bucket Truck	Operations	H13BK9102	2013	195,629 km	15 yrs	✓
	Dump Truck	Operations	M12DP5	2012	71,188 km	16 yrs	✓
Light Vehicle	Pickup Truck	Locates	H17VN4011	2017	198,283 km	11 yrs	✓
	Pickup Truck	Stations	H17PU128	2017	142,285 km	11 yrs	✓
	Pickup Truck	Metering	H17PU9208	2017	143,452 km	11 yrs	✓
	Pickup Truck	Operations	H17PU175	2017	135,110 km	11 yrs	✓

2029							
Proposed			Existing Vehicle				Asset Replacement Criteria Met
Category	Vehicle	Department Assigned	Vehicle Number	Year	Projected Mileage (in 2029)	Age (in 2029)	
Heavy Vehicle	Single Bucket Truck	Operations	M14BK05	2014	276,644 km	15 yrs	✓
	Double Bucket Truck	Operations	H13BK14	2013	51,487 km	16 yrs	✓
Light Vehicle	Pickup Truck	Operations	H19PU195	2019	322,578 km	10 yrs	✓
	Pickup Truck	Operations	H17PU175	2017	147,393 km	12 yrs	✓
2030							
Proposed			Existing Vehicle				Asset Replacement Criteria Met
Category	Vehicle	Department Assigned	Vehicle Number	Year	Projected Mileage (in 2030)	Age (in 2030)	
Heavy Vehicle	Double Bucket Truck	Operations	M15BK22	2015	114,261 km	15 yrs	✓
Other	Tension Machine	Operations	H88UT9553	1988	N/A	42 yrs	✓

B.4. Investment Justification

B.4.3 Demonstrating Accepted Utility Practice:

Asset renewal decisions follow the lifecycle management methodology for the appropriate vehicle class discussed in Section 4.9.1. Asset replacement criteria within the purchasing policy are aligned with Ontario LDC norms.

B.4.4 Cost-Benefit Analysis:

Access to safe and reliable vehicles are necessary to enable the timely, efficient completion of construction and maintenance activities on the distribution system. Failure to access safe and reliable vehicles hampers EPI’s ability to safely perform work on high voltage lines and respond to customer outages/emergency situations promptly. The option to do nothing will result in a decrease in availability of the fleet, as well as material cost increases as significant repairs and refurbishments become required to keep assets in service.

B.4.5 Historical Investments & Outcomes Observed:

Section A.3.3 highlights the historical expenditures in this investment segment. The general outcome of investments in this category is maintaining access to safe and reliable vehicles for EPI crew to perform their field tasks effectively.

B.5. Non-Wires Solution

Non-wires solutions are not applicable to serve the purposes of this investment.

B.6. Innovation

Not Applicable

MATERIAL INVESTMENT NARRATIVE

PROJECT / PROGRAM:

23. Tools

INVESTMENT CATEGORY:

GENERAL PLANT

A. GENERAL INFORMATION ON THE PROJECT/PROGRAM

A.1. Overview

This program captures cyclical purchases of various tools used by EPI's crews during their daily activities.

Examples of tools utilized by EPI personnel include testing equipment, presses, cutters, rubber goods, fault evaluation and infrastructure locating equipment, troubleshooting equipment, radio communication equipment, and cable pulling implements.

Replacement of major tools that come to end of life or have become obsolete due to changing work practices, safety standards, or improved technology is necessary for the execution of work programs in a cost efficient and safe manner (Section 5.1.2.4.1).

The goal of this program is to ensure that EPI's crews have the tools and equipment needed to perform their work safely and effectively.

A.2. Timing

iv. Start Date: January 2026
v. In-Service Date: Through to December 2030
vi. Key factors that may affect timing:
- Unexpected premature tool failure
- Changing work practices

The timing and priority of the project is based on replacing tools and equipment as they reach the end of their useful life or become noticeably damaged. Replacing tools before failure avoids wasted labour hours waiting on site for replacements which increases overall efficiency. Additionally, it ensures employee safety by mitigating the risks of tool failure or outdated work practices. During the 2026-2030 period, the tool replacement costs is expected to match inflation.

A.3. Capital Expenditures

A.3.3 Historical and Future Capital Expenditures

Table 1. Historical and Future Capital ($, million)

Tools - Totals									
Historic Actual Expenditure				Bridge Year	Forecasted Budgeted Expenditure				
2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
$0.12	$0.11	$0.10	$0.09	$0.09	$0.12	$0.20	$0.10	$0.11	$0.11

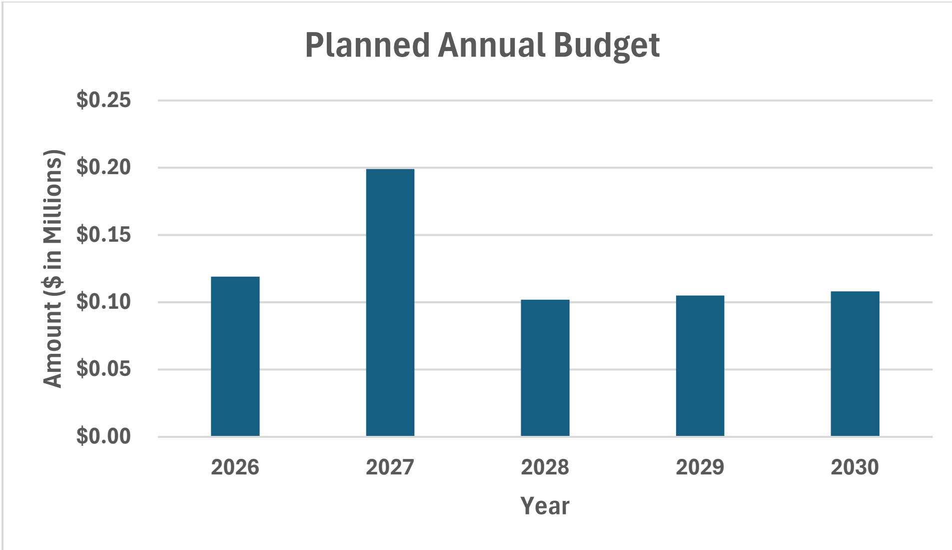


Fig 1: Planned Budget for Tools

A.3.4 Economic Evaluation (Expansion projects)

Not Applicable

A.3.5 Comparative Historical Expenditure

The spending in this category is primarily driven by the need to replace worn down or damaged equipment. This is to increase efficiency as broken tools can delay entire jobs while waiting for the proper replacement as well as safety.

Spending is expected to be maintained within inflation for the forecast period with specific years seeing increases funding to cover incremental costs of outfitting new bucket trucks.

The historic spending from 2021-2024 and planned spending in 2025 has been shown in the figure below:

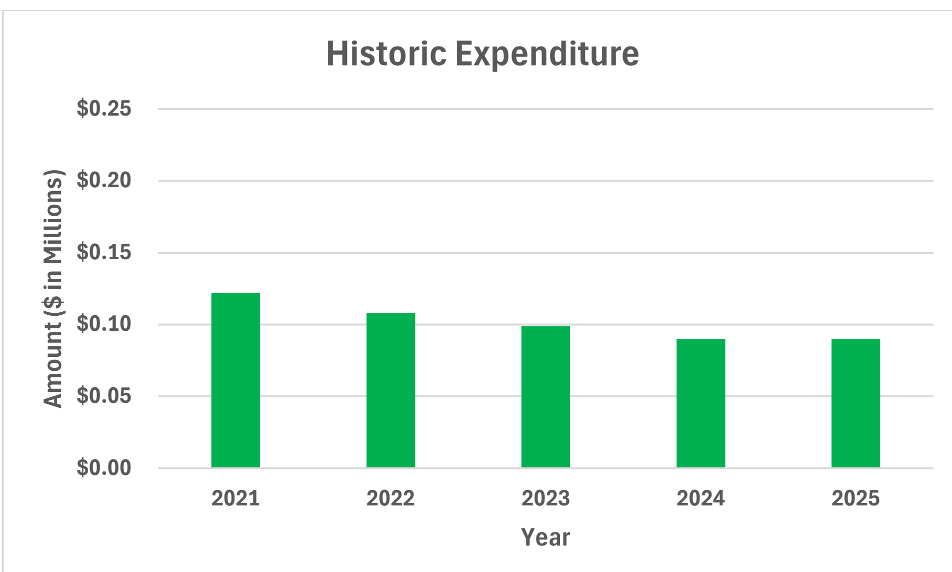


Fig 2: Historic Expenditure –Tools

A.4. Investment Priority

This investment category is ranked 18th out of the 22 categories. proper management and investment in tools are critical to executing work programs efficiently and safely (Section 5.3).

A.5. Alternative Analysis

Investments in this program are evaluated on a case-by-case basis, considering operational needs, asset condition, compliance requirements, and technological advancements.

Maintaining the program at a minimum of its current level is necessary to reduce safety risks associated with damaged, obsolete, or insufficient tools, and to ensure crews are properly equipped to perform their duties efficiently and safely.

The following alternatives are considered:

a. <u>Retire / Decommission Tools</u>
Where it is determined that the number of tools exceeds operational requirements, or where a tool is no longer used due to changes in work practices, the asset is decommissioned and removed from service.
Conclusion: *Applied where surplus is identified. Reduces inventory and eliminates maintenance on unnecessary assets.*

b. <u>Replace with Newer Technology</u>
When a tool is no longer supported by the vendor, or where significant improvements in safety, compliance, or work efficiency can be achieved, EPI opts to replace the existing tool with a modern equivalent. These decisions are guided by regulatory changes, emerging best practices, or material advances in design and performance.
Conclusion: *Preferred when functional or regulatory gains are significant. Supports modernization and safe work practices.*

c. <u>Like-for-Like Replacement (Default Option)</u>
Where existing tools are meeting all performance, safety, and operational requirements, and replacement is required solely due to wear, damage, or quantity shortages, a like-for-like replacement is provided. This approach balances cost optimization with operational continuity.
Conclusion: *Most common and cost-effective option. Maintains tool standardization and supports uninterrupted field work.*

A.6. Innovative Nature of the Project

Not Applicable

A.7. Leave to Construct Approval

This project does not require leave to construct approval under Section 92 of the OEB Act.

B. EVALUATION CRITERIA AND INFORMATION REQUIREMENTS

B.2. Efficiency, Customer Value, Reliability & Safety

Table 23: Investment Evaluation - Efficiency, Customer Value, Reliability & Safety

Criteria	Description
Efficiency	Proactive replacement of aged tools maintains safety and productivity. Improves operational efficiency: - By equipping vehicles and crews with standardized kits, packages and accessories designed to minimize the capital costs while enhancing safety and productivity. - By minimizing costs for installing electrical services through streamlined processes and standards. - By reducing Workplace Safety Insurance Board premiums as a result of maintaining a strong safety record.
Customer Value	Access to safe and reliable tools is necessary to enable the timely, efficient completion of construction and maintenance activities on the distribution system. The net benefit to customers is EPI being able to quickly respond to outages and complete construction in a safe manner. Enhance customer experience: - By ensuring timely, quality work by providing workers with high-quality, reliable tools Improve customer value: - By ensuring a safer, more reliable, and cost-effective distribution system to meet customer needs and maintain customer trust. - By facilitating the timely completion of work through the provision of high-quality, reliable tools
Reliability	This project is the continued safe and reliable operation of EPI’s fleet of tools which allows EPI to respond to outages as soon as possible. Improve system reliability: - By ensuring the utility is equipped to handle operational demands effectively.

	- By reducing the average duration of outages through supplying workers with high-quality, reliable tools - By facilitating high quality installations, maintenance, and repairs through the provision of high-quality, reliable tools
Safety	Reliable tools and tools up to todays standards are critical for EPI's ability to safely perform work on high voltage lines. Ensures public safety: - By reducing safety risks and hazards to the public associated with managing and operating grid infrastructure. Improves worker safety: - By improving safety conditions at the workplace for utility workers. Ensures compliance: - By adherence to legislative requirements, safety standards and regulations such as Electrical Distribution Safety O.Reg. 22/04, ESA, CSA, Building codes, Fire codes, OHSA, etc. Mitigates hazards: - By mitigating equipment-related safety hazards.

B.3. Investment Need

B.3.3 Primary Driver:

The main driver for investment for this project is System Capital Investment Support by repairing worn out or damaged equipment is needed to allow proper work to be done in a timely manner.

B.3.4 Secondary Drivers:

A secondary driver is Failure & Failure Risk. Renewing worn out tools or upgrading them to ones that follow new safety standards help safeguard workers and the public.

B.3.5 Information Used to Justify the Investment:

Crew supervisors identify the replacement needs and discuss them with procurement personnel who undertake the purchases. Investment pacing and prioritization are contemplated case-by-case, depending on the current condition of equipment, expected utilization, and materiality of requisite investments. Replacement of major tools that come to end of life or have become obsolete due to changing work practices, safety standards, or improved technology is necessary for the execution of work programs in a cost efficient and safe manner.x

B.4. Investment Justification

B.4.3 Demonstrating Accepted Utility Practice:

Given the variety of tools and implements that fall into this category and their low materiality, EPI does not consider it practical to maintain a formal asset lifecycle management framework for this group of assets. Accordingly, assets are replaced and replenished as needed – as they reach the ends of their useful lives or require replenishment when considering the anticipated work program.

B.4.4 Cost-Benefit Analysis:

Please see Section B.2.3 above.

B.4.5 Historical Investments & Outcomes Observed:

Section A.3.3 highlights the historical expenditures in this investment program. The general outcome of these investments is maintained crew efficiency and safety by attempting to avoid aged tool failure in the field.

B.5. Non-Wires Solution

Not Applicable

B.6. Innovation

Not Applicable

ATTACHMENT K-1

Request Letters for Information Regarding Capital Investment Plans - Municipality

Entegrus Inc.
320 Queen St. (P.O. Box 70)
Chatham, ON N7M 5K2
Phone: (519) 352-6300
Toll Free: 1-866-804-7325
entegrus.com

November 14, 2024

Re: Capital Plans and Entegrus' Cost-of-Service Rate Application

Entegrus is preparing to file a Cost-of-Service application for electricity distribution rates for the upcoming 2026 – 2030 period. This application includes a Distribution System Plan, which outlines the anticipated capital investments needed to accommodate improvements and growth in the electrical distribution system.

To help us accurately forecast capital expenditures for 2026-2030, we kindly request any information you can share about your upcoming capital investment plans that may impact Entegrus. Examples include planned road expansions requiring the relocation of Entegrus assets, anticipated new or expanding residential or commercial developments, or municipal incentives that may accelerate electrification initiatives.

This coordinated planning effort will ensure that Entegrus can properly accommodate municipal and customer needs.

We appreciate your feedback while we work to ensure a distribution system that meets the needs of our customers. To provide your comments or arrange a meeting, please email planning@entegrus.com.

To give us enough time to incorporate your input into our Distribution System Plan, we kindly ask that you provide any feedback by Friday, November 29, 2024.

We look forward to hearing from you.

Sincerely,

Matthew Meloche, P.Eng

Director of Asset Management & Grid Modernization

Entegrus Powerlines Inc.

ATTACHMENT K-2

Request Letters for Information Regarding Capital Investment Plans - Telecommunications

Entegrus Inc.
320 Queen St. (P.O. Box 70)
Chatham, ON N7M 5K2
Phone: (519) 352-6300
Toll Free: 1-866-804-7325
entegrus.com

November 14, 2024

Re: Capital Plans and Entegrus' Cost-of-Service Rate Application

Entegrus is preparing to file a Cost-of-Service application for electricity distribution rates for the upcoming 2026 – 2030 period. This application includes a Distribution System Plan, which outlines the anticipated capital investments needed to accommodate improvements and growth in the electrical distribution system.

To help us accurately forecast capital expenditures for 2026-2030, we kindly request any information you can share about your upcoming capital investment plans that may impact Entegrus. Examples might include expansion projects in specific towns or neighborhoods, participation in provincial or federal programs that could affect the volume or frequency of service requests, or changes in design standards.

This coordinated planning effort will ensure that Entegrus can accommodate your business and investment needs effectively.

We appreciate your feedback while we work to ensure a distribution system that meets your needs. To provide your comments or arrange a meeting, please email planning@entegrus.com.

To give us enough time to incorporate your input into our Distribution System Plan, we kindly ask that you provide any feedback by Friday, November 29, 2024.

We look forward to hearing from you.

Sincerely,

Matthew Meloche, P.Eng

Director of Asset Management & Grid Modernization

Entegrus Powerlines Inc.

ATTACHMENT L

Public Awareness of Electrical Safety Survey, Prepared by Innovative Research Group (2024)

INNOVATIVE RESEARCH GROUP

Survey Results

Public Awareness of Electrical Safety Scorecard

ENTEGRUS®

Updated Report: April 19, 2024

STRICTLY CONFIDENTIAL

Methodology

Innovative Research Group (INNOVATIVE) was commissioned by **Entegrus** to conduct its 2024 *Public Awareness of Electrical Safety Scorecard* survey as required by the Ontario Energy Board (OEB).

- This survey was conducted online among a demographically representative sample of **603** residents, 18 years or older, currently residing in **Entegrus'** service territory, between March 6th and March 18th, 2024.

- Respondents did not need to be Entegrus customers to qualify for this survey. The OEB's standardized methodology defines qualified respondents as adults who principally reside in the LDC's service territory, regardless of whether they are customers or not.

- The sample has been weighted to n=603 by age, gender, region, and education using the latest Statistics Canada Census data to reflect the actual demographic composition of the adult population residing in Entegrus' service territory.

- This is a representative sample. However, since the online survey was not a random probability-based sample, a margin of error cannot be calculated. Statements about margins of sampling error or population estimates do not apply to most online panels.

- The results from this year's PAESS survey have been compared to previous waves.
  Previous waves (2018-2022) of the PAESS survey were conducted by telephone using random-digit dial (RDD) sampling. The 2024 PAESS survey was moved to an online methodology. Year-over-year data trends should be interpreted with caution due to the change in the survey mode as well as the change from probability (telephone) sampling to non-probability (online) sampling.

  - Wave 1: March 2018 (n=402) MoE ±6.5%, 19 times out of 20.

  - Wave 2: March 2020 (n=600) MoE ±4.0%, 19 times out of 20.

  - Wave 3: March 2022 (n=600) MoE ±4.0%, 19 times out of 20.

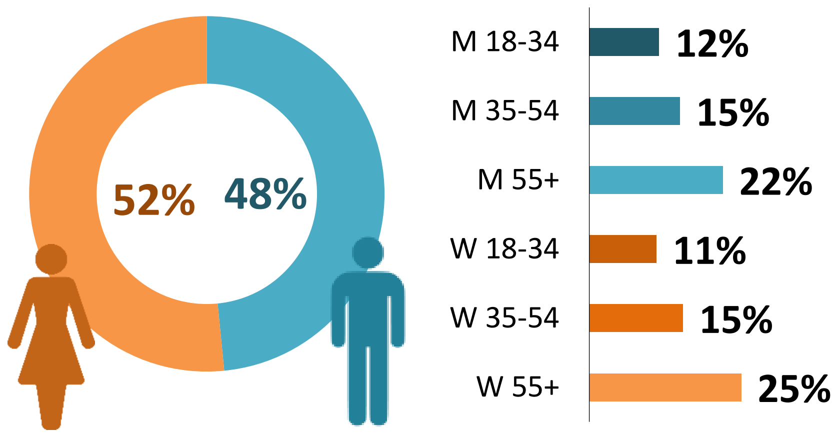
The margin of error for the four waves of telephone surveys will be larger within each sub-grouping of the sample.

Note: *Graphs may not always total 100% due to rounding values rather than any error in data. Sums are added before rounding numbers.*

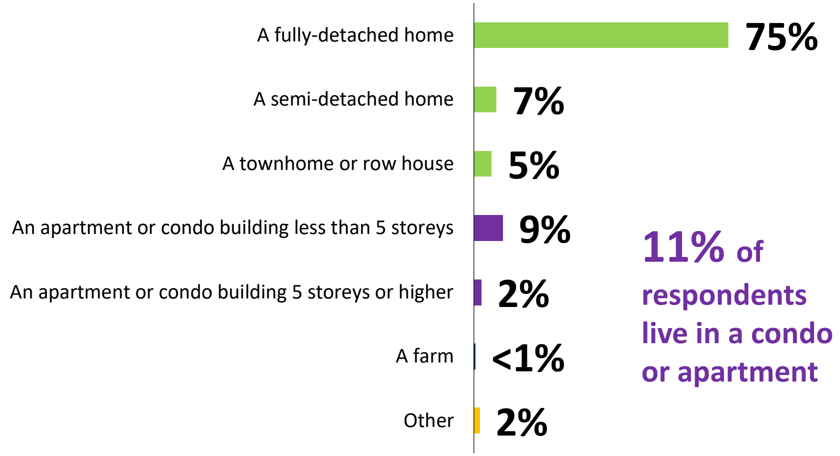
INNOVATIVE RESEARCH GROUP

Demographics: Respondent Profile

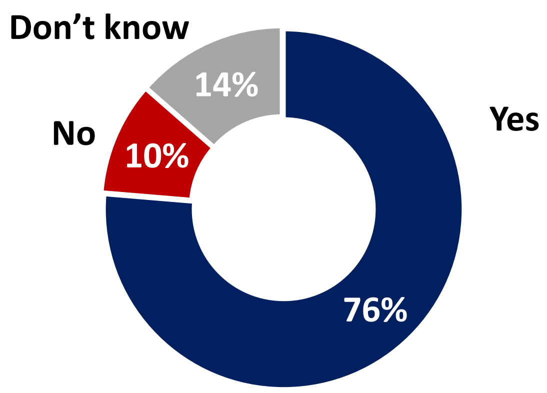
Age-Gender



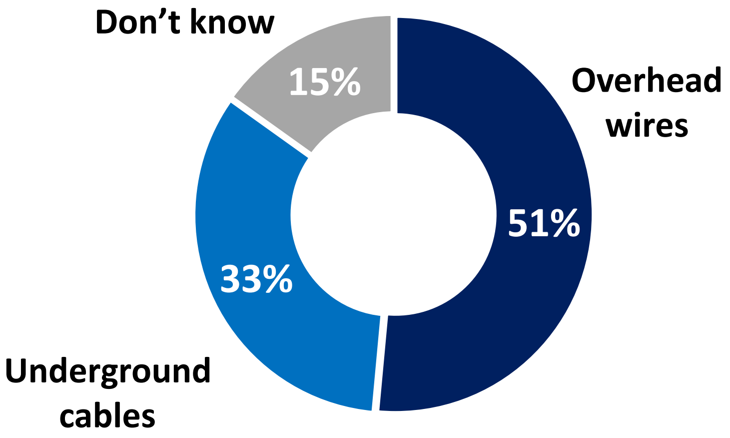
Primary Residence



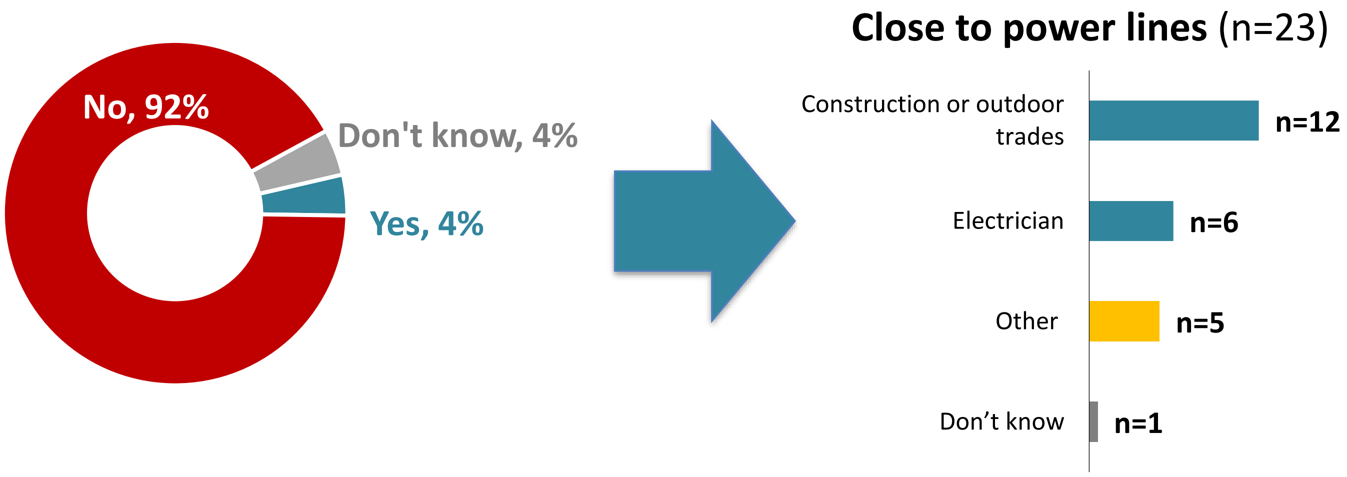
Can you confirm that your household receives an electricity bill from Entegrus?



Does your primary residence receive electricity through …



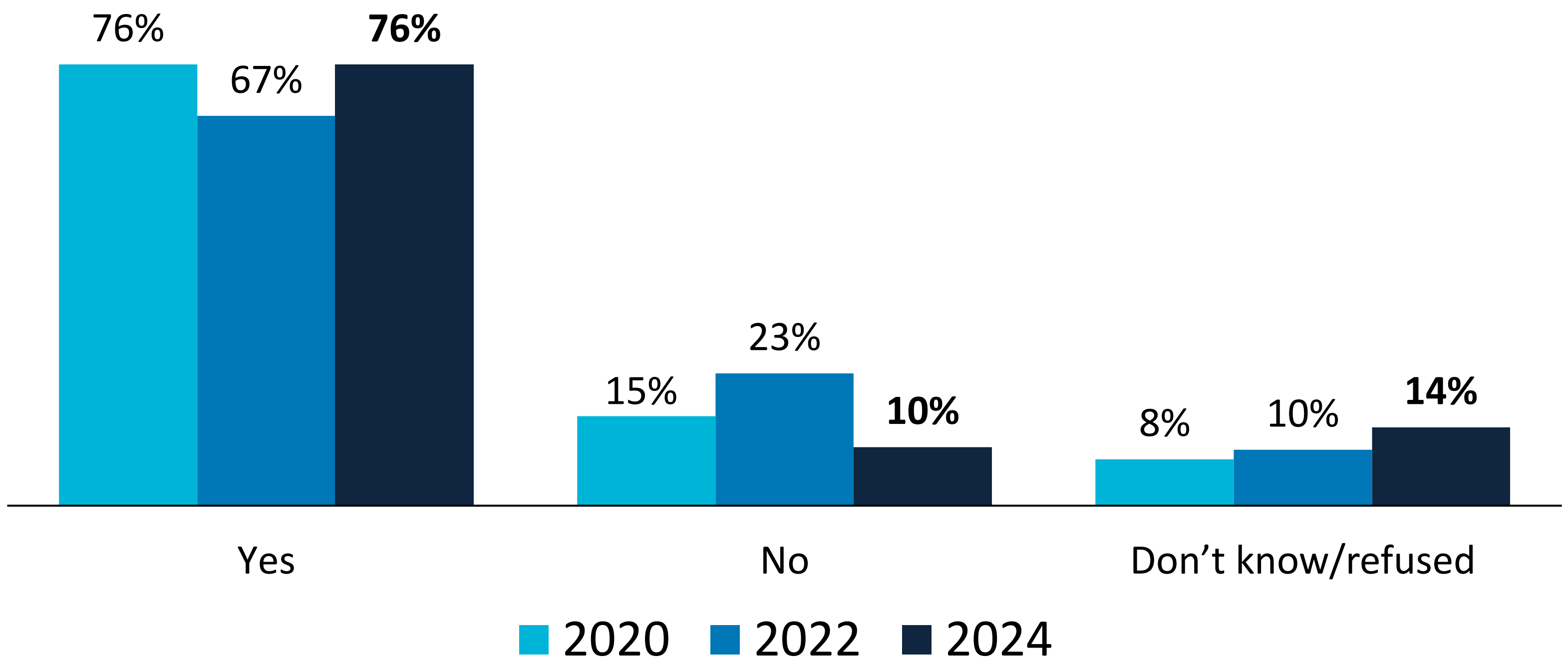
Does your job regularly cause you to come close to energized power lines?



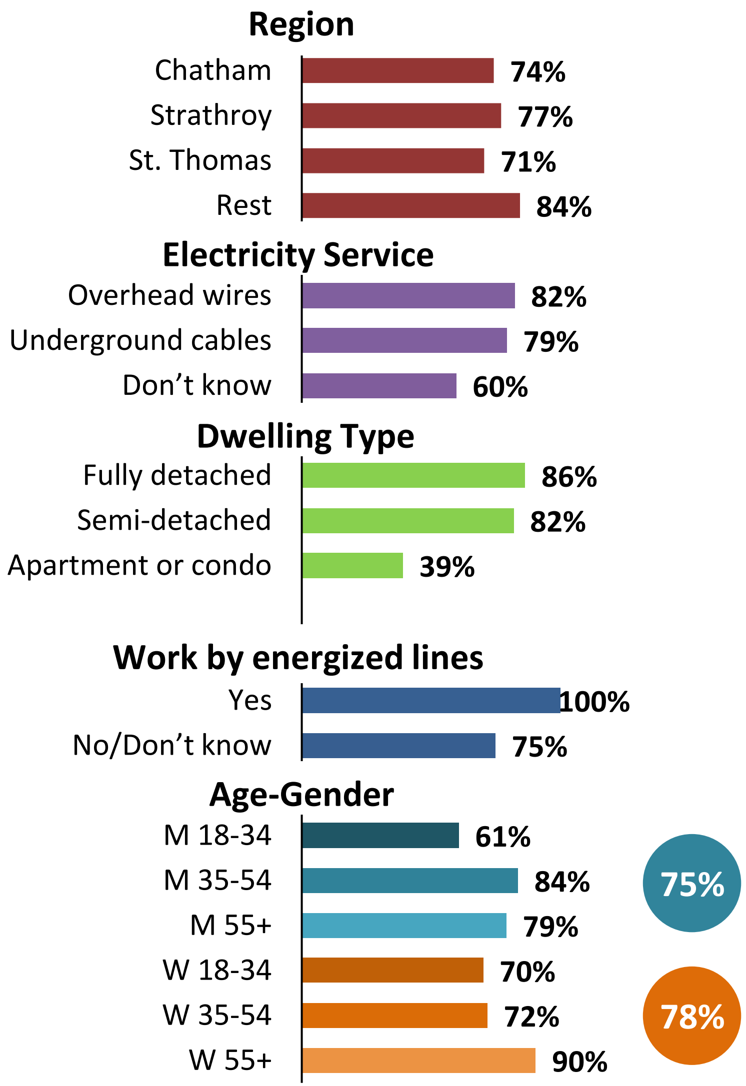
Entegrus Bill

76% of respondents are Entegrus customers

Q Can you confirm that your household receives an electricity bill from Entegrus?
[asked of all respondents, n=603]

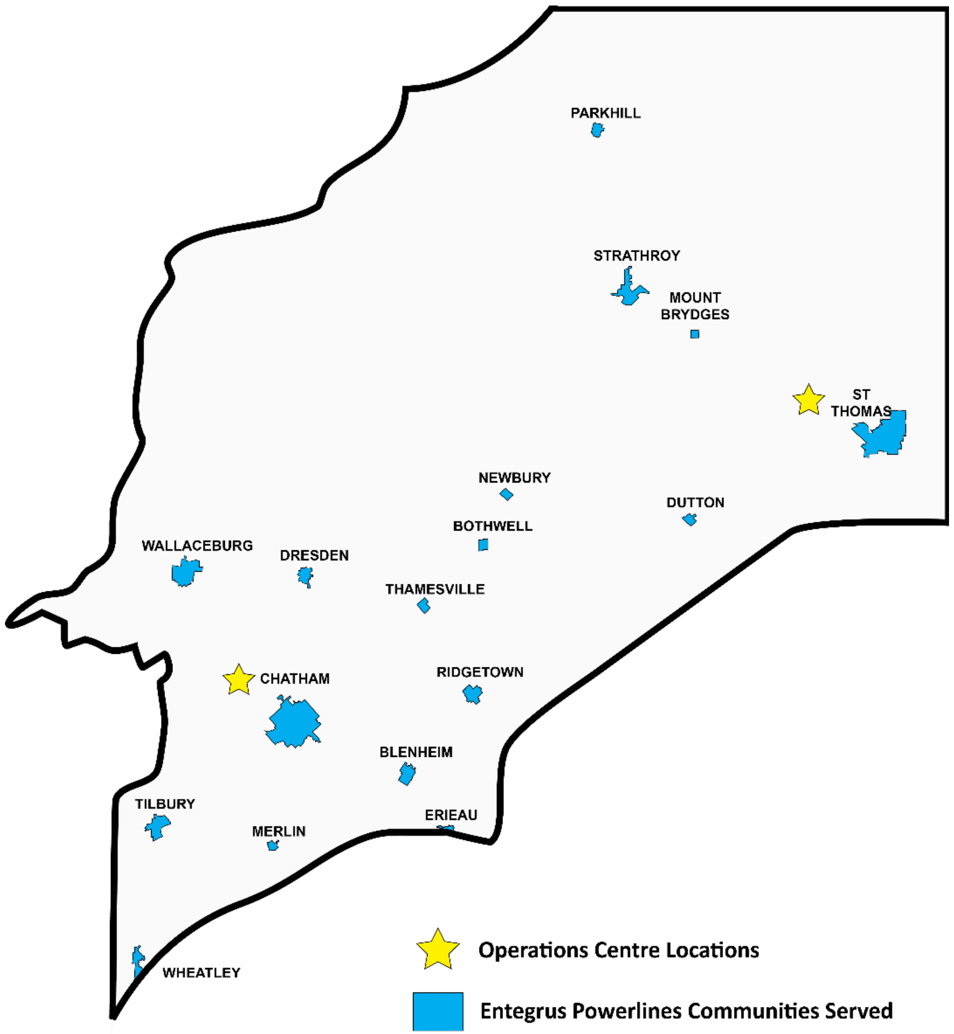


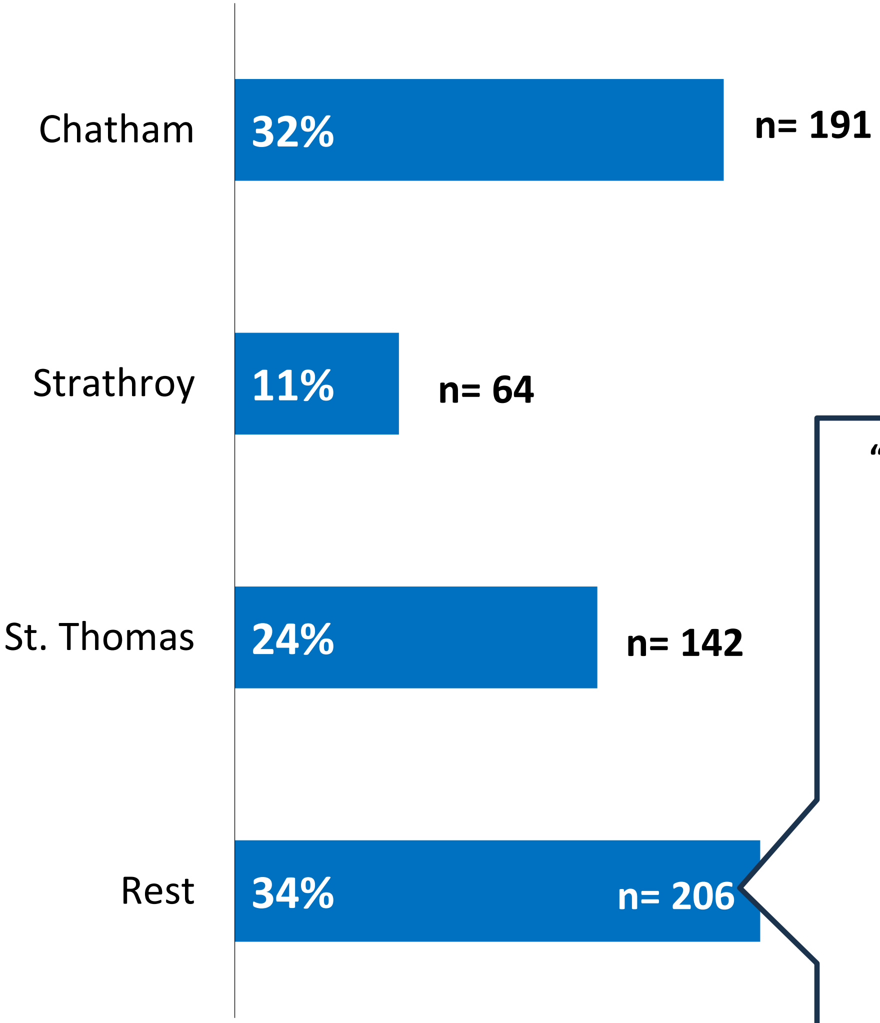
2024 Segmentation
% respondent who are Entegrus customers



Demographics: Regional Profile

Sample (n=603) has been weighted based on age, gender, and region.
Below is the weighted distribution across the Entegrus' service territory:





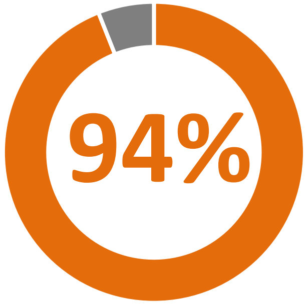
"Rest" includes:
Mount Brydges
Parkhill
Blenheim
Wallaceburg
Dutton
Dresden
Bothwell
Merlin
Tilbury
Newbury
Wheatley
Ridgetown
Thamesville
Erieau

Awareness of Electrical Safety

INNOVATIVE
RESEARCH GROUP

2024 Safety Awareness Dashboard

25%
Believe you should maintain ***3 meters to less than 6 meters*** from an overhead powerline



Say it's
Very dangerous
to touch an overhead power line

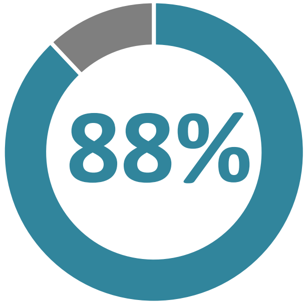
54% Would ***definitely*** call before digging

Overall Public Safety Awareness Index Score

79%

85%
Believe it's ***safer to stay in the vehicle*** in case of a downed power line

Say it's
Very dangerous
to tamper with electrical equipment



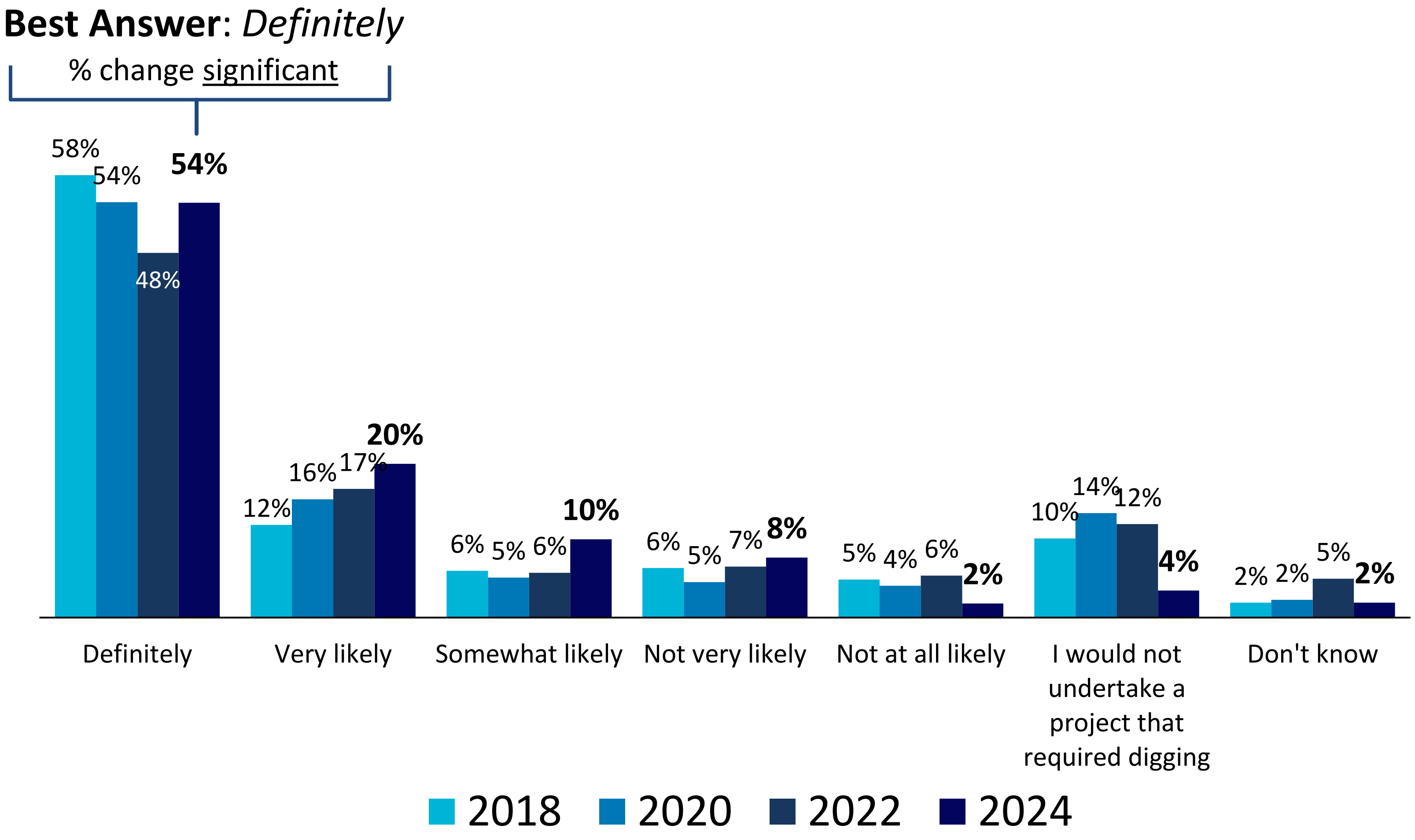
68%
Believe you should maintain ***10 metres or more*** from downed power line

Note: values indicate percentage of respondents who selected the *best answer* to scored questions in the *Public Awareness of Electrical Safety Scorecard* survey.

Likelihood to Call Before You Dig

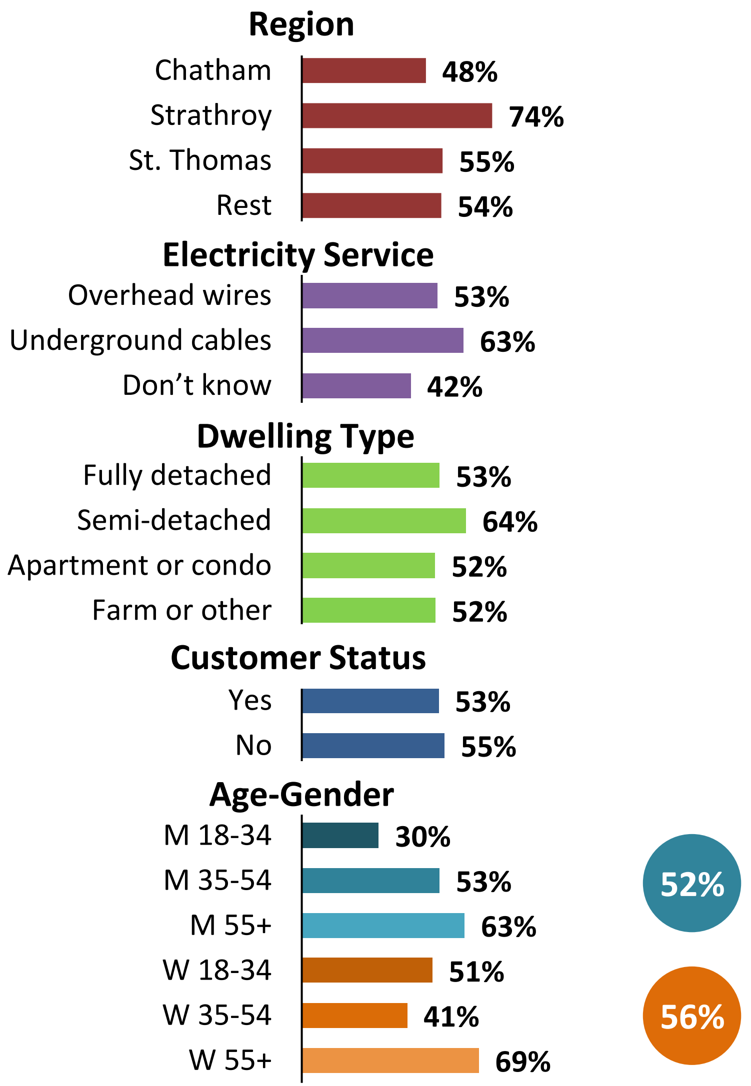
Over half (54%) say they would definitely call before they dig, up 7 points since 2022

Q If you were to undertake a household project that required digging – such as planting a tree or building a deck – how likely are you to call to locate electrical or other underground lines?
[asked of all respondents, n=603]



2024 Segmentation

Respondents who say "Definitely":



Impact of Touching a Power Line

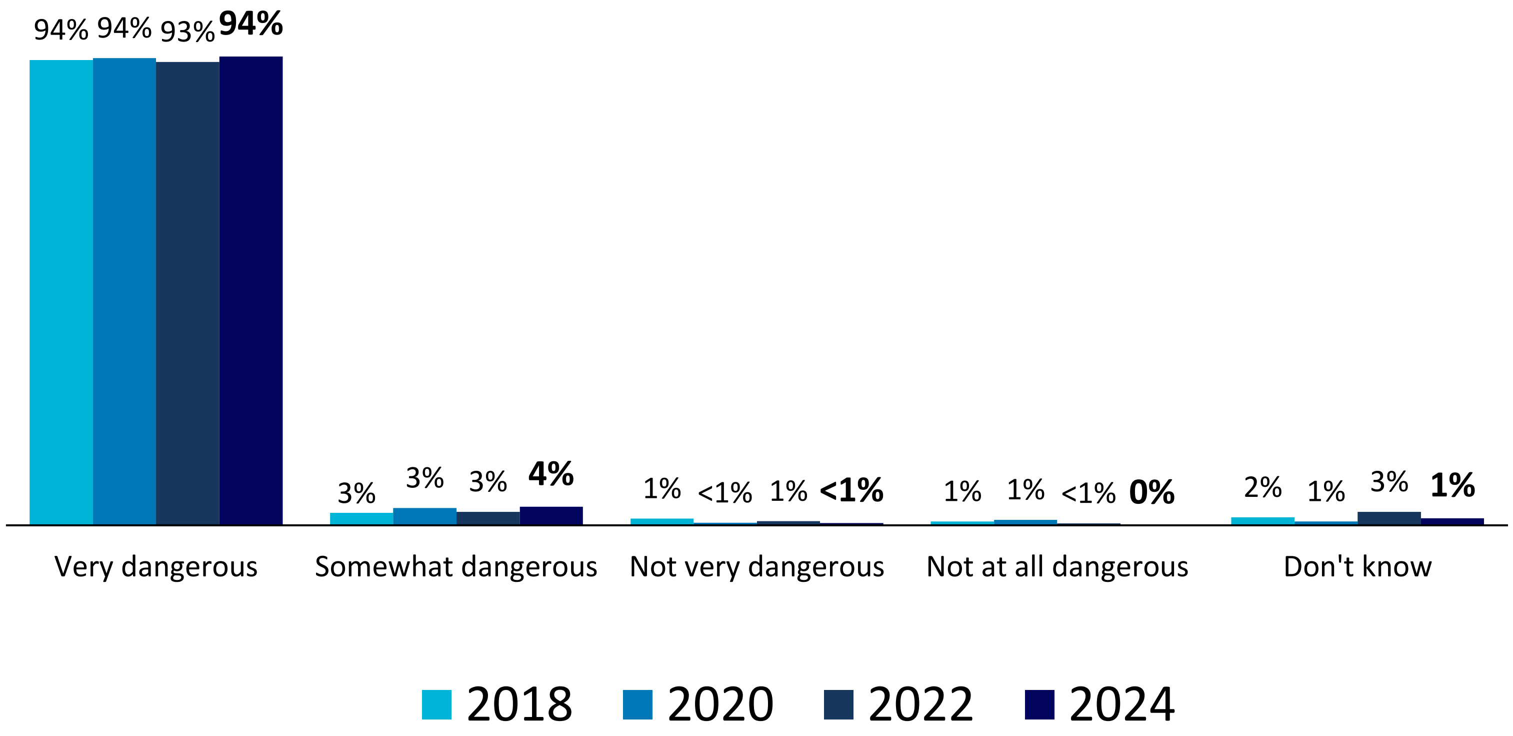
Overwhelming majority (94%) say 'very dangerous', stable since 2022

Q How dangerous do you believe it is to touch - with your body or any object - an overhead power line?

[asked of all respondents, n=603]

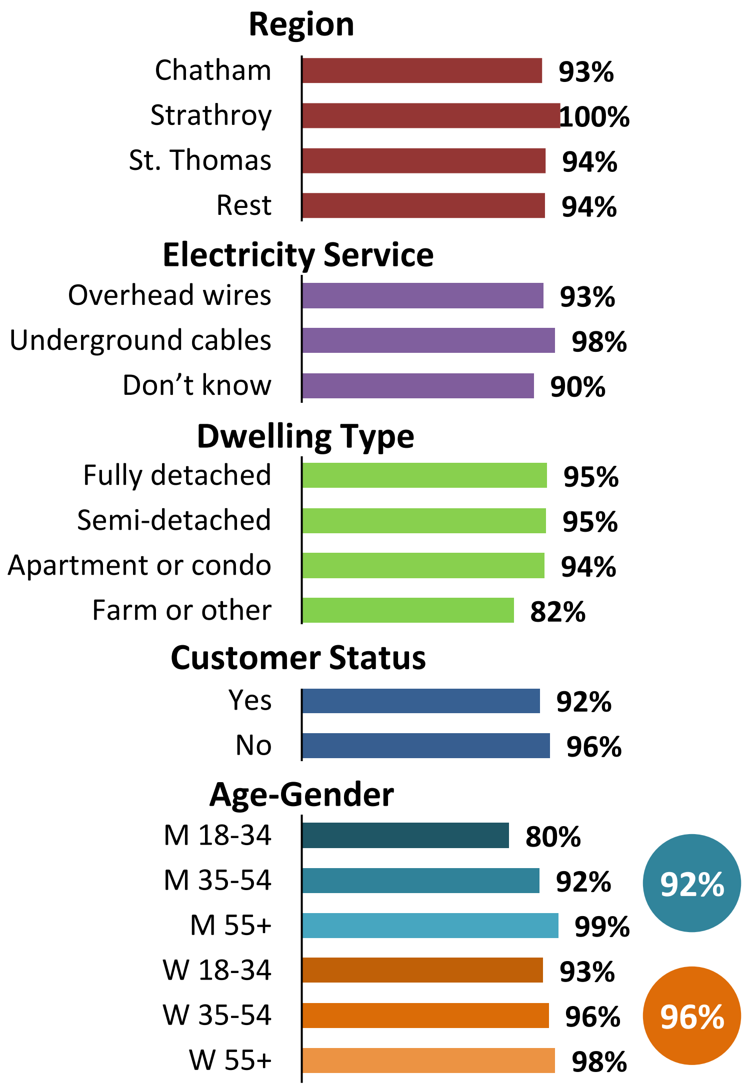
Best Answer: *Very Dangerous*

% change not significant



2024 Segmentation

Respondents who say "Very Dangerous":



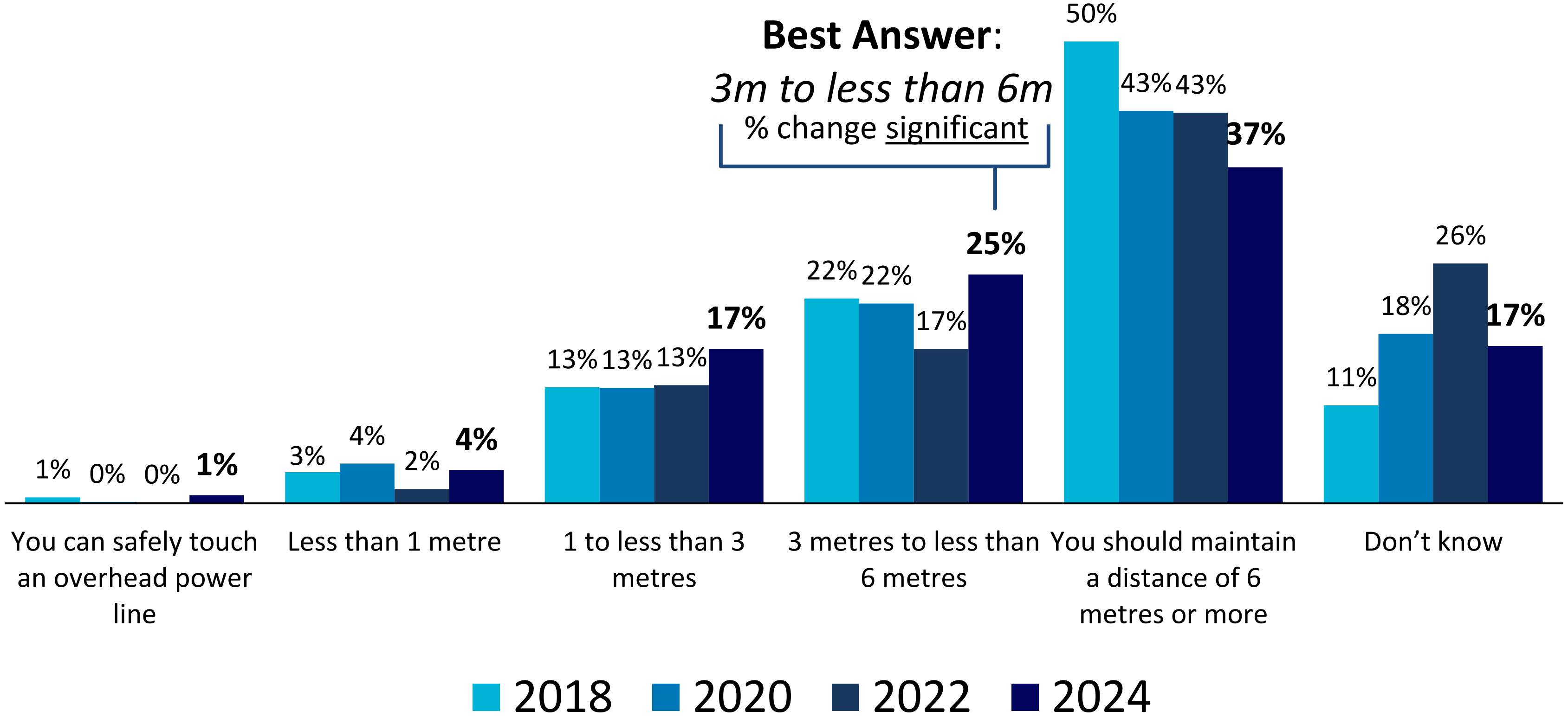
Proximity to Overhead Powerline

A quarter (25%) say ‘3m to less than 6m’, an 8-point increase since 2022

Q

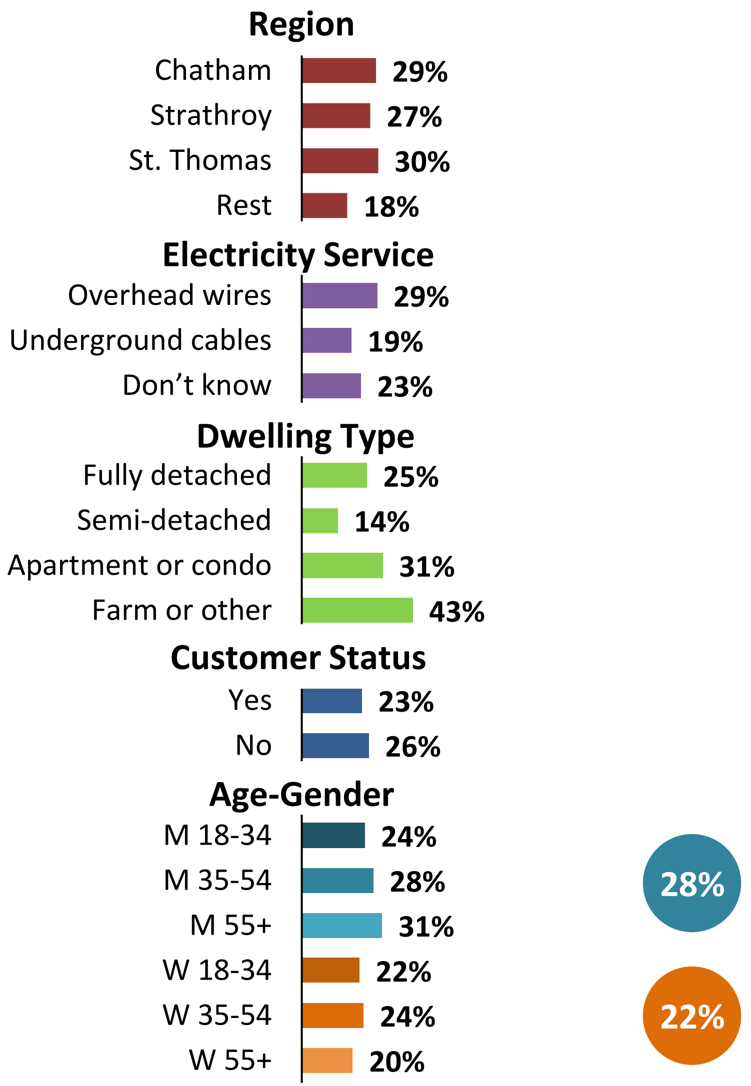
When undertaking outdoor activities – such as, standing on a ladder, cleaning windows or eaves, climbing or trimming trees – how closely do you believe you can safely come to an overhead power line with your body or an object?

[asked of all respondents, n=603]



2024 Segmentation

Respondents who say “3m to <6m”:



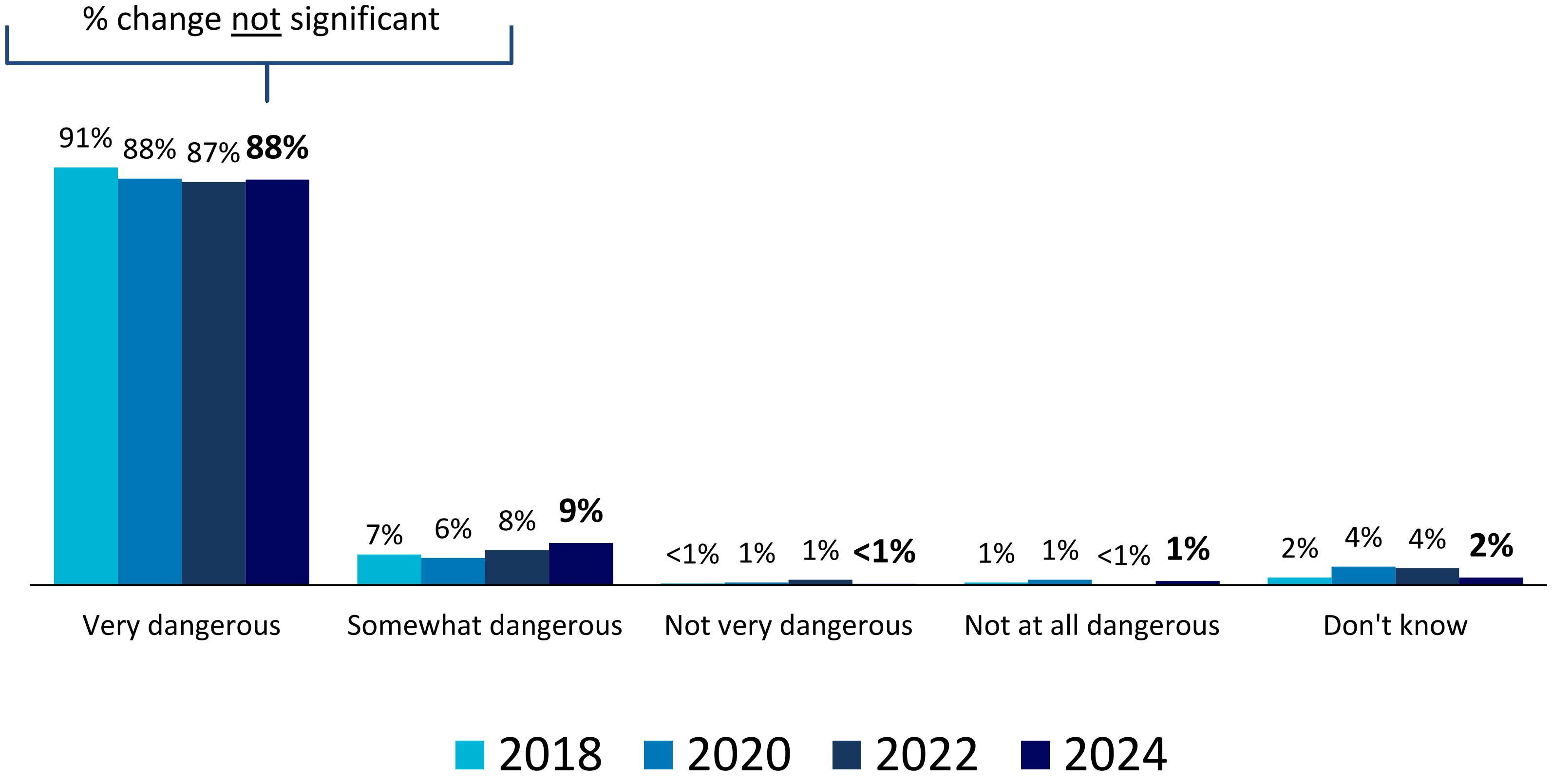
Danger of Tampering with Equipment

9-in-10 (88%) say 'very dangerous', highest among women age 55+ (96%)

Q

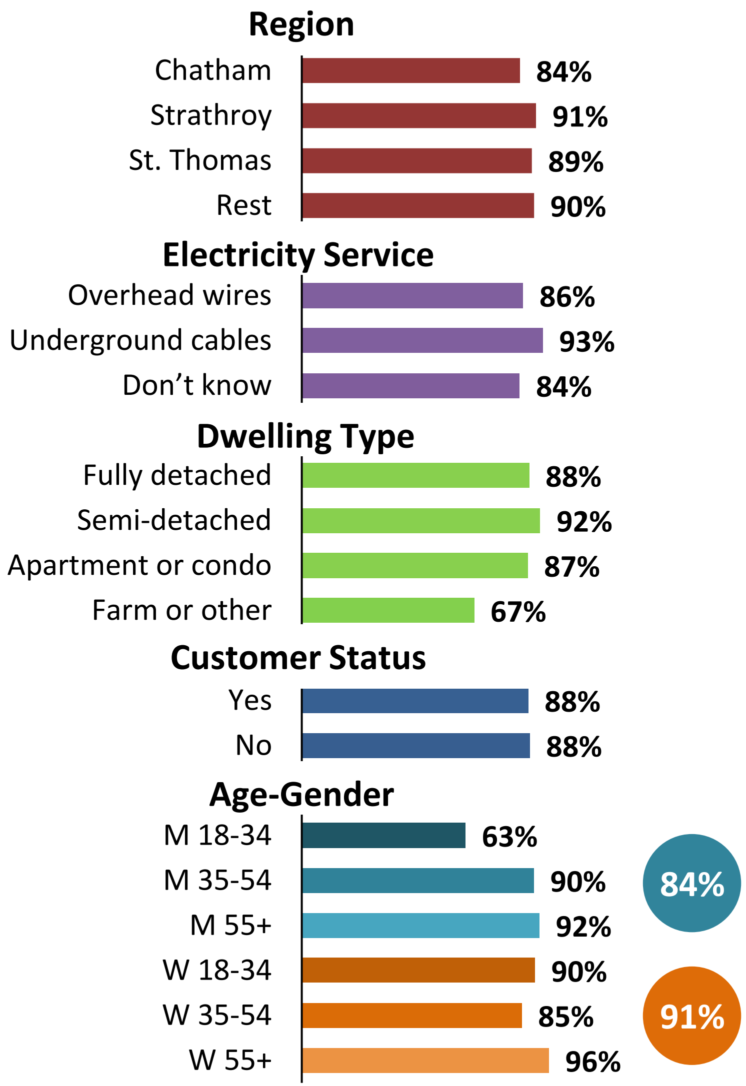
Some electrical utility equipment is located on the ground, such as locked steel cabinets that contain transformers. How dangerous do you believe it is to try to open, remove contents, or touch the equipment inside?
[asked of all respondents, n=603]

Best Answer: *Very Dangerous*



2024 Segmentation

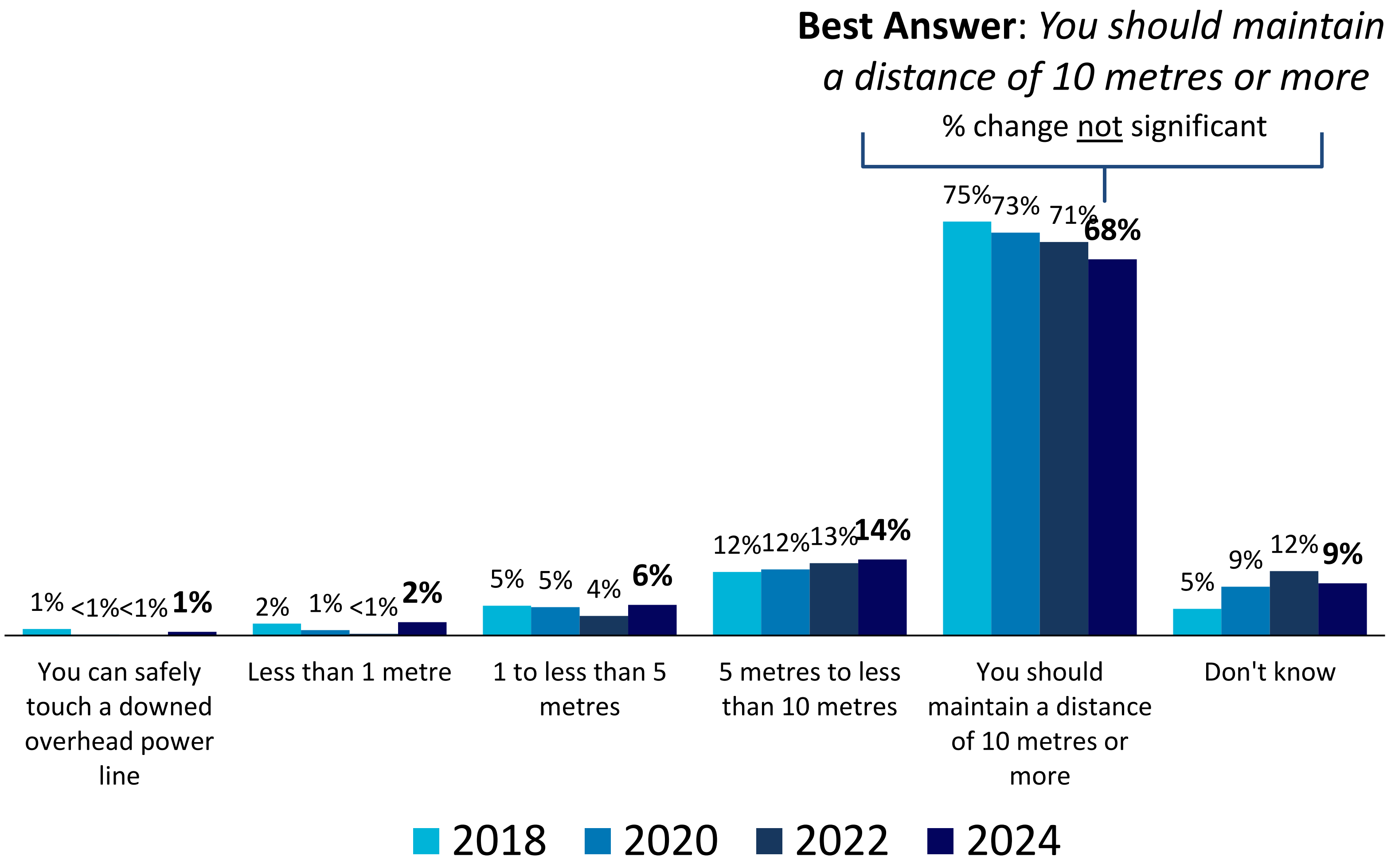
Respondents who say "Very Dangerous":



Proximity to Downed Power Line

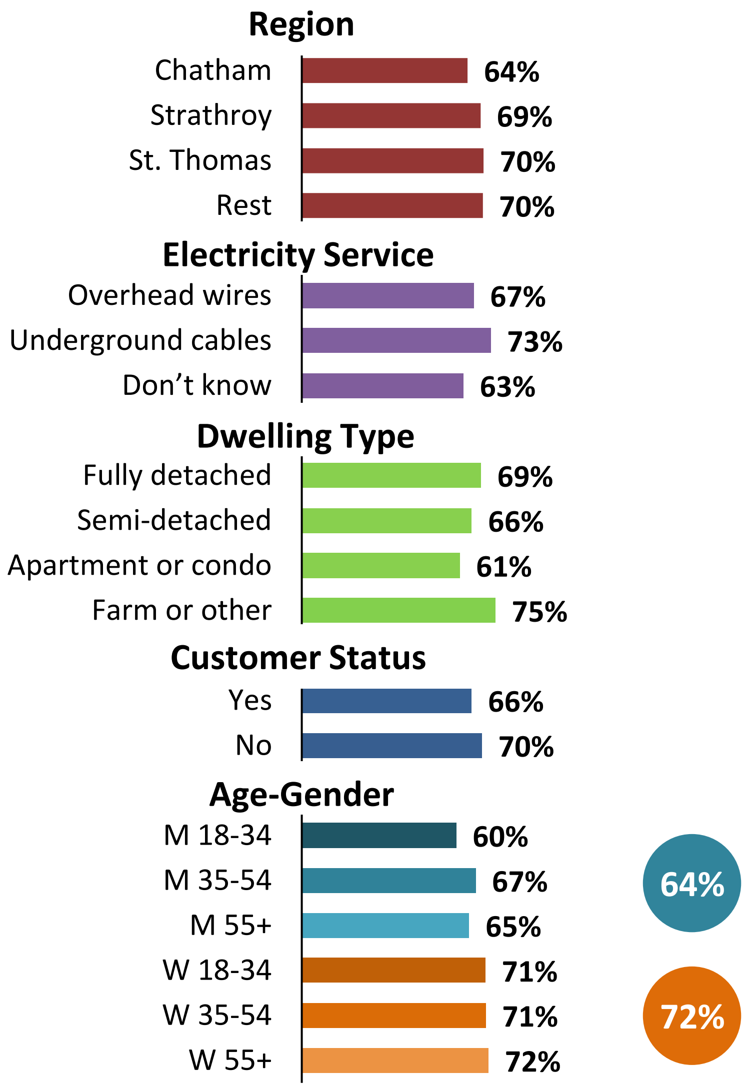
Most (68%) say '10 meters or more', higher among women than men

Q How closely do you believe you can safely come to a downed overhead power line, such as a downed line caused by a storm or accident?
[asked of all respondents, n=603]



2024 Segmentation

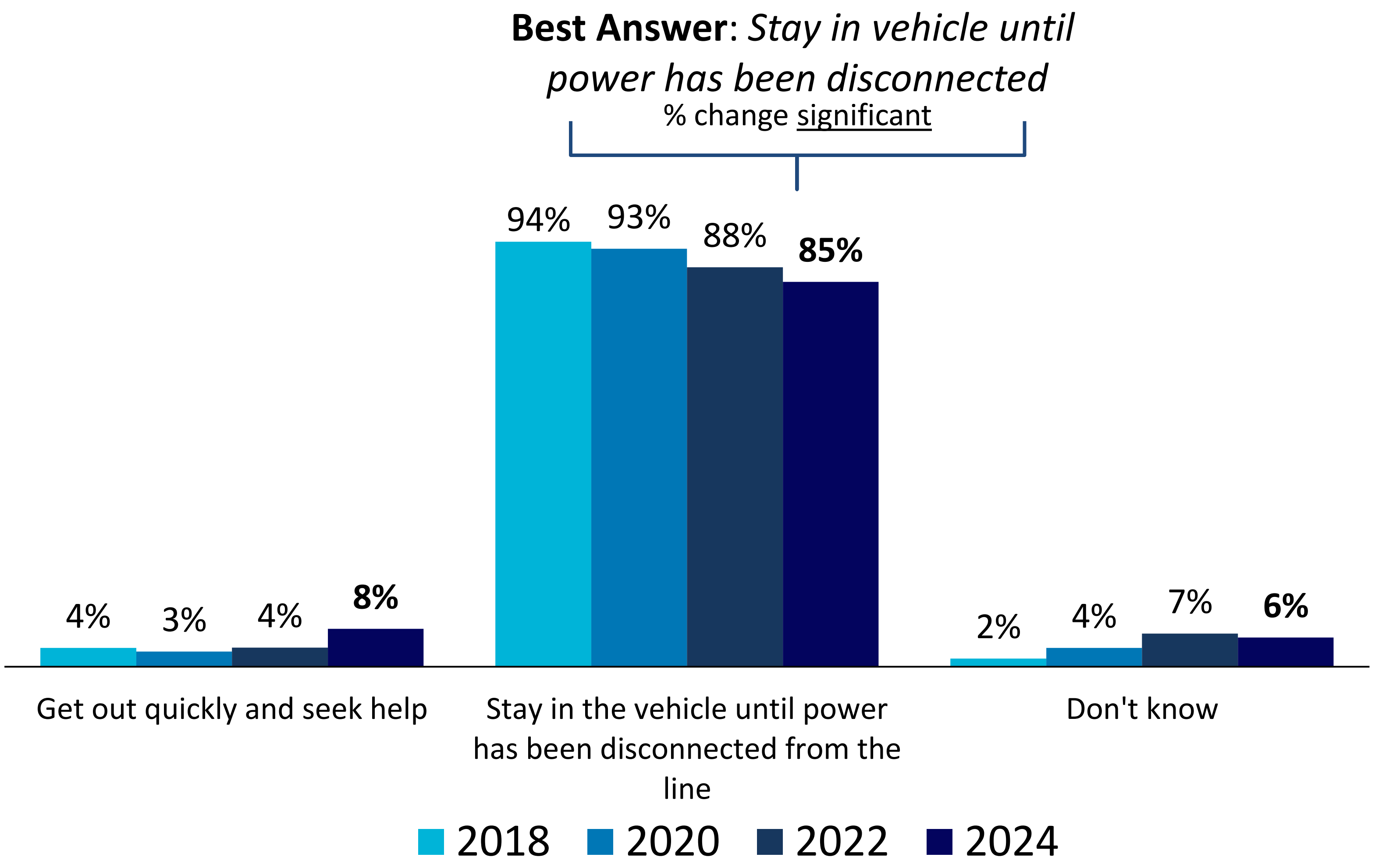
Respondents who say "10m+":



Actions Taken in Vehicle in Contact with Wires

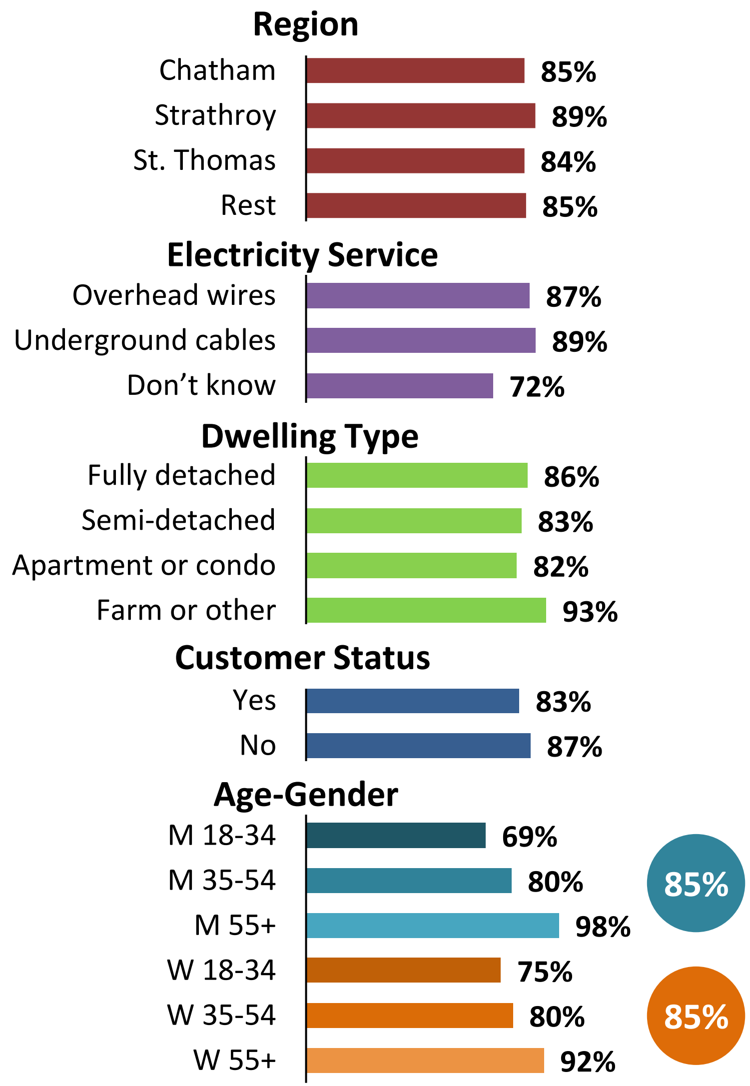
Most (85%) say 'stay in vehicle', a 3-point drop since last wave

Q If you were in a vehicle – such as a car, bus, or truck – and an overhead power line came down on top of it, which of the following options do you believe is generally safer?
[asked of all respondents, n=603]



2024 Segmentation

Respondents who say "Stay in the vehicle":



Actions Taken by Age-Gender

Men 55+ are most likely to stay in the vehicle while younger men between 18-34 are less likely to do so

Q If you were in a vehicle – such as a car, bus, or truck – and an overhead power line came down on top of it, which of the following options do you believe is generally safer?

[asked of all respondents, n=603]

Action Taken	Total	Men 18-34	Men 35-54	Men 55+	Women 18-34	Women 35-54	Women 55+
Get out quickly and seek help	**8%**	15%	13%	2%	14%	11%	4%
Best Answer: Stay in the vehicle until power has been disconnected from the line	**85%**	69%	80%	98%	75%	80%	92%
Don't know	**6%**	15%	7%	0%	11%	9%	4%

Overall Safety Awareness Score

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Calculating the Public Safety Awareness Index Score

Each answer to core safety awareness questions will be allocated points based on the accuracy of the response. Responses deemed "*Best Answer*" will be allocated 1 point, while lesser answers will be awarded progressively less points. Responses are then indexed to create a single comparable Public Safety Awareness Score.

All section points bound between 0 and 1

Likelihood to *call before you dig*	0 to 1pts
Impact of touching a power line	0 to 1pts
Proximity to overhead power line	0 to 1pts
Danger of tampering with electrical equipment	0 to 1pts
Proximity to downed power line	0 to 1pts
Actions taken in vehicle in contact with wires	0 to 1pts

Add all 6 section points among survey respondents

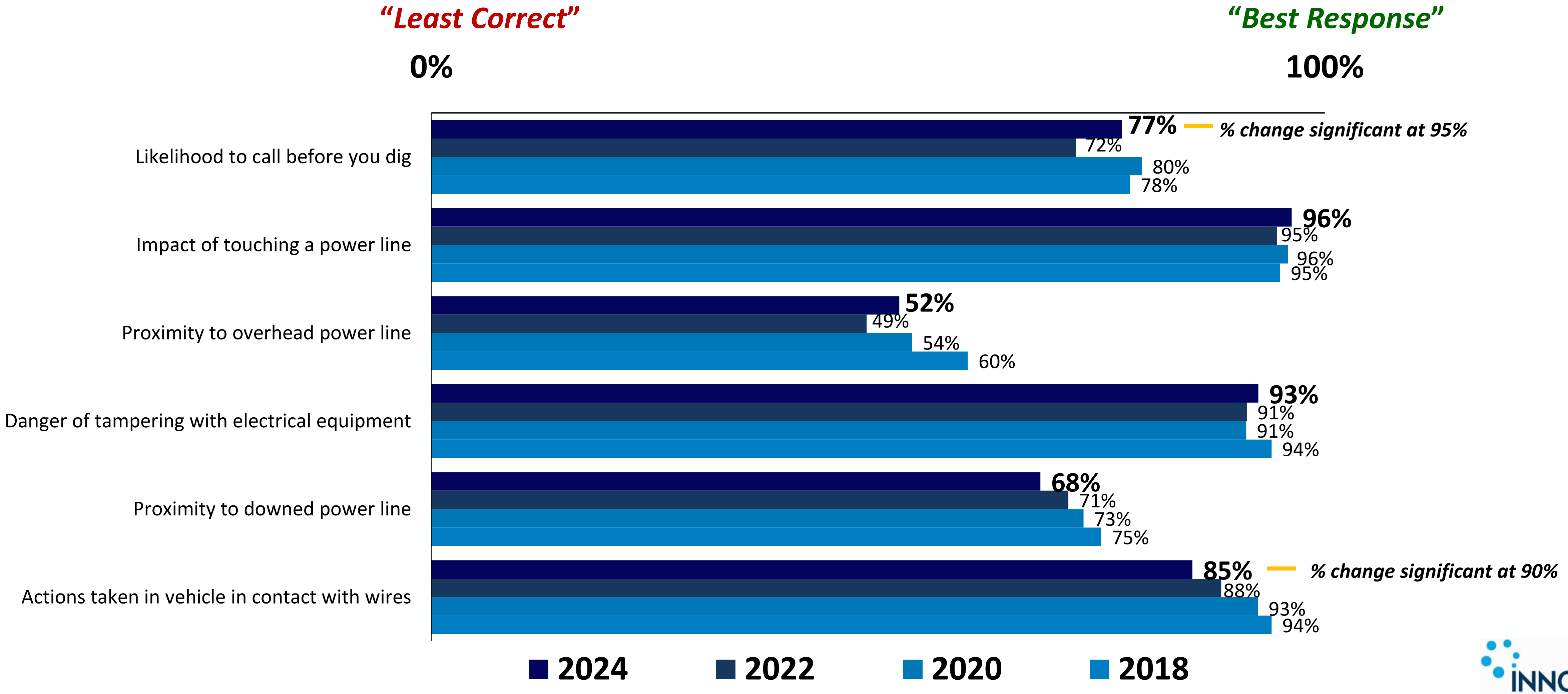
Divide score sections and survey sample size.

Multiply score by 100.

LDC Public Safety Awareness score bound between 0-100%

Calculating the Public Safety Awareness Index Score

Below are the individual index scores for each of the six core electrical safety questions. Each response has been rewarded a score between 0 and 1 based on what has been deemed the "best response".



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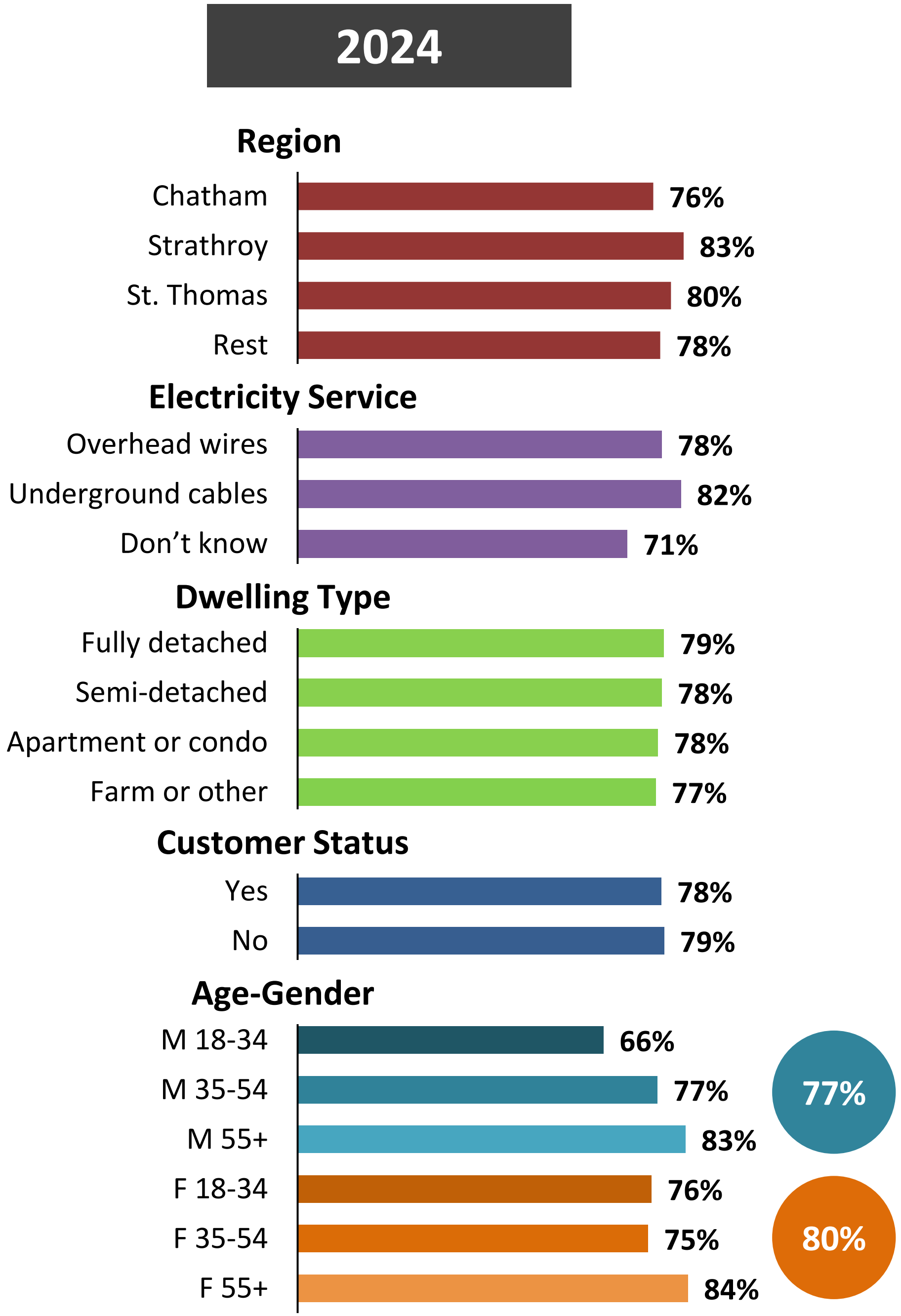
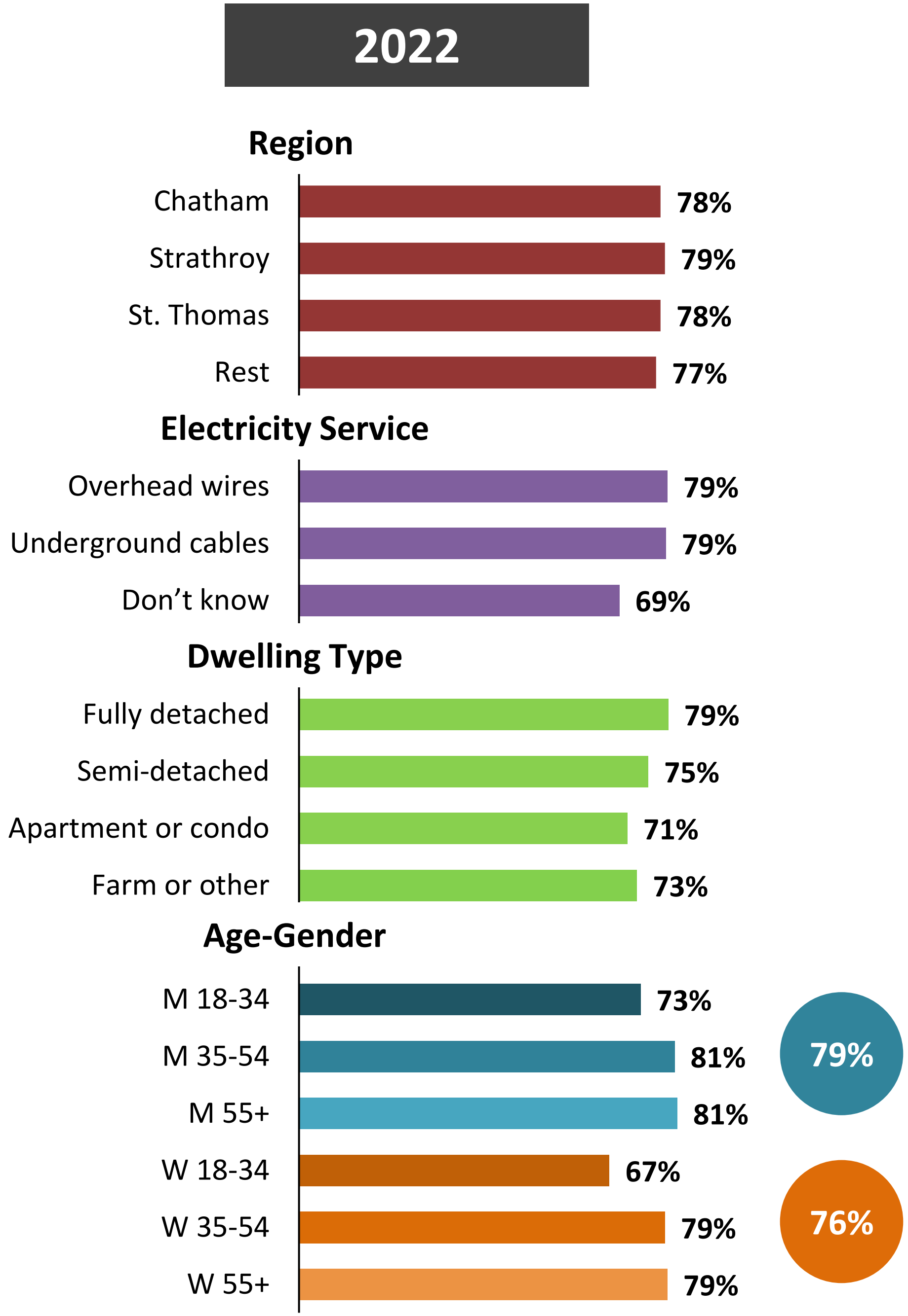
2024 Safety Awareness Score

79%

Historical Scores

78% in 2022
81% in 2020
83% in 2018





Campaign Recall

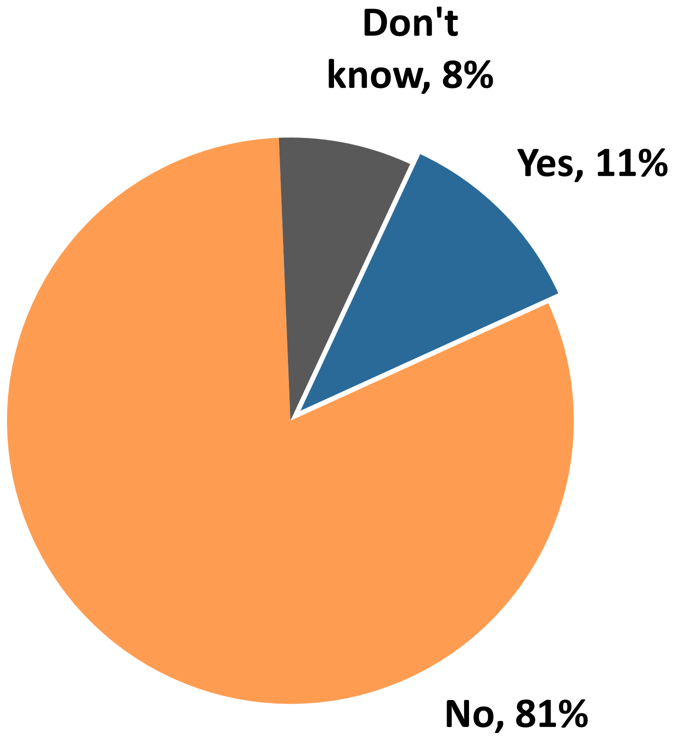
Read, Seen, Heard:

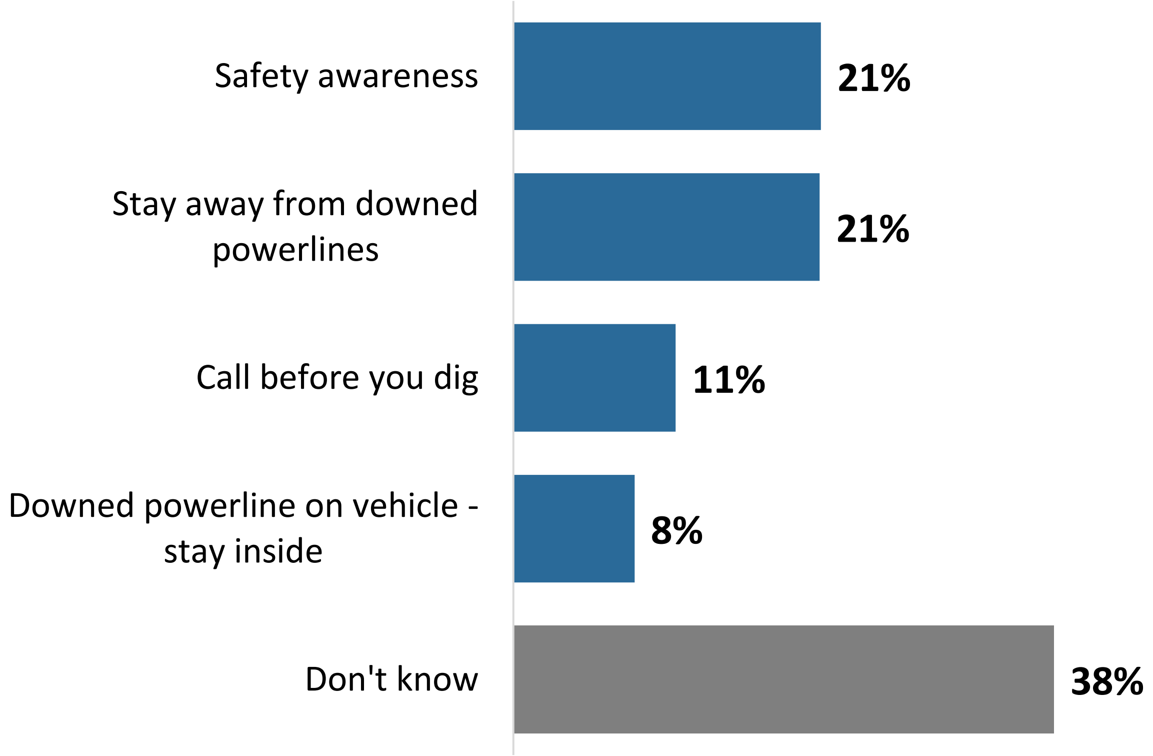
11% have RSH about electric safety campaign

Q Do you recall reading, hearing, or seeing anything about this electrical safety campaign?
[asked of all respondents; n=603]

Q … and being as specific as possible, what was the main message you recall about the Entegrus public safety advertising?
[follow-up question asked of those who have read, seen or heard, n=44]

Of the 11% who read, seen, or heard, 21% recall 'Safety awareness' and 'Stay away from downed powerlines'



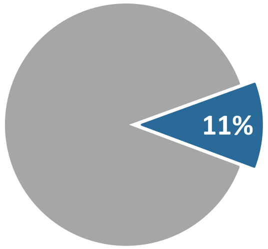


RHS Channels:

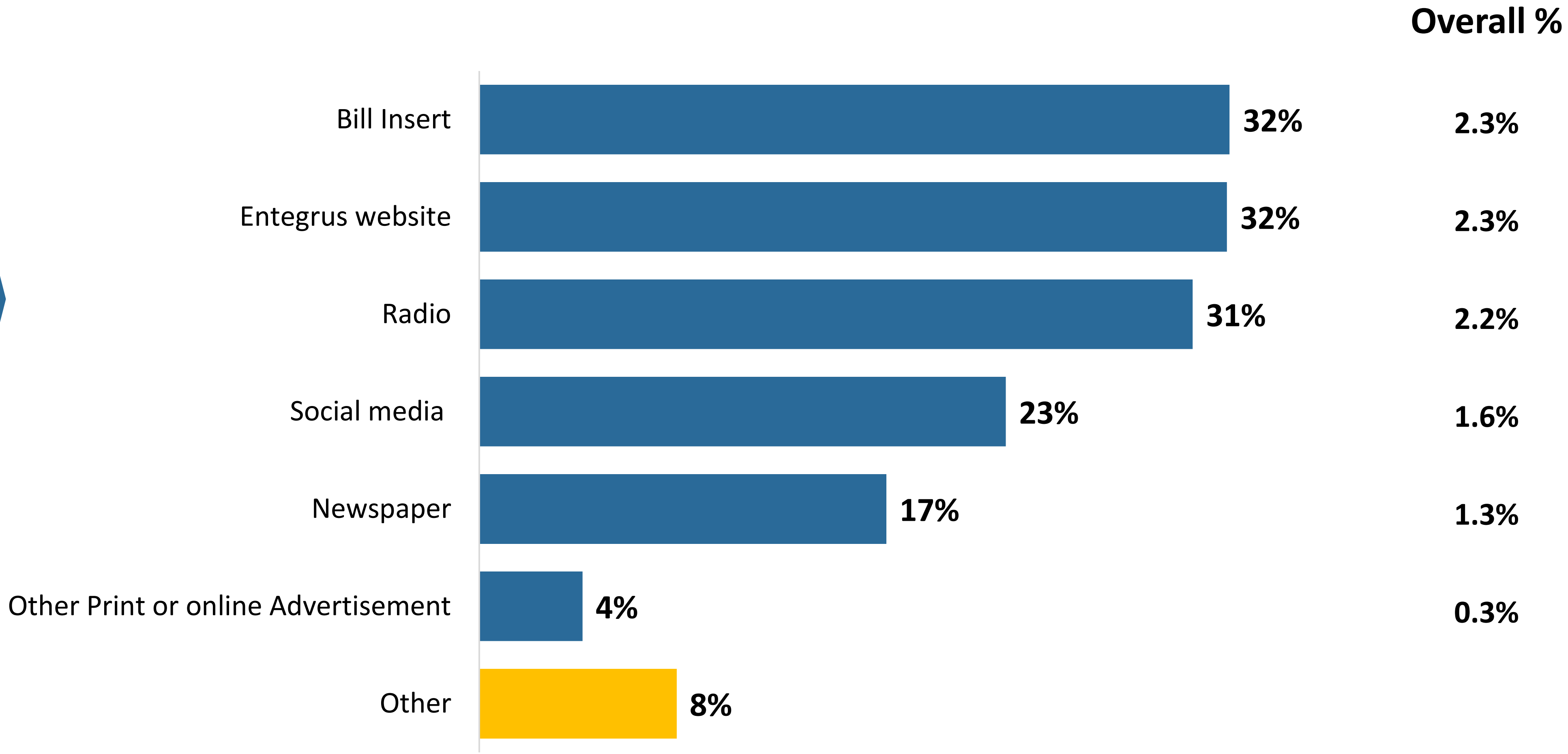
Of those who have RSH, top channels are bill insert, Entegrus website and radio

Q

Where did you recall reading, hearing, or seeing the Entegrus public safety advertising? Please select all that apply.
[follow-up question asked of those who have read, seen or heard, n=44]



Question asked only of all respondents who recall reading, seeing, or hearing information about electric safety.



Note: “Social media (X/Twitter, Facebook, Instagram, YouTube, LinkedIn)” is shortened to “Social media” for conciseness.
Chart total is greater than 100% as multiple mentions were accepted.

Energy Transition

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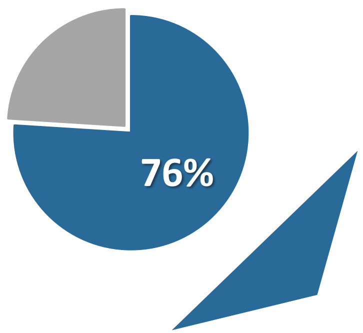
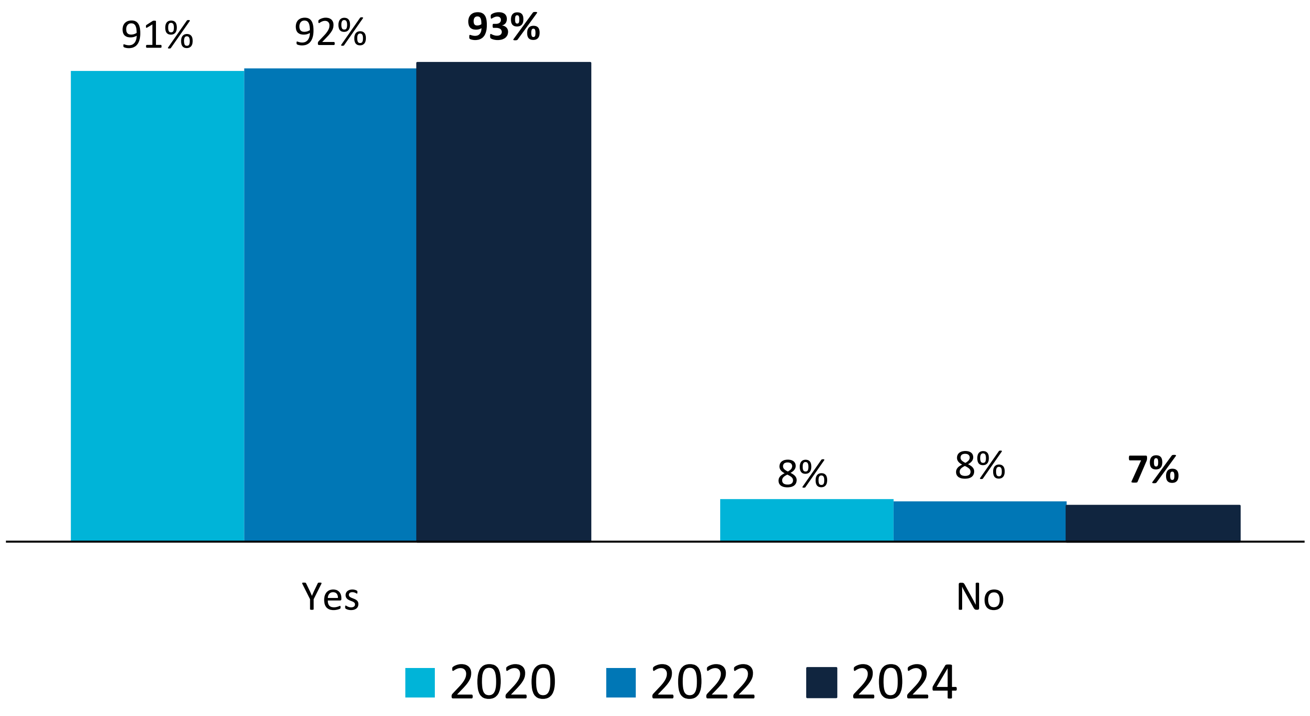
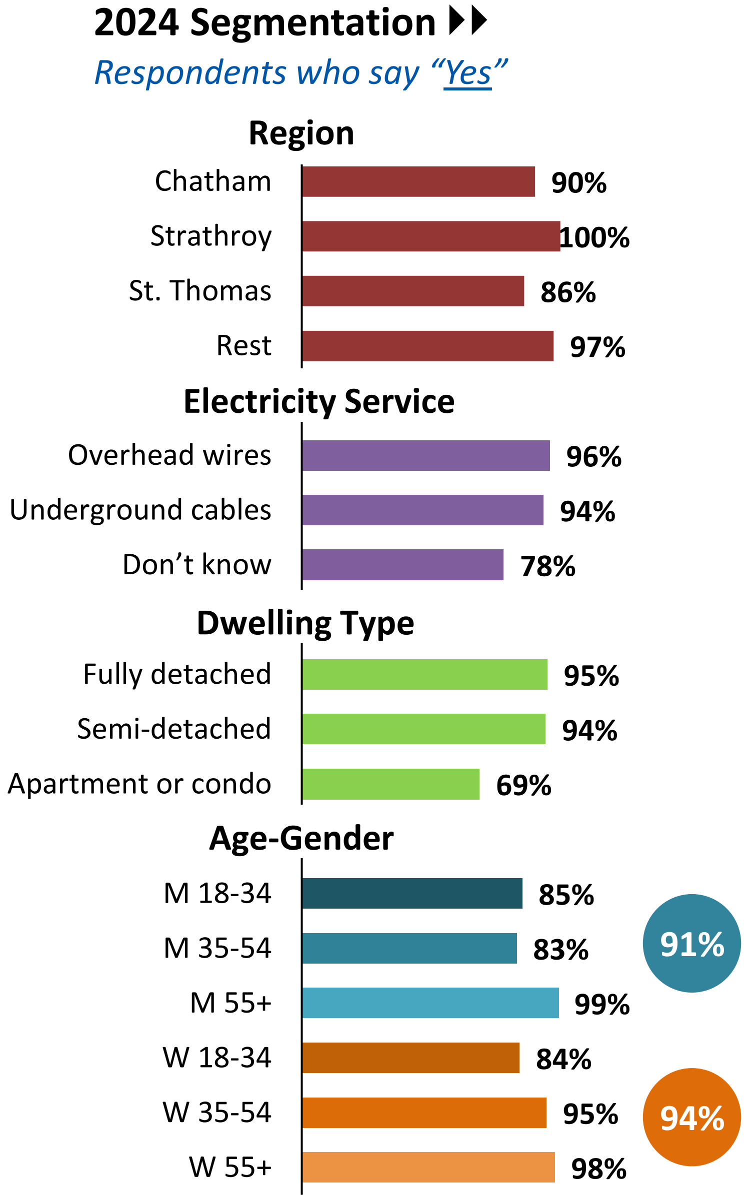
Own an Automobile

9-in-10 (93%) of Entegrus customers own or lease a vehicle; no change since 2022

Q Do you currently own or lease an automobile ?
[asked of all confirmed Entegrus customers; n=534]



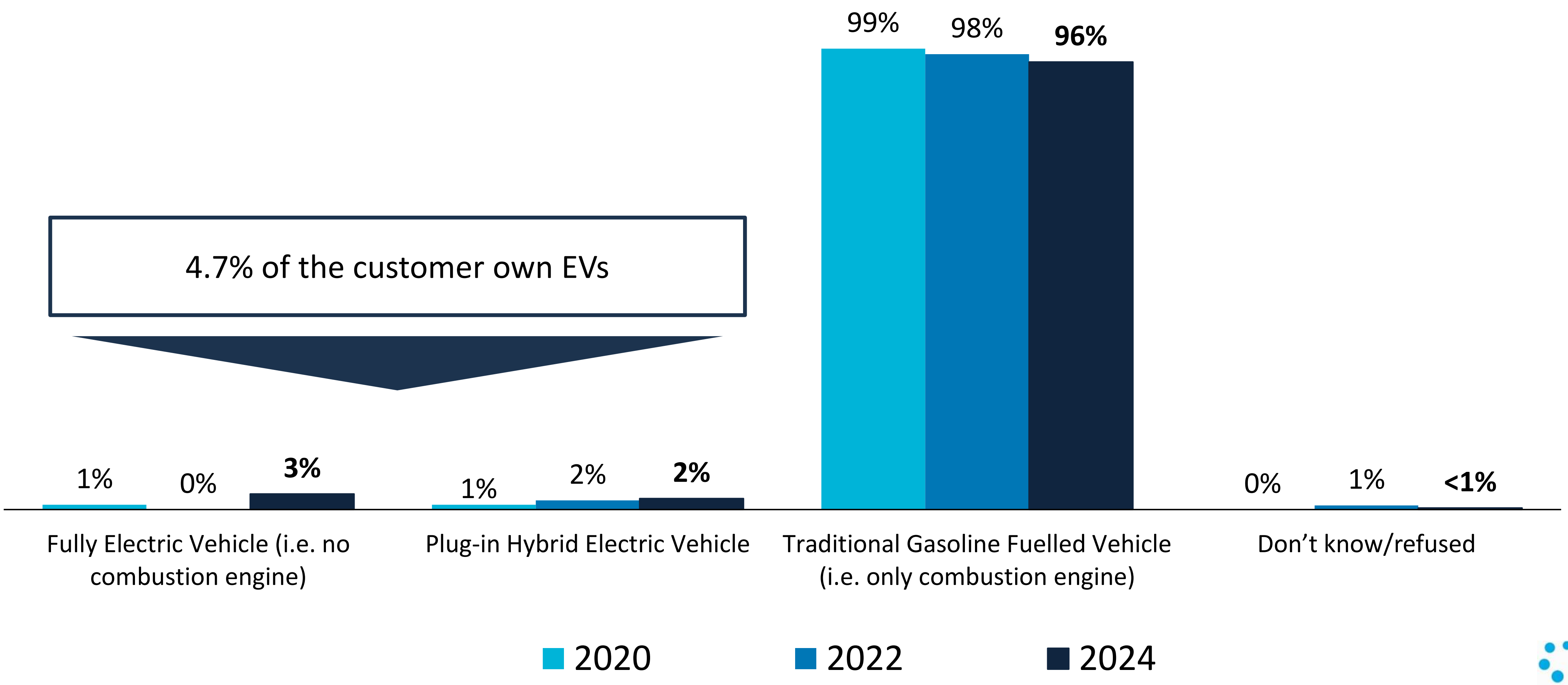




Type of Automobile

A slight drop since last year in terms of vehicle type; almost entirely combustion engines

Q And which of the following best describes the type of automobile or automobiles you currently own or lease?
[asked of confirmed Entegrus customers owning or leasing an automobile; n=496]



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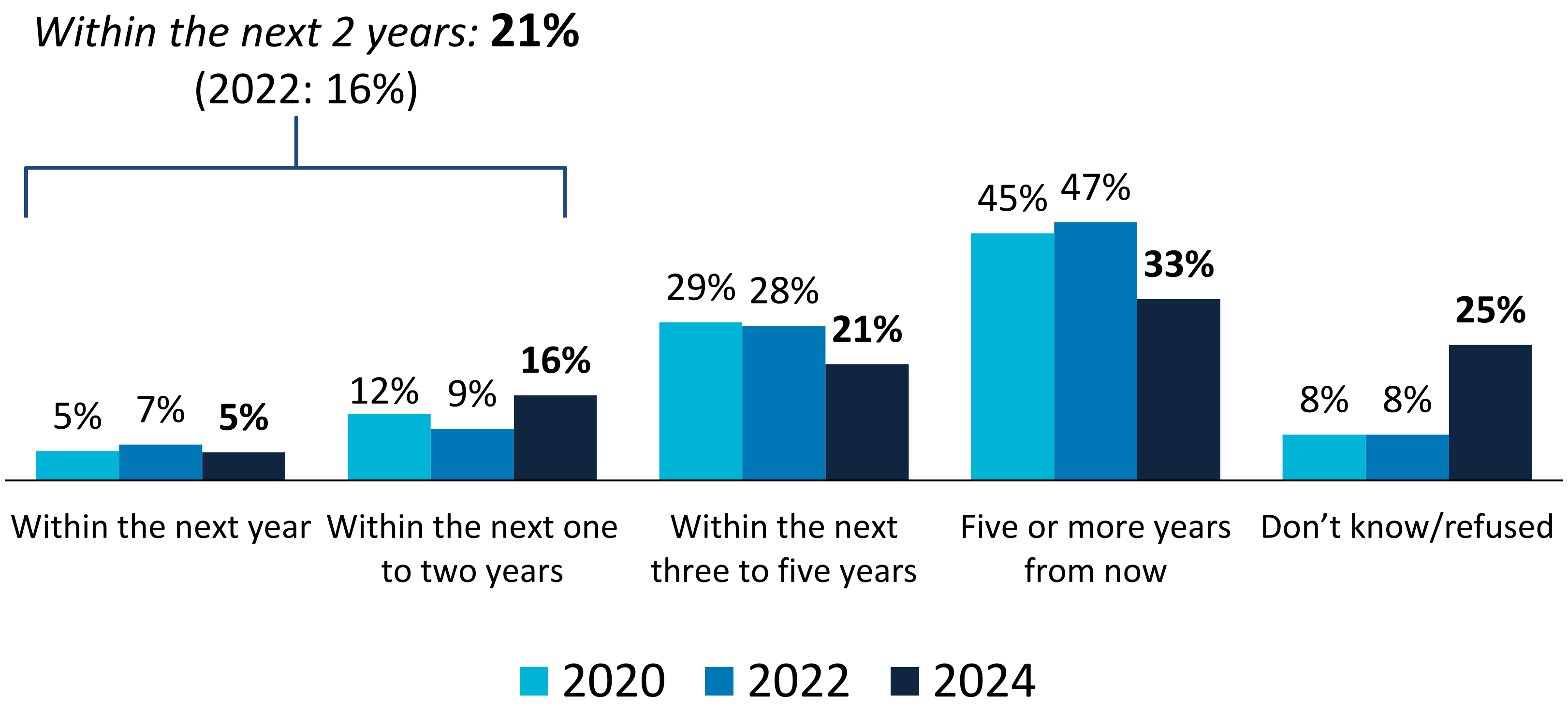
Replacement Timeframe

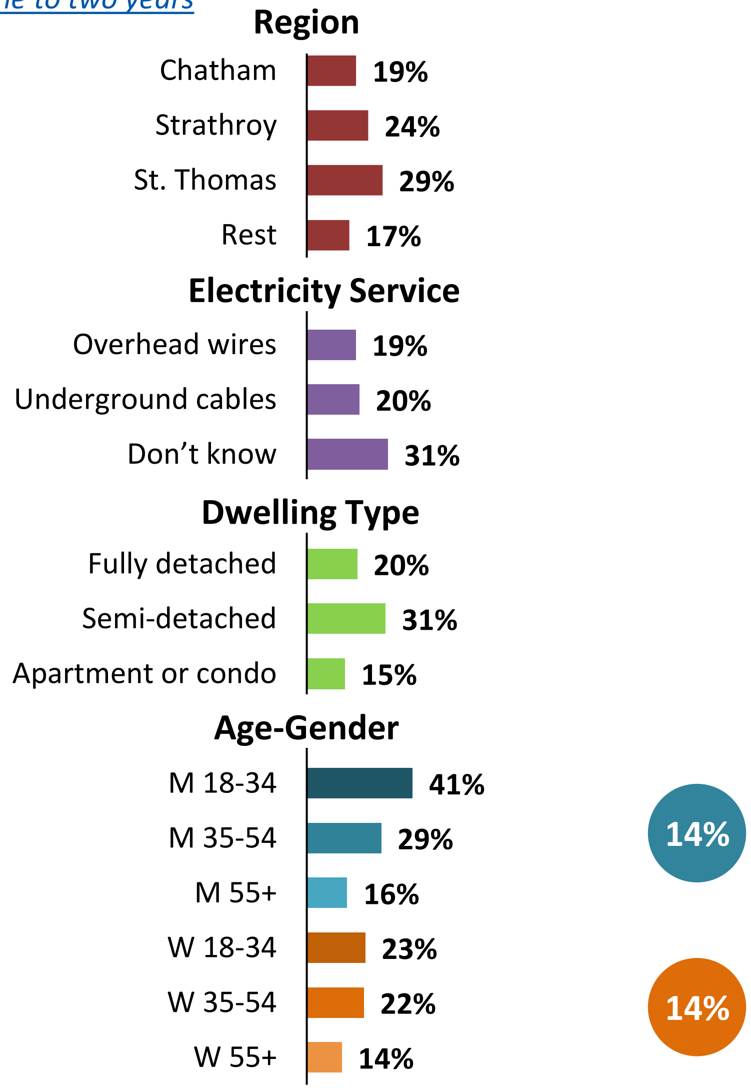
1-in-5 (21%) plan to replace existing vehicle; a 5-point increase since 2022

Q When do you anticipate replacing your current automobile?
[asked of confirmed Entegrus customers owning or leasing an automobile; n=496]



2024 Segmentation

Respondents who say "Within the next year" and "Within the next one to two years"



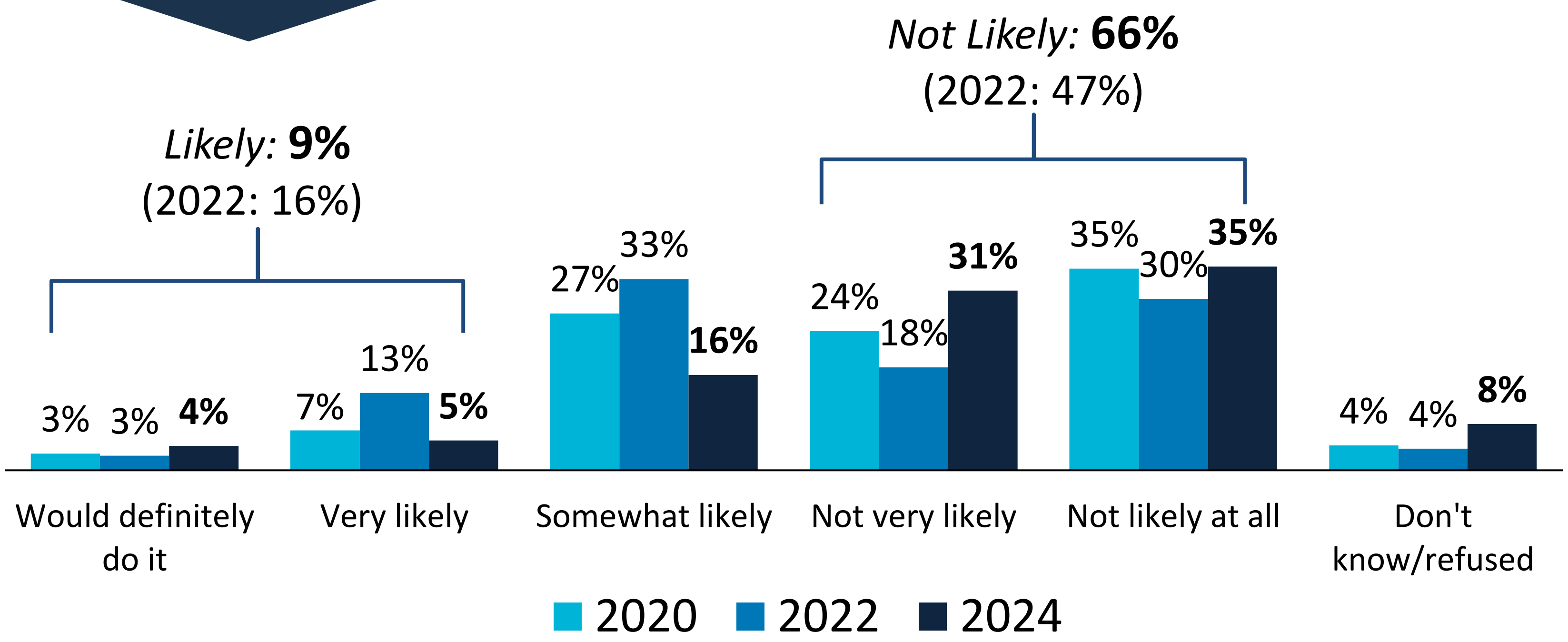
Likelihood to Choose an Electric Vehicle

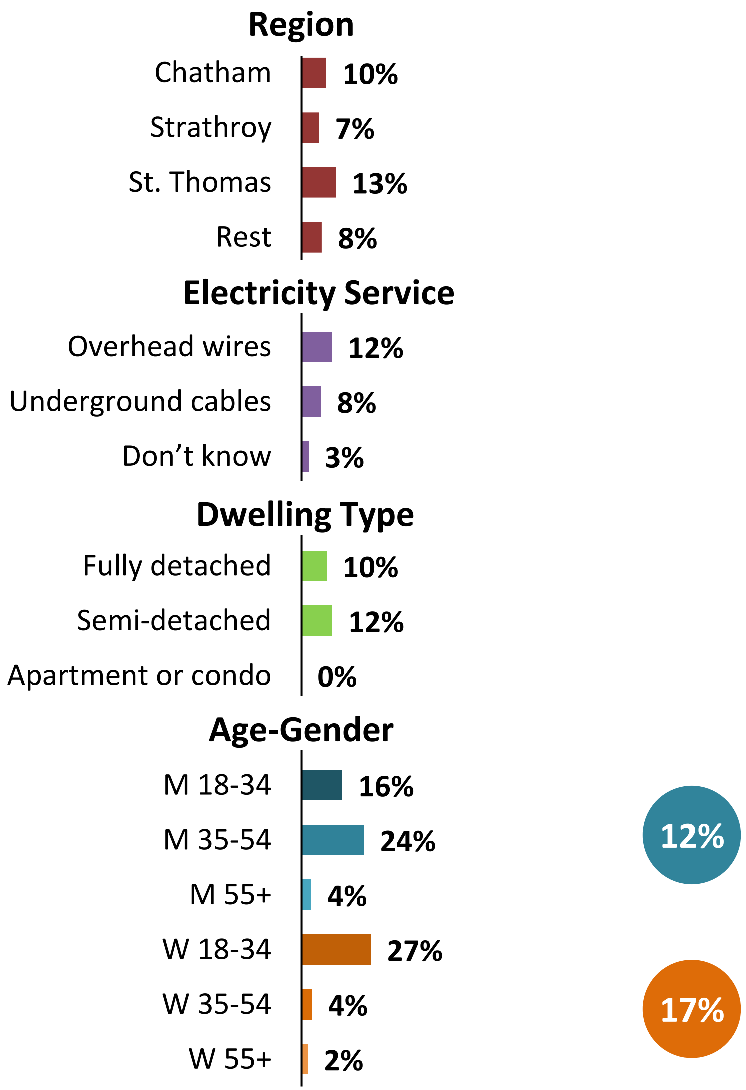
Only 9% say they're likely to buy an EV when it's time to replace their existing vehicle, a 7-pt drop since 2022

Q How likely would you say you are to buy or lease an electric car when it's time to replace your current one? Would you say…

[asked of confirmed Entegrus customers owning or leasing an automobile; n=496]

Estimated 8.3% EV adoption*





* **Note:** Estimated proportion of future EV owners calculated by taking the number of current EV owners and adding the number of current non-EV owners who say they are likely to buy an EV.

Proximity of Vehicle Replace by Likelihood to Buy Electric

Those who anticipate replacing their vehicle within a year are not likely (68%) to consider an EV

[asked of respondents owning or leasing an automobile; n=496]

How likely would you say you are to buy or lease an electric vehicle when it's time to replace your current one?	When do you anticipate replacing your current automobile? Within a year	1 to 2 years	3 to 5 years	5+ years	Don't know	TOTAL
	N=25*	N=77	N=106	N=165	N=123	N=496
Definitely/Very Likely	14%	14%	13%	8%	4%	**9%**
Somewhat likely	6%	17%	19%	22%	8%	**16%**
Not very likely	12%	42%	33%	27%	32%	**31%**
Not likely at all	68%	19%	29%	37%	41%	**35%**
Don't know	0%	8%	5%	6%	15%	**8%**

Note: Interpret the results with caution due to small sample size.

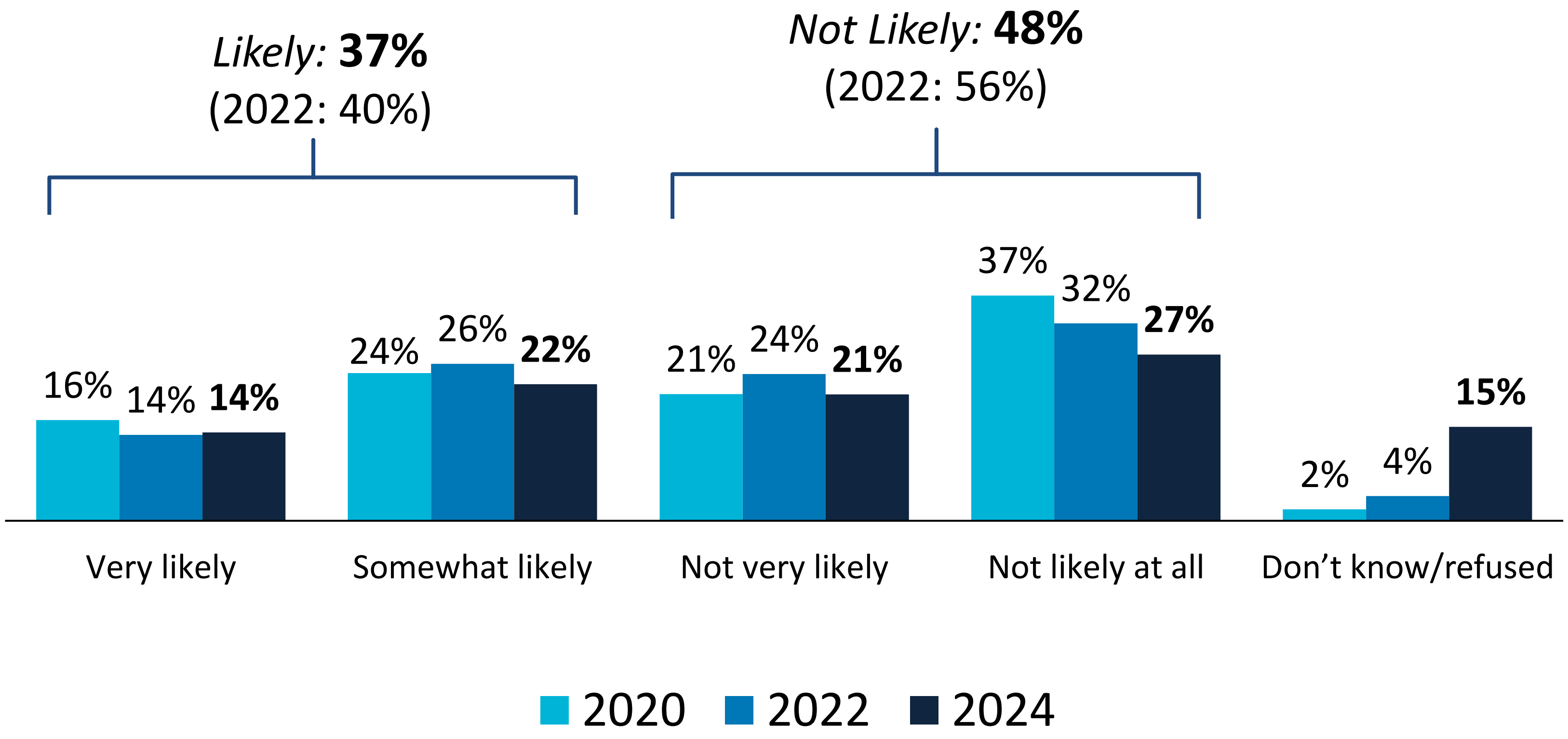
Entegrus a trusted source of advice and information on EVs

2-in-5 (37%) are likely to seek Entegrus' advice; higher among men 55+ (50%) and women 18-34 (46%).

Q

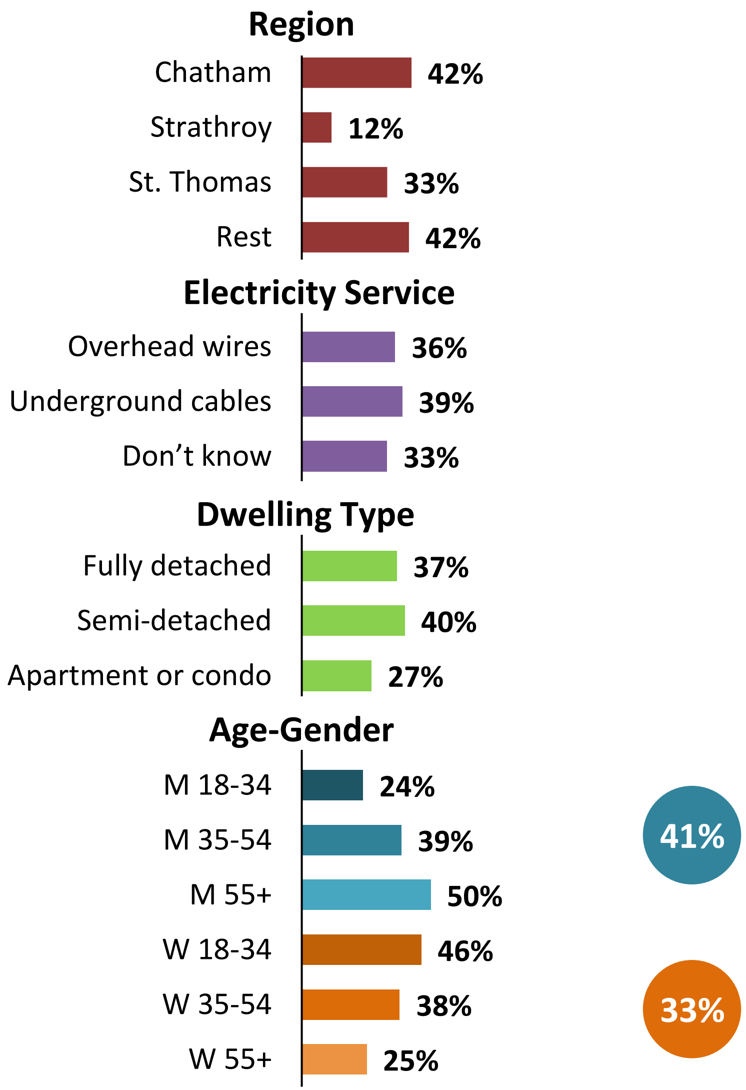
Imagine you were looking for advice or information on making the transition to an electric vehicle. How likely would you be to turn to Entegrus for information and advice? Would you say…

[asked of all confirmed Entegrus customers; n=534]



2024 Segmentation

Respondents who say "Likely"

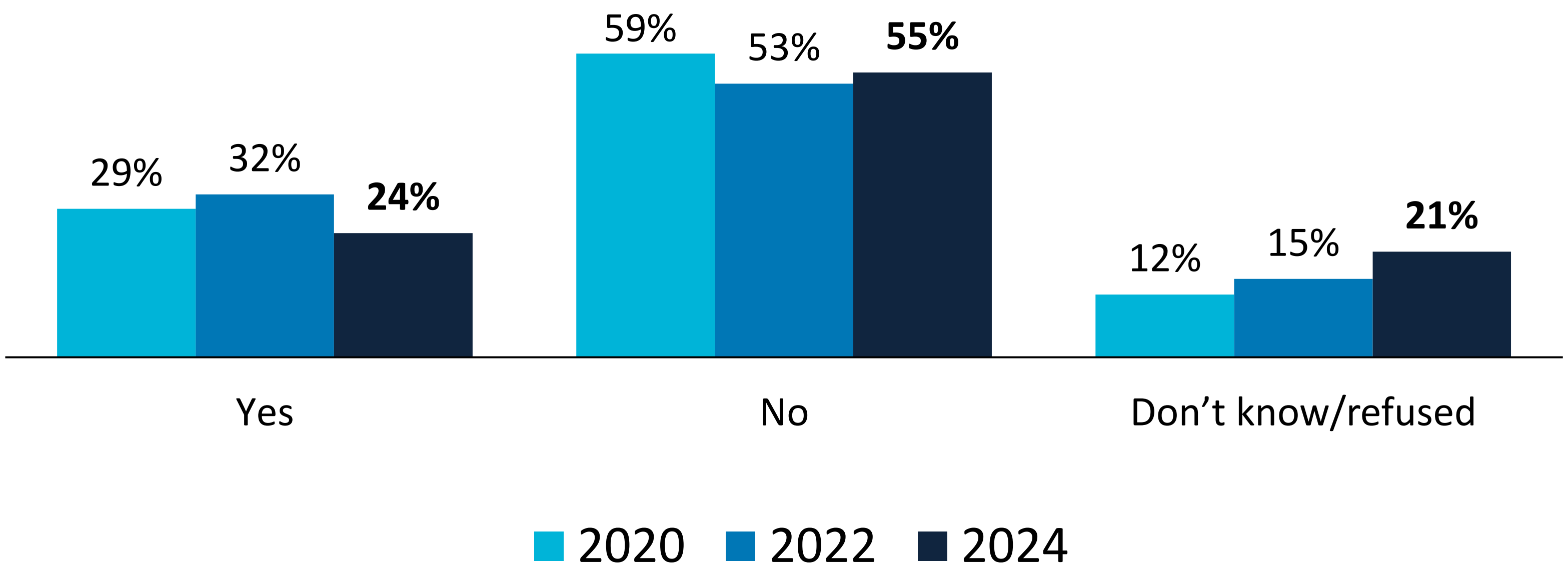


Possibility of Self-Generation

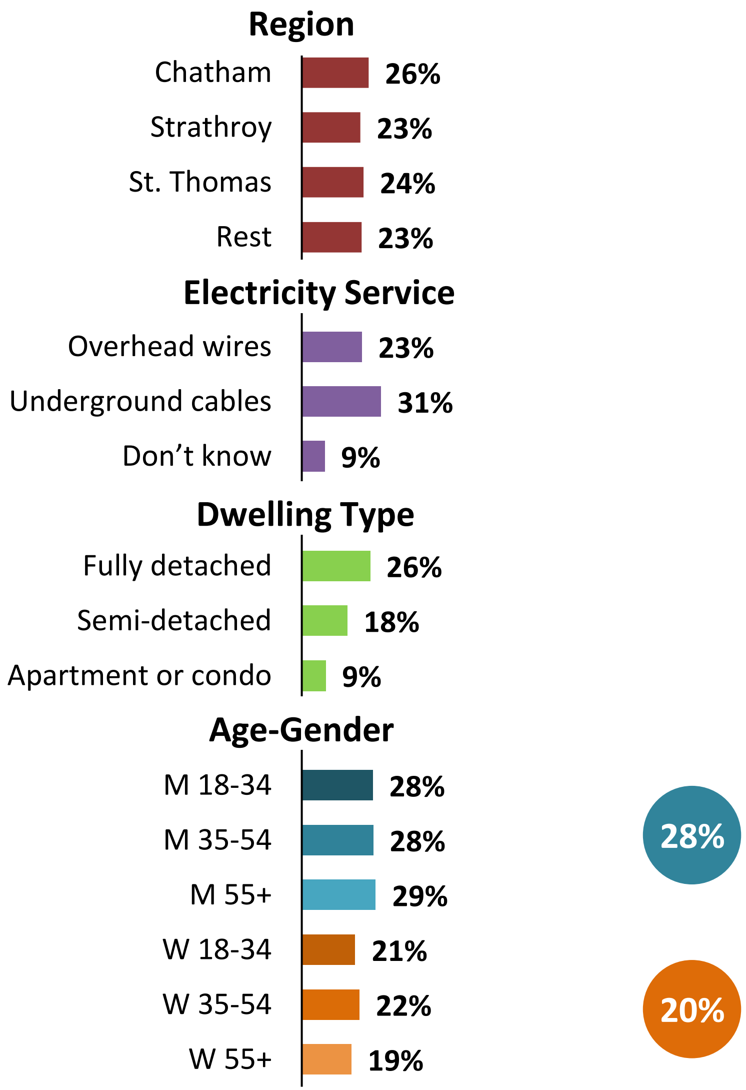
Only a quarter (24%) of customers think they would be able to self-generate electricity at home

Q

Does your current housing situation allow you to invest in technology to self-generate electricity?
[asked of all confirmed Entegrus customers; n=534]



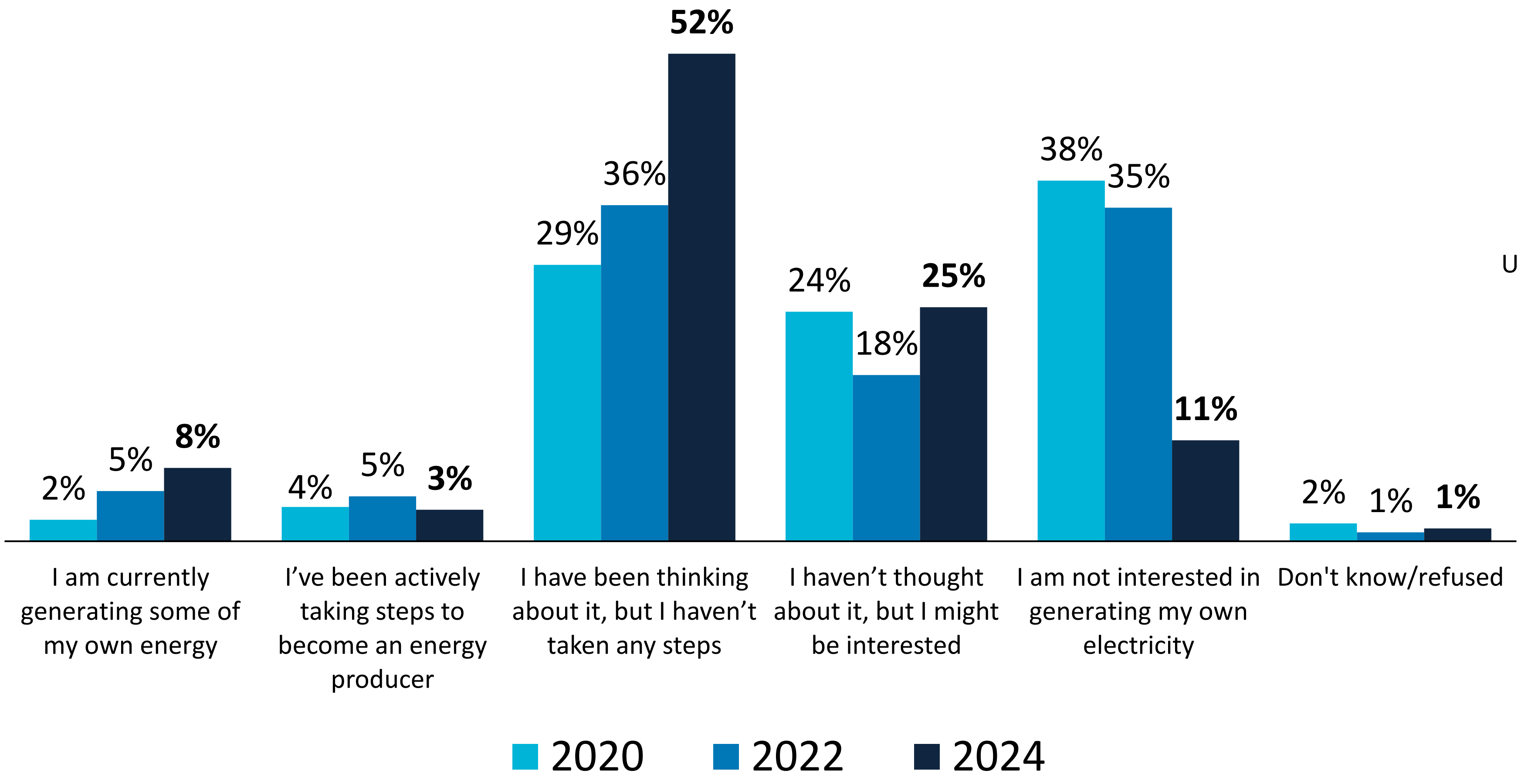
2024 Segmentation
Respondents who say "Yes"



Interest in Self-Generation

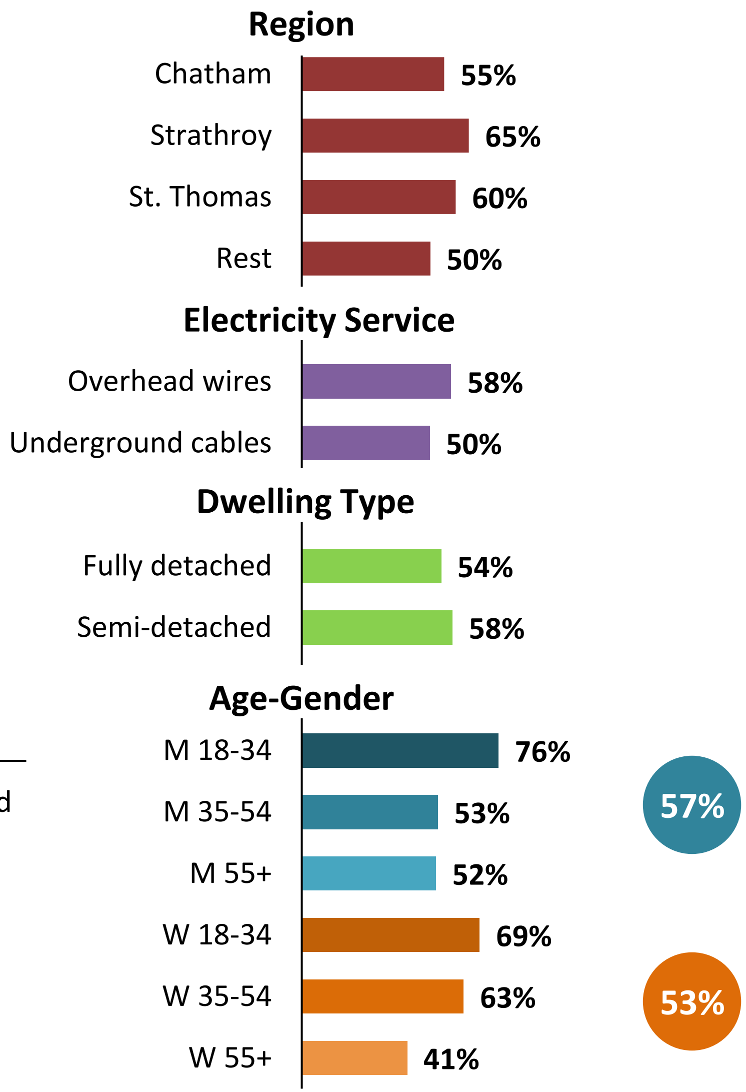
For those who can self-generate, interest in solutions is now top-of-mind for a majority of these customers

Q How would you describe your interest in generating energy yourself? Would you say…
[asked of confirmed Entegrus customers whose current situation allows for self-generation; n=129]



2024 Segmentation

Respondents who say "Interested"

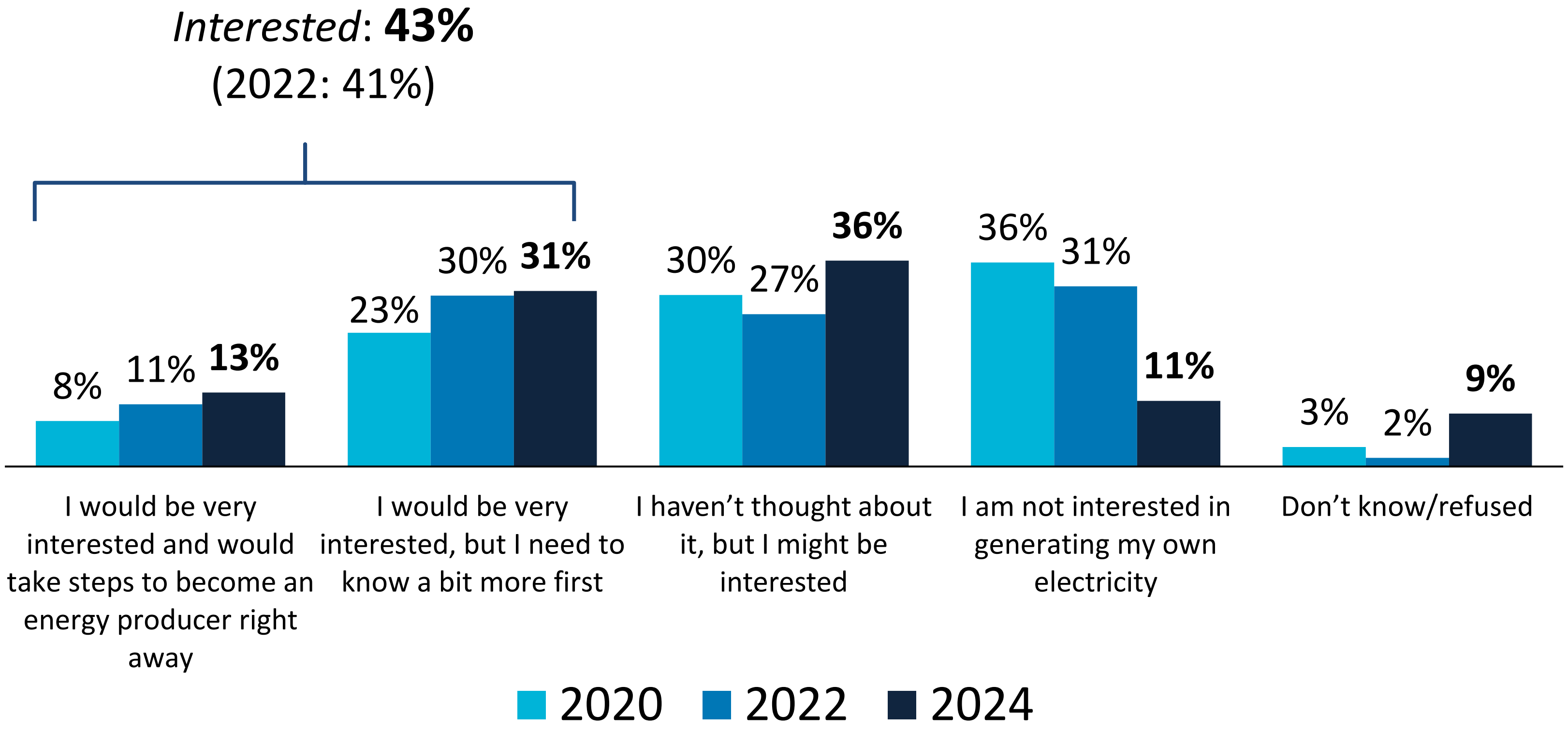


Future Interest in Self-Generation

2-in-5 (43%) of respondents express future interest, higher among participants between 18-54 than those 55+

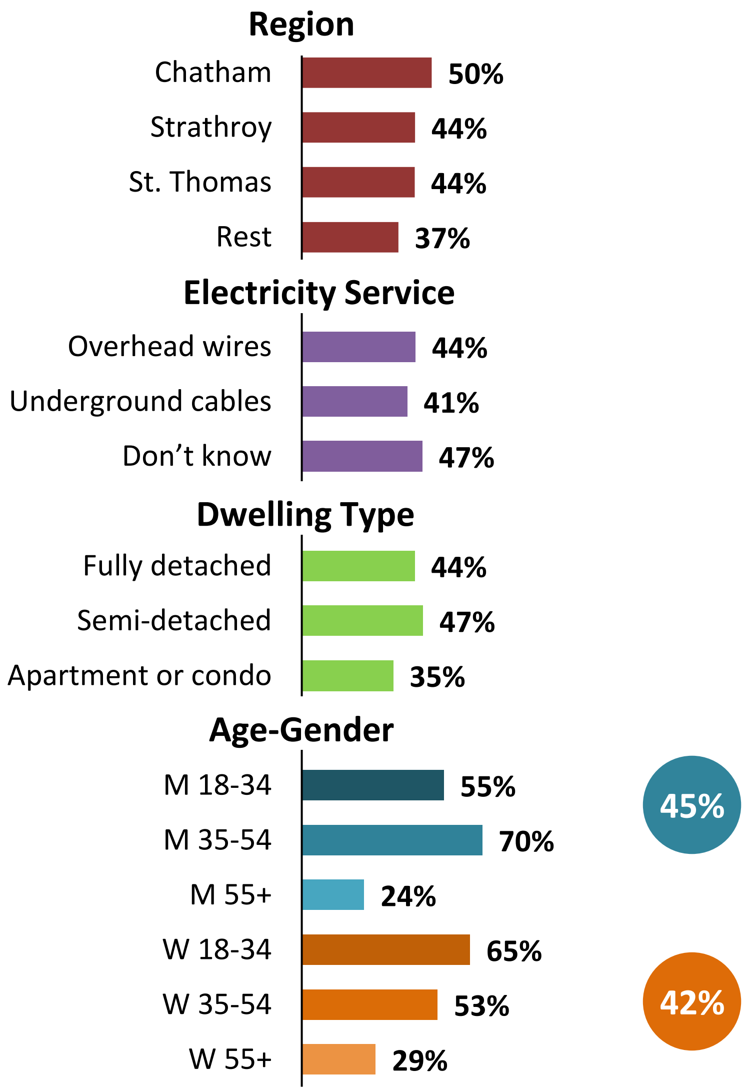
Q If, in the future, your housing situation would allow you to do it, how interested would you be in generating energy yourself? Would you say…

[asked of confirmed Entegrus customers who currently are not able to accommodate self-generation; n=405]



2024 Segmentation

Respondents who say "Interested"

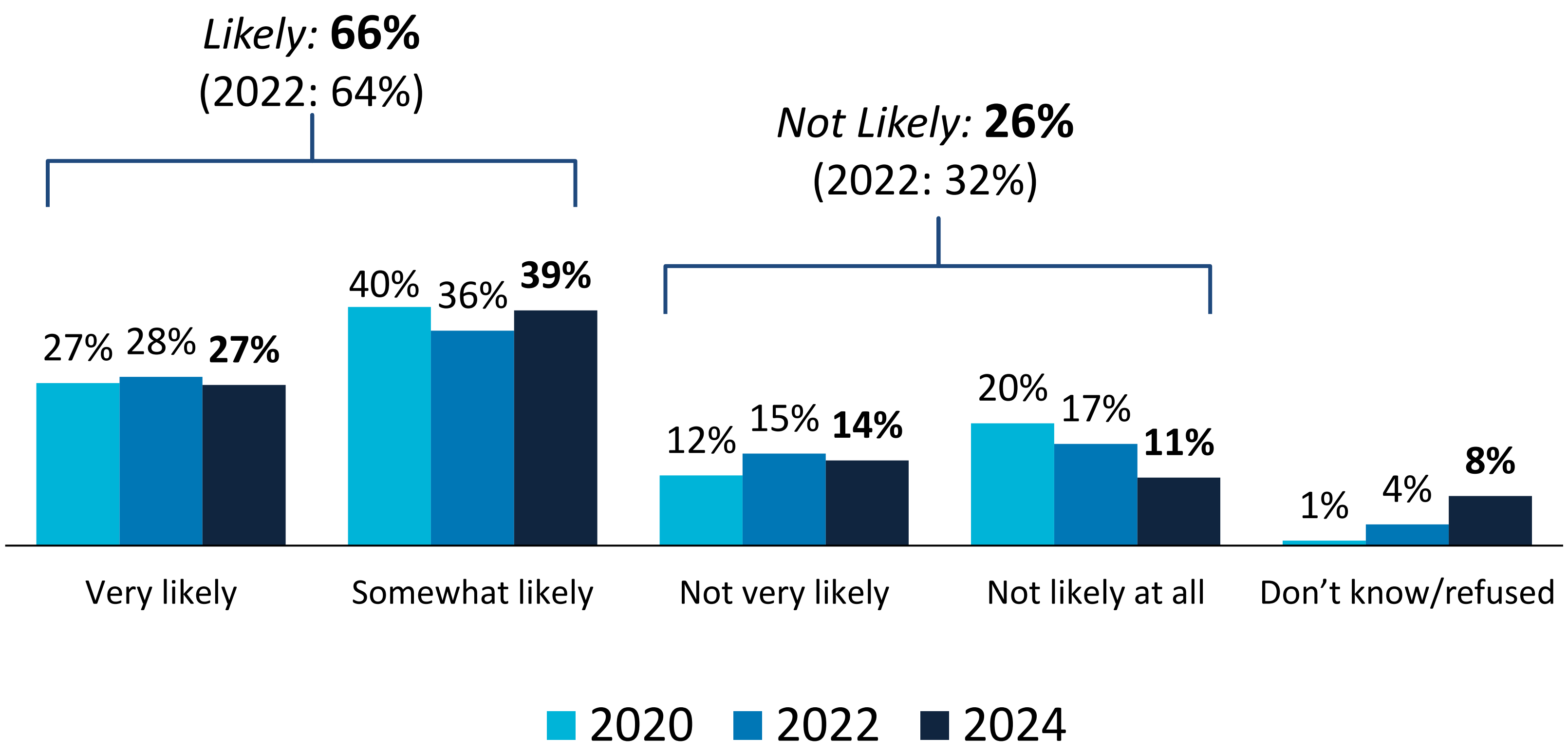


Entegrus Advice & Info

2-in-3 (66%) say they would turn to Entegrus if they needed advice or information on self-generation

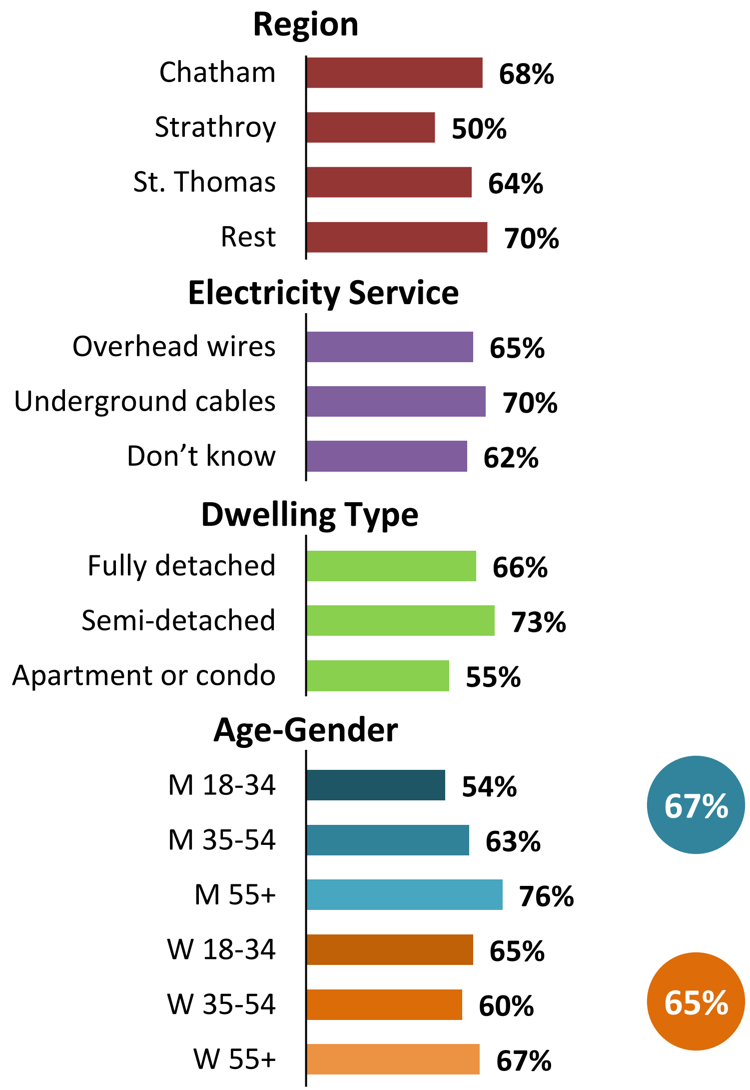
Q Again, imagine you were looking for advice or information on self-generating electricity, how likely would you be to turn to Entegrus for information and advice? Would you say…

[asked of all confirmed Entegrus customers; n=534]



2024 Segmentation

Respondents who say "Likely"

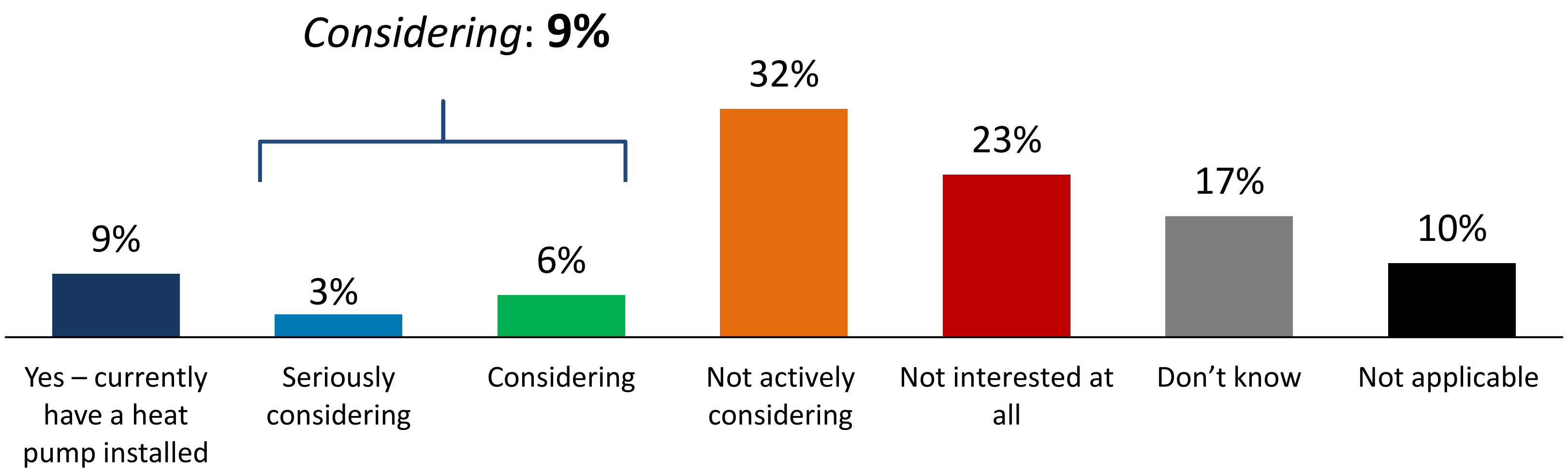


Heat Pump Ownership:

9% would consider installing a heat pump at their home, highest among St. Thomas residents (15%)

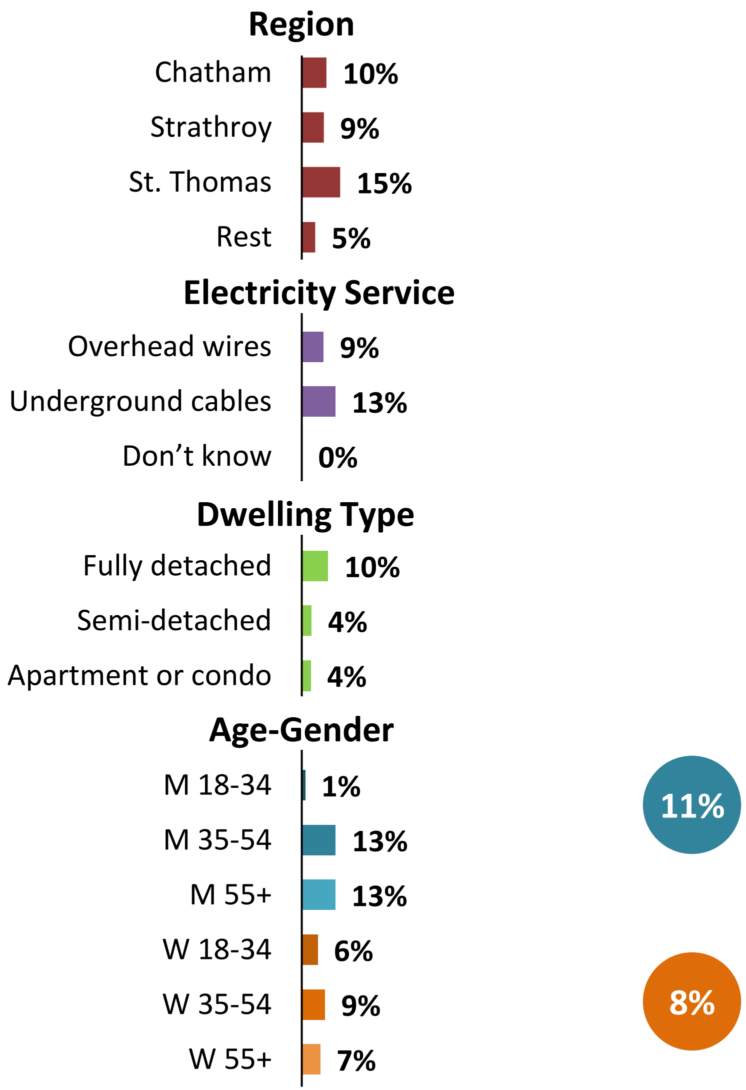
Q

Do you, or the owner of your primary residence, have a heat pump installed at your home? A heat pump uses electricity to provide both heating and cooling to a home or building and can replace traditional furnaces and air conditioners.
[asked of all confirmed Entegrus customers; n=534]



2024 Segmentation

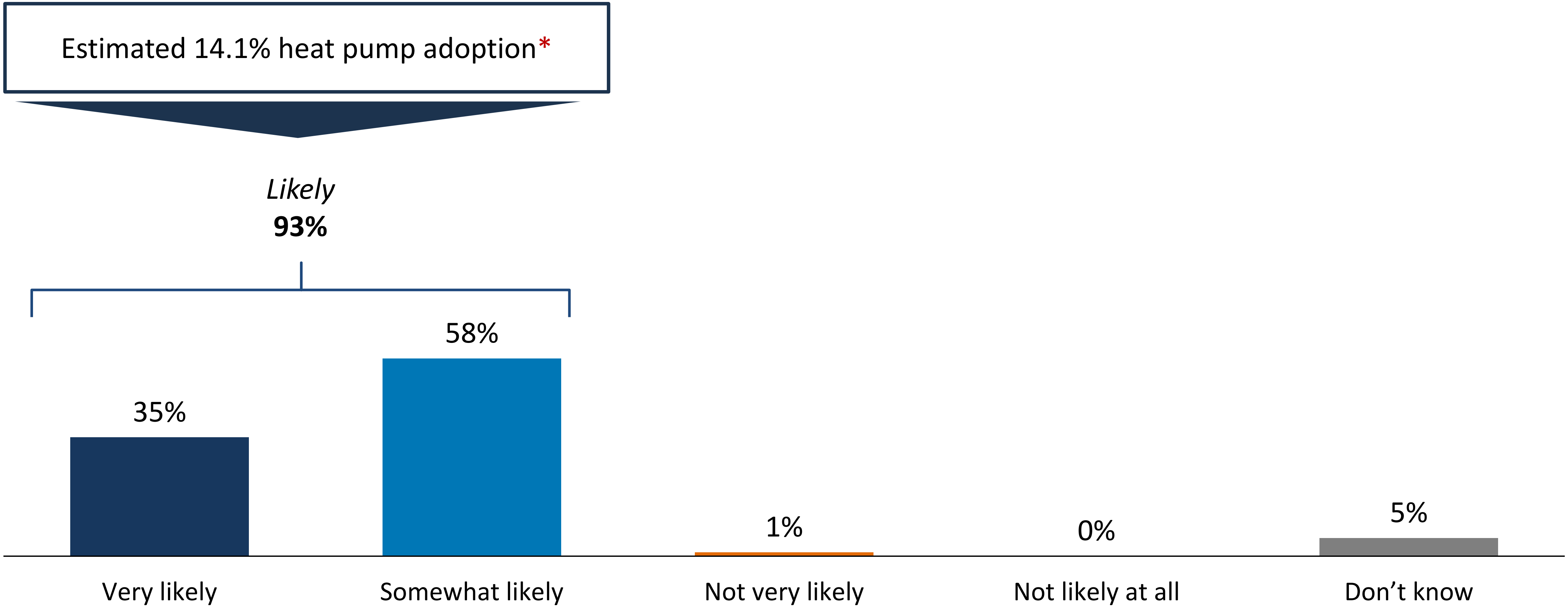
Respondents who say "Seriously considering" and "Considering"



Heat Pump Installation

Among the *small* number considering a heat pump, 93% are likely to install when it is time to replace existing HVAC

Q When it is time to replace your existing furnace/AC system, how likely are you to consider installing a heat pump?
[asked of confirmed Entegrus customers who currently are considering installing a heat pump; n=48]



* **Note:** Estimated proportion of future customers who will install the heat pump calculated by taking the number of current customers with a heat pump and adding the number of current customers without a heat pump who say they are likely to install a heat pump.

Key Findings: Energy Transition

Less than 1-in-20 (4.7%) Entregus customers currently own an EVs (fully EV or hybrid) … but an estimated 8.3% will own one in the (near) future.

- While 4.7% report currently owning a fully electric vehicle and/or a hybrid, 9% say that they are likely to buy one when it's time to buy a new vehicle.
- This means that an **estimated 8.3%** of Entegrus customers will own an electric vehicle in the "near" future (depending on when they buy or lease that next vehicle).
- While Entegrus might not be the first-place customer go to seek information on EVs, nearly 4-in-10 say they would seek some form of advice from the utility.

For those who can self-generate, interest in solutions is growing significantly.

- Only a **quarter (24%)** of customers think they would be able to self-generate electricity at home.
    - However, among this group, 8% say they are already generating power, and 55% are looking into potential solutions.
- While not everyone's current housing can accommodate self-generation, 43% of these customers express future interest, should their housing situation change.
- Unlike advice on EVs, 2-in-3 (66%) say they would turn to Entegrus for information on self-generation solution for their home.

While the number of heat pump "first adopters" is relatively high, future consideration among the rest of Entegrus' customer base remains relatively low.

- 1-in-10 (9%) of the customers currently claim to have a heat pump installed. But only another 9% would consider installing a heat pump at their home when it's time to replace their HVAC system.
- Estimated heat pump adoption among Entegrus customers in the coming years: **14.1%**

INNOVATIVE RESEARCH GROUP

Building Understanding.

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